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Transcript Exhibit(s)

Docket#(s): G-04204A-06-0463

G-04204A-06-0013

G-04204A-05-0831

Exhibit #: ACAA1-ACAA3, Mayes1,

Magruder1 - Magruder9

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BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER, CHAIRMAN
MIKE GLEASON, Commissioner
KRISTIN K. MAYES, Commissioner
WILLIAM MUNDELL, Commissioner
GARY PIERCE, Commissioner

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

DIRECT TESTIMONY OF ARIZONA COMMUNITY ACTION ASSOCIATION BY MIQUELLE SCHEIER.

Q. Please state your name and business address.

A. My name is Miquelle Scheier. My business address is 2625 N. King St. Flagstaff, AZ 86004-1884.

Q. By whom are you employed and what is your position?

A. I am employed by Coconino County Community Services Division and I am the Senior Manager for the Community Resource Division.

EXHIBIT
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ACAA-1
admitted

Q. Ms. Scheier, what is the purpose of your testimony in this proceeding?

A. I am testifying on behalf of the Arizona Community Action Association (ACAA) and low-income residential customers in the Unisource Gas (UES) service territory. I am testifying for several purposes: 1) to urge the Commission to hold low-income customers harmless in this rate case by increasing the R12 discount to an amount commensurate with any residential rate increase the Company may be awarded, and in particular to reject the Company's proposed structure for R12, which reduces the discount to larger, colder climate users; 2) to urge the Commission to increase the marketing of the R12 discount, including funding efforts by Community Action Agencies (CAAs) to reach target low-income customers; 3) to urge the Commission to require the automatic enrollment of LIHEAP eligible customers of record in the R12 discount rate program; 4) to urge the Commission to ask the Company to cease and desist in the practice of referring cash-paying customers to predatory lenders throughout their service territory, and to stop charging additional fees to do so; 5) request that the bill assistance money being made available by the Company be increased from the proposed $21,500 to $50,000 and be directed to the statewide non-profit Arizona fuel fund being created and managed by ACAA; 6) increase the Low-income Weatherization (LIW) funds, currently at $75,000, proposed to be increased to about $104,000 in fact be increased to $200,000 to expand the number of low income residential units that can be weatherized; 7) recommend the LIW funds allow for $20,000 in funding of community volunteer weatherization efforts by CAAs in the service area, thereby allowing them to leverage volunteer efforts, and 8) recommend the proposed reduction of the time between bill date and payment due date from 20 days to 10 days be flatly rejected.

Q. What is your position with ACAA and what has been your experience with low-income issues?

A. I am a member of the Board of Directors for ACAA, and serve as a member of the Executive Committee, a position I have held since 2004. Coconino County Community Services Division is one of ten designated Community Action Agencies in Arizona, and I have been employed with the County for 23 years. I lead the Community Resource

Division and provide the oversight for the Emergency Services programs which provide emergency and crisis services to eligible low-income, elderly, disabled and vulnerable persons; develop collaborations with community agencies throughout Coconino County to provide comprehensive crisis management, and ensure positive working relationships with community agencies and organizations. I direct the planning, development, implementation, administration and evaluation of multiple public programs and activities designed to assist and support our low-income, elderly and disabled populations to move through crisis toward stabilization and self-sufficiency. I supervise and direct senior management, prepare and manage our division budget including grant preparation and negotiation of contracts with various local, state and federal entities. I advocate for our vulnerable populations to ensure equitable and fair treatment by public and private agencies to the populations we serve. The mission of our department is to promote healthy and vital communities throughout Coconino County and to create innovative and effective programs that measurably meet the needs of the low-income, elderly and disabled residents of Coconino County by promoting independence and opportunities for success through coordinated community relationships.

Q. Please describe ACAA.

A. ACAA is a statewide organization of individuals, organizations and private sector members working together to find community based avenues of economic self-sufficiency for the almost 700,000 low-income Arizonans. There are 37 Community Action Programs (CAPs) throughout the State, serving every community. These agencies address self-sufficiency and the crisis needs of low-income individuals and families on a day-to-day basis in several ways: job counseling and training, homeless services, housing counseling and placement, energy assistance, home repair and weatherization, food assistance, senior centers, child care and in some cases Head Start programs. Community Action Agencies stand for the voiceless, the poor, the elderly and the disabled in our State, those who tend to become invisible in our communities, and we have done so for more than 40 years.

Arizona Community Action Association serves as the statewide association for all of the above-mentioned programs. ACAA is a non-partisan, private non-profit 501(c)(3) membership organization, governed by a 23 member Board of Directors. ACAA has developed a reputation throughout our history of providing credibility and factual data on the subject of poverty in Arizona. For example, ACAA conducted and completed the 2003 Arizona Poverty Report, a study on poverty in Arizona, the third such publication we have published since 1985.[1] These studies have been a result of quantitative and qualitative research, including community meetings held throughout the State, soliciting the views of people from diverse walks of life.

Q. What is ACAA's interest and involvement in utility issues?

A. Throughout the past 19 years, ACAA has worked cooperatively with Arizona's utility companies to develop public policies and programs that decrease the energy affordability gaps of low-income customers. An example of these cooperative efforts is the establishment of the Utility Repair Replacement and Deposit program by the Arizona State Legislature. This very successful program was the first of its kind in the nation and has been modeled by several other states since its inception in 1989. This fund now generates in excess of $1 million for low-income utility customers. This is but one example of where Community Action Programs and utilities combined their respective knowledge to find solutions targeted for lower-income customers.

Just as importantly, ACAA has actively engaged every major energy utility company in Arizona over the past 19 years, in full cooperation with the Arizona Corporation Commission, as those companies have proposed rate changes for their residential customers. As a result of ACAA's leadership, every utility company in Arizona has a low-income energy program of some sort, whether it be a discounted rate, bill assistance or weatherization program.

[1] Power in Arizona: Working Towards Solutions, ACAA, 2003

Q. What has ACAA's relationship been with Unisource Gas regarding low-income residential customers?

A. Representatives of ACAA, myself included, began meeting with representatives of UES prior to our intervention in this rate case, in order to learn more about the services offered through the company to the low-income community and customers. Additionally, Community Action Programs provide services using UES funds for bill assistance and weatherization. Meetings have also taken place with Company representatives to voice our concern about the practice of sending cash customers to predatory lending facilities in order to pay their UES utility bills.

Q. When you refer to low-income Arizonans, how many people are you talking about?

A. Poverty is a problem of increasing severity in Arizona. The total number of people living in poverty in Arizona is approximately 698,669 or 13.9%.[2] In the service territory served by UES, the numbers are as follows: Coconino County, 17.9% of the population or 21,619 people; Mohave County, 15.3% or 28,453 people; Navajo County, 29% or 30,796 people; Santa Cruz, 24.5% or 9,356 people; and in Yavapai County, 12.8% or 24,951. For all five counties served, there are at least 115,175 people living in poverty, an average of 19.9% of the population.

Q. Would you more fully describe what you mean by poverty?

A. The 698,669 individuals referenced above, are living at or below the federal poverty line, which means those individuals are earning $10,210 or less annually in 2007. For a family of three, the annual income is $17,170.

[2] Source: US Census Bureau, http://factfinder.census.gov

Q. What does this mean in real terms?

A. Arizona is seeing an increase in the numbers of working poor. We define the working poor as a family with an income of less than 200% of the federal poverty level. 200% may sound like quite a bit, but it actually only equates to $34,340 for a family of three. These families find it more and more difficult to make ends meet, and must constantly make choices about whether to pay the rent, buy food, clothe themselves, forego health insurance or pay their utility bills. Non-payment of utility bills is the second leading cause of homelessness, the first being the inability of an individual or family to pay their rent. These families are living pay check to pay check, without an opportunity to develop assets in order to protect themselves against unforeseen circumstances.

Q. What effects do rising utility rates have on Arizona's low-income population?

A. The issue of affordability has significant consequences for both the low-income ratepayer and utility company. Although low-income households tend to consume less total energy than the average household, the burden of energy bills, expressed as a percentage of income is considerably greater for those who have lower incomes. A study conducted by APPRISE in 2003, found that of the Low Income Home Energy Assistance Program (LIHEAP) eligible households in Arizona (LIHEAP has an eligibility of 150% of poverty), 44% had an energy burden of 10% or greater, 17% had an energy burden of 25% or greater.[3] For a family earning $17,170, this means they are paying approximately $4300 a year on their utilities, leaving them with $12,870 for everything else they need to survive, including housing, food, transportation, insurance, clothing and school supplies to name a few. Any savings that a low-income family might realize could be spent on necessities, and where appropriate, reducing past arrearages in their gas bills.

Throughout Arizona, 37 Community Action Programs (CAPs) operating more than 100 sites, assist approximately 29,000 households with LIHEAP. Fifty-seven percent of those served were living under 75% of the poverty level, 22% were seniors, 49% were

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[3] Source: APPRISE Inc. 2005 Energy Needs: Profile of Low Income Households – Phoenix and Arizona

disabled, and 19% were children. In 2003, the APPRISE study found that of 436,000 LIHEAP eligible households, 18,600 received assistance with their utility bills from LIHEAP. We can say that we are only serving 4% of the eligible households, which is devastating to our communities.

Q. **Why are utility bill assistance programs so important to ACAA and the low-income community?**

A. Often, LIHEAP or utility bill assistance is the only resource available for a family to stay warm in the winter and cool in the summer. Additionally when utility bills are paid through utility bill assistance programs, other money may be used to feed the family and eliminate or reduce other difficult choices a family must make. Recently, the Children's Sentinel Nutrition Assessment Program (C-SNAP), a national network of clinicians and public health specialists, conducted research that indicated that LIHEAP can positively affect children's health and development. "Compared with children in eligible households *not* receiving LIHEAP, children in households receiving LIHEAP experienced: decreased nutritional risk for growth problems; no evidence of increased obesity; and lower odds of acute hospitalization."[4] LIHEAP, and bill assistance programs that help bridge the gap that is not supported through LIHEAP, exerts strong influence on children's health and development.

Through day to day contact with low income utility consumers, Community Action Programs have learned that just paying past due utility bills for families is not the solution to the ongoing problem of unaffordable gas, electricity, water and basic housing needs, but it can mean the difference between good health and homelessness.

Q. **What experience do Community Action Agencies have in energy efficiency and weatherization?**

[4] Source: Children's Sentinel Nutrition Assessment Program "Federal Fuel Assistance Reduces Health Risks for Young Children," February 1, 2007

A. Arizona Community Action Agencies have extensive experience in operating and administering weatherization programs. Community Action Agencies have been operating the federal weatherization program since 1977 and are considered the "presumptive sponsors" of the weatherization assistance program at the local level. All sub-grantees are either non-profit organizations or units of general- purpose government such as a city or a county. The Community Action weatherization program missions are to reduce utility costs for low-income families, particularly for the elderly, people with disabilities and children by improving the energy efficiency of their homes and ensuring their health and safety.

Through more than 40 years of experience at Community Action Programs across the nation and in Arizona, we have learned that combining our philosophy of promoting family self-sufficiency with our belief in integration of services we can make the biggest inroads to long-term problem solving. Through the comprehensive delivery of resources to troubled households we have found we can have the biggest successes in terms of self-sufficiency. Community Action Programs have learned that by targeting the resources of the low-income weatherization program to LIHEAP recipients with the highest utility bills, a real difference can be made on a more permanent basis toward reducing continuing arrearage and shutoff problems.

In addition, when weatherization activities are leveraged with other private and public resources, an entire energy conservation package can be applied to a home, resulting in more cost effective and long-term energy savings.

Q. What services are considered to be weatherization services?

A. Weatherization includes: adding thermal insulation to the building envelope, usually attic insulation; adding programmable thermostats and providing instruction in their use; providing thermal film for windows, especially single pane units; shading sun exposed windows; implementing air leak control measures to reduce excessive infiltration of outside air; testing, tuning and maintaining heating and cooling equipment; reducing duct leakage where heating and central refrigerated air is distributed by a forced air system; and installing low-flow showerheads and other general energy and water efficiency measures.

Q. Is the amount being requested for weatherization services in this case adequate based upon community need?

A. No, it really isn't. $135,000 will weatherize approximately 56 homes, which is an increase from 37 homes previously funded. We believe a more realistic number of homes, in order to have an impact in the community and to realize significant savings, is 100 to 200 homes, which would cost $200,000 to $400,000 if $2000 is spent per home. A portion of these funds should be used to fund volunteer programs throughout the service territory, similar to the program Coconino County ran last year that enabled the volunteers to conduct energy education, install thermostats, and instruct the homeowner about the proper use of the thermostats. We would recommend the volunteer funding begin at approximately $20,000, with an evaluation by the program sponsors to determine effectiveness of these efforts.

Q. Are there any community benefits of the program?

A. Yes. The U.S. Department of Energy reports that for every dollar invested in the Program, weatherization returns $2.69 in energy and non-energy related benefits. Additionally, weatherization creates 52 direct jobs for every $1 million invested and on a national level, weatherization measures reduce energy demand by the equivalent of 18 million barrels of oil per year. Families realize an immediate gain, their energy bills average a 15% savings or approximately $274 per year depending on fuel prices. These are savings that a family can put to use immediately and that directly benefit the communities where the family lives and works.

Q. What is your concern about the Unisource rate increase?

A. We have a number of concerns. The low-income community is already struggling to pay utility bills. This increase would make the ability to maintain service even more difficult. We would request that rather than any increase being passed along to the low-income customers, those customers be held harmless and that the customers eligible for the R12 discount also be held harmless from any increases in the Throughput Adjuster Mechanism (TAM). Any additional charges will simply make it more difficult for these customers to maintain service, and will increase the number of disconnects the company will have to initiate.

At this point, based on data provided by the Company, the bad debt incurred by CARES customers (R12) is only 4% of the total bad debt for residential customers. Increases in the CARES rate will, we believe, cause this number to increase.

Another concern relates to the outreach done by the Company to enroll customers in the CARES program. At this time, there are approximately 5300 CARES rate payers. While we cannot provide a specific number of eligible customers, we know that with an average poverty rate of 19.9% in this service territory, this number should be much higher, closer to 28,000 based on a customer base of 142,206. Therefore, we ask the Commission to require an aggressive marketing/outreach campaign to the potentially eligible customers, informing them of the availability of the CARES program, as well as the Warm Spirits bill assistance and weatherization programs. We also ask that funds be allocated to CAA's to perform this marketing/outreach through the channels that have been established to the eligible customers encouraging sign-up under rate R12.

As we understand it, CARES customers will continue to be exempted from the PGA surcharge, which we support and appreciate.

An additional concern relates to the Warm Spirits program. While we applaud the existence of this program, and the participation by the UES customers who are currently contributing approximately $24,000, we would ask that the Company increase its corporate contribution. When first established, the Company contributed $50,000 to the program. After the first year the program became a dollar for dollar matching program, which actually reduced the Company's contribution, but also resulted in net loss of approximately $2000 to the program. ACAA asks that the Company increase its contribution to a minimum of $50,000 annually, while continuing to support the customer driven efforts. ACAA also volunteers to assist with outreach and efforts to inform the community if that would be helpful.

ACAA has been awarded a contract with the Department of Economic Security (DES) to establish a non-profit fuel fund in Arizona. This is the first warm weather fuel fund that is organized to leverage utility assistance and weatherization dollars in order to provide access to services statewide, including on tribal lands, but also to provide a mechanism for increasing the resources available to the low-income community in Arizona. ACAA asks the Commission to have UES deposit their annual commitment with the fuel fund, and thereby allow the support to their service community to grow and be efficiently managed with the other funds that are being used. It is entirely appropriate that funds raised by UES customers and contributed by UES be directed back to UES customers for support if that is preferred.

ACAA has purchased a software program that will demonstrate, using Company data, that the investment in bill assistance programs realizes a return on investment that is generally much greater than anticipated. In states throughout the Country, the return has been between, 40% - 500 %. If the members of the Commission would be interested in seeing this analytical tool, using UES' data, we would be happy to arrange for the demonstration.

Finally, we are concerned with the $20/month service charge being proposed. While this may result in a decrease for large users over 1200 therms per year, it represents a significant increase for smaller users such as apartment residents or single family units in warmer locations.

Q. You mentioned that you would be asking that Unisource Energy Services cease and desist from the practice of referring customers, specifically customers who wish or need to pay their bills in cash, to predatory lenders. Can you elaborate on this point?

A. Yes. Following the release of a Company press release letting the community know that Unisource would be closing many of their branch offices, ACAA learned that customers were being referred to a variety of locations throughout their service territory if customers needed to pay their bills in cash. The reasons set out in the press release were that the Company needed to realize cost savings, and there were safety concerns related to their staff working in branch offices. After doing some research, ACAA learned that UES is sending customers to predatory lenders, and in some instances, charging an additional fee for those customers who are paying their bills in cash.

This causes us a great deal of concern for the following reasons. Cash paying customers are in all likelihood, low-income customers who pay at the last minute and as indicated earlier, are living pay check to pay check. An additional charge for paying their bills in cash is unreasonable and unfair. While the company may make the decision to save costs by closing offices, it is unfair to ask these customers to pay an increased bill amount simply to pay their bills.

An additional concern is the referral of potentially vulnerable customers to predatory lending facilities. Pay day loan businesses are proliferating throughout the United States, and Arizona is no exception. The Center for Responsible Lending (The Center) recently published a study that demonstrates that 90% of payday lending revenues are based on fees stripped from trapped borrowers, and that the typical payday borrower pays back $793 for a $325 loan. The report further finds that payday lending now costs American families $4.2 billion per year in excessive fees.[5]

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[5] Center For Responsible Lending, "Financial Quicksand: Payday Lending sinks borrowers in debt with $4.2 billion in predatory fees every year, November 30, 2006

As reported by the Center, the industry relies almost entirely on revenue from borrowers caught in a debt trap. Ninety-one percent (91%) of payday loans go to borrowers with five or more loan transactions a year. Sixty-one and a half percent (61.5%) of payday loans go to borrowers with twelve or more loans per year. In addition, many borrowers go to more than one payday lender. The industry depends on establishing and maintaining a substantial repeat customer base.

Q. Why is this an issue in this rate case? Don't consumers have a choice about whether to use a payday loan facility?

A. Absolutely, all consumers have a choice about whether to enter into an agreement with a payday lender. ACAA objects to this practice because it is simply bad policy and an even worse practice, it places already vulnerable customers in a more vulnerable situation. Additionally, we have been told anecdotally that individuals who have had experience with payday lenders are often "afraid" to go back for fear of getting into debt trouble.

We recognize that operating satellite offices in order to accept cash payments is costly. We also recognize that good faith efforts have been made to identify other community partners willing to accept cash payments. We don't understand why other methods cannot be developed, such as the use of technology in the form of "ATM-like kiosks" which can accept cash, nor do we understand when the culture of utility companies accepting the responsibility for accepting cash payments from customers became someone else's problem. Most importantly, we cannot fathom why a reputable company would partner with businesses which have documented predatory practices.

Q. What is ACAA's concern relative to the proposed modification in the time within which a customer must pay their bill – the shift from 20 to 10 days?

A. A bill that is delivered to a home may take up to 3 to 4 days for mail delivery each way. This means that bills need to be paid/mailed essentially the day after they are received. This is unreasonable for anyone, including those struggling to make their payments. If a customer is using the automatic deduction option or paying on-line, this may not present a problem. However, for low-income customers who, as we have stated previously, are struggling to make ends meet, it is unlikely that they will be able to pay within this timeframe, and may need to pay in cash. Again, as previously stated, it is not an option for them to be going to the payday loan store for this purpose. This timeframe may drive even more customers to the predatory lender. Twenty days is an absolutely reasonable timeframe in which to pay UES, ten days simply is not.

Q. Is there anything else you would like to say at this time?

A. No, thank you for the opportunity to share our concerns. We appreciate UES' willingness to provide resources for the low-income community and we appreciate the Commission's permitting our participation.

Attachments:

1. Poverty in Arizona: Working Towards Solutions, Arizona Community Action Association, 2003.
2. APPRISE Inc., "2005 Energy Needs: Profile of Low Income Households – Phoenix and Arizona.
3. Children's Sentinel Nutrition Assessment Program, "Federal Fuel Assistance Reduces Health Risks for Young Children," February 1, 2007.
4. Center for Responsible Lending, "Financial Quicksand: Payday lending sinks borrowers in debt with $4.2 billion in predatory fees every year," November 30, 2006.
5. UNS August 8, 2006 Press Release
6. Payment Agents from www.uesaz.com/electric/yourbill/Agents.html

RESPECTFULL SUBMITTED this February 8, 2007.

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Applied Public Policy Research

APPRISE

Institute for Study and Evaluation

DATE:	May 25, 2005 (Updated June 12, 2005)
TO:	Sue Present
FROM:	APPRISE Incorporated
SUBJECT:	Energy Needs: Profile of Low Income Households – Phoenix and Arizona

Introduction

Policymakers and program managers need information about the energy needs of low-income households to make effective decisions related to program design, operations, and evaluation. Decisions need to be made at the national, state, and local levels; therefore, information needs to be developed for each of those levels as well. In this report, APPRISE uses existing data sources to develop information on the energy needs of low-income households for decision makers in Arizona. The statistics and figures presented in this report represent examples of the broad array of information that can be obtained from existing data sources. Moreover, the findings in this report provide valuable information about the needs and characteristics of low-income households in the United States, Arizona, and the Phoenix metropolitan area. The information presented in this report includes:

- National-level Data: Decision makers in Arizona can use this information to understand the similarities and differences between energy needs of Arizona households and households throughout the United States.
- State-level Data: Arizona LIHEAP managers can use this information to make decisions regarding the design of their statewide program.
- Local-level Data: Local organizations in Phoenix can use this information to improve integration of energy assistance programs with other programs designed to assist low-income households.

Methodology

Each state selects its own LIHEAP income eligibility standard.[1] For this profile, low-income households have been identified using the current Arizona LIHEAP income eligibility standard of 150 percent of the Federal Poverty Guidelines, which was $27,600 for a four-person household in 2003. APPRISE used the year-appropriate federal poverty guideline threshold values when analyzing data for this report. Throughout the document, the terms low-income, LIHEAP eligible, and LIHEAP income-eligible are used interchangeably.

[1] LIHEAP grantees can set the household income cutoff at any figure no less than 110 percent of the Federal Poverty Guidelines and no more than the greater of 150 percent of the Federal Poverty Guidelines or 60 percent of state median income (http://www.acf.dhhs.gov/programs/liheap/eligible.htm).

APPRISE used data from various sources to generate the information provided in this report:

- National-level Data: APPRISE used data from the United States Division of Energy Assistance and the United States Energy Information Administration.
- State-level Data: APPRISE developed statistics for the state of Arizona using the Census 2000 Public Use Microdata (PUMS) Five Percent Sample and the 2002-2004 Current Population Survey Annual Social and Economic Supplement (ASEC).
- Local-level Data: APPRISE developed statistics for the Phoenix metropolitan area using the 2002 American Housing Survey (AHS) Phoenix Metropolitan Area Sample.

Impact of Poverty and Energy Prices on Low-Income Households in the United States

In the United States, the poverty rate and energy prices are increasing.

- The poverty rate has increased from 11.3% in 2000 to 12.5% in 2003.[2]
- Electricity prices have risen from 8.24 cents per kWh in 2000 to 8.94 cents in 2004.
- Natural Gas prices have risen from $7.76 per Thousand Cubic Feet in 2000 to $10.74 in 2004.[3]
- The total residential energy bill for all low-income households has increased from $25.1 billion in 2001 to $28.3 billion in 2003.[4] The total residential energy bill increase results from both the growth in the number of low-income households and the rise in average home energy bills.

Energy burden is a statistic that is often used to assess the difficulties that households have in paying their energy bills. Energy burden is defined as the percent of income spent on energy. In 2003, the median residential energy burden was 3 percent for all households and 10 percent for all low-income households.[5]

Energy gap is defined as the dollar amount needed to reduce a customer's energy burden to an amount equal to a specified energy burden percentage. In 2003, the total dollar amount needed to ensure that no American low-income household spends more than 15 percent of income on

[2] 2000 Report: Dalaker, Joseph, U.S. Census Bureau, Current Population Reports, Series P60-214, Poverty in the United States: 2000, U.S. Government Printing Office, Washington, DC, 2001. 20-03 Report: DeNavas-Walt, Carmen, Bernadette D. Proctor, and Robert J. Mills, U.S. Census Bureau, Current Population Reports, P60-226, Income, Poverty, and Health Insurance Coverage in the United States: 2003, U.S. Government Printing Office, Washington, DC, 2004.
[3] Energy Information Administration, U.S. Department of Energy. "Monthly Energy Review, April 2005", Table 9.9 (Average Retail Prices of Electricity) and Table 9.11 (Natural Gas Prices).
[4] U.S. Department of Health and Human Services, Administration for Children and Families, Office of Community Services, Division of Energy Assistance. LIHEAP Home Energy Notebook For Fiscal Year 2003: Page 22, Figure 3-13.
[5] U.S. Department of Health and Human Services, Administration for Children and Families. Office of Community Services, Division of Energy Assistance. LIHEAP Home Energy Notebook For Fiscal Year 2003. All U.S. Households: Page 54, Figure A-2c. All Low-Income Households (150 percent of the federal poverty guidelines): Page 17, Figure 3-6.

residential energy was $4.9 billion. The total dollar amount required to reduce residential energy bills for low-income households to 25 percent of income was $2.7 billion.[6]

Impact of Poverty and Energy Prices on Low-Income Households in Arizona

Arizona policymakers and program managers can use state-level information to understand the energy needs of Arizona households. Arizona is a microcosm of the national trends in poverty and energy prices. Arizona is a growing state with an increasing population of low-income households. As shown in Table 1, the number of households in Arizona that are income-eligible for LIHEAP increased by 73,000 households in just three years, from 362,800 in 2000 to 436,000 in 2003.

Table 1
Arizona LIHEAP Eligible Households (2000 and 2003)

	Number of Households	Percent of all Arizona Households
LIHEAP Eligible Households, 2000	362,800[1]	19.1%
LIHEAP Eligible Households, 2003	436,000[2]	21.4%

[1] Source: 2000 Decennial Census PUMS 5 Percent Sample.
[2] Source: Three-year Average of the CPS ASEC 2002-2004.

Table 2 displays the changes in natural gas and electricity prices in Arizona from 1999 to 2001. Natural gas prices rose 16 percent from $8.99 per Million BTU in 1999 to $10.45 in 2001. Electricity prices remained stable between 1999 and 2001.[7] Based on the rise in national energy prices since 2000 described on page two, energy prices in the state of Arizona have probably also increased since 2001.

Table 2
Arizona Historical Energy Prices (1999-2001)

Year	Natural Gas	Electricity
1999	8.99	25.01
2000	9.33	24.73
2001	10.45	24.32

Source: Table 2. EIA Arizona State Energy Data 2001. Prices in Nominal Dollars per Million BTU.

[6] U.S. Department of Health and Human Services, Administration for Children and Families, Office of Community Services, Division of Energy Assistance. LIHEAP Home Energy Notebook For Fiscal Year 2003: Page 21, Figure 3-12.
[7] State data beyond 2001 has not been published by EIA. APPRISE will seek out additional information sources to update the energy price table data closer to 2005 for the next draft of these findings. APPRISE would appreciate assistance from any of the Arizona utility companies or NLIEC board members in obtaining state-level energy price data.

In Arizona, energy expenditures, particularly related to cooling for the elderly, disabled, and young children, are not a luxury, but a necessity due to extreme summer high temperatures that average over 100 degrees during the months of June, July, and August. High-energy prices and the need for energy have a direct impact on the amount of money that low-income households spend on energy. Table 3 shows that 26 percent of LIHEAP eligible households reported that they spent more than $1,500 per year on residential energy expenditures.

Table 3
Energy Expenditures for Arizona LIHEAP Eligible Households (1999)

	Percent of Households
No Separate Energy Bill	10%
Less than $500	12%
$500 - $999	27%
$1,000 - $1,499	25%
$1,500 - $1,999	13%
Over $2,000	13%
All LIHEAP Eligible Households	100%

Source: 2000 Decennial Census PUMS 5 Percent Sample.

Table 4 shows that 44 percent of LIHEAP eligible households in Arizona had an energy burden of 10 percent or greater (i.e., spent 10 percent or more of their income on total residential energy). Moreover, 17 percent of LIHEAP eligible households had an energy burden of 25 percent or greater. By comparison, the median residential energy burden for all US households was 3 percent.

Table 4
Energy Burden for Arizona LIHEAP Eligible Households (1999)

	Percent of Households
No Separate Energy Bill	10%
Less than 5%	17%
5 - <10%	28%
10 - <15%	16%
15 - <20%	7%
20 - <25%	4%
25% or greater	17%
All LIHEAP Eligible Households	100%

Source: 2000 Decennial Census PUMS 5 Percent Sample.

The needs of low-income Arizona households are growing faster than the State's capacity to provide energy assistance. In FY 2004, LIHEAP provided $5.7 million in home energy assistance to nearly 18,600 low-income households in Arizona.[8] However, as shown in Table 5, the LIHEAP recipient households represent only 4 percent of the LIHEAP income-eligible households in Arizona.

Table 5
Arizona LIHEAP Eligible and Recipient Households (2003)

	Number of Households
LIHEAP Eligible	436,000[1]
LIHEAP Recipient	18,600[2]

[1] Source: Three-year Average of the CPS ASEC 2002-2004.
[2] Source: LIHEAP Household Reports FY 2004.

Decision makers can estimate the severity of the energy needs for low-income Arizona households by considering the funding level needed to ensure that no low-income household spent more than a certain percentage of income on energy expenses. Although there is no standard measure of energy affordability, Table 6 displays the funding needed to reduce the energy burden of low-income Arizona households in 1999 to 5 percent, 10 percent, and 25 percent.

- 5 Percent Energy Burden: There were approximately 266,700 LIHEAP eligible households with energy burdens greater than 5 percent. It would require over $222 million of assistance to reduce their energy bills to 5 percent of household income.
- 10 Percent Energy Burden: There were approximately 166,000 LIHEAP eligible households with energy burdens greater than 10 percent. It would require over $128 million of assistance to reduce their energy bills to 10 percent of household income.
- 25 Percent Energy Burden: There were approximately 68,500 LIHEAP eligible households with energy burdens greater than 25 percent. It would require $57 million of assistance to reduce their energy bills to 25 percent of household income.

In FY 2004, LIHEAP provided $5.7 million of benefits to 18,600 households. Arizona expended $16.4 million of additional resources to supplement LIHEAP and low-income energy efficiency programs.[9] In total, Arizona households received over $22 million in energy assistance benefits. However, the dollars needed to ensure that no LIHEAP eligible Arizona household spends more than 5 percent of household income on residential energy is over $222 million.

[8] The number of FY 2004 LIHEAP recipients was obtained from Arizona's FY 2004 LIHEAP household reports. The amount of FY 2004 benefits provided was obtained from Arizona's FY 2004 LIHEAP Grantee Survey for FY 2004.
[9] http://www.liheap.ncat.org/Supplements/2004/supplement04.htm (Source Date: May 17, 2005; Download Date: June 9, 2005)

Table 6
Energy Gap for Arizona LIHEAP Eligible Households (1999)

	Number of Households	Energy Gap
Households with Energy Burdens Greater Than 5%	266,700	$222,100,000
Households with Energy Burdens Greater Than 10%	166,000	$128,400,000
Households with Energy Burdens Greater Than 25%	68,500	$57,000,000

Source: 2000 Decennial Census PUMS 5 Percent Sample.

Demographic Characteristics of Low-Income Households in Arizona

Arizona policymakers and program managers could use additional state-level information to make decisions that are more directly appropriate to the particular financial and demographic needs of low-income households in Arizona. For example, decision makers need information on demographic characteristics, which could be used to target limited State funding to the most vulnerable populations where assistance might have the greatest impact.

The LIHEAP statute identifies vulnerable and high energy-burden households as having the highest home energy needs. The statute defines a vulnerable household as those with at least one member that is a young child, an individual with disabilities, or a frail older individual. LIHEAP has explicit national performance goals for FY 2003 that include increasing the percentage of LIHEAP recipient households having at least one member age 60 years or older or age 5 years or younger.[10]

The following tables describe the characteristics of these LIHEAP eligible households. The majority of LIHEAP eligible households in Arizona have at least one vulnerable member. These households are vulnerable with respect to poverty, rising energy prices, and high energy burdens. These vulnerable individuals, in particular the elderly population, are also at great health risk due the extreme summer heat in Arizona. Table 7 shows that 73 percent of all LIHEAP eligible households reported having at least one household member who is an elderly (i.e., age 60 years or older) individual, a disabled individual, or a young (i.e., age five years or younger) child. The information reveals that targeting assistance benefits will be a challenge for Arizona decision makers, because most low-income Arizona households have vulnerable individuals.

Table 7
Arizona LIHEAP Eligible Households with Any Vulnerable Group Members (2003)

	Number of Households	Percent of Households
Household With Vulnerable Member(s)	316,500	73%

[10] U.S. Department of Health and Human Services, Administration for Children and Families, Office of Community Services, Division of Energy Assistance. LIHEAP Home Energy Notebook For Fiscal Year 2003: Page ix.

	Number of Households	Percent of Households
Household with No Vulnerable Members	119,500	27%
All LIHEAP Eligible Households	436,000	100%

Source: Three-year Average of the CPS ASEC 2002-2004.

Table 8 describes the number of LIHEAP eligible households that reported having one or more household members particularly vulnerable to unaffordable energy bills. Thirty-five percent of households reported having at least one household member who was elderly, 15 percent reported having at least one household member who was nonelderly and disabled, and 27 percent reported having at least one household member who was a young child.

Table 8
Arizona LIHEAP Eligible Households with Vulnerable Group Members (2003)

	Number of Households	Percent of Households
Household With Elderly (Age 60 or older)	154,100	35%
Household With Nonelderly Disabled	64,375	15%
Household With Young Child (Age 5 or under)	117,200	27%

Source: Three-year Average of the CPS ASEC 2002-2004.

Table 9 presents the number of LIHEAP eligible households that reported receiving income from public assistance (e.g., TANF), Supplemental Security Income, or Social Security. Six percent reported receiving public assistance benefits, another 6 percent received supplemental security income, 30 percent received social security, and 58 percent reported not having received benefits from any income program.

Table 9
Income Program Participation of Arizona LIHEAP Eligible Households (2003)

	Number of Households	Percent of Households
Public Assistance	24,600	6%
Supplemental Security Income	26,400	6%
Social Security	132,400	30%
No Income Program Participation	252,600	58%
All LIHEAP Eligible Households	436,000	100%

Source: Three-year Average of the CPS ASEC 2002-2004.

As shown in Table 10, 21 percent of all LIHEAP eligible households reported that the household was a single parent household.

Table 10
Single-Parent Arizona LIHEAP Eligible Households (2003)

	Number of Households	Percent of Households
Single-Parent Household	90,300	21%
Not Single Parent Household	345,700	79%
All LIHEAP Eligible Households	436,000	100%

Source: Three-year Average of the CPS ASEC 2002-2004.

Table 11 shows that 15 percent of all LIHEAP eligible households reported that the primary language spoken in their household is Spanish and none of the household members speak English "very well". Given this data, it is incumbent on program managers to design programs to accommodate the language needs of their population.

Table 11
Linguistically Isolated Arizona LIHEAP Eligible Households (2000)

	Number of Households	Percent of Households
Spanish Isolation	54,800	15%
Not Isolated	308,000	85%
All LIHEAP Eligible Households	362,800	100%

Source: 2000 Decennial Census PUMS 5 Percent Sample.

In Arizona, cooling needs are not a luxury for these low-income households. Households with elderly, disabled, or children are at great risk for heat-related illnesses during the extreme Arizona summer. Table 12 displays the average high temperature during the warm weather months in Arizona. The average high temperature during the months between April and October is above 90 degrees with temperatures above 100 for most of June, July, and August.

Table 12
Historical Weather Data (April – Oct)

Month	Average High Temperature
Apr	84.8
May	93.3
Jun	102.9
Jul	105.2
Aug	103.6
Sep	99.3
Oct	89.3

Source: Western Regional Climate Center.[11]

The Energy Needs of Low-Income Households in Phoenix

In addition to information related to energy needs and demographic characteristics of low-income households, policymakers and program managers at the local level might also consider information related to other factors that are associated with energy (e.g., housing) for the purposes of devising complementary direct assistance programs. These decision makers can use statistical information on the relationship between energy needs and housing adequacy to develop policies and procedures to more effectively operate energy assistance programs that complement housing programs.

As shown in Table 13, approximately 203,800 households in Phoenix, or 17.5% of all Phoenix households, are LIHEAP eligible.

Table 13
Phoenix LIHEAP Eligible Households (2002)

	Number of Households	Percent of all Phoenix Households
LIHEAP Eligible Households, 2002	203,800	17.5%

In Phoenix, the extreme summer temperature creates a substantial need for cooling energy, particularly in households with an elderly person, disabled person, or young child. These households come to rely on air conditioners not as a luxury, but as an essential appliance for health-related use. Table 14 displays the number of LIHEAP eligible households in Phoenix with and without air conditioning units[12]. With steady summer high temperatures above 100 degrees, 23,400 (or 12 percent of 203,800) LIHEAP eligible households in Phoenix do not have air conditioning units.

Table 14
Phoenix LIHEAP Eligible Households with Air Conditioning Units (2002)

	Number of Households	Percent of Households
Household With Air Conditioning Unit(s)	180,400	88%
Household with no Air Conditioning Unit	23,400	12%
All LIHEAP Eligible Households	203,800	100%

Source: 2002 American Housing Survey, Phoenix Metropolitan Area Sample.

The significant need for air conditioning comes at a price. In a table not shown here, we find that those LIHEAP eligible households with air conditioners are paying heavily for that necessity.

[11] Period of Record Monthly Climate Summary; Phoenix, Arizona. Period of Record 7/1/1948 – 12/31/1998.
[12] Evaporative coolers are not included in the American Housing Survey definition of air conditioning units and the survey does not provide data about the use of evaporative coolers.

Among the 180,400 low-income households that have an air conditioning unit, 37 percent have energy burdens at or greater than 10% and 18 percent have energy burdens at or greater than 25%.

Table 15 reports the energy burden statistics for the Phoenix Metropolitan area. In Phoenix, 37 percent of LIHEAP eligible households had an energy burden of 10 percent or greater. Moreover, 18 percent of LIHEAP eligible households had an energy burden of 25 percent or greater. As evidenced by table 4, the energy burden distribution for LIHEAP eligible households in Phoenix is very similar to the distribution for LIHEAP eligible households throughout Arizona.

Table 15
Energy Burden for Phoenix LIHEAP Eligible Households (2002)

	Number of Households	Percent of Households
No Separate Energy Bill	21,400	11%
Less than 5%	50,700	25%
5 - <10%	54,300	27%
10 - <15%	18,900	9%
15 - <20%	12,600	6%
20 - <25%	8,600	4%
25% or greater	37,300	18%
All LIHEAP Eligible Households	203,800	100%

Source: 2002 American Housing Survey, Phoenix Metropolitan Area Sample.

Policymakers and researchers often focus on shelter burden when considering the plight of low-income households. Shelter burden is defined as the percent of income spent on housing costs (including residential energy costs). According to the United States Department of Housing and Urban Development (HUD), the generally accepted definition of affordable housing is "housing for which the occupant is paying no more than 30 percent of his or her income for gross housing costs, including utilities;[13] families who pay more than 30 percent of their income for housing are considered cost burdened and may have difficulty affording necessities such as food, clothing, transportation and medical care."[14]

Some researchers have defined severe shelter burden more conservatively as a household that spends 50 percent or more of their income on shelter costs.[15] Table 16 presents shelter burden and energy burden for LIHEAP eligible households in Phoenix. Nearly all LIHEAP eligible households with an energy burden of 25 percent or greater have a severe shelter burden (i.e., spend 50 percent or more of their income on housing costs). Table 16 shows that as energy

[13] http://www.hud.gov/offices/cpd/library/glossary/a/index.cfm (Source Date: December 6, 2002; Download Date: June 1, 2005)
[14] http://www.hud.gov/offices/cpd/affordablehousing/index.cfm (Source Date: May 27, 2005; Download Date: June 1, 2005)
[15] See Cushing N. Dolbeare. 2001. "Housing Affordability: Challenge and Context." Cityscape: A Journal of Policy Development and Research, (5)2:111-130. A Publication of the U.S. Department of Housing and Urban Development, Office of Policy Development and Research.

burden increases so does the likelihood of having a *severe* shelter burden. These findings suggest that energy burden has a substantial impact on housing costs.

Table 16
Shelter Burden and Energy Burden for Phoenix LIHEAP Eligible Households (2002)

	Shelter Burden					
	Less than 50%		50% or greater		All LIHEAP Eligible Households	
Energy Burden	**Number**	**Percent**	**Number**	**Percent**	**Number**	**Percent**
Less than 10%	84,700	67%	41,700	33%	126,400	100%
10 - <25%	13,600	34%	26,600	67%	40,200	100%
25% or greater	200	1%	37,100	99%	37,300	100%

Source: 2002 American Housing Survey, Phoenix Metropolitan Area Sample.

Conclusion

This report presented some examples of the broad array of information that can be developed related to the energy needs of low-income households using existing data sources. Moreover, the analyses presented here provide constructive information about the needs and characteristics of low-income households in the United States, Arizona, and the Phoenix metropolitan area.

The general findings demonstrate that low-income households in Arizona spend a significant amount of their income on residential energy. Moreover, the energy burdens of most LIHEAP eligible Arizona households are significantly higher than the energy burden of the average American household. In addition, the financial commitment to reduce energy bills to 5 percent of income for low-income Arizona households would require over $222 million more in energy assistance funding each year.

Policymakers and program managers can use information developed from existing data sources for program design, operations and evaluation at the national, state, city and neighborhood levels. However, there are limitations to what can be learned from these data. For example, the sources presented in this report do not provide information regarding how individual households manage their unaffordable energy needs. Further questions like these can be investigated by talking directly to customers via in-depth interviews and surveys, as seen in the work conducted by Roger Colton on energy insecurity.

BOSTON MEDICAL CENTER

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University of Arkansas for Medical Sciences

University of Maryland Medical Center

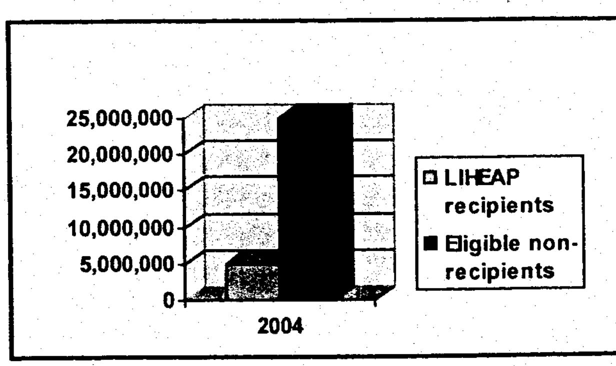
Federal Fuel Assistance Reduces Health Risks for Young Children

Prepared for National Fuel Funds Network's Washington Action Day for LIHEAP, February 1, 2007

Data from the Children's Sentinel Nutrition Assessment Program (C-SNAP) suggest that participation in the Low Income Home Energy Assistance Program (LIHEAP) can positively affect children's health and development.

- Compared with children in eligible households *not* receiving LIHEAP, children in households receiving LIHEAP experienced:
    - **Decreased nutritional risk for growth problems**
    - **No evidence of increased obesity**
    - **Lower odds of acute hospitalization**

- Public funding for LIHEAP, however, has never been sufficient to serve more than a small minority of income-eligible people. In 2004, LIHEAP benefits reached only five million (17%) of the thirty million eligible households. This means that twenty-*five million American families* did not receive the assistance for which they qualified.
    - The average annual household income among LIHEAP recipients in 2004 was $8000. This extreme level of poverty forces many families to make tough choices about which bills to pay. This terrible dilemma is often termed the "heat or eat" phenomenon.
    - Federal funding for LIHEAP has not increased in recent years, despite rapidly rising energy costs and harsh winter conditions.



- These findings have important implications: although not traditionally considered a federal nutrition-assistance program, LIHEAP exerts a strong influence on children's health and development.
    - From a clinical perspective, pediatric health providers caring for children from low-income families should consider encouraging caretakers to apply early for LIHEAP. C-SNAP's research shows this to be a medically-valid **prescription for better child health.**
    - From a public policy perspective, expanding funding for LIHEAP constitutes a **sound investment in the health and development of America's neediest children,** protecting them from nutritional risk and unnecessary hospitalizations.

About C-SNAP: *C-SNAP is a national network of clinicians and public health specialists whose mission is to be the preeminent nonpartisan resource for research in pediatric settings on the effect of U.S. social policy on young, low-income children's health and nutrition. C-SNAP's research is based on a sample of nearly 24,000 children under age 3 from seven urban medical centers across the United States.* ***For more information about C-SNAP, please visit*** *www.c-snap.org.*

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Financial Analyst Contact: Jo Smith, (520) 884-3650

UES To Close Four Walk-In Lobbies;
Customers Will Have A Variety Of Options Available
For Payments And Customer Service

(Flagstaff, AZ) — UniSource Energy Services (UES) will be closing its walk-in lobbies in the northern Arizona communities of Flagstaff, Prescott, Cottonwood and Show Low on September 29, 2006, but customers will still have access to a variety of alternative payment methods and ways to contact UES Customer Care.

"More and more of our customers have been taking advantage of electronic payment options via the Internet or telephone, or through automatic withdrawals," explained UES Senior Vice President and Chief Operating Officer Dennis R. Nelson. "Growth in the volume of electronic payments should increase even more once we launch our new online billing and payment program later this year."

Nelson said that the growing popularity of electronic payments was just one of several reasons why the company made the move to discontinue walk-in lobby operations in those four communities. "Customers who prefer to pay with cash, or who need payments credited to their accounts right away, can now visit one of our authorized independent payment agents rather than a UES lobby," Nelson said.

Another factor in the decision, according to Nelson, was the personal safety issue for employees created by the handling of cash payments in the lobbies.

Nelson added that "we're constantly looking for ways to do things more productively and efficiently. After all, any cost savings we achieve will eventually benefit our customers through lower rates."

Along with the various electronic payment options and the availability of cash-payment agents, UES provides drop boxes as an alternative to the US Mail for check or money order payments, Nelson said.

He also said that many other customer transactions and inquiries can be handled online at uesaz.com, or with a toll-free call to 877-UES-4YOU (877-837-4968).

Contractors and others who are involved in construction projects will still be able to talk with a UES representative by phone or in person at their local UES offices.

Nelson encouraged customers to visit the company's Web site, uesaz.com, for a complete list of cash payment agents and drop box locations, as well as details on other payment options. "Or they can call 877-UES-4YOU toll-free, 7 a.m. to 7 p.m., Monday through Friday, and talk to a Customer Care representative," Nelson said.

UniSource Energy Services, a subsidiary of UniSource Energy Corporation (NYSE: UNS), provides gas service to more than 142,000 customers in Mohave, Yavapai, Coconino, Navajo and Santa Cruz Counties. UES also provides electric service to more than 91,000 customers in Mohave and Santa Cruz Counties. For more information about UniSource Energy Services, visit www.uesaz.com. For more information about its parent company, UniSource Energy, visit www.uns.com.

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Payment Agents

- ACE Cash Express Locations
- Additional Cash Only Locations

- Cash only -

- You will be provided with a receipt after cash payment has been made.
- Please verify the accuracy of your account number on your receipt before leaving.
- Please take your bill stub with you. This will help make sure your payment is processed accurately.
- A $1.00 fee will apply at selected locations (see below)

ACE Cash Express Locations

Bullhead City

1812 Highway 95, Ste 20, Bullhead City, AZ 86442 - (928) 763-8865

Store Hours: Monday through Thursday 8:30 a.m. to 6:30 p.m.; Friday 8:30 a.m. to 7:00 p.m.; Saturday 9 a.m. to 5 p.m.; Closed Sunday

Camp Verde

522 Finnie Flats Road, #F, Camp Verde, AZ 86322 - (928) 567-0676

Store Hours: Monday through Friday 9:00 a.m. to 6:00 p.m.; Saturday 9 a.m. to 3 p.m.; Closed Sunday

Chino Valley

1578 N. US-89 Suite A, Chino Valley, AZ 86323 - (928) 636-5545

Store Hours: Monday through Thursday 8:00 a.m. to 6:30 p.m.; Friday 8:00 a.m. to 7:00 p.m.; Saturday 9:00 a.m. to 5:00 p.m.; Closed Sunday

Cottonwood

989 S. Main, Ste B, Cottonwood, AZ 86326 - (928) 639-1000

Store Hours: Monday through Friday 8:30 a.m. to 6:30 p.m.; Saturday 10:00 a.m. to 5:00 p.m.; Closed Sunday

Kingman

3787 Stockton Hill Road, Kingman, AZ 86401 - (928) 692-7110
2785 Northern Ave, Kingman, AZ 86401 - (928) 757-7575
($1 fee will apply)

Store Hours: Monday through Thursday 8 a.m. to 6:30 p.m.; Friday 8:00 a.m. to 7 p.m.; Saturday 9:00 a.m. to 5:00 p.m.; Closed Sunday

Lake Havasu

20 N. Acoma Blvd, Lake Havasu City, AZ 86403 - (928) 854-4447

Store Hours: Monday through Thursday 8:00 a.m. to 6:30 p.m.; Friday 8:00 a.m. to 7:00 p.m.; Saturday 9:00 a.m. to 5:00 p.m.; Closed Sunday

Nogales

1965 N. Grand Ave. Nogales, 85621 - (520) 761-3999

Store Hours: Monday through Saturday 9:00 a.m. to 9:00 p.m.; Sunday 10:00 a.m. to 6:00 p.m.

570 W. Mariposa, Nogales, AZ 85621 - (520) 377-2013
($1 fee will apply)

Store Hours: Monday through Saturday 9:00 a.m. to 6:00 p.m.; Sunday 9:00 a.m. to 4:00 p.m.

43 N. Morley Ave, Nogales, AZ 85621 - (520) 287-7400
($1 fee will apply)

Store Hours: Monday through Saturday 10:00 a.m. to 6:00 p.m.; Sunday 10:00 a.m. to 4:00 p.m.

Prescott

621 Miller Valley Road, Prescott, AZ 86301 - (928) 777-0039

Store Hours: Monday through Thursday 8:00 a.m to 6:30 p.m.; Friday 8:00 a.m. to 7:00 p.m.; Saturday 9:00 a.m. to 5:00 p.m.; Closed Sunday

Prescott Valley

8101 E. Hwy. 69, Ste A, Prescott Valley, AZ 86314, (928) 759-9939

Store Hours: Monday through Thursday 9:00 a.m. to 6:30 p.m.; Friday 9:00 a.m. to 7:00 p.m.; Saturday 9:30 a.m. 5:00 p.m.; Closed Sunday

Additional Cash Only Locations

Flagstaff

Ozark 'Advanced Quick Cash'
3470 E. Route 66, Suite 101, Flagstaff AZ 86004
Phone: (928) 526-5626
9:00 a.m. to 5:30 p.m., Monday through Friday
10:00 a.m. to 2:00 p.m., Saturday

Winslow

The Scoop Advertising
108 E. Second Street, Winslow AZ 86047
Phone: (928) 289-2020

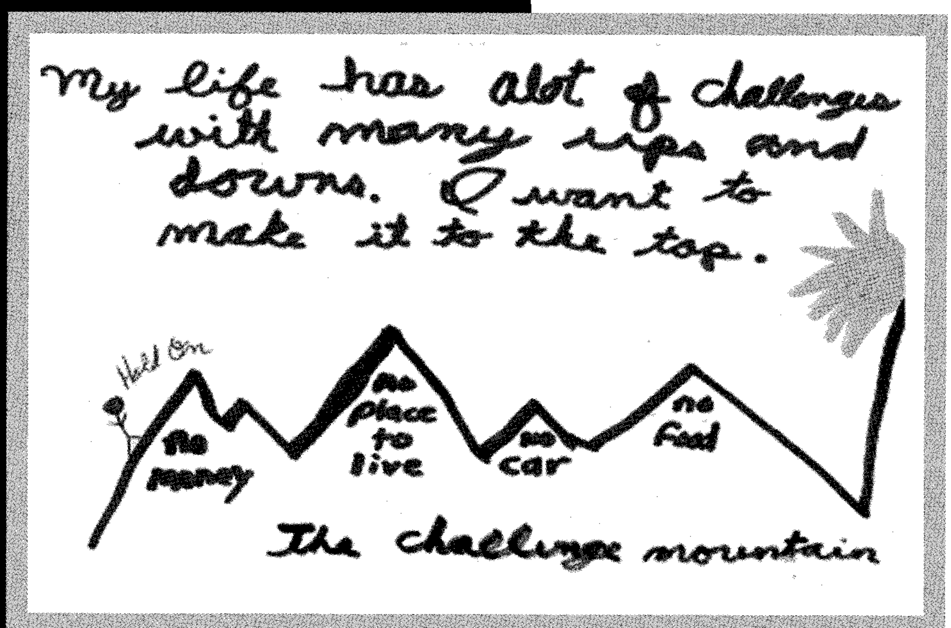
Show Low

Audio Advantage/Radio Shack
4431 S. White Mountain Rd., Suite 1, Show Low AZ 85901
Phone: (928) 532-0462

Sedona

Weber IGA Food & Drug
100 Verde Valley School, Sedona AZ 86351
Phone: (928) 284-1144

Poverty in Arizona



9 year old from Pappas School for Homeless Children

WORKING TOWARDS SOLUTIONS

Arizona Community Action Association, Inc.

This report is dedicated to Joe Montoya

We thank him for his years of courage and persistence in the fight against poverty. He taught us that to care means taking action and never accepting "no" as an answer. His legacy to community action will stand for generations to come.

We also thank and acknowledge all of the front line people who make a positive difference everyday in the lives of people whom they serve.

Report contains artwork created by homeless children attending the Thomas J. Pappas Elementary School in Phoenix Arizona.

Acknowledgements

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Special thanks to Cynthia Olsen for her initial work and research on this report.

Principal Author and Consultant
Steve Capobres

(September 2003)

Table of Contents

Introduction

Poverty persists in the midst of plenty.

POVERTY IN ARIZONA: A People's Perspective, published in 1985 by the Arizona Community Action Association, was the first comprehensive, statewide investigation of the issues surrounding poverty. It combined statistical information with feedback from 22 community meetings, offering readers both facts and figures mixed with human experiences.

The results of the 1990 Census revealed an alarming growth in poverty in Arizona. Conditions among children had worsened and average wages failed to keep up with inflation, leaving many working, but still poor. Despite the recommendations in the previous report, conditions had diminished.

With the goal of "putting a face on poverty," *POVERTY IN ARIZONA: A Shared Responsibility* was created. This second report included a demographic profile of Arizona and its 15 counties, comparing data from 1980 and 1990 to identify trends and areas of particular concern. It is in this context that the third volume, *POVERTY IN ARIZONA: Working Towards Solutions* has evolved.

The ACAA Poverty Reports were originally designed as tools for community members to have a voice with elected officials about the conditions and causes of poverty. The ACAA reports rely on two primary sources of information: statistical data and community input. It is the community piece of this equation, gleaned from numerous community meetings held around the state that allows low-income people to have that voice.

The Arizona Community Action Association (ACAA), through its Community Action Programs and their affiliates around the state, advocates for low income Arizonans and assists on their path to economic stability. It is our sincere hope that this report will provide you with a better understanding of the complexity and depth of poverty in Arizona as well as the many ways that we individually and collectively can improve the quality of life for all the citizens of Arizona

Executive Summary

A look at poverty in Arizona offers one way to assess how well the quality of life is for all of our citizens. Unfortunately, many are quick to promote the successes of Arizona and neglect to convey the other side of the story. While Arizona may lead the nation in growth and job creation, the state continues to feel the negative effects of the types of jobs we are creating -- low-wage.

POVERTY IN ARIZONA: Working Towards Solutions attempts to demonstrate what is happening to our state's most vulnerable citizens by describing the conditions of poverty across the state. The report also provides some insights into the contributing factors of poverty and offers some philosophical reflections along with policy recommendations as possible solutions to ending poverty in Arizona.

The Extent of Poverty in Arizona

Poverty Rates and Income

- The poverty rate for the State of Arizona in 1999 was 13.9 percent, down from 15.7 percent in 1989.
- In 1999, Arizona's poverty rate continues to be higher than the national average of 12.4 percent. In 1999, thirty-six states had a poverty rate lower than Arizona.
- In 1999, people below the poverty thresholds numbered 698,669, a figure 134,307 higher than the 564,362 poor in 1989 (a 23.8 percent increase).
- According to the Center on Budget and Policy Priorities, Arizona is among 10 states with the largest gap between the rich and the poor.
- The average 1999 per capita personal income in Arizona was $23,937, 14 percent below the national average of $27,880. Compared to all the states, Arizona ranked 37th in per capita personal income.
- According to an Arizona Children's Action Alliance report completed in 2002, "The Self-Sufficiency Standard for Arizona," a single parent with an infant and a preschool-age child needs to earn a minimum of $40,153 annually to cover basic expenses in Maricopa County.

- In April of 2000, 256,006 people or 5 percent of the population received food stamps. At the same time, 32,927 or 2.5 percent of families were enrolled in TANF. This represents a 20.7 percent decrease in food stamps from April of 1990, and a 25.6 percent decrease in TANF caseloads during the same period.
- Over the last ten years, the number of working poor persons grew 36.8 percent from 718,109 in 1989 to 982,207 in 1999 (ACAA defines "working poor" as people who had incomes equal to or above the poverty level, but less than 199 percent).
- In total, there are close to 1.7 million people in Arizona who are poor or "working poor," one-third of the state's total population.

Age, Families and Race

- At 19.3 percent, the poverty rate for children remained higher than that of other age groups. Over 44 percent of Arizona's children are living below 200 percent of the poverty line.
- The 1999 poverty rates are higher than twenty years ago for all age groups except those over 65 who experienced an improvement from 12.3 percent in 1979 to 8.4 percent in 1999.
- In 1999, there were 123,318 families below the poverty line (9.9 percent), up from 67,577 (9.5 percent) in 1979.
- The number of poor families with children headed by single females rose 128.8 percent over the last twenty years, from 20,169 in 1979 to 46,150.
- Among racial/ethnic groups, American Indians experienced the highest poverty rate at 36 percent and Whites had the lowest at 10.1 percent in 1999. American Indians were also represented at a disproportionately higher rate among those in poverty than in the overall population. All races in the State of Arizona saw an improvement in poverty rates from 1989.

Geographic Distribution

- 1999 poverty rates in Arizona's counties ranged from a high of 37.8 percent in Apache County to a low of 9.9 percent in Greenlee County. The state's urban areas had a poverty rate of 11.7 percent for Maricopa County and 14.7 percent for Pima County.
- From 1989 to 1999, all Arizona counties experienced an increase in the number of people in poverty, except Apache, Coconino, Greenlee, and La Paz, who saw a 9.9 percent, 0.9 percent, 16.6 percent, and 2 percent decrease respectively.
- The poverty rate for all Arizona Indian reservations was 42.1 percent. The number of people in poverty on Indian reservations dropped 8.8 percent from 1989 to 1999. This was not just isolated to tribes with gaming. The Hopi and Navajo Nations experienced an 18.8 percent and 11.1 percent decrease respectively.

Community Responses

- Over 1,100 people participated in twenty-nine community meetings on poverty around the state held between 2000 and 2002. Over half of all those surveyed believe that conditions have gotten ***worse*** in the following areas over the last ten years: Homelessness, emergency food and utility assistance, and affordable health care.

Contributing Factors to Poverty

- Low wages continue to be the primary challenge for low-income families across the state. Six of Arizona's ten industrial sectors have an average annual salary below the U.S. average of $29,245. These six sectors make up 63 percent of all Arizona jobs.
- The lowest income households have the most serious housing needs and have few alternatives to secure affordable housing. The total affordability gap in Arizona is estimated at 194,700 or about 10.3% of all households. The 2000 Census reports that 16.2 percent of homeowners and 30.0 percent of renters pay 35 percent or more of their income for housing.
- According to research, only one out of ten individuals in the bottom income quintile have a chance to get out of poverty without appropriate education. According to the 2000 Census, 7.8 percent of Arizona's adults 25 years and older had less than a 9th grade education and 81 percent had a high school education or higher. Arizona's ranking among the states dropped from 20th in 1991 to 37th in 2000 for residents with a bachelor's degree.

- In 1997, the Arizona Network for Community Responsibility reported that there are over 300,000 children under 13 living in low-income families who may be eligible for child care subsidies. Yet, current funding will support subsidies for only about 35,000 children. Even though not all eligible children need assistance, thousands of low-income families go without help.
- St. Luke's Health Initiatives reports that Arizona's uninsurance rate in 2000 was one of the highest in the nation at 16 percent or 805,000 people without health coverage. Businesses with 10 employees or less have the highest rate of uninsurance at 45 percent.
- Low income Arizonans cite transportation as one of the most significant barriers to finding and maintaining employment. Studies show that a parent with a car is more likely to be employed and work longer hours than one without a car.
- According to the Arizona Network for Community Responsibility, survey data suggests that many families continue to struggle coming off of welfare. Many are getting behind in rent, rely on family for shelter, or do not have enough to eat at times and rely on getting food from others. Almost one out of every ten parents reported that they were forced to send children elsewhere to live.

Philosophical Reflections

ACAA believes the time has come for a comprehensive vision to end poverty in Arizona. But ACAA cannot do it alone. Others who are moved to compassion and committed to help must share this vision.

Community Involvement

- We must all work together to solve poverty. The active involvement of different actors is essential. Government, business, the non-profit and faith community, along with any caring individual all have distinctive contributions to make.

Strategic Focus

- Any serious effort at reducing poverty needs to have clearly articulated goals:

1) Ensure that those who work for a living earn a "livable wage" so they can support their own families.
2) Provide necessary resources for those who want to better themselves.
3) Maintain a decent safety net to provide for basic needs and to protect families during hard times.

Arizona's Priorities

If the state is serious about improving quality of life for all citizens, certain issues need to be placed at the top of the public policy agenda.

Economic Development & Jobs

- Our state and our nation need a set of policies that will raise wages, provide opportunities for the development of real job skills, expand tax benefits for the poor, and create higher quality, living wage jobs.

Education

- Quality education is central in a strategy to reduce poverty. Arizona must strengthen the foundations for increasing academic achievement, improving graduation rates, and encouraging lifelong learning.

Prevention and Early Intervention

- Often a crisis will happen before a family in poverty will seek help. Many times, the cost of dealing with a family's situation may be more problematic than had the family sought assistance sooner. There are a number of strategies the state and communities can take to be more proactive than reactive.

Sound Fiscal Policy

- Because of the downturn in the economy, more families are seeking help. ACAA believes that we cannot morally cut services to our poorest and most vulnerable citizens and must continue to promote their general welfare. The state must find ways to increase revenue to pay for vital services.

Building Wealth

- Arizona, along with the rest of the nation, needs to address the distressing financial condition of low-income families and promote measures that could be taken to help them save and build wealth. As they accumulate assets, both individuals and communities acquire invaluable benefits.

Safety Net

- While Arizona's welfare rolls have been dramatically reduced over the last few years, thousands of "hard to serve" families still remain. Multiple barriers faced by these families and other issues preclude many from ever reaching full self-sufficiency. Arizona needs a strong, comprehensive system of social and income supports to strengthen and support all families across Arizona through good times and bad.

Policy Recommendations

If we do not sufficiently increase disposable income for working people, we must have programs and services to provide essential supports to families in need. That is why ACAA is calling for the following recommendations to provide that support.

Food and Nutrition

- More than 173,000 Arizonans go hungry every week. To expand opportunities for low-income families to obtain food and basic nutrition, efforts should focus on the following: 1) Enhancing and improving Arizona's current nutrition assistance programs, 2) Maintaining and expanding state resources to support private hunger relief efforts, and 3) Engaging all sectors of the food system to help solve Arizona's hunger problem.

Affordable Housing

- To assist in the elimination of poverty in Arizona, affordable housing efforts should focus on two areas, 1) Continuing the use of various federal and state resources to subsidize the cost of housing for lower-income households, and 2) Promoting efforts at the local government level to reduce the cost of housing through innovative design and the reduction of barriers.

Child Care

- To expand opportunities for low-income parents to receive quality, affordable care for their children while they work, ACAA recommends 1) Expanding existing publicly supported child care programs, 2) Promoting the expansion of privately sponsored affordable child care, and 3) Ensuring quality and accessibility for all.

Health Care

- To assist more low-income Arizonans to improve their chances for affordable, quality health care, ACAA recommends 1) Expanding existing public health care programs, 2) Providing incentives and assurances to increase insurance coverage, and 3) Supporting community health clinics.

Transportation

- To expand transportation opportunities for low-income families ACAA recommends 1) Understanding the need and gaps, 2) Increasing the use of public resources that offer an array of transportation services, and 3) Creatively encouraging the development of local services through community partnerships and coordination.

Jobs and Income

- To expand opportunities for low-income individuals to improve their wages, ACAA recommends 1) Providing adequate employment assistance in finding and securing a job, 2) Expanding opportunities for training and skill development, and 3) Ensuring that adequate wage supports are in place to help lift families out of poverty.

Call to Action

An effectively implemented anti-poverty strategy for children and families will assist in providing an economic and social environment where many more Arizonans can enjoy a higher quality of life. Substantive action will require adequate funding and forward-thinking long-term strategies. It is time for the focus in Arizona to shift beyond process to results.

What Is Poverty?

Federal Definition

The basic concepts and assumptions used to measure poverty in the United States have not changed for over 30 years. Given increased understanding about poverty and its causes, many question whether this measure is still appropriate for the 21st Century.

The Official Measure of Poverty

There are two slightly different versions of the federal poverty measure:

- The poverty thresholds, and
- The poverty guidelines.

The poverty thresholds are the original version of the federal poverty measure and are updated each year by the U.S. Census Bureau. The thresholds are used mainly for statistical purposes — for instance, preparing estimates of the number of Americans in poverty each year. The Census Bureau uses a set of money income thresholds that vary by family size and composition to determine who is poor. If a family's total income is less than that family's threshold, then that family, and every individual in it, is considered poor. The official poverty thresholds do not vary geographically, but they are updated annually for inflation using the Consumer Price Index.

The poverty guidelines are the other version of the federal poverty measure. They are issued each year in the *Federal Register* by the U.S. Department of Health and Human Services (HHS). The guidelines are a simplification of the poverty thresholds for administrative purposes — for instance, determining financial eligibility for certain federal programs. The poverty guidelines are sometimes loosely referred to as the "federal poverty level." These HHS guidelines consist of a threshold level of income based on family size. The amount of income defined as "poor" at each level is calculated based on the cost of food consumption by multiplying the cost of food by three. This assumption was originally developed thirty years ago when the belief was that if a family could not meet its food cost needs, it would be considered poor.

The U.S. Department of Health and Human Services poverty guidelines below are for 1999, the year the Census data was collected, and for 2003, which will dictate assistance programs for the year this report was written.

HHS Poverty Guidelines - 48 Contiguous States					
Size of family	1999		2003		% Change
	Annual	Monthly	Annual	Monthly	
1	$8,240	687	$8,980	748	9.0%
2	$11,060	922	$12,120	1,010	9.6%
3	$13,880	1,157	$15,260	1,272	9.9%
4	$16,700	1,392	$18,400	1,533	10.2%
5	$19,520	1,627	$21,540	1,795	10.3%
6	$22,340	1,862	$24,680	2,057	10.5%
7	$25,160	2,097	$27,820	2,318	10.6%
8	$27,980	2,332	$30,960	2,580	10.7%
For each additional person, add	$2,820		$3,140		

During the early 1990's, the National Academy of Sciences appointed an independent panel to undertake an in-depth review of how poverty is measured in the United States. The Panel on Poverty and Family Assistance was asked to address concepts, measurement methods and information needs for a poverty measure, but not necessarily to specify a new poverty "line."

On the basis of their deliberations, the Panel recommended a new official poverty measure. In particular, it was believed that the current poverty measure had weaknesses in the implementation of the threshold concept and in the definition of family resources. Additionally, changing social and economic conditions over the last 30 years have made these weaknesses more obvious. As a result, the Panel felt the current measure does not accurately reflect differences in poverty over time and across population groups and therefore has recommended a new measure for the future.

More specifically, the Panel on Poverty and Family Assistance identified the following weaknesses in the current poverty measure. ***It does not account for:***

1) The different needs of families in which parents work or do not work outside the home.
2) Differences in health status and insurance coverage.
3) Variations across geographic areas.
4) Changing demographic and family characteristics.
5) Rising living standards.
6) The effects of important government policy initiatives that may significantly alter families' disposable income.

The Panel recognized it was not easy to recommend an alternative measure, but recommended changes based on the best scientific evidence available, their best judgment and three additional criteria. First, the poverty measure should be understood and accepted by the public. Second, the measure should be statistically defensible and consistent. Third, the measure should be feasible to implement with readily available data. More importantly, the Panel recommended that the measure should comprise a budget for the three basic categories of food, clothing, shelter (including utilities), and a small additional amount to allow for other needs (e.g. household supplies and personal care).

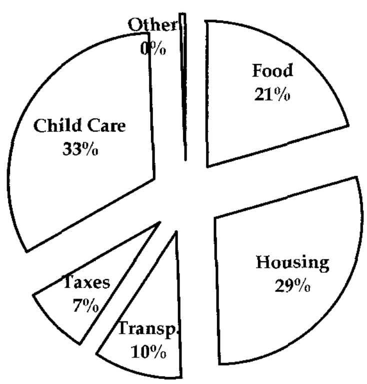
Despite the Panel's recommendations and the voices of others with similar concerns, the federal government has taken no action to adopt new poverty measures to date. In fact, the Census Bureau has recognized the data's limitations and points out that while the thresholds in some sense represent families' needs, the official poverty measure should be interpreted as a statistical yardstick rather than as a complete description of what families need to live.

This Poverty Report contains the latest figures related to poverty in Arizona using the 2000 Census numbers. Given the fact that the current official numbers remain just a statistical yardstick, ACAA also makes an attempt to more fully present what is truly happening with the poor in Arizona by introducing other local research which gets to the real public policy debate – that of self sufficiency.

Basic Needs

To fully understand the struggle of lower-income families, we need to understand Arizona's cost of living. To illustrate, the Arizona Children's Action Alliance profiles what the typical monthly expenses for a married couple with two children (ages 3 and 7) would be in Arizona. Each parent works full time and earns $7.75 per hour for an annual income of approximately $32,000 ($2,667 per month). This income places this family at about 175 percent of the federal poverty level, therefore making them not eligible for food stamps or child care subsidies. This family's monthly budget would be as follows:

- Child care: $887
- Food: $552
- Taxes: $195
- Housing: $778
- Transportation: $263
- Other: $12



Source: Children's Action Alliance 2003.

With only $12 left over in the other category, not much remains. This represents what would be left over for health care costs, phone, clothing, personal items, school supplies, haircuts... you get the picture. Even if a parent's employer provided health coverage, this family would still pay approximately $348 per month for their portion. This would be impossible with only $12 remaining.

Self Sufficiency

A recent analysis commissioned by Wider Opportunities for Women and performed by researchers at the University of Washington demonstrates what it takes for Arizona families to make ends meet on their own without public or other kinds of assistance. A report prepared for the Arizona Children's Action Alliance, *The Self-Sufficiency Standard for Arizona* (March 2002), details the wages necessary for all Arizona families to live based on the cost of living in the different communities of Arizona.

The costs include expenses necessary for working families and also take into account both the Earned Income Tax Credit and the Child Care Tax Credit by counting them as income, thus subtracting them from the monthly budget. It is based on a budget that allows solely for basic needs with no extras such as restaurant meals, retirement savings, college tuition, and emergency expenses.

This ACAA Poverty Report provides examples of the self sufficiency standard for each of Arizona's counties in the County Profile section. A careful examination of each clearly shows the challenge that many lower-income working families have providing for their basic needs. These profiles point to a very real need to shore up supports for working families in Arizona.

Although services do exist to assist the poor, budget cuts and population increases have reduced the capacity to serve many individuals in need. But the need just for the basics continues to grow. One indicator is the number of people seeking food assistance. According to the Association of Arizona Food Banks, approximately 850,000 people sought assistance in 1999 compared to 465,000 people in 1991.

We know that many families in Arizona do not get the support that they need. A recent survey of more than 700 clients using food banks in Arizona found that only 25 percent received food stamps, even though it appeared that 75 percent were eligible. Less than 25 percent of families leaving welfare use child care subsidies according to data from the Arizona Department of Economic Security. The 2000 Census reports that only 54 percent of Arizonans eligible for food stamps actually participate in the program (more than 300,000 people who qualify go without this benefit). The complicated eligibility and application process and the stigma and loss of dignity connected to the process are cited as major contributors for the low participation rate.

Working Poor

Understanding families in Arizona who are below the poverty level is only part of the story. While more families are working, many are still struggling to make ends meet as the report, *The Self-Sufficiency Standard for Arizona* (Arizona Children's Action Alliance), describes in much detail.

While there is an official poverty line, many question whether that is truly reflective of all persons who are struggling to make ends meet, particularly those working full time. For example, many people would find it hard to provide for themselves and their children on an annual salary of $23,000 a year—yet this is over 50 percent more than the official poverty threshold for a single-parent with two children ($15,260 in 2003). Furthermore, the official poverty threshold does not account for costs associated with working, such as transportation, child care, and other work-related expenses. *The Self Sufficiency Standard for Arizona* report calculates that it would take $40,153 for a single parent with two children in Maricopa County to meet basic needs, over 250 percent above the official poverty level.

Self Sufficiency Compared to the Poverty Level

Annual Self Sufficiency Wage	Adult	Adult + Infant Preschooler	2 Adults + Infant Preschooler
Apache	$14,168	$32,206	$38,947
Cochise	$14,168	$31,699	$38,555
Coconino	$19,235	$39,140	$45,958
Gila	$14,175	$33,204	$39,953
Graham	$14,168	$31,699	$38,555
Greenlee	$14,168	$31,699	$38,555
La Paz	$14,296	$31,238	$38,373
Maricopa	$18,442	$40,153	$47,495
Mohave	$14,175	$36,174	$43,053
Navajo	$14,168	$32,206	$38,947
Pima	$16,098	$36,166	$43,440
Pinal	$17,213	$36,818	$44,060
Santa Cruz	$14,761	$32,300	$39,278
Yavapai	$14,552	$33,276	$40,023
Yuma	$15,350	$33,410	$40,308
2003 HHS 100% Poverty Guideline	$8,980	$15,260	$18,400
2003 HHS 200% Poverty Guideline	**$17,960**	**$30,520**	**$36,800**

Source: Arizona Children's Action Alliance, "The Self-Sufficiency Standard for Arizona", 2002 and U.S. Department of Health and Human Services.

But who are the working poor? There is no "official" definition. To attempt to understand its extent, ACAA uses the following: families over the poverty threshold, but making below 200 percent of the poverty line, per the Census.

Why this definition? *The Self-Sufficiency Standard for Arizona* report demonstrates that this is a conservative estimate of all who potentially could be defined as working poor. Even families making 200 percent of the poverty level are still below the estimated self-sufficiency standards. Setting the lower limit at the poverty level was used principally because of data limitations, but it is still reasonable when you consider that a full-time employed single individual making the minimum wage ($10,712) is slightly above the poverty line ($8,980).

Estimated "Working Poor" in Arizona

Number of Persons Between 100%-199% of Poverty Level (% of population)	1989	1999	% Change
Apache	14,578 (24.0%)	18,629 (27.3%)	27.8%
Cochise	23,020 (25.0%)	25,852 (23.1%)	12.3%
Coconino	20,158 (22.4%)	23,698 (21.0%)	17.6%
Gila	10,639 (26.9%)	12,888 (25.6%)	21.1%
Graham	7,247 (29.7%)	8,355 (27.6%)	15.3%
Greenlee	1,774 (22.2%)	1,728 (20.4%)	-2.6%
La Paz	4,109 (29.9%)	5,593 (28.9%)	36.1%
Maricopa	369,791 (17.7%)	528,451 (17.5%)	42.9%
Mohave	21,876 (23.7%)	37,993 (24.8%)	73.7%
Navajo	19,530 (25.6%)	24,542 (25.8%)	25.7%
Pima	134,655 (20.7%)	168,231 (20.4%)	24.9%
Pinal	28,415 (25.7%)	36,919 (22.4%)	29.9%
Santa Cruz	8,564 (29.0%)	11,396 (29.8%)	33.1%
Yavapai	25,847 (24.5%)	36,170 (22.1%)	39.9%
Yuma	27,906 (27.0%)	41,762 (27.1%)	49.7%
State of Arizona	**718,109 (20.0%)**	**982,207 (19.6%)**	**36.8%**
United States	43,166,432 (17.8%)	47,294,797 (17.3%)	9.6%

Source: U.S. Census.

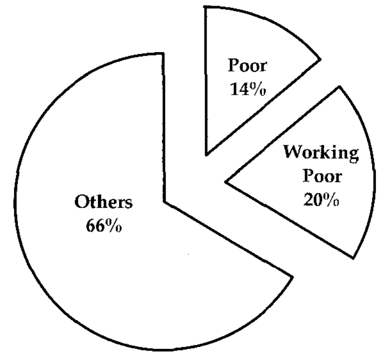
Over the last ten years, the number of working poor persons grew 36.8 percent from 718,109 in 1989 to 982,207 in 1999. When you add this to the number of people living below the poverty level in 1999 (698,669), ***there are close to 1.7 million people who are struggling to make ends meet in Arizona, one-third of Arizona's total population.***

Number of Persons Struggling to Make Ends Meet in Arizona

Total # of Persons Between 0% and 199% of Poverty Level (% of population)	1989	1999	% Change
Apache	43,218 (71.0%)	44,427 (65.1%)	2.8%
Cochise	41,741 (45.3%)	45,624 (40.8%)	9.3%
Coconino	40,963 (45.4%)	44,307 (39.2%)	8.2%
Gila	17,873 (45.3%)	21,640 (43.1%)	21.1%
Graham	13,770 (56.3%)	15,307 (50.6%)	11.2%
Greenlee	2,784 (34.9%)	2,570 (30.3%)	-7.7%
La Paz	7,984 (58.1%)	9,391 (48.4%)	17.6%
Maricopa	627,150 (30.0%)	884,119 (29.2%)	41.0%
Mohave	34,925 (37.9%)	59,245 (38.7%)	69.6%
Navajo	45,988 (60.3%)	52,596 (55.3%)	14.4%
Pima	246,535 (37.9%)	289,009 (35.1%)	17.2%
Pinal	54,567 (49.3%)	64,735 (39.4%)	18.6%
Santa Cruz	16,360 (55.4%)	20,752 (54.3%)	26.8%
Yavapai	40,155 (38.1%)	55,722 (34.0%)	38.8%
Yuma	48,458 (46.9%)	71,432 (46.3%)	47.4%
State of Arizona	**1,282,471 (35.8%)**	**1,680,876 (33.5%)**	31.1%
United States	74,909,296 (31.0%)	81,194,609 (29.6%)	8.4%

Source: U.S. Census.

The Poor and Working Poor in Arizona - 1999

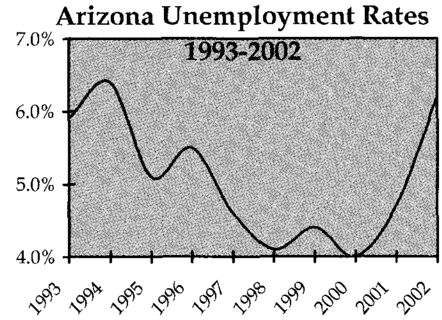


Poor = 0-99% of the poverty line.
Working Poor = 100-199% of the poverty line.
Others = Over 200% of the poverty line.

Changing Conditions

At the time the 2000 Census was taken, Arizona enjoyed the benefits of a thriving economy. Since then, Arizona, along with the rest of the nation, has experienced an economic recession. As the graph below illustrates, Arizona's unemployment rate has climbed back to the levels of ten years ago.

Arizona Unemployment Rates



Source: Arizona Department of Economic Security.

Despite the value of Census data to portray the status of poverty, it is merely a "snapshot" at the time it was taken. A more accurate picture of the conditions of poverty today may be better represented by recent data on the economy and the increasing numbers of people requesting assistance that many of the community action agencies are experiencing. When you combine this, along with the research on self-sufficiency presented by the Arizona Children's Action Alliance, most would agree that poverty is being experienced in so many more ways, than what the Census numbers reveal.

Extent of Poverty in Arizona

State of Arizona

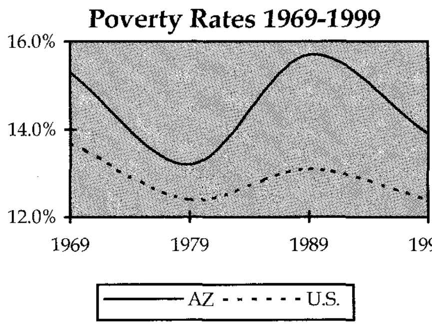
The 2000 Census revealed 5,130,632 people living in State of Arizona, a 40.0 percent increase from the 1990 Census of 3,665,228. In 1999, Arizona had nearly 14 percent of its population or 698,669 people living below the poverty level. While the overall percentage of people in poverty decreased over the last ten years, the number of people in poverty did not. In fact, Arizona experienced a 23.8 percent increase since 1989 when 564,362 people or 15.7 percent of the state's population lived in poverty. 1999 poverty rates in Arizona's counties ranged from a high of 37.8 percent in Apache County to a low of 9.9 percent in Greenlee County. The rate for all Arizona Indian reservations was 42.1 percent.

Poverty In Arizona

Number of Persons Below Poverty Level (Poverty Rate)	1989	1999	% Change
Apache County	28,640 (47.1%)	25,798 (37.8%)	-9.9%
Cochise County	18,721 (20.3%)	19,772 (17.7%)	5.6%
Coconino County	20,805 (23.1%)	20,609 (18.2%)	-0.9%
Gila County	7,234 (18.3%)	8,752 (17.4%)	21.0%
Graham County	6,523 (26.7%)	6,952 (23.0%)	6.6%
Greenlee County	1,010 (12.6%)	842 (9.9%)	-16.6%
La Paz County	3,875 (28.2%)	3,798 (19.6%)	-2.0%
Maricopa County	257,359 (12.3%)	355,668 (11.7%)	38.2%
Mohave County	13,049 (14.2%)	21,252 (13.9%)	21.0%
Navajo County	26,458 (34.7%)	28,054 (29.5%)	6.0%
Pima County	111,880 (17.2%)	120,778 (14.7%)	8.0%
Pinal County	26,152 (23.6%)	27,816 (16.9%)	6.4%
Santa Cruz County	7,796 (26.4%)	9,356 (24.5%)	20.0%
Yavapai County	14,308 (13.6%)	19,552 (11.9%)	36.7%
Yuma County	20,552 (19.9%)	29,670 (19.2%)	44.4%
All Reservations	81,609 (53.7%)	74,388 (42.1%)	-8.8%
State of Arizona	564,362 (15.7%)	698,669 (13.9%)	23.8%

Source: U.S. Census and Research Advisory Services, Inc.

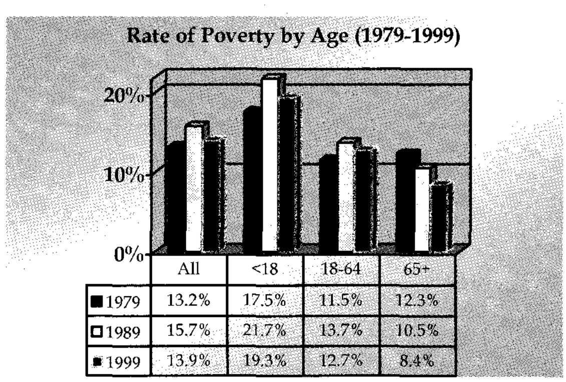
An examination of poverty rates over the last thirty years shows how the rate dropped during the 1970's and 1990's, and rose during the 1980's in the state of Arizona and nation as well. In 1999, Arizona's poverty rate at 13.9 percent continues to be higher than the national average of 12.4 percent. In 1999, thirty-six states had a poverty rate lower than Arizona.



Poverty and Age

In 1999, among all age categories examined, children under 18 years of age experienced the highest rate of poverty at 19.3 percent, while those 65 and older had the lowest rate at 8.4 percent. Over the last ten years, the rate of poverty has decreased for all age groups. The 1999 rates are still higher than twenty years ago for all age groups except for those over 65 who experienced an improvement from 12.3 percent in 1979 to 8.4 percent in 1999.

An examination of national poverty rates reveal that while Arizona's was higher than the U.S. average in 1999 among children and the working age population (18-64), the senior citizen poverty rate was lower (8.4 percent in Arizona compared to 9.9 percent nationally).



	All	<18	18-64	65+
■1979	13.2%	17.5%	11.5%	12.3%
□1989	15.7%	21.7%	13.7%	10.5%
■1999	13.9%	19.3%	12.7%	8.4%

Source: U.S Census.

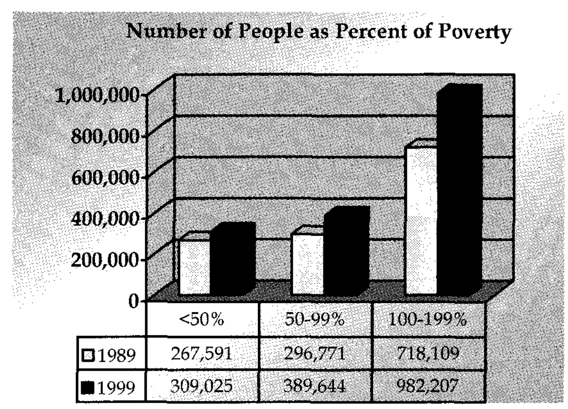
The 2000 Census revealed that one out of every five children in Arizona lived in poverty. The state of Arizona had the 13th highest percentage of children in poverty in the United States in 2000. Although the child poverty rate has decreased from 22 percent in 1990 to 19.3 percent in 2000, the number of children living in poverty has increased from 215,846 to 257,710, an increase of 19.4 percent or 41,864.

The 2000 Census reveals other indicators to show the extent of poverty for Arizona's children:

- Over 44 percent or 591,601 of Arizona's children are living below 200 percent of the poverty line.
- Over 29 percent of all Arizona children (400,675) live in high-poverty neighborhoods where more than 20 percent of the population is below poverty.

Poverty and Income Levels

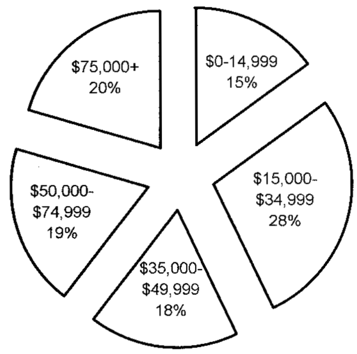
Examination of the income to poverty ratio reveals that 309,025 people or 44.2 percent of those below the poverty rate in the State of Arizona were *very poor,* with incomes less than 50 percent of the poverty threshold. Another 982,207 people had incomes equal to or above the poverty level, but less than 199 percent (ACAA's definition of "working poor"). ***In total, there are close to 1.7 million people in Arizona who are poor or "working poor," one-third of the state's total population.***



	<50%	50-99%	100-199%
□1989	267,591	296,771	718,109
■1999	309,025	389,644	982,207

Source: U.S Census.

1999 Household Income Distribution – State of Arizona



Source: U.S Census. Note: The median household income in Arizona was $40,558 in 1999 compared to $27,540 in 1989 (47.3 percent increase).

The median household income for Arizona in 1999 was 3.4 percent less than the national average. The average 1999 per capita personal income in Arizona was $23,937, 14 percent below the national average of $27,880. Compared to all the states, Arizona ranked 37th in per capita personal income.

The following shows how counties compare to the nation's per capita personal income.

Per Capita Personal Income As a Percent of the U.S.	1999
Apache	47%
Cochise	65%
Coconino	75%
Gila	64%
Graham	49%
Greenlee	71%
La Paz	63%
Maricopa	96%
Mohave	64%
Navajo	50%
Pima	82%
Pinal	52%
Santa Cruz	60%
Yavapai	71%
Yuma	57%
All Metropolitan Areas	89%
All Nonmetropolitan Areas	61%
State of Arizona	85%

Source: U.S. Department of Commerce, Bureau of Economic Analysis.

Despite the tremendous overall economic growth of the 1980's and 1990's, the gaps between high-income and low- and middle-income families are historically wide, according to a recent study by the Center on Budget and Policy Priorities and the Economic Policy Institute. According to the study, Arizona is among 10 states with the largest gap between the rich and the poor. From 1998 to 2000, the richest fifth of Arizona households earned an average of $135,114, about ten times the $13,453 earned by the poorest fifth. The national average was also 10 times the poorest fifth, but Arizona was higher than 41 other states. The 10 states with the largest income gap ratios:

The Gap Between the Rich and the Poor

State	Average Income of Bottom 20% Families	Average Income of Top 20% Families	Top-to-Bottom Ratio
1. New York	$12,639	$161,858	12.8
2. Louisiana	10,130	117,374	11.6
3. Texas	12,568	138,001	11.0
4. California	14,053	154,304	11.0
5. Massachusetts	15,740	165,729	10.5
6. Tennessee	13,078	137,524	10.5
7. Kentucky	12,602	130,825	10.4
8. Alabama	11,781	120,473	10.2
9. Arizona	13,453	135,114	10.0
10. North Carolina	13,110	131,598	10.0
U.S. AVERAGE	**$14,618**	**$145,985**	**10.0**

Source: Economic Policy Institute using U.S. Census figures.

In fact, Arizona's income gap has widened significantly during the past two decades. The average income for Arizona's poorest fifth fell by nearly 7 percent in inflation-adjusted dollars from 1978-1980 to 1998-2000, compared with a 7 percent gain nationally. Across the board, among the poor, middle class and wealthy, Arizonans ranked lower than the nation in average income.

Poverty and Families

In 1999, the poverty rate among all families with children under 18 years of age living in the State of Arizona was 15.2 percent. The rates for families with children headed by single females were 32.1 percent and even higher with younger children (less than 5 years) at 43.7 percent. Married couple families with children experienced a much lower rate at 9.6 percent.

Poverty and Families

Number Below Poverty Level (Poverty Rate)	1979	1989	1999	% Change '79-'99
All	67,577 (9.5%)	108,662 (11.4%)	123,318 (9.9%)	89.9%
With children under 18	49,395 (13.2%)	84,870 (17.5%)	102,378 (15.2%)	107.3%
Female-headed with children under 18	20,169 (34.5%)	39,910 (40.0%)	46,150 (32.1%)	128.8%
Female headed with children under 5*	10,508 (48.3%)	21,203 (56.4%)	23,205 (43.7%)	120.8%

*1979 numbers include 5 year olds. Source: U.S. Census.

Poverty and Race

Among racial/ethnic groups, American Indians experienced the highest poverty rate at 36 percent and Whites had the lowest at 10.1 percent. American Indians were also represented at a disproportionately higher rate among those in poverty than in the overall population. All races in the State of Arizona saw an improvement in poverty rates from 1989.

Poverty and Race

Race Ethnicity	% of Total Population 1999	% of Poverty Population 1999	Poverty Rate by Race 1999	Poverty Rate by Race 1989
White	75.5%	55.9%	10.1%	11.3%
Black	3.1%	4.1%	18.1%	27.5%
American Indian	5.0%	13.2%	36.0%	49.2%
Asian/PI	1.9%	1.7%	12.1%	16.2%
Other	14.5%	25.1%	23.6%	30.8%
Hispanic Origin*	25.3%	44.4%	24.0%	28.3%

NOTE: Categories include those identifying themselves as Hispanic.
*Those of Hispanic Origin may be of any race. Source: U.S. Census.

Poverty on Indian Reservations

Arizona is one of the few states with a large American Indian population. Five percent or 255,879 people in Arizona reported themselves as American Indian. Nearly 177,000 people lived on reservation lands, which incorporate over one-fourth of the state's land mass. The 2000 Census surveyed 20 reservations in Arizona. Poverty rates ranged from a low of 6.6 percent to a high of 94.4 percent. Poverty rates among people living on reservations were higher than the non-reservation population (42.1 percent and 12.9 percent respectively).

Poverty on Reservations

Number of Persons Below Poverty Level (Poverty Rate)	1989	1999	% Change (Number of Persons)
Camp Verde Yavapai Apache	381 (62.6%)	256 (33.4%)	-32.8%
Cocopah	319 (55.2%)	330 (31.4%)	3.4%
Colorado River	1,914 (28.2%)	1,590 (22.2%)	-16.9%
Fort Apache	5,273 (50.8%)	5,949 (48.8%)	12.8%
Fort McDowell	177 (28.2%)	144 (17.4%)	-18.6%
Fort Mohave	213 (49.8%)	133 (18.5%)	-37.6%
Fort Yuma	16 (100.0%)	34 (94.4%)	112.5%
Gila River	5,975 (63.0%)	5,625 (52.1%)	-5.9%
Havasupai	130 (30.0%)	223 (50.2%)	71.5%
Hopi	3,456 (48.2%)	2,808 (41.6%)	-18.8%
Hualapai	446 (54.7%)	462 (35.8%)	3.6%
Kaibab	33 (27.5%)	75 (31.6%)	127.3%
Maricopa (Ak-Chin)	198 (44.6%)	198 (27.0%)	0.0%
Navajo	48,968 (54.4%)	43,522 (41.9%)	-11.1%
Papago (Tohono O'Odham)	5,517 (65.1%)	4,929 (46.4%)	-10.7%
Pasqua Yaqui	1,474 (62.9%)	1,435 (43.8%)	-2.6%
Salt River Pima Maricopa	1,896 (40.2%)	1,923 (30.5%)	1.4%
San Carlos	4,447 (62.0%)	4,724 (50.8%)	6.2%
Tonto Apache	13 (12.6%)	16 (9.8%)	23.1%
Yavapai-Prescott	34 (17.9%)	12 (6.6%)	-64.7%
All Reservations	81,609 (53.7%)	74,388 (42.1%)	-8.8%
State of Arizona	564,362 (15.7%)	698,669 (13.9%)	23.8%

Source: U.S. Census and Research Advisory Services, Inc.

Between 1989 and 1999, the number of people below the poverty level for those living on reservations dropped 8.8 percent. While some continue to see increases in the number of people in poverty, others saw significant improvements. This was not just isolated to tribes with gaming. The Hopi and Navajo Nations experienced an 18.8 percent and 11.1 percent decrease respectively.

Public Assistance

According to the 2000 Census, 54,645 households or 2.9 percent of all households in the State of Arizona received public assistance. Public assistance or welfare payments include cash public assistance payments low-income people receive, such as Aid To Families With Dependent Children (AFDC), Temporary Assistance To Needy Families (TANF), general assistance, and emergency assistance. The mean or average amount of annual public assistance income for 1999 was $2,596, a decrease from the 1989 average of $3,711 and $3,865 in 1979.

Participation levels in the Food Stamp and Temporary Assistance to Needy Families (TANF) programs serve as indicators of the extent of poverty in the State of Arizona. In April of 2000, 256,006 people or 5 percent of the population received food stamps. At the same time, 32,927 or 2.5 percent of families were enrolled in TANF.

Public Assistance (PA)	Base Year	1990	2000	% Change 1990-2000	% Change Base Year-2000
Households receiving PA (1980)	50,044	84,132	54,645	-35.0%	9.2%
Persons Food Stamps (1985*)	208,589	322,735	256,006	-20.7%	22.7%
Families AFDC-TANF (1985*)	25,803	44,278	32,927	-25.6%	27.6%

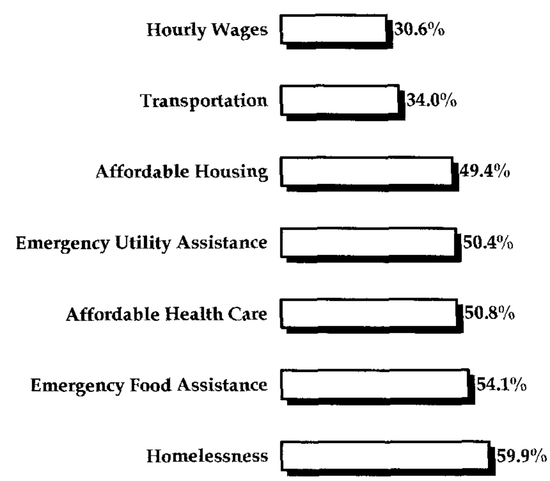
NOTE: Base year in parentheses. *April figures. TANF is the new name for Aid to Families with Dependent Children (AFDC). Source U.S. Census and Arizona Department of Economic Security.

These numbers are particularly telling when you compare them to the people who could benefit from the assistance these programs provide. As presented earlier, ACAA estimates that there are close to 1.7 million people who are struggling to make ends meet in Arizona, one-third of Arizona's total population. The demand for assistance clearly exceeds Arizona's capacity to serve the need.

Perceptions from the Community

Community meetings were essential to the creation of the first two POVERTY IN ARIZONA volumes. To continue this process, between 2000 and 2002, ACAA held two series of twenty-nine community meetings around the state to gather thoughts and opinions about Arizona's poor and to provide suggestions to help end the cycle of poverty. Meetings were held in every county in Arizona. Participants included local elected officials, private citizens, business owners, and low-income persons.

Over 1,100 people participated and were surveyed on issues that affect poverty in Arizona. The chart below shows the percentage of participants who believe conditions have gotten ***worse*** in the following areas over the last ten years:



NOTE: On average, 10 to 20 percent of respondents had no opinion. Results by county are presented in each county profile.

In addition to the survey, ACAA sought public comments at each of the community meetings. Participants from all corners of the state, both urban and rural, cited low wages as a top concern. Communities agreed that although wages have increased over the last 10 years, they have not increased enough to keep up with the cost of living. The primary factor in the cost of living increase is housing, both the rising cost and the limited availability of affordable housing throughout most of the state. Transportation services have shown some improvement, according to participants from urban areas where increased services such as extended hours and increased bus routes are evident. However, rural areas have seen no improvement in transportation services, and have experienced diminished services due to funding cuts.

Access to benefits and the availability of assistance is a challenge to Arizona's low income families. Participants report that the ability to access government benefits for which they are eligible differs depending on the benefit in question. Many believe that healthcare benefits improved with the expansion of AHCCCS and KidsCare but that other benefits are more difficult to obtain. The biggest concerns about healthcare are affordable prescription medicine, and available doctors who accept AHCCCS patients.

The majority of respondents to the survey believe that homelessness, hunger and requests for emergency assistance have increased. Numbers from state and private agencies support this public opinion.

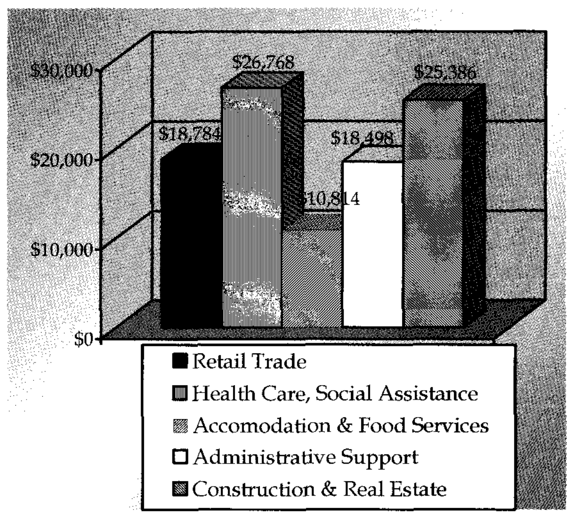
Most participants agreed that programs such as Head Start, school lunches and KidsCare were beneficial and merited increased funding. Participants expressed an overwhelming desire for more job training and education, due to the huge concern for economic development and job creation with better wages.

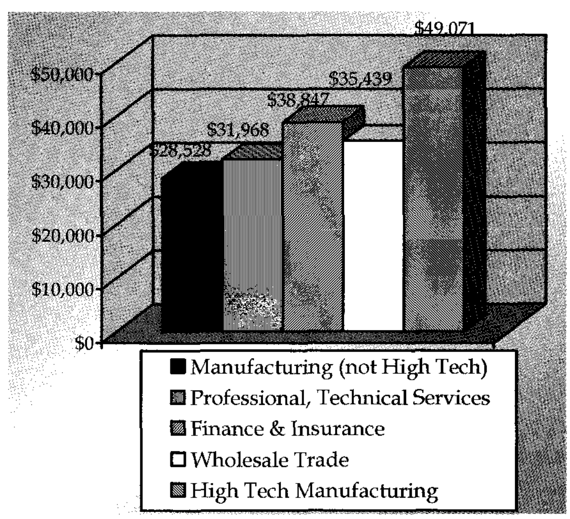
Contributing Factors To Poverty

Substandard Wages

Low wages continue to be the primary challenge for low-income families across the state. The Morrison Institute publication, *Five Shoes Waiting to Drop*, provides some insight on the challenge of a low wage legacy. It states, "Arizona always looks like an economic success because the state racks up impressive job growth numbers. Once again, however, this seemingly positive trend obscures a deeper, more worrisome concern: Most of these new jobs don't pay well." The charts below show how jobs in six of Arizona's ten industrial sectors have an average annual salary below the U.S. average of $29,245. These six sectors make up 63 percent of all Arizona jobs.

Average Annual Wages by Industry





Source: Morrison Institute and Center for Business Research, Arizona State University 2001

The report goes on to highlight Arizona Department of Economic Security job forecasts for 2008 that predict half of the state's workforce will be employed in either tourism or retail at an average wage of about $12 per hour, or less than $25,000 per year. Of the 25 fastest growing jobs in the state, most require no higher education and pay, on average, less than $11 per hour.

One emerging facet of the working poor that is especially prevalent in metropolitan areas of the state is the phenomenon of day labor. Literally thousands of workers in Arizona engage in day labor, which consists of temporary, primarily manual labor jobs. A 2002 study by the Center for Applied Sociology at the University of Arizona demonstrates that many day laborers receive wages far below the minimum wage. Because many are charged for equipment, transportation, and food, the actual average wage many day laborers receive is around $3.87 per hour.

Unfortunately, many low-income persons are ill equipped to compete for the good jobs. Government, business and providers must help them to overcome these obstacles. Employment assistance, job training and the promotion of life-long learning are keys to eliminating poverty. Quality education and training programs can substantially enhance an individual's chances of securing employment, earning a livable wage and offering room for advancement.

Not only are low-income families earning low wages, many are missing out on other sources of income that is rightfully theirs. A number of families with divorced parents are missing needed income to support their children due to poor child support collections. For the year 2000 in Arizona, over $1.5 billion in child support remained uncollected. While this represents all families, many low-income families are represented in this amount. In 2000, Arizona ranks 42nd of all the states on collections:

Child Support Collection Rates - 2000

State		# Children	Amount Due	Collection Rate
1	Iowa	230,803	$1,033,544,530	71%
4	Utah	98,901	$380,271,416	69%
16	Idaho	79,766	$321,155,275	55%
17	Colorado	158,152	$1,198,413,411	53%
23	Oregon	275,093	$1,029,546,497	46%
26	Wyoming	35,530	$239,443,985	45%
35	California	2,388,343	$15,773,984,622	39%
42	***Arizona***	***283,842***	***$1,525,819,973***	***34%***
43	Nevada	143,422	$641,849,978	34%
47	Texas	1,298,459	$7,887,487,252	29%
50	New Mexico	150,845	$411,385,785	18%
51	Illinois	1,148,908	$2,372,520,354	16%
United States		19,449,414	$83,954,091,390	42%

Source: Federal Office of Child Support Enforcement, U.S Department of Health and Human Services.

Housing Affordability

According to the *2002 Arizona Affordable Housing Profile* (Arizona Housing Commission), affordable housing is defined as a household's ability to pay 28 percent or less of its income on housing (not including utilities). The "affordability gap" is the difference between the number of households within each income range and the number of housing units affordable to those households.

This "affordability gap" was identified during a housing inventory to help each community in Arizona address housing affordability issues. Using the 2000 Census, the total affordability gap in Arizona is estimated at 194,700 or about 10.3% of all households, including those on Native American reservations. This report concluded that the lowest income households have the most serious housing needs and have few alternatives to secure affordable housing. Left with no choice, many low-income families double up to share costs or pay more than they should for housing. The 2000 Census reports that 16.2 percent of homeowners and 30.0 percent of renters pay 35 percent or more of their income for housing.

Affordability Gap By County

(Excluding Native American Reservations)

County	Affordability Gap (Households)	Total Households (2000)	Gap as % of Total Households
Apache	57	5,075	1.1%
Cochise	1.945	43,893	4.4%
Coconino	5,232	34,294	15.3%
Gila	2,421	18,524	13.1%
Graham	248	9,127	2.7%
Greenlee	-	3,117	0.0%
La Paz	835	5,937	14.1%
Maricopa	108,547	1,130,029	9.6%
Mohave	3,840	62,151	6.2%
Navajo	1,614	18,897	8.5%
Pima	25,142	328,980	7.6%
Pinal	1,870	58,895	3.2%
Santa Cruz	2,070	11,809	17.5%
Yavapai	11,950	69,923	17.1%
Yuma	5,336	53,428	10.0%
State (excl. Reservations)	171,107	1,854,079	9.2%
Reservations	23,654	41,703	56.7%
State of Arizona	194,761	1,895,782	10.3%

Source: Affordable Housing Profile, Arizona Housing Commission and Pollack & Company.

The National Low Income Housing Coalition recently published, *Rental Housing for America's Poor Families: Farther Out of Reach than Ever - 2002*. The study showed that the hourly wage necessary to afford a two-bedroom rental unit in the Phoenix/Mesa region is $15.50 an hour for a 40-hour week, or 301 percent of the minimum wage. A rental unit is considered affordable if it costs no more than 30 percent of the renter's income. Between 2000 and 2002, the wage required for two-bedroom housing increased by 22.8 percent; the federal minimum wage remains unchanged since 1997.

Home energy costs are also financially crippling low-income Arizona households. Arizona households with incomes of below 50% of the Federal Poverty Level pay 40% or more of their annual income simply for their home energy bills.

The lack of affordable housing is also one of the primary reasons people become homeless. Other reasons include the lack of livable wages; untreated mental illness and substance abuse disorders; or a variety of other unexpected circumstances. But regardless of the reason, the majority of people who are homeless share one thing in common -- they are poor.

In 2001, the Arizona Department of Economic Security (DES) reported 30,277 homeless persons on any given night in Arizona, a significant increase from the 6,700 - 14,100 reported in 1991. Forty-three percent of homeless people in Arizona were persons in families, sixty-two percent of them children, while fifty-seven percent were single individuals including homeless youth.

Although housing and support services for persons who are homeless continue to increase, they are still largely inadequate. In 2001, DES reported a total of 8,474 emergency shelter and transitional housing beds for the approximately 30,000 homeless persons, leaving roughly 21,500 people with no roof over their heads.

An increasing number of state and local governments are recognizing that housing assistance is critical to the success of welfare reform and lifting families out of poverty. How can housing subsidies help? By making housing more affordable, they help stabilize the lives of low-income families and reduce the likelihood of problems like evictions and utility cutoffs, which can make it difficult for families to secure and retain jobs. Housing subsidies also free up funds within families' budgets for work-related expenses.

The 2002 Congressional Millennial Housing Commission report noted the success of linking welfare reform to housing assistance. The report states, "There is evidence that combining incentives to work with job-promoting services for welfare recipients is more effective for those who receive housing assistance than for other welfare families. This may be because subsidized housing provides the stability that people need to find and hold jobs, allows families to devote more of their earnings to work-related expenses such as child care, and/or helps families move to areas with better job opportunities."

Education Issues

A number of indicators show that people with the lowest incomes (bottom fifth of the population) are not likely to move out of poverty during the course of their lives. According to research (Beyond Welfare), only one out of ten individuals in the bottom income quintile have a chance to get out of poverty without appropriate education.

According to the 2000 Census, 7.8 percent of Arizona's adults 25 years and older had less than a 9th grade education and 81 percent were high school graduates or higher. Arizona lags behind the nation in the number of adults with a bachelor's degree or higher --23.5 percent to the nation's 24.4 percent. In fact, Arizona's ranking among the states dropped from 20th in 1991 to 37th in 2000 for residents with a bachelor's degree. The following shows education attainment levels by county:

Educational Attainment

County	Population 25 Years and Over		
	% With Less Than a 9th Grade Education	% High School Graduate or Higher	% With Bachelor's Degree or Higher
Apache	18.8%	63.6%	11.3%
Cochise	9.4%	79.5%	18.8%
Coconino	7.0%	83.8%	29.9%
Gila	6.4%	78.2%	13.9%
Graham	8.8%	75.6%	11.8%
Greenlee	6.3%	82.5%	12.2%
La Paz	9.9%	69.3%	8.7%
Maricopa	7.4%	82.5%	25.9%
Mohave	5.0%	77.5%	9.9%
Navajo	12.0%	71.2%	12.3%
Pima	6.4%	83.4%	26.7%
Pinal	10.6%	72.7%	11.9%
Santa Cruz	20.4%	60.7%	15.2%
Yavapai	4.6%	84.7%	21.1%
Yuma	17.4%	65.8%	11.8%
State	***7.8%***	***81.0%***	***23.5%***

Source: U.S. Census

An examination of the next generation of Arizonans does not bode well for the future. The Arizona Minority Education Policy Analysis Center's (AMEPAC) 2002 study, *"Dropping Out of Arizona's Schools"*, made the following observations:

- Almost one third of Arizona students who begin the 9th grade drop out prior to completing their high school graduation.
- A total of almost 200,000 children dropped out of Arizona's schools during the last six school years of the 1990's.
- The 1999-2000 annual drop out rate for Maricopa County (7.7%) was lower than the rate for the state as a whole (8.3% or 30,186 total dropouts).
- The lowest annual dropout rates (1999-2000) were in Cochise County (6%) and Greenlee County (3.1%), while the highest rates were found in Mohave County (10.8%), Apache County (9.8%) and Pinal County (9.9%).

AMEPAC also illustrates the costs to society for a high dropout rate due to a loss of earning potential. Over a lifetime of work, this could translate to well over half a million dollars in lost income for each individual who drops out of school. Lost income also means lost tax revenues.

In his book *Money: Who has How Much and Why,* Andrew Hacker illustrates how education adds to income. According to Hacker, men who worked full-time in 1995 but never finished high school earned an average of $20,466 a year. Men with high school diplomas earned an average of $32,689 while men with bachelor's degrees earned an average of $57,196 a year. Hacker also cites Census Bureau studies that show that during the course of a career, a college graduate can expect to earn about $600,000 more than a person with a high school diploma.

Poverty also prevents some low-income families and children from keeping up with technology. This "digital divide" keeps low income people from employment opportunities ranging from the basic need to provide résumés, to the inability to gain technical skills required by most well-paying jobs. Without access to computers and current technology, low income Arizonans find it virtually impossible to better their circumstances and rise above poverty.

Child Care

The average annual cost for full time child care ranges from $3,500 to $7,500 depending on the age of the child, the type of provider, and area of the state. With these prices, child care can cost parents more than college tuition. When low income families struggle to meet basic needs, parents seek assistance when they have no other options:

- In 1999, a monthly average of 36,590 Arizona children were in subsidized child care. (Note: at the writing of this report the number has grown to about 42,000.)
- In 2000, 11,882 Arizona children were served by Head Start, a 6 percent increase from 1999.
- In 2000, Arizona spent 5.9% of its $265 million in TANF funds on child care.

Only 4 percent of the families that receive state assistance are two-parent families. The typical family served is a single mother with two preschool age children.

Only working families with low incomes qualify for child care subsidies. The state currently only helps a family of three with gross income below $25,200 a year (165 percent of the federal poverty level). Compared to other states, Arizona's child care assistance is extremely limited according to the Arizona Children's Action Alliance. Thirty-five states have higher qualifying income eligibility levels and 41 states have lower co-pays. Eligible families in Arizona pay a significant amount of the cost. The upper qualifying levels pay a minimum of $330 per month out of pocket, or 17 percent of their gross income. Additionally, while the cost of child care has increased by 17 percent or more between 1996 and 2000, Arizona's child care subsidy amounts are still based on costs back in 1996.

As Arizona's welfare rolls shrink, the number of families needing child care assistance has grown significantly. In 1997, the Arizona Network for Community Responsibility reported that there are over 300,000 children under 13 living in low-income families who may be eligible for child care subsidies. Yet, current funding will support subsidies for only about 35,000 children. Even though not all eligible children need assistance, thousands of low-income families go without help.

Low-income families who purchase care also spend a greater proportion of their earnings on child care, according to a 2000 study by the Urban Institute. Nationally, it found, families in which the youngest child was younger than 5 spent about 10 percent of their earnings on child care, or an average of $325 per month. Low-income families spend an average of 16 percent of their earnings on child care or $1 of every $6 earned.

Because of high costs and questionable alternatives, many parents are forced into insecure child care arrangements with relatives or neighbors. Often when these arrangements fall through, parents must choose between their jobs or their kids. Additionally, more grandparents are becoming the caregivers of children. The 2000 Census showed 52,210 grandparents in Arizona who are now responsible for taking care of their grandchildren.

High quality child care is important for all children. Research has revealed that the first three years of life are critical times for brain development. Studies have shown that young children exposed to high-quality settings exhibit better learning and social skills. For example, Maricopa County Head Start tracks the outcomes for enrolled children in the areas of language and literacy, social and emotional, cognitive development and physical. In program year 2001-2002, the County saw Head State kids improve 17 percent in these areas.

Like other states, Arizona has a long way to go to ensure that those who work with young children have adequate, high quality care. The State of Arizona needs to establish the architecture for high quality child care that is available to all families. Greater attention and investments are needed. The state's investment not only will help families work toward self-sufficiency and break the bonds of welfare dependency, it also has multiple benefits throughout the economy and the State.

Health Care

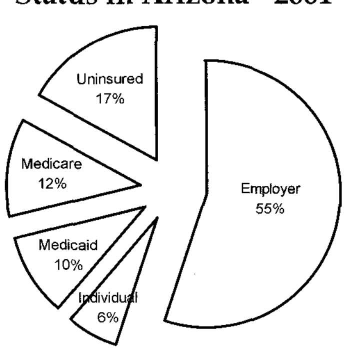
The lack of health insurance is obviously the most visible public health issue in Arizona today. The lack of adequate health care hits lower income families hard with uninsured children more likely to go without preventive care and immunizations and sometimes not receiving medical care when they need it.

Until recently, Arizona, like many other states, enjoyed a healthy economy that provided funding for a variety of health services programs, including direct services for low-income families and various prevention programs. Now with the recent economic downturn and lower state revenues, the state has begun to reduce the availability of health services to many lower-income families.

Increasing health care costs are impacting all Arizonans. For example, the largest employer in Arizona, State Government, has experienced increases in employee health insurance premiums by as much as 66 percent. Increases in co-payments for office visits and medications are projected to be up as much as 400 percent. If those with health insurance are experiencing these increases, imagine the costs facing lower-income families and the uninsured.

St. Luke's Health Initiatives (St. Luke's) reports that Arizona's uninsurance rate in 2000 was one of the highest in the nation at 16 percent or 805,000 people without health coverage. The Kaiser Family Foundation reported a 17 percent uninsurance rate for Arizona in 2001.

Population Distribution by Insurance Status in Arizona - 2001



Source: Kaiser Family Foundation, State Health Facts.

Using data from the Center for Cost and Financing Studies, the Kaiser Family Foundation also reports that in 2000, 62.9 percent of Arizona's private sector employers offer health insurance to their employees. This is slightly better than the national average of 59.3 percent. St. Luke's also reports that businesses with 10 employees or less have the highest rate of uninsurance at 45 percent. This is particularly disturbing when small businesses make up the majority of employers in Arizona.

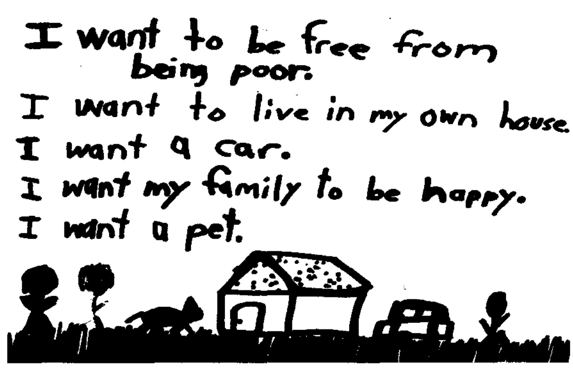
The American Academy of Pediatrics estimated that about 356,000 of the 1.4 million children in Arizona still do not have health insurance in 2000. They also state that more than three-fourths of the number of uninsured children in Arizona are eligible for Medicaid or KidsCare but are not enrolled. While public programs exist, there are many families who make too much to qualify, but not enough to allow them to purchase coverage on their own (insurance premiums can equal more than 20 percent of their take home pay). Many of these families turn to community clinics that offer a sliding fee scale. St. Luke's recently reported that numbers are up at all clinics - roughly in the 5-10 percent range - and providers informally note that the general population seems to be in greater need of immediate medical attention.

While high costs are a barrier to quality health care, close access to services in many rural areas can also be a problem. The Arizona Department of Health Services primary care data show substantial portions of the state's rural population live more than half an hour away from any kind of health care service and cope with minimal services.

Ironically, people who are working but lack health insurance have a harder time getting care than people who aren't working. If you are unemployed in Arizona, chances are you'll qualify for AHCCCS health insurance benefits. But if you're employed in a job where you make more than the AHCCCS eligibility ceiling - up to 100 percent of the federal poverty level ($17,650 for a family of four) - then your options are limited unless your employer provides a health insurance benefit.

Over the past few years, the Arizona Health Cares Campaign has promoted KidsCare, Healthcare Group and Premium Sharing (which is being eliminated in 2003) in an effort to increase awareness of these alternative public health coverage products. While nearly 100,000 children and families have been provided new coverage thanks to the public outreach campaign, more than 800,000 people still remain uninsured.

Not only should health insurance be expanded, but also Arizona needs to continue to strengthen the development of a comprehensive safety net for health care. This safety net should support an array of organizations that are providing significant care to Medicaid patients, the underinsured and other "vulnerable" populations. These organizations include many county and community hospitals/clinics that are explicitly charged with providing services to those who are poor and unable to get health care through other means. Public officials, private hospitals and other safety net providers need to come together and explore ways to improve safety net services for the uninsured and the working poor.



Transportation

Low income Arizonans cite transportation as one of the most significant barriers to finding and maintaining employment. Studies show that a parent with a car is more likely to be employed and work longer hours than one without a car (Joint Center for Poverty Research). Lack of transportation is a barrier for the following reasons:

- Low income families live far away from job opportunities. This is true in both urban and rural areas.
- Public transportation does not meet the current needs (lack of public transit systems in rural areas, non-standard work hours, the need to stop at other destinations en route to work such as child care centers).
- Car ownership is too expensive; insurance and maintenance costs are difficult for low income people to pay.

A number of programs are available to states and communities to respond to the transportation needs of low-income people. For example, TANF-funded allowances -- transit passes, reimbursements, vouchers or cash payments -- could be made available for income eligible families.

Also, networks of alternative transportation providers (currently in existence for specific populations, such as Dial-A-Ride), can be the "building blocks" for alternatives for low income workers. In fact, Pinal County Head Start operates a transportation service for low income working parents that could serve as a model for other communities. Some states like Kansas and Nebraska provide funds for auto licensing fees, insurance costs and taxes for low income workers who require cars for employment.

Arizona was recently among six states using Temporary Assistance to Needy Families (TANF) funds to support car ownership programs that solicit donations of cars. Unfortunately, Arizona's Wheels to Work program which provided 271 individuals with vehicles in 2001, was eliminated in 2002 due to lack of state funding.

Welfare Reform

In 1996, Arizona adapted its existing welfare program, EMPOWER (the state's version of the federal Temporary Assistance to Needy Families [TANF] program), after Congress passed welfare reform nationwide. The federal legislation shifted the measure of success away from family economic stability to reduced caseloads with an emphasis on transitioning people to work. Many studies tout the success of welfare reform as demonstrated by high caseload reductions.

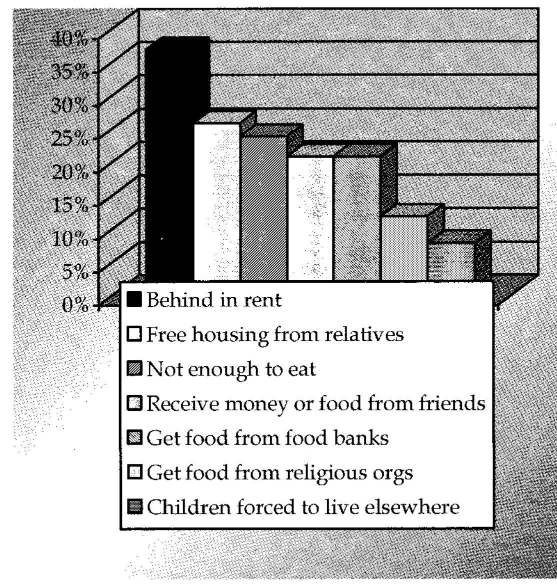
Like the rest of the country, Arizona has enjoyed tremendous success in reducing the number of families on welfare. Between April 1990 and April 2000, Arizona experienced a 25.6 percent decrease in caseloads, moving from 44,278 families to 32,927.

While many former recipients are transitioning to work, most continue to struggle economically. Not only do employed former welfare recipients generally have low earnings, but as their earnings grow, they lose other public benefits (i.e. food stamps). Going to work also may increase their work-related expenses, such as for child care and transportation, which cancels out part of their new earnings.

In 2000, the Arizona Department of Economic Security conducted the Arizona Cash Assistance Exit Study that followed over 10,000 families who left welfare. Of those 10,000, more than 800 participants were interviewed. Approximately 43 percent of those interviewed were not working at the time, even after leaving welfare. The remaining 57 percent reported an average wage of $7.47 an hour. Reports continue to show average annual wages of former welfare recipients to be less than $10,000 annually.

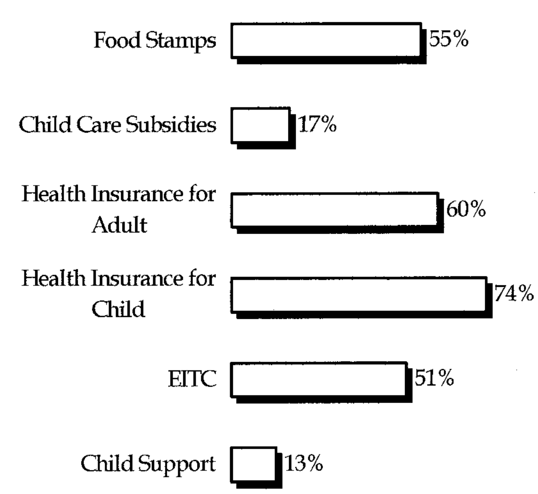
According to the Arizona Network for Community Responsibility, survey data also suggests that many families continue to struggle coming off of welfare. Many are getting behind in rent, rely on family for shelter, or do not have enough to eat at times and rely on getting food from others. Almost one out of every ten parents reported that they were forced to send children elsewhere to live.

Percent of Families Reporting Need



The Arizona Network for Community Responsibility also reports that while virtually all families leaving welfare would qualify for various kinds of other public assistance, only 60 percent or less of families take advantage of these critical supports. With the exception of child care subsidies, the primary reason families say that they do not use the program is because they thought they were not eligible.

% of Former Welfare Families Seeking Services



Philosophical Reflections

Shared Responsibility

Just as many in Arizona value hard work and individual responsibility, we must also value the necessity of caring for and sustaining families in poverty. Just as society finds ways to invest in protecting and preserving our natural resources, it is time to re-examine our commitment to our most precious resource - people.

Arizona must begin to recognize that the persistence of poverty, as a key determinant of health, compromises the long-term well being of our state and future generations. Public policy must recognize that any and all families can be vulnerable to factors that lead to poverty. ACAA believes the time has come for a comprehensive vision to end poverty in Arizona. But ACAA cannot do it alone. Others who are moved to compassion and committed to help must share this vision.

Community Involvement

We must all work together to solve poverty. The active involvement of different actors is essential. Government, business, the non-profit and faith community, along with any caring individual all have distinctive contributions to make:

- Government intervention and interagency cooperation is key to the success of any poverty reduction strategy.
- Private sector must show leadership and involvement to demonstrate corporate responsibility and investment back to the community.
- Non-profits and advocacy groups, including the media, have a critical role in promoting open dialogue and consultation.
- Faith-based organizations in Arizona are a strong, largely untapped resource with thousands of motivated volunteers.

Arizonans have proven they care, with over half reporting in a recent Arizona State University study that they both volunteer and/or make a household financial contribution to a charity. Over 87% of those polled reported making a financial contribution to a charitable organization in the past 12 months with a $1,572 average total amount donated.

Strategic Focus

Any serious effort at reducing poverty needs to have clearly articulated goals. The primary mission of Arizona's anti-poverty campaign should be the reduction of poverty and the enhancement of economic security of our most vulnerable families. To do this, Arizona needs social welfare and other policies that:

1) Ensure that those who work for a living earn a "livable wage" so they can support their own families.
2) Provide necessary resources for those who want to better themselves by providing basic nutrition, affordable housing, health care, child care, transportation, or assistance in pursuing advanced education.
3) Maintain a decent safety net to provide for basic needs and to protect families during hard times.

ACAA is committed to certain principles that are necessary to effectively meet these goals:

- Anti-poverty efforts should be focused not only on alleviating poverty but also on improving overall family and child well being.
- Anti-poverty programs need to provide comprehensive family supports that combine job training, quality job creation, job placement, job retention, health insurance, high quality child care and transportation services.
- Policy makers and providers need to use quality data to support the design of good policy and effective programming.
- As more and more public programs are evaluated for effectiveness, efforts should be redirected toward those that are truly making a difference.
- When public and private entities are looking to expand efforts, the community should look for ways to collaborate to maximize existing anti-poverty efforts.
- The public sector needs to provide a significant and consistent commitment of resources that are seen as a "hand up" not a "hand out."
- Decision makers need to establish clear priorities in state and local policy-making, recognizing that resources are limited.

Arizona's Priorities

If the state is serious about improving quality of life for all citizens, certain issues need to be placed at the top of the public policy agenda.

Economic Development & Jobs

People who work full-time should not live in poverty but earn a living wage. Our state and our nation need a set of policies that will raise wages, provide opportunities for the development of real job skills, expand tax benefits for the poor, and create higher quality, living wage jobs.

With the New Economy upon us, Arizona's commitment to serious economic development and high quality job creation is needed now more than ever. But this will happen only if the state is focused and ready, leaving no one behind.

To position Arizona in the global economy, economic developers should focus their strategies in areas that will lead to the creation of higher paying jobs:

- Target relocating corporate headquarters and attracting technology investments and other higher-paying "clean" industries.
- Help existing business to thrive and expand by providing training and assistance to upgrade old economy enterprises (i.e. incorporating technology into existing industry, both worker and industry training).
- Develop policies and support the implementation of a statewide workforce development system, congruous with the economic development initiatives that will effectively prepare Arizonans for work.
- Assist Arizona's communities and Indian Tribes to develop a sense of place (quality of life) and the foundations necessary for future economic growth through careful planning and capacity building.
- Support and accelerate entrepreneurship, small business creation/expansion, and the development of new emerging industries by providing assistance, capital, and other incentives.

Education

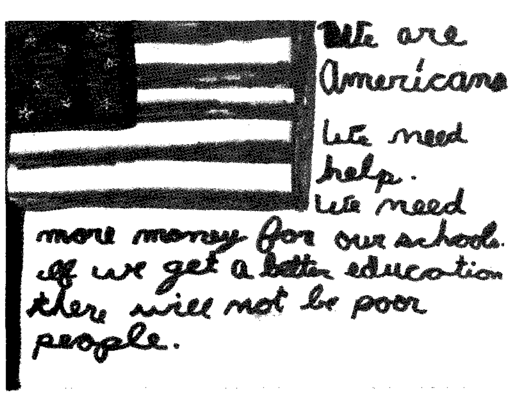
The Morrison Institute's recent report, *Five Shoes Waiting To Drop*, highlighted the importance of knowledge and education for Arizona's future. The report claims that talented prospective workers have reservations about locating in Arizona because of:

- Poor Performing Public Schools (52%)
- Lack of Workforce Training Programs (27%)
- Image of Sprawling Communities (15%)
- Not Considered a "Cool" Place (14%)
- Lack of Cultural Diversity (14%)
- Not Top-Tier Technology Hot Spot (10%)
- Lack of Environmental Amenities (2%)

Not only does this have ramifications on the State's economic development efforts, it is telling about what others think of our public education system. But it's not just perception:

- Student achievement is questionable: reading scores showed minimal gains in 2002 compared to 1997. (*Arizona Department of Education's analysis of Stanford Achievement Test, Ninth Edition (SAT9) results for Spring* 2002)
- Arizona's public school spending is grossly inadequate. Education Week gives Arizona a failing grade of F for the adequacy of its public school spending. *(Education Week, Quality Counts 2002)*

Quality education is central in a strategy to reduce poverty. Arizona must strengthen the foundations for increasing academic achievement, improving graduation rates, and encouraging lifelong learning.



Prevention and Early Intervention

Often a crisis will happen before a family in poverty will seek help. Many times, the cost of dealing with a family's situation may be more problematic than had the family sought assistance sooner.

There are a number of strategies the state and communities can take to be more proactive than reactive when it comes to issues that adversely affect the family. They include:

- *Community Mobilization*: Develop ongoing grassroots efforts and partnerships to coordinate resources and deal effectively with issues affecting families in poverty. For example, implementation of the proposed "211 system" represents a tremendous opportunity to promote true collaboration to improve the delivery of health and human services in Arizona.
- *Public Information*: Offer targeted messages and promotional material on topics and services available to assist low income families.
- *Targeting Of High-Risk Families*: Identify areas and neighborhoods with high levels of poverty to offer targeted education and assistance.
- *Comprehensive Family Education*: Offer training on issues critical to life and social skills. Healthy Families Arizona is an example of a program that offers such service including encouraging self-sufficiency through education and employment; modeling effective parent-child interactions; providing child development, nutrition, and safety education; and linking families with other community services.
- *Mentorship*: Promote the use of positive role models to provide support and guidance to assist individuals in achieving personal growth.

Sound Fiscal Policy

Recently, many individuals and advocacy groups have been voicing their concerns over Arizona's fiscal policies. This movement gained ground with the formation of a new coalition – Protecting Arizona's Family Coalition – made up of various human service providers and those who care about the well being of families.

The Coalition formed in response to the current state fiscal crisis and the potential loss of human services funding. The work of human services providers is even more critical during these times because of the downturn in the economy. ACAA stands united that we cannot morally cut services to our poorest and most vulnerable citizens and must continue to promote their general welfare. In fact, ACAA has been promoting this agenda since its inception over 30 years ago.

In particular, ACAA is advocating for true tax reform, starting with an elimination of special interest tax exemptions. The Morrison Institute notes the "revenue sieve" of tax exemptions, stating: "Arizona no longer has a balanced and efficient tax structure." ACAA supports and will work with others in researching equitable tax structures and advocating for fair changes in the tax structure.

ACAA supports maintaining human service funding and believes that in order for human needs to be met, the state must increase revenue to pay for it. We believe that Arizonans have demonstrated they are willing to be taxed for essential services and are willing to do what is necessary for their working families.

But it's not just human service agencies that are calling for a change in tax policy. Participants at a recent Arizona Town Hall stated it best: "Arizona needs to have a cohesive overall tax policy and should form a community-based task force to engage in a thorough examination of its tax system at all levels to insure that Arizona's tax system is adequate, equitable and competitive." Governor Napolitano has responded with the creation of a Citizens Finance Review Commission that will be making recommendations by the end of 2003.

Building Wealth

America's current financial system does little to support low-income working people. Many U.S. tax policies assist those who already are accumulating assets. At the same time the government encourages the affluent to save, it requires the poor to deplete their assets in order to be eligible for public assistance.

One-quarter (25 percent) of U.S. households have net assets under $10,000, and therefore are "wealth-poor," concludes a joint report by the Consumer Federation of America (CFA), the National Credit Union Foundation (NCUF), and the Credit Union National Association (CUNA) using 1998 figures. The report also found that these wealth-poor households are more likely than other American families to plan for the next few months, rather than years; spend more than their incomes; and not save regularly.

The 2001 Survey of Consumer Finances by the Federal Reserve reveals the need for most American households to save. While the typical household has net assets of $86,100 (mostly home equity), it has net financial assets (including retirement accounts) of only $24,500. Moreover, the typical low to moderate income household has net financial assets of less than $2,000. Research by Ohio State University using the same information also revealed that the net financial assets and net wealth of these low- and moderate-income households actually fell in the late 1990s. Between 1995 and 1998, a period of strong economic growth and rising incomes, the net assets of very low-income households (under $10,000) fell from $4,992 to $3,950 and that of other low-income households ($10,000-25,000) sank from $31,940 to $24,650. Rising consumer and home equity debt was an important reason for this decline.

Family Wealth Facts

Typical American Family	
Net Wealth	$86,100
Net Financial Assets	$24,500
Typical Low-Income American Family (poorest 20%)	
Net Wealth	$7,900
Net Financial Assets	$2,000

Source: 2001 Survey of Consumer Finances, Federal Reserve.

Asset poverty is particularly acute in Arizona. In 2002, the Corporation for Enterprise Development (CFED) published a "report card" evaluating asset development policies and outcomes in the 50 states. While Arizona earned a "B" and ranked 19th in the *Asset Policy Index* reflecting state support for several key policies related to building and protecting assets, the state earned an "F" and ranked 49th in the *Asset Outcomes Index* reflecting poor results in indicators of financial, homeownership, small business, and human capital.

Arizona needs to address the distressing financial condition of low-income families and promote measures to help them save and build wealth. Strengthening the financial security of low-income people is good public policy. As they accumulate assets, both individuals and communities acquire invaluable benefits.

Individual Development Accounts (IDAs) are a practical method to make savings accounts available to low-income individuals and families. IDAs are matched savings accounts that reward the monthly savings of working families who are saving toward a high-return asset such as a first home purchase, post-secondary education, or a small business. The savings accounts are created through matching funds from private and public sources.

The Corporation for Enterprise Development reports that among 1,326 low-income families in pilot IDA programs nationwide, individuals saved more than $378,000, and garnered more than $741,000 in matching funds. In addition, evidence shows that the very poorest families save almost the same dollar amount as other families, making their savings rates proportionately higher than others.

To promote establishing IDA programs across Arizona, several agencies have formed a collaborative known as the *Assets for Arizona Alliance.* The purpose of the Alliance is to disseminate effective IDA practices, to expand their reach across Arizona and to create a larger constituency for IDAs. Other types of social marketing initiatives should also take place to persuade lower-income households, and the public at large, to save and build wealth.

Safety Net

With the recent emphasis on welfare reform, many have been focused on efforts to move families into self-sufficiency. Unfortunately, many have judged the success of this effort on the reduction of caseloads and not on the reduction of poverty. As this Poverty Report has shown, the success of Arizona's welfare reform efforts to move families off welfare rolls has not assisted in moving them out of poverty.

And, while Arizona's welfare rolls have been dramatically reduced over the last few years, thousands of "hard to serve" families still remain. Multiple barriers faced by these families and other issues preclude many from ever reaching full self-sufficiency.

Additionally, until there is wide spread public support and political will for ensuring that no one who works full-time is poor, there will also be the "working poor" who will require assistance in meeting basic needs for themselves and their families. Therefore, Arizona needs a strong, comprehensive system of social and income supports to strengthen and support all families across Arizona through good times and bad.

But do public supports work? A 1999 study by Wendell Primus and Kristina Daugirdas demonstrated that 16 percent of poor children nationally, were lifted from poverty in 1997 due to the use of government benefits. Recent Census data and other research studies show that among working families, the Earned Income Tax Credit (EITC) lifts substantially more children out of poverty than any other government program or category of programs. According to the President's Council of Economic Advisors, the EITC lifted more than four million Americans out of poverty between 1993 and 1997.

What programs make up Arizona's safety net? While welfare and food stamps come most readily to mind, many other excellent programs exist at both the federal and state levels to provide income support to poor families so that their wages can be stretched to meet their needs.

Low-income families depend on transportation programs to provide access to jobs and other necessary appointments. Energy assistance and weatherization programs enable low-income families to maintain their homes in comfort. Medicaid and KidsCare help many children in poverty receive the health care they need. Federal policies and laws that provide wage supports like the minimum wage and Earned Income Tax Credit also help. These and other programs/policies must be expanded and adequately funded to meet the needs of low-income Arizonans, and appropriate outreach must be done to ensure that families are aware of their eligibility.

But government policies and programs are not enough. Many believe that current welfare reform efforts are beginning to re-define the safety net for poor people. The safety net is no longer a set of programs and services; instead, the safety net is a job. While many may share that belief, there are not enough good jobs available to meet the need. Until the economy is producing jobs that pay a living wage, a safety net is not only needed, but also essential.

Call to Action

An effectively implemented anti-poverty strategy for children and families will assist in providing an economic and social environment where many more Arizonans can enjoy a higher quality of life. Substantive action with adequate funding and a forward-thinking long-term strategy are required to move forward on addressing poverty and building vibrant communities. It is time for the focus in Arizona to shift beyond process to results.

Policy Recommendations

Many low-income Arizonans are trapped in the cycle of poverty and lack what most consider the basic necessities for survival—food, clothing, shelter, health care, and education. If we do not sufficiently increase disposable income for working people, we must have programs and services to provide essential supports to families in need. That is why ACAA is calling for the following recommendations to provide that support.

Food and Nutrition

More than 173,000 Arizonans go hungry every week. To expand opportunities for low-income families to obtain food and basic nutrition, efforts should focus on the following: 1) Enhancing and improving Arizona's current nutrition assistance programs, 2) Maintaining and expanding state resources to support private hunger relief efforts, and 3) Engaging all sectors of the food system to help solve Arizona's hunger problem.

1) Government Nutrition Assistance Programs

- Food stamps should be made as flexible as possible, with the state implementing all possible waivers and options in order to remove barriers to participation.
- Automation and interactive, online applications should be implemented to facilitate and expedite the application process for all nutrition assistance programs, where appropriate.
- The state should strive for full participation in all government nutrition assistance programs utilizing public and private outreach efforts, such as ArizonaSelfHelp.org, and other pilot programs to improve participation.
- The state should initiate efforts to develop streamlined applications, share application information where appropriate, and ultimately strive for a universal application for all programs administered by state agencies.

2) State Resources

- Maintain and expand legislatively appropriated funds supporting private hunger relief efforts.

- Use state funds to leverage allocation of federal matching grants to support such programs as WIC Farmer's Market Nutrition Program, and Food Stamp Outreach.
- Create and conduct periodic, possibly annually, hunger and food security measurement tools for Arizona. Without this type of measurement it will be very difficult to determine what progress is being made in this area.

3) Private and Community Resources
- Encourage public support of hunger relief programs such as food banks and pantries and expand food distribution to rural and remote areas of the state where these services do not currently exist.
- Promote development of community gardens and farmer's markets as a local food acquisition alternative for low-income households.
- Promote variety and improved quality of food dispensed through public and private nutrition assistance and hunger relief programs.
- Engage all sectors of the food system to help solve Arizona's hunger problem - especially consider development of local, county and statewide food policy councils to lay the groundwork for building food security.

Affordable Housing

To assist in the elimination of poverty in Arizona, affordable housing efforts should focus on two areas, 1) Continuing the use of various federal and state resources to subsidize the cost of housing for lower-income households, and 2) Promoting efforts at the local government level to reduce the cost of housing through innovative design and the reduction of barriers.

1) Public Subsidies
- Federal, state and local governments should increase funds for affordable housing and make housing subsidies available to a larger proportion of those who are income-eligible.
- Federal, state and local governments should target more of their resources toward those in serious need– the working poor.
- Federal, state and local governments should work together to standardize applications/forms and share and/or defer monitoring and other responsibilities to reduce barriers and administrative burdens.
- All affordable housing programs should be linked and supported by an array of comprehensive services that will work to address all issues confronting the family in an effort to stabilize families and increase their chances of long-term self-sufficiency.

2) Local Innovation and Barrier Reduction
- Local governments should examine their zoning and design standards and determine if barriers exist that drive up housing costs.
- Local governments should consider ways they can contribute to the reduction of housing costs by promoting design innovation, integrating land uses, waiving fees or contributing land.
- Local governments should specifically target ways to integrate new or rehabilitate existing housing in the community that is affordable for those in poverty.
- Communities must build support for strengthening awareness and generating action. There is relatively strong public support for policy changes that might produce more affordable housing according to a 2002 survey performed in Maricopa County by the Collaboration for a New Century.

Child Care

To expand opportunities for low-income parents to receive quality, affordable care for their children while they work, ACAA recommends 1) Expanding existing publicly supported child care programs, 2) Promoting the expansion of privately sponsored affordable child care, and 3) Ensuring quality and accessibility for all.

1) Child Care Subsidies

- The federal government should fully fund quality child care and youth development programs such as Head Start, Early Head Start and the Child Care and Development Block Grant.
- The federal and state government should provide an adequate refundable child care credit that benefits low-income working families.
- The state should continue to fully fund and expand child care vouchers by appropriating all available federal funds and providing full matching support.
- The state should work to expand eligibility for subsidized child care.

2) Private Options

- The state should encourage local businesses to invest in systems of high quality, accessible child care for their employees.
- The state and communities should work to increase private, faith-based and local partnerships to provide more after-school programs for low-income children.

3) Quality and Accessibility

- The state should increase opportunities for early childhood education.
- The state should enforce quality standards for state-subsidized child care.
- The state and providers should provide care that is accessible to families with non-traditional child care needs — evenings, weekends, wrap-around, etc.

Health Care

To assist more low-income Arizonans to improve their chances for affordable, quality health care, ACAA recommends 1) Expanding existing public health care programs, 2) Providing incentives and assurances to increase insurance coverage, and 3) Supporting community health clinics.

1) Public Health Care Programs

- The federal government should work to ensure that every American has access to affordable quality health care.
- Federal and state governments should continue to find ways to deliver affordable prescription drugs, particularly for the elderly.
- The federal government should work to give states the tools and incentives to allow them to expand coverage to the uninsured.
- The federal and state governments should increase funding and eligibility for needed public health programs like Medicaid, AHCCCS, KidsCare, Premium Sharing, etc.
- The state should identify and develop a dedicated publicly subsidized source of funding for the uninsured in Arizona.
- The state should encourage ways to streamline administration and regulations to reduce costs and expand coverage.
- The state should continue to focus on disease prevention efforts such as childhood immunization, nutrition education, mental health and substance abuse prevention and treatment, and smoking-related education programs.
- The community should support initiatives to conduct outreach and enrollment in available programs.

2) Private Coverage Incentives and Assurances

- The state should support market-based reforms such as tax incentives and subsidies for individuals and small employers should be pursued.
- The state should support and facilitate efforts to enable small employers to join together to participate more effectively in the health insurance market.
- The state should work to ensure that all licensed insurers that wish to do business in Arizona be required to present plans for ensuring that adequate and reasonably priced health insurance is available throughout Arizona.

3) Community Clinics

- The state should work to support community health centers and other providers who offer sliding scale health care. This includes working with them to aggressively pursue all federal subsidies available for care.

Transportation

To expand transportation opportunities for low-income families ACAA recommends 1) Understanding the need and gaps, 2) Increasing the use of public resources that offer an array of transportation services; and 3) Creatively encouraging the development of local services through community partnerships and coordination.

1) Understanding the Gaps

- The state should develop a statewide comprehensive plan to address transportation barriers to work. The plan should include the unique problems of rural areas.
- Local communities should use ADOT Small Area Transportation Studies and needs assessments to determine greater detail of transit needs.

2) Public Funding

- TANF funded transportation assistance should continue to be flexible and diverse - for example there should be an array of services including drivers education, assistance with insurance, car repairs, gas vouchers and mileage reimbursements.
- Eligibility for all transportation assistance programs should be expanded.
- The state should revise asset limits associated with assistance programs to recognize the importance of vehicles as a means to get to work (24 states now place no limit on the value of one car owned).
- The state should use TANF and other funds to assist low-income workers with matching grants to acquire cars and provide ongoing assistance for car operating expenses. For example, resurrect the *Wheels to Work* Program.
- Transitional transportation assistance should continue for a longer period - perhaps up to two years after individuals are successfully employed.

3) Local Program Development

- Local governments should work to develop public transit programs (where appropriate) to meet the needs of transit dependant populations.
- Communities should also consider "paratransit" alternatives like Dial-A-Ride and other types of public program transportation services.
- Local Workforce Investment Boards should participate in the purchase of vouchers for transit dependant working poor, utilizing private for profit services or Public Transit Services.
- TANF funds should be used to hire transportation coordinators to organize new transit alternatives for low-income workers to include coordination with existing "paratransit" services.

Jobs and Income

To expand opportunities for low-income parents to improve their wages, ACAA recommends 1) Providing adequate employment assistance in finding and securing a job, 2) Expanding opportunities for training and skill development, and 3) Ensuring that adequate wage supports are in place to help lift families out of poverty.

1) Employment Services

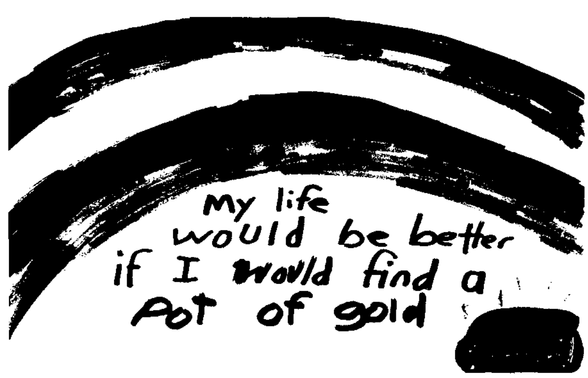
- The state should support programs that provide services to assist lower-income persons to find higher paying jobs.
- To help unemployed and underemployed people secure work and gain appropriate jobs skills and experience, federal, state and local governments should create public sector jobs programs.
- The federal and state governments should continue to support the creation and expansion of microenterprise lending programs to expand self-employment opportunities.
- To assist those looking for work, the state should raise its unemployment benefits. Arizona's maximum unemployment insurance benefit is only $205 a week, well behind our neighboring states New Mexico ($277), Nevada ($301), and Utah ($365).
- Existing health, safety, and anti-discrimination laws should be enforced or expanded to cover more people and improve the quality of available jobs.

2) Training and Skill Development

- Funding for training and education through the Workforce Investment Act should be increased.
- The state should continue to support and enhance its workforce development system designed to provide unemployed and under-employed workers with the training and support they need to obtain employment and advance in their careers.
- Existing programs and partnerships should be expanded to provide low-income youth mentoring and support for post-secondary education and training.
- The state should work with colleges and the business community to provide enough financial aid, apprenticeship programs, and other training options to all students interested in postsecondary education.
- Programs should be created or expanded to provide low-income people the benefits of information technology through training and access to computers and the Internet.

3) Wage Supports

- The federal Earned Income Tax Credit program should be expanded by raising income thresholds.
- The state should follow the lead of other states and consider the establishment of a similar earned income tax credit in Arizona.
- Congress should raise the federal minimum wage so that fulltime employment brings a family's income above the poverty line. During the 1960s and 1970s, the poverty level for a family of three was roughly equal to the yearly earnings of a full-time worker earning the minimum wage. According to the Economic Policy Institute, the minimum wage would have to be raised to $6.53 to restore the purchasing power it had in 1979.
- The state should also consider the establishment of a state minimum wage.
- State and local governments should consider passing laws requiring businesses that benefit from public money to pay workers a living wage. More than 100 communities across the country, including Tucson Arizona, have enacted living wage ordinances.



Best Practices and Success Stories

Family Support

Circles of Support

Circles of Support represents a promising program that goes beyond emergency services and seeks to help families out of poverty by promoting the development of deep relationships with those who can help. Regular meetings are held for the participants of these circles and are composed of human service providers, businesses, members of churches and other individuals. An example of this concept can be seen in Iowa from an organization called Beyond Welfare where half of the participants have successfully transitioned off of welfare and became self sufficient. Circles of Support has begun to take shape in Arizona as several Community Action Agencies and community-based programs have received training and initiated support circles throughout the state.

Building Wealth

Vermont Development Credit Union (VDCU)

In 1988, the Burlington Ecumenical Action Ministry created VDCU to be dedicated to creating financial stability for lower-income families. Its services include lending, financial services such as check cashing and savings accounts, and development services such as homeownership counseling. VDCU has had a high social return on investment with the first $50 million in loans made to its members saving an estimated $8.5 million in interest payments compared with predatory forms of credit.

Jobs and Income

Women in Construction Program

In 1995, the Kentucky River Foothills Development Council began a program to train low-income women for highway construction jobs. The program was designed primarily for single mothers who needed to increase their earning power. Enrollees receive technical training through a combination of classroom and hands-on instruction, and receive placement assistance and support as they transition into the workforce. Results from an outside evaluation show that program graduates are highly employable. In fact, 71% of women who went through the program are employed, earning $10.28 per hour on average.

Affordable Housing

Beyond Shelter

In 1988, an innovative California non-profit organization called Beyond Shelter was founded with a concept that provided a new approach to ending family homelessness - placing families as quickly as possible into permanent housing, with supportive services. The program builds on the existing system of emergency and transitional housing by providing the next step: assistance in relocation to permanent housing with transitional support, as families are integrated back into communities. From 1989 to 2001, more than 85% of 2,300 program participants were stabilized in permanent housing within one year. According to an outside evaluation, more than 90% of the mothers and 80% of the children who completed the program achieved their goals.

Education

Cincinnati Youth Collaborative Mentoring Program (CYC)

Residents in Cincinnati decided to be proactive in reducing the dropout rate. In 1987 CYC was formed to offer a variety of programs including tutoring, mentoring, internships and college preparation assistance. Over 60 local corporations, organizations and individuals provide financial support to CYC. An outside evaluation of the program found that mentoring can reduce the dropout rate. Ninety percent of the teens studied stayed in school, compared to graduation rates of 40 to 75%.

Project Learn - a Program of Boys and Girls Clubs of America

Project Learn reinforces and enhances the skills and knowledge young people learn at school through "high-yield" learning activities at the Club and in the home. Based on Dr. Reginald Clark's research that shows fun, but academically beneficial activities increase academic performance, these activities include leisure reading, writing activities, homework help and games. Project Learn emphasizes collaborations between staff, parents and school personnel. Formally evaluated by Columbia University, Project Learn has been proven to boost the academic performance of Club members.

Health Care

Dental Health for Arlington (DHA)

In 1992, representatives from 16 community agencies and professional dental health organizations worked together to form DHA in Tarrant County Texas to provide comprehensive dental care to low-income families. More than 200 volunteer dental professionals have provided $4.8 million in free dental care. Between 1993 and 2000, the number of participating schools in DHA's SMILES program has increased by 90%, and the number of children screened by 99%. Evaluations have shown a dramatic increase in the knowledge of dental health in schools.

Child Care

North Carolina Rural Center's Statewide Communities of Faith Initiative

A recent look at child care providers notes that nearly one of every six child care centers is housed in a religious facility. North Carolina's Church Child Care initiative represents a partnership to work with the faith community to expand child care facilities in rural parts of the state. The initiative provides: 1) Technical assistance to persons wanting to develop, expand or improve child care programs in rural churches; and 2) Loan guarantees to churches needing capital for programs and educational opportunities.

Transportation

Cedar Rapids' Neighborhood Transportation Service (NTS)

The NTS was started to provide door-to-door transportation to and from work on days when city buses did not operate. NTS connects residents to jobs, job training, employment-related treatment services, and educational opportunities that further their employability. It's a "neighbor to neighbor" solution -- NTS employees come from the same neighborhoods that they serve. Ridership has grown from 556 in 1994 to 27,397 in 2001. Riders pay $3 per ride that covers 30% of costs. In a recent study, 83% of customers reported using its services for work-related transportation. NTS customers also reported that the service enabled them to increase their income, save and get off welfare.

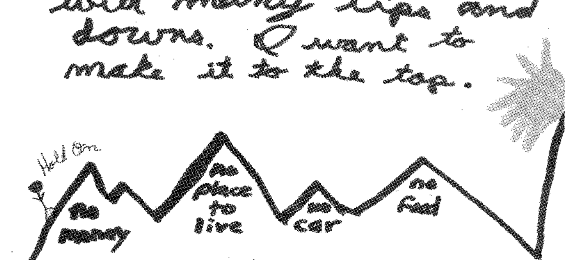
ACAA Success Stories

Arizona's Community Action Agencies are also making a difference in the lives of the thousands of families and individuals they serve every year. Here are a few of those successes:

Karen from Holbrook...

As a single parent, recently divorced I was facing and encountering so many difficult situations. Being unemployed and unable to seek employment left me in a financial bind. I had little hope left. I went to the Holbrook Senior Citizen Center seeking aid. One does not comprehend the emotions you face when you're not sure if the roof over your head will be protecting your children for another cold night. I have four children, 18, 15, 8, and 5. My utilities were being shut off and my home was going into default. It was to my relief to find out that I was able to keep my home after being awarded assistance. I decided to go to the Senior Center to show my appreciation when, with surprise I was offered a job as a Case Manager. Since that day, I had been able to renovate my home into a better living situation. Presently, as a Case Manager, I get a personal satisfaction that I am able to assist many families and many single parents. Knowing how they have to feel when seeking assistance, it is a tremendous relief to feel that I in return can assist these families as I was once standing.

My life has alot of challenges with many ups and downs. I want to make it to the top.



The challenge mountain

Jessica from Phoenix...

I am 21 years old and I have a 3 year old son. I was in the Young Families CAN program through the City of Phoenix and I just want to say that if it weren't for the program, I wouldn't have graduated from college. The Young Families CAN program and my case manager have always been there for me. They helped me with transportation, paying for my classes and books and gave my son and me a good Christmas. When I started the program, I was barely entering college and didn't have a good paying job and no skills. Now, I have graduated from Phoenix College with my AA degree in Administration of Justice Studies. I am working and recently got my license to sell insurance. My goals for the future are to become a police officer. I give Young Families CAN credit for who I am today. Thank you.

Lynn and Kami from Gilbert...

We would like to express our heartfelt gratitude for the help CAP (Gilbert Community Action Program) has given us. In October 2001, I was laid off and could not make my house payment. CAP was able to help us out by paying 1-½ months mortgage payments for us, which was enough to keep us in our home. Our heat pump had gone out and we were without heat. Two of the burners on our stove were out. Through CAP, our heat pump and furnace were replaced and we received a new stove as well. We also received help with payments on our electricity bill. At Christmas time we were given a very generous gift of food for our Christmas dinner, as well as gifts for our 2 youngest daughters. These things have meant the world to us and we sincerely wish to express our thanks for all who made this possible. In the past, it was we who have been on the giving end of things. What an eye-opening experience to be the recipient of others' goodwill and kindness. We will certainly do our best to be more aware of the needs of others and look for ways to repay the help we received.

Single woman from Casa Grande...

I contacted CAHRA (Community Action Human Resources Agency) in early January 2003 for help getting a place of my own because I was homeless and living in my van...I came to Mesa from Mississippi to live with my son and his wife to help them out. After making the move, I found out that my son and his wife had very bad drug problems. They both became verbally abusive and threatened to harm me physically. I was very frightened...the abuse and stress continued and I suffered a mild stroke and developed congestive heart failure. On Christmas Day 2002, I ran from my son's home because he was out of control...when I left I did not take anything with me, not even my clothes. In February I was able to find subsidized apartment for $45 a month that I could afford with my income of $339 a month. CAHRA also provided me with funds to cover my utility deposit, move-in deposit and first month's rent. The agency also signed me up for the Telephone Assistance Program and enrolled me in the utility discount program. I was also referred to the St. Vincent de Paul Society, and they helped me get furniture, pots, pans and dishes and some clothes. Since I have gotten my own place and feel safe, my health has gotten better. I have a Bible study group meeting in my home on Saturdays. Friends from my church gave me a sewing machine and I plan to start making my own clothes. I just turned 65 so my Social Security has increased so that I have a little a bit more income to cover my needs.

County Profiles

Apache County

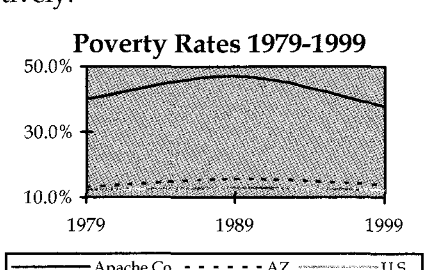
The 2000 Census revealed 69,423 people living in Apache County, a 12.7 percent increase from the 1990 Census of 61,591. In 1999, Apache County had nearly 38 percent of its population or 25,798 people living below the poverty level. Apache County's poverty rate was the highest among Arizona's 15 counties. It should be noted that more than 79 percent of its population lies within the Fort Apache and Navajo Reservations. The poverty rate for people not living on reservation lands in Apache County was 15.1 percent or 2,098 people compared to 43.7 percent or 23,700 people in poverty on reservation lands.

Poverty in Selected Communities

Number of Persons Below Poverty Level (Poverty Rate)	1989	1999	% Change
Eagar	560 (14.2%)	303 (7.4%)	-45.9%
St. Johns	370 (11.2%)	481 (15.3%)	30.0%
Springerville	278 (15.4%)	407 (21.0%)	46.4%
Window Rock	685 (21.8%)	741 (24.6%)	8.2%
Reservations	27,041 (56.2%)	23,700 (43.7%)	-12.4%
Apache County	28,640 (47.1%)	25,798 (37.8%)	-9.9%
Arizona	564,362 (15.7%)	698,669 (13.9%)	23.8%

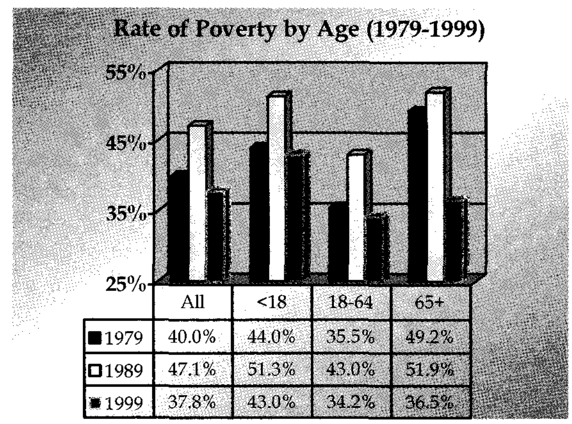
Source: U.S. Census and Research Advisory Services, Inc.

While the number of people in poverty decreased over the last ten years, the 1999 figure represents a 24.8 percent increase since 1979 when 20,675 people or 40.0 percent of the county's population lived in poverty. In 1999, Apache County's poverty rate still remains significantly higher than the state and national average of 13.9 percent and 12.4 percent respectively.



Poverty and Age

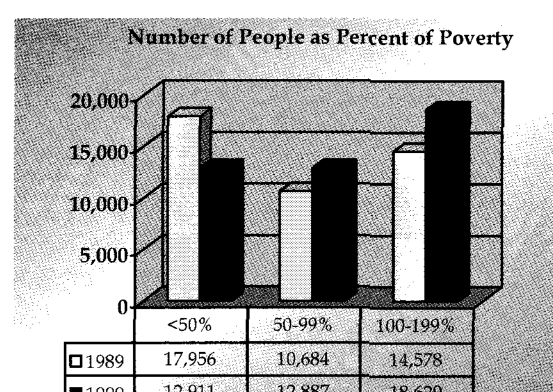
In 1999, among all age categories examined, children under 18 years of age experienced the highest rate of poverty at 43 percent, while those age 18 to 64 had the lowest rate at 34.2 percent. Over the last ten years, the rate of poverty has decreased for all age groups. Compared to 1979, 1999 poverty rates are about the same for all age groups except those over 65 who experienced an improvement from 49.2 percent to 36.5 percent.



Source: U.S Census.

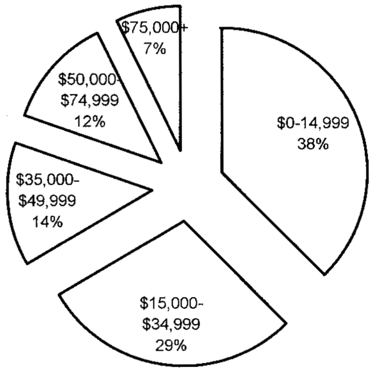
Poverty and Income Levels

Examination of the income to poverty ratio reveals that 12,911 people or half of those below the poverty rate in Apache County were *very poor*, with incomes less than 50 percent of the poverty threshold. Another 18,629 people had incomes equal to or above the poverty level, but less than 199 percent (ACAA's definition of "working poor"). ***In total, there are 44,427 people in Apache County who are poor or "working poor," 65.1 percent of the county's total population.***



Source: U.S Census.

1999 Household Income Distribution - Apache County



Source: U.S Census. Note: The median household income in Apache County was $23,344 in 1999 compared to $14,100 in 1989 (65.6 percent increase).

From 1990 to 1999, personal income for Apache County increased 71.2 percent compared to the state's nearly 90 percent (according to the Arizona Department of Economic Security). On a per capita basis, the gain of 54.6 percent was 8.3 percent above the state's growth of 46.3 percent. Apache County per capita income was approximately $13,193 in 1999, about one half of the state's level. Average earnings per job were $27,825 in 1999, which represented an increase of nearly one-third since 1990 compared to the state's increase of 40.3%.

Poverty and Families

In 1999, the poverty rate among all families with children under 18 years of age living in Apache County was 37.8 percent. The rates for families with children headed by single females were 53.9 percent and even higher with younger children (less than 5 years) at 65.5 percent. Married couple families with children experienced a lower rate at 28 percent.

Number Below Poverty Level (Poverty Rate)	1979	1989	1999	% Change '79-'99
All	3,734 (35.3%)	5,508 (41.5%)	5,108 (33.5%)	36.8%
With children under 18	3,002 (37.2%)	4,459 (44.8%)	3,879 (37.8%)	29.2%
Female-headed with children under 18	860 (51.7%)	1,565 (63.9%)	1,715 (53.9%)	99.4%
Female headed with children under 5*	476 (54.3%)	819 (66.5%)	821 (65.5%)	72.5%

*1979 numbers include 5 year olds. Source: U.S. Census.

Poverty and Race

Among racial/ethnic groups, American Indians experienced the highest poverty rate at 43.9 percent and Whites had the lowest at 12 percent. American Indians were also represented at a disproportionately higher rate among those in poverty than in the overall population. Over the last ten years, the poverty rate increased for all races except American Indians and those of Hispanic Origin.

Race Ethnicity	% of Total Population 1999	% of Poverty Population 1999	Poverty Rate by Race 1999	Poverty Rate by Race 1989
White	19.5%	6.3%	12.0%	10.9%
Black	0.2%	0.2%	24.3%	8.9%
American Indian	76.9%	90.9%	43.9%	57.2%
Asian/PI	0.2%	0.1%	28.8%	-
Other	3.2%	2.5%	29.2%	26.3%
Hispanic Origin*	4.5%	3.1%	25.5%	27.5%

NOTE: Categories include those identifying themselves as Hispanic. *Those of Hispanic Origin may be of any race. Source: U.S. Census.

Public Assistance

According to the 2000 Census, 2,678 households or 13.4 percent of all households in Apache County received public assistance. The mean or average amount of public assistance income for 1999 was $3,237, a decrease from the 1989 average of $3,344 and $3,997 in 1979. Participation levels in the Food Stamp and Temporary Assistance to Needy Families (TANF) programs serve as indicators of the extent of poverty. In 2000, 18,732 people or 27 percent of the population received food stamps. At the same time, 2,040 or 13.4 percent of families were enrolled in TANF.

Public Assistance (PA)	Base Year	1990	2000	% Change 1990-2000	% Change Base Yr-2000
Households receiving PA (1980)	2,312	4,116	2,678	-34.9%	15.8%
Persons Food Stamps (1985*)	18,387	19,096	18,732	-1.9%	1.9%
Families AFDC-TANF (1985*)	1,818	2,347	2,040	-13.1%	12.2%

NOTE: Base year in parentheses. *April figures. Source U.S. Census and Arizona Department of Economic Security.

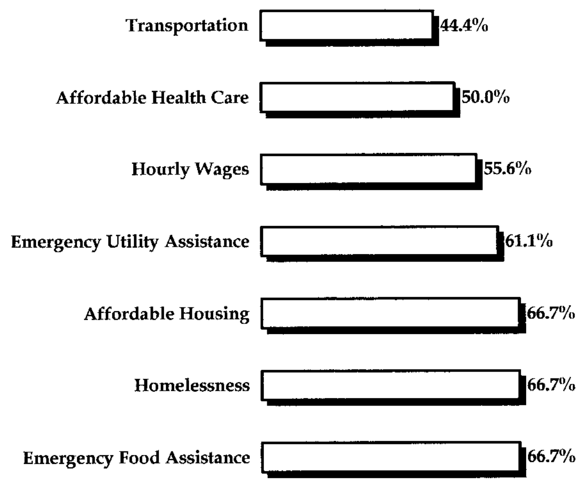
Self-Sufficiency

According to an Arizona Children's Action Alliance report completed in 2002, "The Self-Sufficiency Standard for Arizona," a single parent with an infant and a preschool-age child needs to earn a minimum of $32,206 annually to cover basic expenses in Apache County. In comparison, the following chart notes that a two parent household with an infant and a preschool-age child would need to make $38,947 annually, while a single adult would need $14,168 to cover basic living needs in Apache County.

Monthly Costs	Adult	Adult + Infant Preschooler	2 Adults + Infant Preschooler
Housing	396	503	503
Child Care	0	825	825
Food	176	345	496
Transportation	221	227	437
Health Care	102	289	358
Miscellaneous	90	219	262
Taxes	196	456	545
Earned Income Tax Credit (-)	0	0	0
Child Care Tax Credit (-)	0	-80	-80
Child Tax Credit	0	-100	-100
Self-Sufficiency Wage:			
Hourly	**$6.71**	**$15.25**	**$9.22 Per adult**
Monthly	**$1,181**	**$2,684**	**$3,246**
Annual	**$14,168**	**$32,206**	**$38,947**

Perceptions from the Community

Two community meetings were held to discuss the major issues regarding poverty in Apache County. The chart below shows the percentage of participants surveyed who believe conditions have gotten *worse* in the following areas over the last ten years:



More specifically, participants expressed concerns over the lack of employment opportunities and public transportation, reductions in tourism and spotty telephone/Internet service. One of the biggest concerns was the exodus of young people from the area to find work in larger communities. Suggestions made to improve the area included increasing economic development efforts, improving education and expanding telecommunications infrastructure.

Cochise County

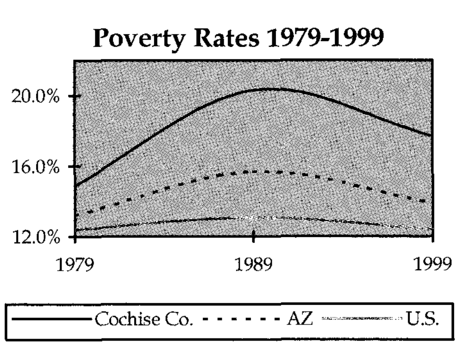
The 2000 Census revealed 117,755 people living in Cochise County, a 20.6 percent increase from the 1990 Census of 97,624. In 1999, Cochise County had almost 18 percent of its population or 19,772 people living below the poverty level. While the overall percentage of people in poverty decreased over the last ten years, the number of people in poverty did not. Cochise County experienced a 5.6 percent increase since 1989 when 18,721 people or 20.3 percent of the county's population lived in poverty.

Poverty in Selected Communities

Number of Persons Below Poverty Level (Poverty Rate)	1989	1999	% Change
Bisbee	1,351 (21.6%)	1,046 (17.5%)	-22.6%
Douglas	5,512 (43.1%)	5,015 (36.6%)	-9.0%
Sierra Vista	3,288 (10.7%)	3,630 (10.5%)	10.4%
Wilcox	705 (23.1%)	963 (27.0%)	36.6%
Cochise County	18,721 (20.3%)	19,772 (17.7%)	5.6%
Arizona	564,362 (15.7%)	698,669 (13.9%)	23.8%

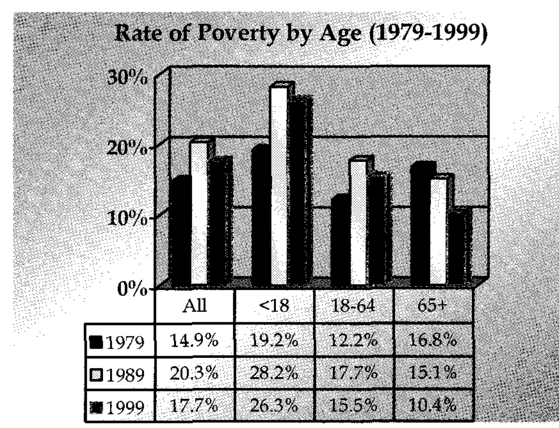
Source: U.S. Census and Research Advisory Services, Inc.

When you compare poverty rates over the last twenty years, Cochise County's poverty rate increased from 14.9 percent in 1979 to 17.7 percent in 1999, 12,393 to 19,772 people respectively. In 1999, Cochise County's poverty rate still remains higher than the state average of 13.9 percent and the national average of 12.4 percent.



Poverty and Age

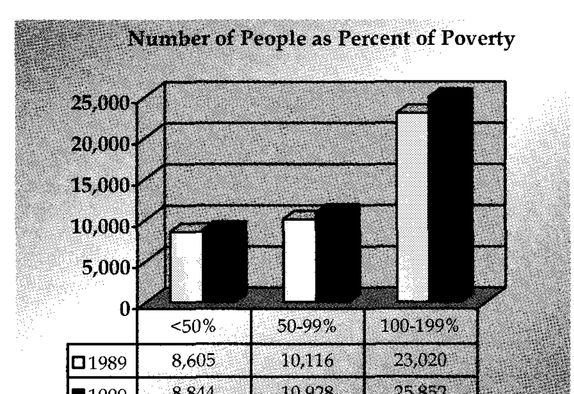
In 1999, among all age categories examined, children under 18 years of age experienced the highest rate of poverty at 26.3 percent, while those 65 and older had the lowest rate at 10.4 percent. Over the last twenty years, the rate of poverty has increased for all age groups, except those over 65 who experienced an improvement from 16.8 percent in 1979 to 10.4 percent in 1999.



Source: U.S Census.

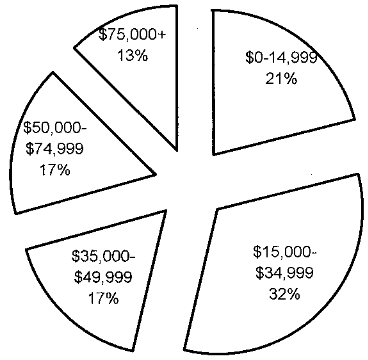
Poverty and Income Levels

Examination of the income to poverty ratio reveals that 8,844 people or 44.7 percent of those below the poverty rate in Cochise County were ***very poor***, with incomes less than 50 percent of the poverty threshold. Another 25,852 people had incomes equal to or above the poverty level, but less than 199 percent (ACAA's definition of "working poor"). ***In total, there are 45,624 people in Cochise County who are poor or "working poor," 40.8 percent of the county's total population.***



Source: U.S Census.

1999 Household Income Distribution – Cochise County



Source: U.S Census. Note: The median household income in Cochise County was $32,105 in 1999 compared to $22,425 in 1989 (43.2 percent increase).

From 1990 to 1999, local total personal income in Cochise County increased 54.4 percent compared to the state's nearly 90 percent (according to the Arizona Department of Economic Security). On a per capita basis, the gain of 34 percent was below the State's growth of 46.3 percent. Cochise County per capita income was $18,797 in 1999, about 75 percent of the state average, down from 81.5 percent in 1990. Average earnings per job increased 0.8 percent in 1999 to $27,284 - 3.3 percent less than the state's gain of 4.1 percent.

Poverty and Families

In 1999, the poverty rate among all families with children under 18 years of age living in Cochise County was 21.6 percent. The rates for families with children headed by single females were 47.2 percent and even higher with younger children (less than 5 years) at 61.4 percent. Married couple families with children experienced a much lower rate at 13.5 percent.

Number Below Poverty Level (Poverty Rate)	1979	1989	1999	% Change '79-'99
All	2,629 (11.8%)	4,060 (15.8%)	4,195 (13.5%)	59.6%
With children under 18	1,977 (15.6%)	3,105 (23.2%)	3,328 (21.6%)	68.3%
Female-headed with children under 18	796 (47.5%)	1,438 (55.9%)	1,575 (47.2%)	97.9%
Female headed with children under 5*	457 (57.6%)	724 (74.2%)	725 (61.4%)	58.6%

*1979 numbers include 5 year olds. Source: U.S. Census.

Poverty and Race

Among racial/ethnic groups, those of Hispanic Origin experienced the highest poverty rate at 29.5 percent and Blacks had the lowest at 9.8 percent. Other races and those of Hispanic Origin were represented at a disproportionately higher rate among those in poverty than in the overall population. All races in Cochise County saw an improvement in poverty rates from 1989 except Asian/Pacific Islanders.

Race Ethnicity	% of Total Population 1999	% of Poverty Population 1999	Poverty Rate by Race 1999	Poverty Rate by Race 1989
White	76.7%	70.7%	15.4%	18.1%
Black	4.5%	2.7%	9.8%	24.8%
American Indian	1.1%	1.3%	19.3%	24.8%
Asian/PI	1.9%	1.4%	12.2%	9.5%
Other	15.8%	24.2%	25.7%	38.6%
Hispanic Origin*	30.7%	54.0%	29.5%	37.0%

NOTE: Categories include those identifying themselves as Hispanic. *Those of Hispanic Origin may be of any race. Source: U.S. Census.

Public Assistance

According to the 2000 Census, 1,793 households or 4.1 percent of all households in Cochise County received public assistance. The mean or average amount of public assistance income for 1999 was $2,357, a decrease from the 1989 average of $3,530 and $3,677 in 1979. Participation levels in the Food Stamp and Temporary Assistance to Needy Families (TANF) programs serve as indicators of the extent of poverty. In 2000, 9,753 people or 8.3 percent of the population received food stamps. At the same time, 1,085 or 3.5 percent of families were enrolled in TANF.

Public Assistance (PA)	Base Year	1990	2000	% Change 1990-2000	% Change Base Yr-2000
Households receiving PA (1980)	2,024	2,999	1,793	-40.2%	-11.4%
Persons Food Stamps (1985*)	8,629	11,441	9,753	-14.8%	13.0%
Families AFDC-TANF (1985*)	901	1,459	1,085	-25.6%	20.4%

NOTE: Base year in parentheses. *April figures. Source U.S. Census and Arizona Department of Economic Security.

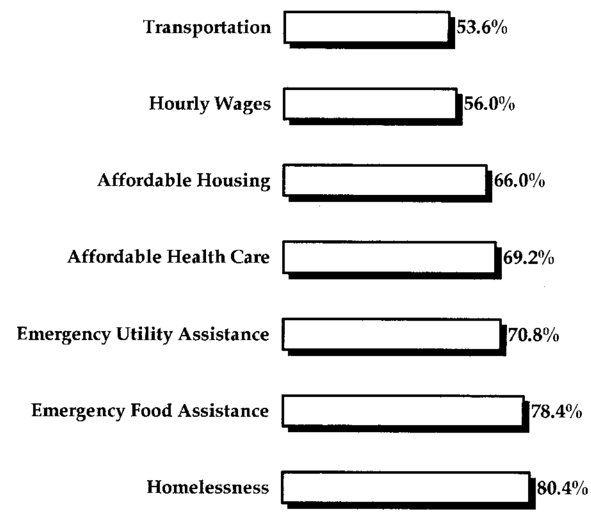
Self-Sufficiency

According to an Arizona Children's Action Alliance report completed in 2002, "The Self-Sufficiency Standard for Arizona," a single parent with an infant and a preschool-age child needs to earn a minimum of $31,699 annually to cover basic expenses in Cochise County. In comparison, the following chart notes that a two parent household with an infant and a preschool-age child would need to make $38,555 annually, while a single adult would need $14,168 to cover basic living needs in Cochise County.

Monthly Costs	Adult	Adult + Infant Preschooler	2 Adults + Infant Preschooler
Housing	396	503	503
Child Care	0	803	803
Food	176	345	496
Transportation	221	227	437
Health Care	102	289	358
Miscellaneous	90	217	260
Taxes	196	445	537
Earned Income Tax Credit (-)	0	-7	0
Child Care Tax Credit (-)	0	-80	-80
Child Tax Credit	0	-100	-100
Self-Sufficiency Wage:			
Hourly	**$6.71**	**$15.01**	**$9.13 Per adult**
Monthly	**$1,181**	**$2,642**	**$3,213**
Annual	**$14,168**	**$31,699**	**$38,555**

Perceptions from the Community

One meeting was held in Cochise County to discuss poverty issues and solutions for change. Information was also obtained through surveys distributed throughout the county with the help of local agencies. The chart below shows the percentage of participants surveyed who believe conditions have gotten ***worse*** in the following areas over the last ten years:



More specifically, participants indicated that the greatest need is education, basic literacy and skills training. Improvements to the economic base and transportation were noted as necessary to bring more opportunities to the area. Of particular concern were single working mothers who still need assistance. A need for increased domestic violence services were also mentioned along with more accountability and money management for those seeking assistance. Participants also noted long lines for assistance and a 30 percent increase in demand over the last year at Southeastern Arizona food banks.

Coconino County

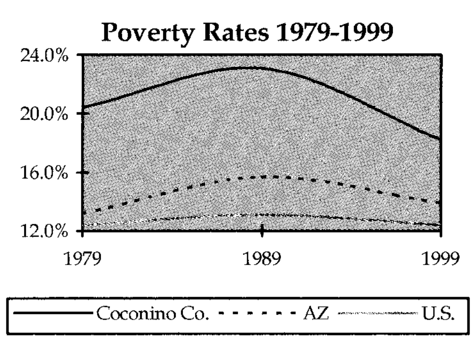
The 2000 Census revealed 116,320 people living in Coconino County, a 20.4 percent increase from the 1990 Census of 96,591. Nearly 22 percent lived on reservation lands including all or parts of the Havasupai, Hopi and Navajo Reservations. In 1999, Coconino County had over 18 percent of its population or 20,609 people living below the poverty level (over 40 percent of those on reservations). The 1999 non-reservation poverty rate was 13.9 percent. Over the last ten years the number of those in poverty remained virtually unchanged helped by significant improvements on reservations.

Poverty in Selected Communities

Number of Persons Below Poverty Level (Poverty Rate)	1989	1999	% Change
Flagstaff	6,813 (17.2%)	8,751 (17.4%)	28.4%
Page	604 (9.2%)	947 (13.9%)	56.8%
Reservations	10,520 (49.7%)	8,283 (33.6%)	-21.3%
Coconino County	20,805 (23.1%)	20,609 (18.2%)	-0.9%
Arizona	564,362 (15.7%)	698,669 (13.9%)	23.8%

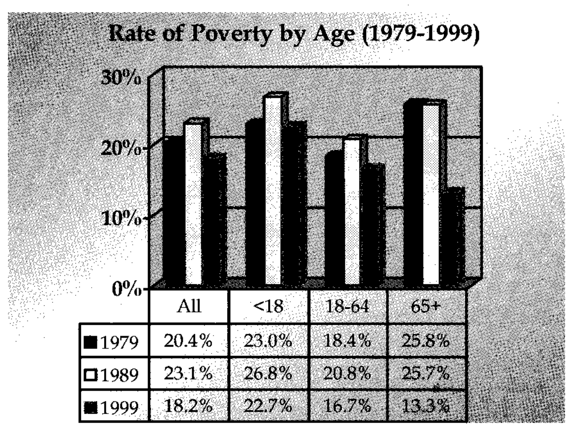
Source: U.S. Census and Research Advisory Services, Inc.

When you compare the number of people in poverty over the last twenty years, Coconino County increased 45.7 percent from 14,141 people below the poverty line in 1979 compared to 20,609 people in 1999. In 1999, Coconino County's poverty rate still remains higher than the state average of 13.9 percent and the national average of 12.4 percent.



Poverty and Age

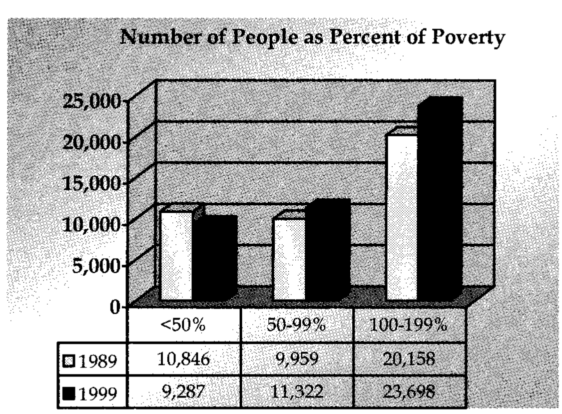
In 1999, among all age categories examined, children under 18 years of age experienced the highest rate of poverty at 22.7 percent, while those 65 and older had the lowest rate at 13.3 percent. Since 1979, the rate has decreased for all age groups with those over 65 improving the most.



Source: U.S Census.

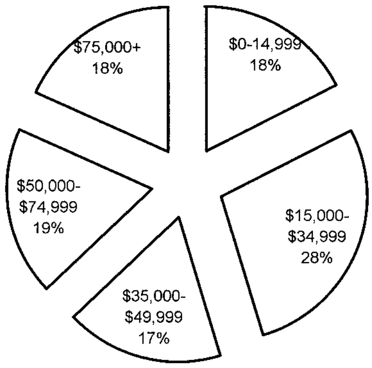
Poverty and Income Levels

Examination of the income to poverty ratio reveals that 9,287 people or 45.1 percent of those below the poverty rate in Coconino County were *very poor*, with incomes less than 50 percent of the poverty threshold. Another 23,698 people had incomes equal to or above the poverty level, but less than 199 percent (ACAA's definition of "working poor"). ***In total, there are 44,307 people in Coconino County who are poor or "working poor," 39.2 percent of the county's total population.***



Source: U.S Census.

1999 Household Income Distribution - Coconino County



Source: U.S Census. Note: The median household income in Coconino County was $38,256 in 1999 compared to $26,112 in 1989 (46.5 percent increase).

From 1990 to 1999, local total personal income in Coconino County increased about 79 percent compared to the State's nearly 90 percent (according to the Arizona Department of Economic Security). On a per capita basis, the gain of 52 percent was greater than the state's growth of 46 percent. Coconino County per capita income was $21,297 in 1999, about 84.6 percent of the state average, up from 81.6 percent in 1990. Average earnings per job increased 2.9 percent in 1999 to $25,533 - slightly less than the gain for the state at 4.1 percent.

Poverty and Families

In 1999, the poverty rate among all families with children under 18 years of age living in Coconino County was 18.8 percent. The rates for families with children headed by single females were 43.2 percent and even higher with younger children (less than 5 years) at 55.7 percent. Married couple families with children experienced a much lower rate at 9.6 percent.

Number Below Poverty Level (Poverty Rate)	1979	1989	1999	% Change '79-'99
All	2,501 (15.2%)	3,583 (16.9%)	3,549 (13.1%)	41.9%
With children under 18	1,919 (18.1%)	2,859 (21.4%)	2,940 (18.8%)	53.2%
Female-headed with children under 18	632 (43.3%)	1,210 (46.0%)	1,585 (43.2%)	150.8%
Female headed with children under 5*	279 (48.9%)	698 (59.8%)	834 (55.7%)	198.9%

*1979 numbers include 5 year olds. Source: U.S. Census.

Poverty and Race

Among racial/ethnic groups, American Indians experienced the highest poverty rate at 31.4 percent and Whites had the lowest at 11.3 percent. American Indians were also represented at a disproportionately higher rate among those in poverty than in the overall population. All races in Coconino County saw an improvement in poverty rates from 1989.

Race Ethnicity	% of Total Population 1999	% of Poverty Population 1999	Poverty Rate by Race 1999	Poverty Rate by Race 1989
White	63.1%	40.2%	11.3%	11.7%
Black	1.0%	1.2%	20.4%	36.7%
American Indian	28.5%	50.5%	31.4%	45.3%
Asian/PI	0.9%	0.8%	15.4%	38.3%
Other	6.5%	7.4%	20.1%	24.1%
Hispanic Origin*	10.9%	12.4%	20.1%	20.5%

NOTE: Categories include those identifying themselves as Hispanic. *Those of Hispanic Origin may be of any race. Source: U.S. Census.

Public Assistance

According to the 2000 Census, 1,549 households or 3.8 percent of all households in Coconino County received public assistance. The mean or average amount of public assistance income for 1999 was $2,504, a decrease from the 1989 average of $3,309 and $3,885 in 1979. Participation levels in the Food Stamp and Temporary Assistance to Needy Families (TANF) programs serve as indicators of the extent of poverty. In 2000, 8,759 people or 7.5 percent of the population received food stamps. At the same time, 914 or 3.4 percent of families were enrolled in TANF.

Public Assistance (PA)	Base Year	1990	2000	% Change 1990-2000	% Change Base Yr-2000
Households receiving PA (1980)	1,489	2,641	1,549	-41.3%	4.0%
Persons Food Stamps (1985*)	8,858	10,412	8,759	-15.9%	-1.1%
Families AFDC-TANF (1985*)	914	1,108	914	-17.5%	0.0%

NOTE: Base year in parentheses. *April figures. Source U.S. Census and Arizona Department of Economic Security.

Self-Sufficiency

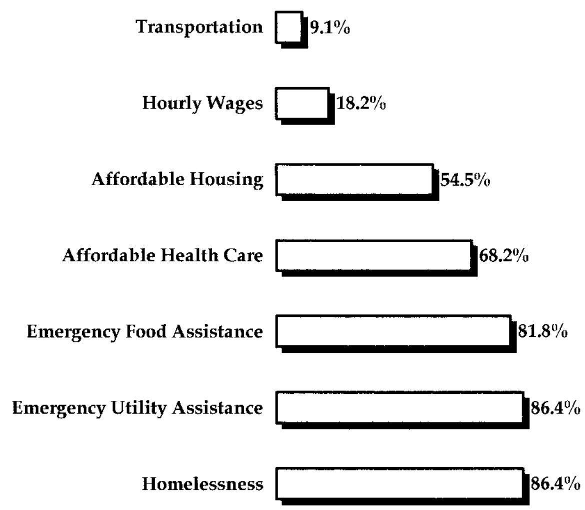
According to an Arizona Children's Action Alliance report completed in 2002, "The Self-Sufficiency Standard for Arizona," a single parent with an infant and a preschool-age child needs to earn a minimum of $39,140 annually to cover basic expenses in Flagstaff. In comparison, the following chart notes that a two parent household with an infant and a preschool-age child would need to make $45,958 annually, while a single adult would need $19,235 to cover basic living needs in Flagstaff.

Monthly Costs	Adult	Adult + Infant Preschooler	2 Adults + Infant Preschooler
Housing	685	889	889
Child Care	0	825	825
Food	176	345	496
Transportation	221	227	437
Health Care	101	282	351
Miscellaneous	118	257	300
Taxes	301	617	713
Earned Income Tax Credit (-)	0	0	0
Child Care Tax Credit (-)	0	-80	-80
Child Tax Credit	0	-100	-100
Self-Sufficiency Wage:			
Hourly	**$9.11**	**$18.53**	**$10.88 Per adult**
Monthly	**$1,603**	**$3,262**	**$3,830**
Annual	**$19,235**	**$39,140**	**$45,958**

NOTE: Numbers represent those living in Flagstaff only. Costs for living in the balance of Coconino County are 3%-6% less.

Perceptions from the Community

Two community meetings were held in Coconino County to discuss the major issues regarding poverty. The chart below shows the percentage of participants surveyed who believe conditions have gotten ***worse*** in the following areas over the last ten years:



More specifically, participants indicated that increasing child care opportunities was a top concern. While transportation was rated low, many did note the lack of public transportation outside of Flagstaff. Other specific issues raised included the need for dental services and improved access to mental health services. Many also indicated that the area is witnessing many new families seeking services that never sought them before.

Gila County

The 2000 Census revealed 51,335 people living in Gila County, a 27.6 percent increase from the 1990 Census of 40,216. In 1999, Gila County had over 17 percent of its population or 8,752 people living below the poverty level. That rate drops to 12.8% for people not living on reservation lands (Fort Apache, San Carlos and Tonto Apache Reservations).

While the overall percentage of people in poverty decreased over the last ten years, the number of people in poverty did not. Gila County experienced a 21.0 percent increase since 1989 when 7,234 people or 18.3 percent of the county's population lived in poverty.

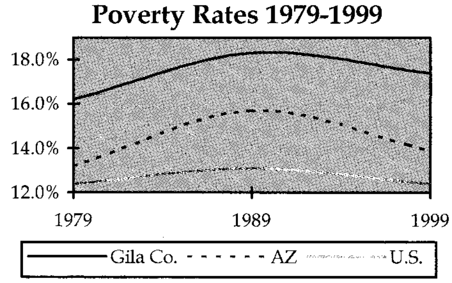
Poverty in Selected Communities

Number of Persons Below Poverty Level (Poverty Rate)	1989	1999	% Change
Globe	682 (11.7%)	793 (11.4%)	16.3%
Payson	984 (11.9%)	1,360 (9.9%)	38.2%
San Carlos	1,728 (58.8%)	2,236 (58.8%)	29.4%
Reservations	4,892 (53.4%)	3,133 (49.4%)	-36.0%
Gila County	7,234 (18.3%)	8,752 (17.4%)	21.0%
Arizona	564,362 (15.7%)	698,669 (13.9%)	23.8%

Source: U.S. Census and Research Advisory Services, Inc.

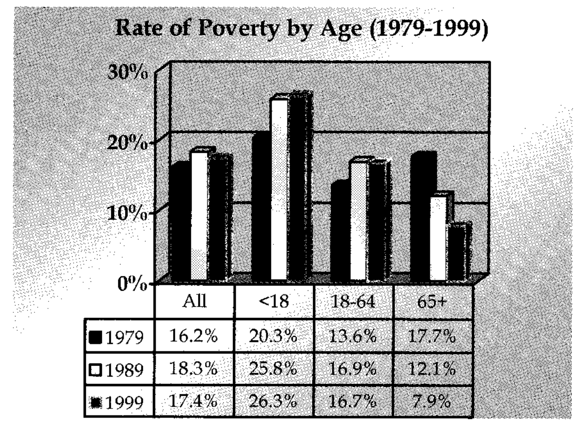
When you compare poverty rates over the last twenty years, Gila County's poverty rate increased from 16.2 percent in 1979 to 17.4 percent in 1999, 5,961 to 8,752 people respectively. In 1999, Gila County's poverty rate still remains higher than the state average of 13.9 percent and the national average of 12.4 percent.

Poverty Rates 1979-1999



Poverty and Age

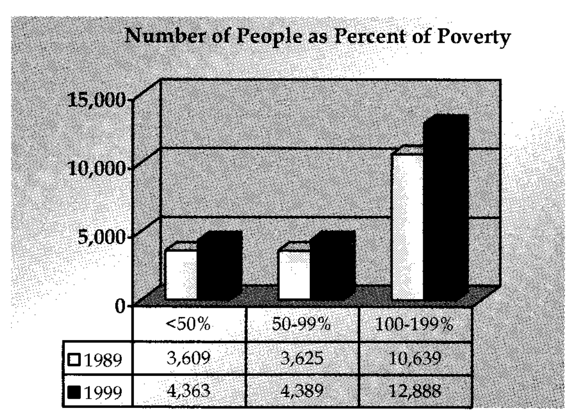
In 1999, among all age categories examined, children under 18 years of age experienced the highest rate of poverty at 26.3 percent, while those 65 and older had the lowest rate at 7.9 percent. Over the last twenty years, the rate of poverty has increased for all age groups, except those over 65 who experienced a significant improvement from 17.7 percent in 1979 to 7.9 percent in 1999.



Source: U.S Census.

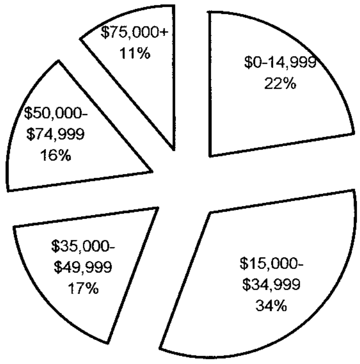
Poverty and Income Levels

Examination of the income to poverty ratio reveals that 4,363 people or half of those below the poverty rate in Gila County were ***very poor,*** with incomes less than 50 percent of the poverty threshold. Another 12,888 people had incomes equal to or above the poverty level, but less than 199 percent (ACAA's definition of "working poor"). ***In total, there are 21,640 people in Gila County who are poor or "working poor," 43.1 percent of the county's total population.***



Source: U.S Census.

1999 Household Income Distribution - Gila County



Source: U.S Census. Note: The median household income in Gila County was $30,917 in 1999 compared to $20,964 in 1989 (47.5 percent increase).

From 1990 to 1999, local total personal income in Gila County increased 71.7 percent compared to the state's almost 90 percent (according to the Arizona Department of Economic Security). On a per capita basis, the gain of 41.3 percent was close to 5 percent below the state's growth of 46.3 percent. Gila County per capita income was $19,002 in 1999, about 75.5 percent of the state average, down from 78.1 percent in 1990. Average earnings per job increased 2.3 percent in 1999 to $23,828, approximately one half the gain of the state at 4.1 percent.

Poverty and Families

In 1999, the poverty rate among all families with children under 18 years of age living in Gila County was 22 percent. The rates for families with children headed by single females were 43.8 percent and even higher with younger children (less than 5 years) at 58.9 percent. Married couple families with children experienced a much lower rate at 13.5 percent.

Number Below Poverty Level (Poverty Rate)	1979	1989	1999	% Change '79-'99
All	1,281 (12.8%)	1,514 (13.5%)	1,785 (12.6%)	39.3%
With children under 18	846 (16.5%)	1,110 (22.1%)	1,348 (22.0%)	59.3%
Female-headed with children under 18	315 (43.1%)	523 (56.4%)	634 (43.8%)	101.3%
Female headed with children under 5*	211 (64.5%)	358 (78.9%)	298 (58.9%)	41.2%

*1979 numbers include 5 year olds. Source: U.S. Census.

Poverty and Race

Among racial/ethnic groups, American Indians experienced the highest poverty rate at 45.7 percent and Blacks had the lowest at 2.5 percent. American Indians were also represented at a disproportionately higher rate among those in poverty than in the overall population. All races in Gila County saw an improvement in poverty rates from 1989 except those of Other races and of Hispanic Origin.

Race Ethnicity	% of Total Population 1999	% of Poverty Population 1999	Poverty Rate by Race 1999	Poverty Rate by Race 1989
White	77.8%	54.2%	11.9%	13.1%
Black	0.4%	0.1%	2.5%	7.8%
American Indian	12.9%	34.6%	45.7%	52.2%
Asian/PI	0.5%	0.3%	9.7%	11.8%
Other	8.4%	10.8%	22.0%	14.9%
Hispanic Origin*	16.6%	17.6%	18.0%	14.8%

NOTE: Categories include those identifying themselves as Hispanic. *Those of Hispanic Origin may be of any race. Source: U.S. Census.

Public Assistance

According to the 2000 Census, 954 households or 4.7 percent of all households in Gila County received public assistance. The mean or average amount of public assistance income for 1999 was $2,525, a decrease from the 1989 average of $3,733 and $4,142 in 1979. Participation levels in the Food Stamp and Temporary Assistance to Needy Families (TANF) programs serve as indicators of the extent of poverty. In 2000, 5,652 people or 11 percent of the population received food stamps. At the same time, 770 or 5.4 percent of families were enrolled in TANF.

Public Assistance (PA)	Base Year	1990	2000	% Change 1990-2000	% Change Base Yr-2000
Households receiving PA (1980)	850	1,477	954	-35.4%	12.2%
Persons Food Stamps (1985*)	5,521	7,023	5,652	-19.5%	2.4%
Families AFDC-TANF (1985*)	596	771	770	-0.1%	29.2%

NOTE: Base year in parentheses. *April figures. Source U.S. Census and Arizona Department of Economic Security.

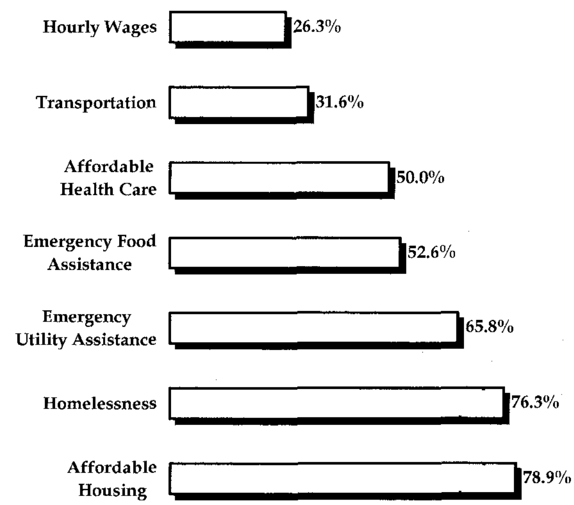
Self-Sufficiency

According to an Arizona Children's Action Alliance report completed in 2002, "The Self-Sufficiency Standard for Arizona," a single parent with an infant and a preschool-age child needs to earn a minimum of $33,204 annually to cover basic expenses in Gila County. In comparison, the following chart notes that a two parent household with an infant and a preschool-age child would need to make $39,953 annually, while a single adult would need $14,175 to cover basic living needs in Gila County.

Monthly Costs	Adult	Adult + Infant Preschooler	2 Adults + Infant Preschooler
Housing	396	503	503
Child Care	0	880	880
Food	176	345	496
Transportation	221	227	437
Health Care	102	289	358
Miscellaneous	90	224	267
Taxes	196	479	569
Earned Income Tax Credit (-)	0	0	0
Child Care Tax Credit (-)	0	-80	-80
Child Tax Credit	0	-100	-100
Self-Sufficiency Wage:			
Hourly	**$6.71**	**$15.72**	**$9.46 Per adult**
Monthly	**$1,181**	**$2,767**	**$3,329**
Annual	**$14,175**	**$33,204**	**$39,953**

Perceptions from the Community

Two community meetings were held in Gila County to discuss the major issues regarding poverty and possible solutions. The chart below shows the percentage of participants surveyed who believe conditions have gotten *worse* in the following areas over the last ten years:



More specifically, participants indicated that one of the biggest concerns was the need for more mental health services including drug and alcohol programs. Transportation was another area of concern with participants agreeing that vehicle ownership was necessary for the working poor but too expensive for most to afford. Participants also cited specific employment issues including:

- The lack of new jobs
- Retraining needed for lost industries
- Minimum wage jobs not sufficient to pay bills

Graham County

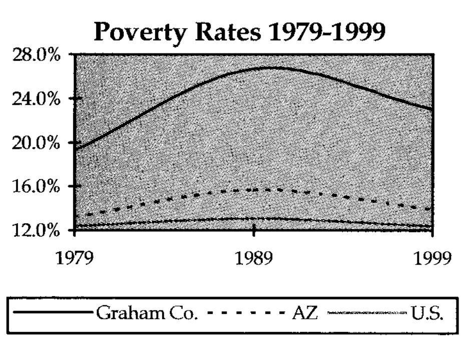
The 2000 Census revealed 33,489 people living in Graham County, a 26.1 percent increase from the 1990 Census of 26,554. In 1999, Graham County had 23 percent of its population or 6,952 people living below the poverty level. While the overall percentage of people in poverty decreased over the last ten years, the number of people in poverty did not. Graham County experienced a 6.6 percent increase since 1989 when 6,523 people or 26.7 percent of the county's population lived in poverty. In 1999, people living on the San Carlos Reservation accounted for 15 percent of the population in Graham County. The poverty rate for those 4,578 persons was 48.4 percent.

Poverty in Selected Communities

Number of Persons Below Poverty Level (Poverty Rate)	1989	1999	% Change
Safford	1,431 (20.1%)	1,565 (17.3%)	9.4%
Thatcher	810 (22.6%)	758 (20.2%)	-6.4%
Reservation	3,644 (63.7%)	2,218 (48.4%)	-39.1%
Graham County	6,523 (26.7%)	6,952 (23.0%)	6.6%
Arizona	564,362 (15.7%)	698,669 (13.9%)	23.8%

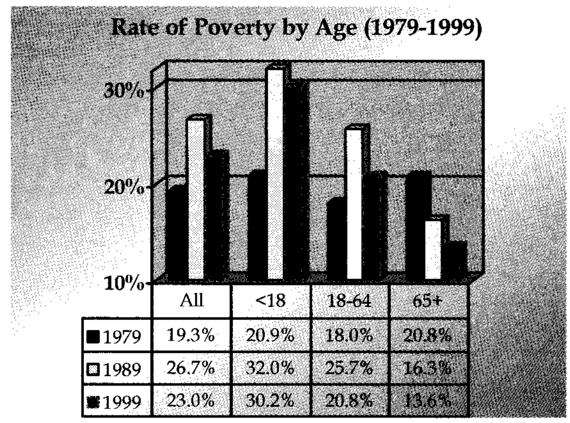
Source: U.S. Census and Research Advisory Services, Inc.

When you compare poverty rates over the last twenty years, Graham County's poverty rate increased from 19.3 percent in 1979 to 23.0 percent in 1999, 4,132 to 6,952 people respectively. In 1999, Graham County's poverty rate is almost double the state average of 13.9 percent and the national average of 12.4 percent.



Poverty and Age

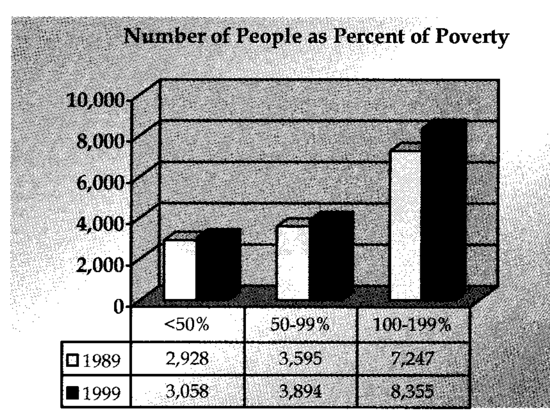
In 1999, among all age categories examined, children under 18 years of age experienced the highest rate of poverty at 30.2 percent, while those 65 and older had the lowest rate at 13.6 percent. Over the last twenty years, the rate of poverty has increased for all age groups, except those over 65 who experienced an improvement from 20.8 percent in 1979 to 13.6 percent in 1999.



Source: U.S Census.

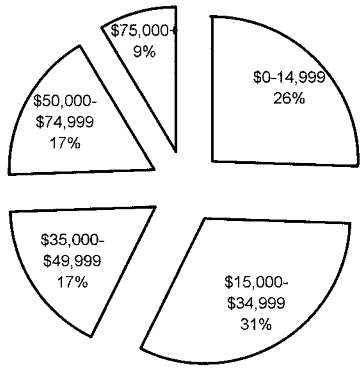
Poverty and Income Levels

Examination of the income to poverty ratio reveals that 3,058 people or 44 percent of those below the poverty rate in Graham County were ***very poor***, with incomes less than 50 percent of the poverty threshold. Another 8,355 people had incomes equal to or above the poverty level, but less than 199 percent (ACAA's definition of "working poor"). ***In total, there are 15,307 people in Graham County who are poor or "working poor," 50.6 percent of the county's total population.***



Source: U.S Census.

1999 Household Income Distribution – Graham County



Source: U.S Census. Note: The median household income in Graham County was $29,668 in 1999 compared to $18,455 in 1989 (60.8 percent increase).

From 1990 to 1999, local total personal income in Graham County increased 72.5 percent compared to the state's almost 90 percent (according to the Arizona Department of Economic Security). On a per capita basis, the gain of 43.3 percent was just below the state's growth of 46.3 percent. Graham County per capita income was $14,719 in 1999, about 58.5 percent of the state average, down from 59.7 percent in 1990. Average wage per job increased 3.3 percent in 1999 to a level of $22,677 - 0.8 percent less than the state's gain of 4.1 percent.

Poverty and Families

In 1999, the poverty rate among all families with children under 18 years of age living in Graham County was 24.9 percent. The rates for families with children headed by single females were 52.2 percent and even higher with younger children (less than 5 years) at 62.1 percent. Married couple families with children experienced a much lower rate at 15.7 percent.

Number Below Poverty Level (Poverty Rate)	1979	1989	1999	% Change '79-'99
All	820 (15.2%)	1,369 (21.9%)	1,363 (17.7%)	66.2%
With children under 18	602 (18.3%)	1,067 (29.4%)	1,115 (24.9%)	85.2%
Female-headed with children under 18	256 (51.9%)	467 (60.0%)	549 (52.2%)	114.5%
Female headed with children under 5*	122 (53.7%)	213 (64.2%)	229 (62.1%)	87.7%

*1979 numbers include 5 year olds. Source: U.S. Census.

Poverty and Race

Among racial/ethnic groups, American Indians experienced the highest poverty rate at 45.5 percent and Asian/Pacific Islanders had the lowest at 12.9 percent. American Indians were also represented at a disproportionately higher rate among those in poverty than in the overall population. All races in Graham County saw an improvement in poverty rates from 1989.

Race Ethnicity	% of Total Population 1999	% of Poverty Population 1999	Poverty Rate by Race 1999	Poverty Rate by Race 1989
White	67.1%	46.1%	14.2%	19.1%
Black	1.9%	2.5%	27.7%	31.2%
American Indian	14.9%	32.7%	45.5%	61.9%
Asian/PI	0.6%	0.4%	12.9%	29.8%
Other	15.5%	18.3%	24.6%	38.7%
Hispanic Origin*	27.0%	31.9%	24.5%	31.2%

NOTE: Categories include those identifying themselves as Hispanic. *Those of Hispanic Origin may be of any race. Source: U.S. Census.

Public Assistance

According to the 2000 Census, 698 households or 6.9 percent of all households in Graham County received public assistance. The mean or average amount of public assistance income for 1999 was $2,684, a decrease from the 1989 average of $3,806 and $3,586 in 1979. Participation levels in the Food Stamp and Temporary Assistance to Needy Families (TANF) programs serve as indicators of the extent of poverty. In 2000, 3,700 people or 11 percent of the population received food stamps. At the same time, 392 or 5.1 percent of families were enrolled in TANF.

Public Assistance (PA)	Base Year	1990	2000	% Change 1990-2000	% Change Base Yr-2000
Households receiving PA (1980)	536	1.033	698	-32.4%	30.2%
Persons Food Stamps (1985*)	4,214	4,639	3,700	-20.2%	-12.2%
Families AFDC-TANF (1985*)	427	573	392	-31.6%	-8.2%

NOTE: Base year in parentheses. *April figures. Source U.S. Census and Arizona Department of Economic Security.

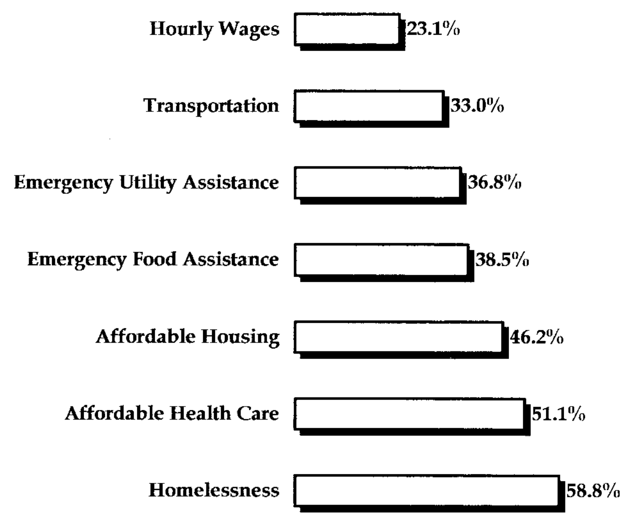
Self-Sufficiency

According to an Arizona Children's Action Alliance report completed in 2002, "The Self-Sufficiency Standard for Arizona," a single parent with an infant and a preschool-age child needs to earn a minimum of $31,699 annually to cover basic expenses in Graham County. In comparison, the following chart notes that a two parent household with an infant and a preschool-age child would need to make $38,555 annually, while a single adult would need $14,168 to cover basic living needs in Graham County.

Monthly Costs	Adult	Adult + Infant Preschooler	2 Adults + Infant Preschooler
Housing	396	503	503
Child Care	0	803	803
Food	176	345	496
Transportation	221	227	437
Health Care	102	289	358
Miscellaneous	90	217	260
Taxes	196	445	537
Earned Income Tax Credit (-)	0	-7	0
Child Care Tax Credit (-)	0	-80	-80
Child Tax Credit	0	-100	-100
Self-Sufficiency Wage:			
Hourly	**$6.71**	**$15.01**	**$9.13 Per adult**
Monthly	**$1,181**	**$2,642**	**$3,213**
Annual	**$14,168**	**$31,699**	**$38,555**

Perceptions from the Community

Information on community attitudes about poverty was obtained through surveys distributed throughout Graham County with the help of local agencies. The chart below shows the percentage of participants surveyed who believe conditions have gotten ***worse*** in the following areas over the last ten years:



More specifically, participants expressed concerns over the availability of well paying jobs. The following comments were made:

- Families need college education and job training assistance
- Job benefits are needed (health, education)
- People need more than part-time work

Other community concerns included the need for affordable housing, expanded and flexible child care and transportation. A common sentiment was that those who are working need additional supports.

Greenlee County

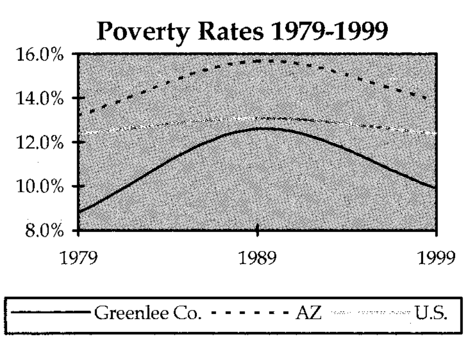
The 2000 Census revealed 8,547 people living in Greenlee County, a 6.7 percent increase from the 1990 Census of 8,008. In 1999, Greenlee County had almost 10 percent of its population or 842 people living below the poverty level. Greenlee County experienced a 16.6 percent decrease since 1989 when 1,010 people or 12.6 percent of the county's population lived in poverty.

Poverty in Selected Communities

Number of Persons Below Poverty Level (Poverty Rate)	1989	1999	% Change
Clifton	367 (13.3%)	292 (11.5%)	-20.4%
Duncan	124 (18.8%)	133 (16.5%)	7.3%
Greenlee County	1,010 (12.6%)	842 (9.9%)	-16.6%
Arizona	564,362 (15.7%)	698,669 (13.9%)	23.8%

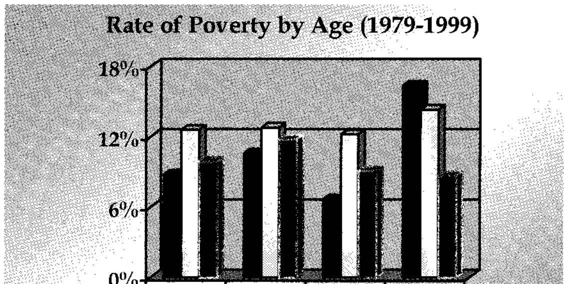
Source: U.S. Census and Research Advisory Services, Inc.

Between 1989 and 1979 the number of people in poverty remained virtually unchanged in Greenlee County despite a drop in population of nearly 30 percent from 11,406 to 8,008 persons. These trends changed during the 1990's, when Greenlee County experienced an increase in population along with a decrease in the number of people in poverty. Greenlee County continues to have the lowest poverty rate of all Arizona Counties. In 1999, Greenlee County's poverty rate remains lower than the state average of 13.9 percent and the national average of 12.4 percent.



Poverty and Age

In 1999, among all age categories examined, children under 18 years of age experienced the highest rate of poverty at 11.8 percent, while those 65 and older had the lowest rate at 8.7 percent. Over the last twenty years, the rate of poverty has increased for all age groups, except those over 65 who experienced a significant improvement from 16.4 percent in 1979 to 8.7 percent in 1999.

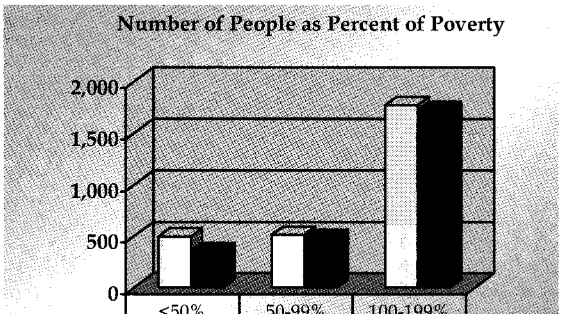


	All	<18	18-64	65+
1979	8.8%	10.6%	6.7%	16.4%
1989	12.6%	12.8%	12.2%	14.3%
1999	9.9%	11.8%	9.1%	8.7%

Source: U.S Census.

Poverty and Income Levels

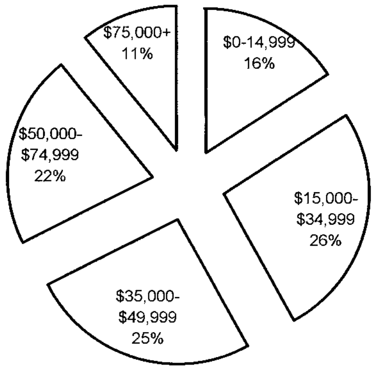
Examination of the income to poverty ratio reveals that 355 people or 42.2 percent of those below the poverty rate in Greenlee County were ***very poor***, with incomes less than 50 percent of the poverty threshold. Another 1,728 people had incomes equal to or above the poverty level, but less than 199 percent (ACAA's definition of "working poor"). ***In total, there are 2,570 people in Greenlee County who are poor or "working poor," 30.3 percent of the county's total population.***



	<50%	50-99%	100-199%
1989	497	513	1,774
1999	355	487	1,728

Source: U.S Census.

1999 Household Income Distribution – Greenlee County



Source: U.S Census. Note: The median household income in Greenlee County was $39,384 in 1999 compared to $27,491 in 1989 (43.3 percent increase).

From 1990 to 1999, local total personal income in Greenlee County increased 64.7 percent compared to the state's roughly 90 percent (according to the Arizona Department of Economic Security). On a per capita basis, the gain of 46.8 percent was 0.5 percent higher than the state's growth of 46.3 percent. Greenlee County per capita income was $19,237 in 1999, about 76.4 percent of the state average, up from 76.1 percent in 1990. Average earnings per job increased by 0.6 percent in 1999 and was 13.2 percent higher than the state's level.

Poverty and Families

In 1999, the poverty rate among all families with children under 18 years of age living in Greenlee County was 9.5 percent. The rates for families with children headed by single females were 40.9 percent and even higher with younger children (less than 5 years) at 52.6 percent. Married couple families with children experienced a much lower rate at 2.7 percent.

Number Below Poverty Level (Poverty Rate)	1979	1989	1999	% Change '79-'99
All	203 (6.8%)	233 (10.8%)	181 (8.0%)	-10.8%
With children under 18	166 (8.8%)	150 (11.3%)	130 (9.5%)	-21.7%
Female-headed with children under 18	65 (54.2%)	82 (48.8%)	88 (40.9%)	35.4%
Female headed with children under 5*	48 (66.7%)	33 (70.2%)	40 (52.6%)	-16.7%

*1979 numbers include 5 year olds. Source: U.S. Census.

Poverty and Race

Among racial/ethnic groups, other races and those of Hispanic Origin experienced the highest poverty rate at 11.7 percent and 11.5 percent respectively. All races in Greenlee County saw an improvement in poverty rates from 1989 except Blacks and American Indians where the rate increased by 4.5 and 1.8 percentage points respectively.

Race Ethnicity	% of Total Population 1999	% of Poverty Population 1999	Poverty Rate by Race 1999	Poverty Rate by Race 1989
White	74.2%	70.9%	9.4%	13.0%
Black	0.5%	0.2%	4.5%	-
American Indian	1.7%	1.1%	6.3%	4.5%
Asian/PI	0.2%	0.0%	0.0%	-
Other	23.5%	27.8%	11.7%	12.7%
Hispanic Origin*	43.1%	50.4%	11.5%	15.4%

NOTE: Categories include those identifying themselves as Hispanic. *Those of Hispanic Origin may be of any race. Source: U.S. Census.

Public Assistance

According to the 2000 Census, 121 households or 3.9 percent of all households in Greenlee County received public assistance. The mean or average amount of public assistance income for 1999 was $2,134, a decrease from the 1989 average of $3,980 and $4,113 in 1979. Participation levels in the Food Stamp and Temporary Assistance to Needy Families (TANF) programs serve as indicators of the extent of poverty. In 2000, 471 people or 5.5 percent of the population received food stamps. At the same time, 54 or 2.4 percent of families were enrolled in TANF.

Public Assistance (PA)	Base Year	1990	2000	% Change 1990-2000	% Change Base Yr-2000
Households receiving PA (1980)	213	222	121	-45.5%	-43.2%
Persons Food Stamps (1985*)	1,470	876	471	-46.2%	-68.0%
Families AFDC-TANF (1985*)	84	114	54	-52.6%	-35.7%

NOTE: Base year in parentheses. *April figures. Source U.S. Census and Arizona Department of Economic Security.

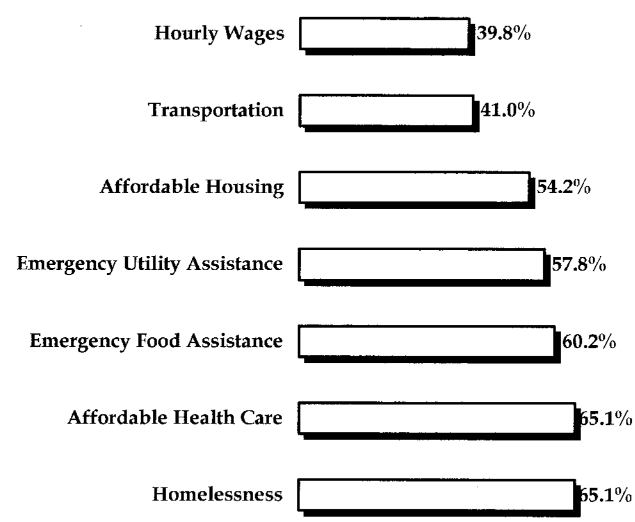
Self-Sufficiency

According to an Arizona Children's Action Alliance report completed in 2002, "The Self-Sufficiency Standard for Arizona," a single parent with an infant and a preschool-age child needs to earn a minimum of $31,699 annually to cover basic expenses in Greenlee County. In comparison, the following chart notes that a two parent household with an infant and a preschool-age child would need to make $38,555 annually, while a single adult would need $14,168 to cover basic living needs in Greenlee County.

Monthly Costs	Adult	Adult + Infant Preschooler	2 Adults + Infant Preschooler
Housing	396	503	503
Child Care	0	803	803
Food	176	345	496
Transportation	221	227	437
Health Care	102	289	358
Miscellaneous	90	217	260
Taxes	196	445	537
Earned Income Tax Credit (-)	0	-7	0
Child Care Tax Credit (-)	0	-80	-80
Child Tax Credit	0	-100	-100
Self-Sufficiency Wage:			
Hourly	**$6.71**	**$15.01**	**$9.13 Per adult**
Monthly	**$1,181**	**$2,642**	**$3,213**
Annual	**$14,168**	**$31,699**	**$38,555**

Perceptions from the Community

Information on community attitudes about poverty was obtained through surveys distributed throughout Greenlee County with the help of local agencies. The chart below shows the percentage of participants surveyed who believe conditions have gotten ***worse*** in the following areas over the last ten years:



More specifically, participants expressed a major concern over the lack of jobs and the lack of transportation services. Others noted that there are no job training programs in the county and the fact that many more people are living with other family members to make ends meet.

La Paz County

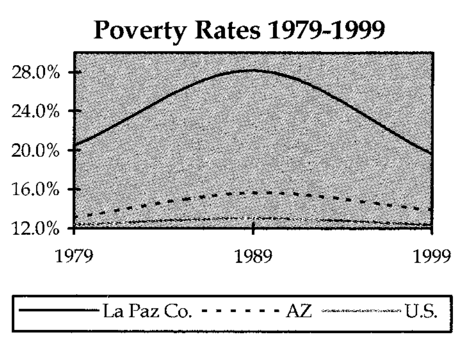
The 2000 Census revealed 19,715 people living in La Paz County, a 42.4 percent increase from the 1990 Census of 13,844. Those living on the Colorado River Reservation represented 37 percent of the total. In 1999, La Paz County had almost 20 percent of its population or 3,798 people living below the poverty level. The rate goes up to 22.2 percent for those living on the Colorado River Reservation.

Poverty in Selected Communities

Number of Persons Below Poverty Level (Poverty Rate)	1989	1999	% Change
Parker	492 (17.0%)	460 (14.7%)	-6.5%
Quartzsite	430 (23.5%)	457 (13.5%)	6.3%
Reservation	1,913 (28.2)	1,590 (22.2%)	-16.9%
La Paz County	3,875 (28.2%)	3,798 (19.6%)	-2.0%
Arizona	564,362 (15.7%)	698,669 (13.9%)	23.8%

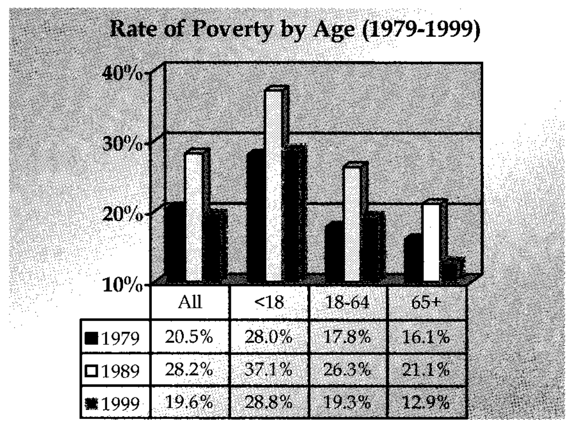
Source: U.S. Census and Research Advisory Services, Inc.

Over the last ten years, the number of people in poverty decreased by 77 persons in La Paz County. During the same period, the number of people in poverty decreased 16.9 percent on the Colorado River Reservation. When you compare the numbers over the last twenty years, there were 1,445 more people living in poverty in La Paz County, up from 2,353 in 1979. In 1999, La Paz County's poverty rate still remains higher than the state average of 13.9 percent and the national average of 12.4 percent.



Poverty and Age

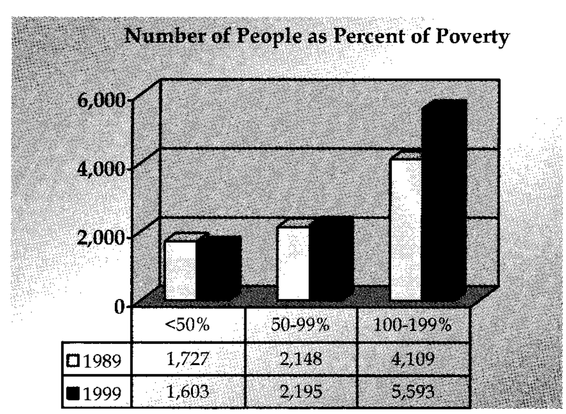
In 1999, among all age categories examined, children under 18 years of age experienced the highest rate of poverty at 28.8 percent, while those 65 and older had the lowest rate at 12.9 percent. Over the last twenty years, the rate of poverty has increased for all age groups, except those over 65 who experienced an improvement from 16.1 percent in 1979 to 12.9 percent in 1999.



Source: U.S Census.

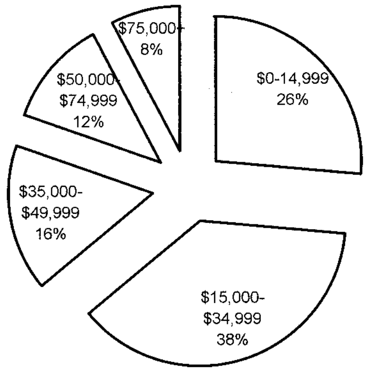
Poverty and Income Levels

Examination of the income to poverty ratio reveals that 1,603 people or 42.2 percent of those below the poverty rate in La Paz County were ***very poor***, with incomes less than 50 percent of the poverty threshold. Another 5,593 people had incomes equal to or above the poverty level, but less than 199 percent (ACAA's definition of "working poor"). ***In total, there are 9,391 people in La Paz County who are poor or "working poor," 48.4 percent of the county's total population.***



Source: U.S Census.

1999 Household Income Distribution – La Paz County



Source: U.S Census. Note: The median household income in La Paz County was $25,839 in 1999 compared to $16,555 in 1989 (56.1 percent increase).

From 1990 to 1999, local total personal income in La Paz County increased 48.6 percent compared to the state's nearly 90 percent (according to the Arizona Department of Economic Security). On a per capita basis, the gain of 38.6 percent was 7.7 percent below the state's growth of 46.3 percent. La Paz County per capita income was $22,133 in 1999, about 87.9 percent of the state average, down from 92.8 percent in 1990. Average wage per job increased about 2 percent in 1999 to a level of $23,567 – only 75 percent of the state's level.

Poverty and Families

In 1999, the poverty rate among all families with children under 18 years of age living in La Paz County was 22.6 percent. The rates for families with children headed by single females were 43.9 percent and even higher with younger children (less than 5 years) at 53 percent. Married couple families with children experienced a much lower rate at 14.6 percent.

Number Below Poverty Level (Poverty Rate)	1989	1999	% Change '89-'99
All	906 (23.6%)	764 (13.6%)	-15.7%
With children under 18	563 (31.4%)	463 (22.6%)	-17.8%
Female-headed with children under 18	567 (60.3%)	230 (43.9%)	-59.4%
Female headed with children under 5*	106 (66.7%)	79 (53.0%)	-25.5%

*1979 numbers include 5 year olds. Source: U.S. Census.

Poverty and Race

Among racial/ethnic groups, American Indians experienced the highest poverty rate at 32 percent and Asian/Pacific Islanders had the lowest at 2 percent. American Indians and those of Hispanic Origin were also represented at a disproportionately higher rate among those in poverty than in the overall population. All races in La Paz County saw an improvement in poverty rates from 1989.

Race Ethnicity	% of Total Population 1999	% of Poverty Population 1999	Poverty Rate by Race 1999	Poverty Rate by Race 1989
White	74.2%	62.5%	16.2%	24.2%
Black	0.8%	1.3%	31.6%	84.2%
American Indian	12.5%	20.8%	32.0%	37.7%
Asian/PI	0.5%	0.1%	2.0%	29.9%
Other	12.0%	15.4%	24.6%	45.1%
Hispanic Origin*	22.4%	33.2%	28.5%	35.9%

NOTE: Categories include those identifying themselves as Hispanic. *Those of Hispanic Origin may be of any race. Source: U.S. Census.

Public Assistance

According to the 2000 Census, 258 households or 3.1 percent of all households in La Paz County received public assistance. The mean or average amount of public assistance income for 1999 was $3,005, a decrease from the 1989 average of $3,972. Participation levels in the Food Stamp and Temporary Assistance to Needy Families (TANF) programs serve as indicators of the extent of poverty. In 2000, 1,226 people or 6.2 percent of the population received food stamps. At the same time, 137 or 2.4 percent of families were enrolled in TANF.

Public Assistance (PA)	Base Year	1990	2000	% Change 1990-2000	% Change Base Yr-2000
Households receiving PA (1980)	NA	492	258	-47.6%	NA
Persons Food Stamps (1985*)	1,174	1,424	1,226	-13.9%	4.4%
Families AFDC-TANF (1985*)	104	182	137	-24.7%	31.7%

NOTE: Base year in parentheses. *April figures. Source U.S. Census and Arizona Department of Economic Security.

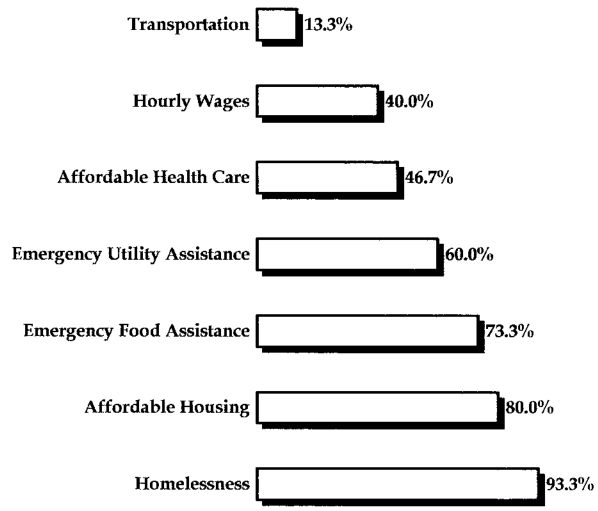
Self-Sufficiency

According to an Arizona Children's Action Alliance report completed in 2002, "The Self-Sufficiency Standard for Arizona," a single parent with an infant and a preschool-age child needs to earn a minimum of $31,238 annually to cover basic expenses in La Paz County. In comparison, the following chart notes that a two parent household with an infant and a preschool-age child would need to make $38,373 annually, while a single adult would need $14,296 to cover basic living needs in La Paz County.

Monthly Costs	Adult	Adult + Infant Preschooler	2 Adults + Infant Preschooler
Housing	396	503	503
Child Care	0	781	781
Food	176	345	496
Transportation	230	235	453
Health Care	101	283	352
Miscellaneous	90	215	258
Taxes	199	436	534
Earned Income Tax Credit (-)	0	-15	0
Child Care Tax Credit (-)	0	-80	-80
Child Tax Credit	0	-100	-100
Self-Sufficiency Wage:			
Hourly	**$6.77**	**$14.79**	**$9.08 Per adult**
Monthly	**$1,191**	**$2,603**	**$3,198**
Annual	**$14,296**	**$31,238**	**$38,373**

Perceptions from the Community

One community meeting was held in La Paz County to discuss concerns regarding poverty. The chart below shows the percentage of participants surveyed who believe conditions have gotten ***worse*** in the following areas over the last ten years:



More specifically, of particular concern was the lack of child care in the community. Participants stated that special hours were needed for working parents and that many kids were left home alone. Other concerns were the need for more livable wage jobs, the lack of affordable housing and property to build, and the increased need for collaboration with Indian tribes.

Maricopa County

The 2000 Census revealed 3,072,149 people living in Maricopa County, a 44.8 percent increase from the 1990 Census of 2,122,101. In 1999, Maricopa County had 11.7 percent of its population or 355,668 people living below the poverty level. While the overall percentage of people in poverty decreased over the last ten years, the number of people in poverty did not. Maricopa County experienced a 38.2 percent increase since 1989 when 257,359 people or 12.3 percent of the county's population lived in poverty. In 1999, over half of Arizona's poor lived in Maricopa County.

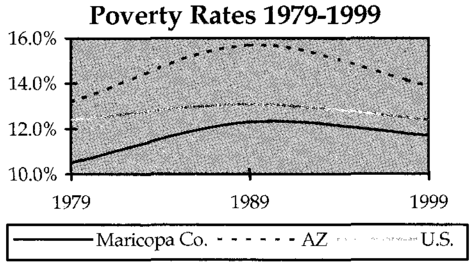
Poverty in Selected Communities

Number of Persons Below Poverty Level (Poverty Rate)	1989	1999	% Change
Guadalupe (*highest rate in county*)	2,175 (40.1%)	1,391 (26.7%)	-36.0%
Mesa	27,087 (9.5%)	35,031 (8.9%)	29.3%
Paradise Valley (*lowest rate in county*)	388 (3.3%)	334 (2.5%)	-13.9%
Phoenix	137,406 (14.2%)	205,320 (15.8%)	49.4%
Reservations	NA	4,088 (39.7%)	NA
Maricopa County	257,359 (12.3%)	355,668 (11.7%)	38.2%
Arizona	564,362 (15.7%)	698,669 (13.9%)	23.8%

Source: U.S. Census and Research Advisory Services, Inc.

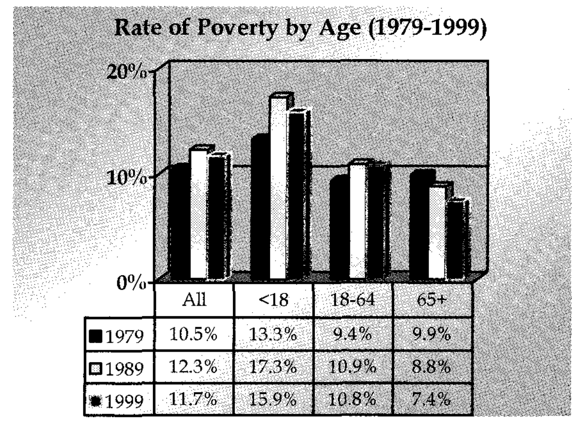
When you compare poverty rates over the last twenty years, Maricopa County's poverty rate increased from 10.5 percent in 1979 to 11.7 percent in 1999, 156,813 to 355,668 people respectively. In 1999, Maricopa County's poverty rate still remains lower than the state average of 13.9 percent and the national average of 12.4 percent.

Poverty Rates 1979-1999



Poverty and Age

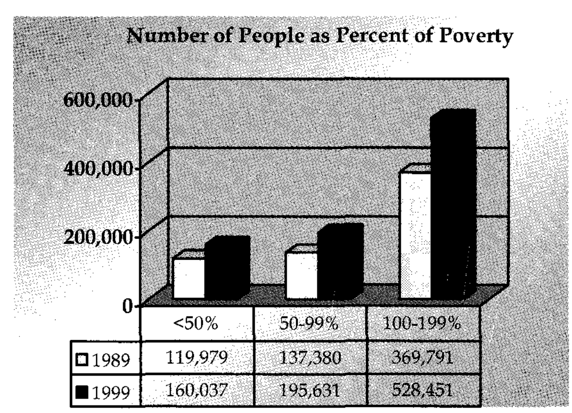
In 1999, among all age categories examined, children under 18 years of age experienced the highest rate of poverty at 15.9 percent, while those 65 and older had the lowest rate at 7.4 percent. Over the last twenty years, the rate of poverty has increased for all age groups, except those over 65 who experienced an improvement from 9.9 percent in 1979 to 7.4 percent in 1999.



Source: U.S Census.

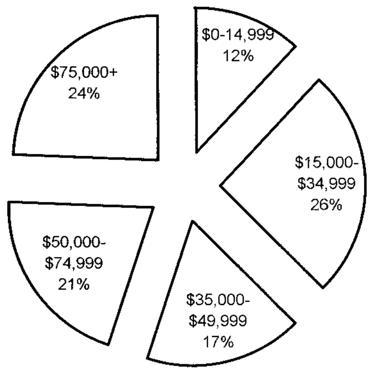
Poverty and Income Levels

Examination of the income to poverty ratio reveals that 160,037 people or 45 percent of those below the poverty rate in Maricopa County were ***very poor***, with incomes less than 50 percent of the poverty threshold. Another 528,451 people had incomes equal to or above the poverty level, but less than 199 percent (ACAA's definition of "working poor"). ***In total, there are 884,119 people in Maricopa County who are poor or "working poor,"*** *29.2* ***percent of the county's total population.***



Source: U.S Census.

1999 Household Income Distribution - Maricopa County



Source: U.S Census. Note: The median household income in Maricopa County was $45,358 in 1999 compared to $30,797 in 1989 (47.3 percent increase).

From 1990 to 1999, local total personal income in Maricopa County increased 97 percent compared to the state's roughly 90 percent (according to the Arizona Department of Economic Security). On a per capita basis, the gain of 46.7 percent was above the state's growth of 46.3 percent. Maricopa County per capita income was $28,205 in 1999, about 12 percent above the state average, slightly up from the 11.7 percent above the state average in 1990. Average earnings per job for 1999 was $33,448 compared to $31,307 for the state.

Poverty and Families

In 1999, the poverty rate among all families with children under 18 years of age living in Maricopa County was 12.3 percent. The rates for families with children headed by single females were 26 percent and even higher with younger children (less than 5 years) at 37.5 percent. Married couple families with children experienced a much lower rate at 7.9 percent.

Number Below Poverty Level (Poverty Rate)	1979	1989	1999	% Change '79-'99
All	29,910 (7.5%)	48,505 (8.8%)	61,519 (8.0%)	105.7%
With children under 18	21,662 (10.5%)	38,322 (13.6%)	50,191 (12.3%)	131.7%
Female-headed with children under 18	9,529 (29.2%)	18,553 (33.9%)	21,247 (26.0%)	123.0%
Female headed with children under 5*	4,949 (43.8%)	10,627 (50.7%)	11,234 (37.5%)	127.0%

*1979 numbers include 5 year olds. Source: U.S. Census.

Poverty and Race

Among racial/ethnic groups, American Indians and those of Hispanic Origin experienced the highest poverty rate at 24.5 percent and 23.9 percent respectively. Whites had the lowest rate at 8.7 percent. Those of Hispanic Origin were also represented at a disproportionately higher rate among those in poverty than in the overall population. All races in Maricopa County saw an improvement in poverty rates from 1989.

Race Ethnicity	% of Total Population 1999	% of Poverty Population 1999	Poverty Rate by Race 1999	Poverty Rate by Race 1989
White	77.4%	58.3%	8.7%	9.5%
Black	3.7%	6.0%	18.8%	27.4%
American Indian	1.8%	3.9%	24.5%	34.8%
Asian/PI	2.3%	2.2%	11.0%	14.7%
Other	14.8%	29.6%	23.2%	29.8%
Hispanic Origin*	24.8%	51.3%	23.9%	27.5%

NOTE: Categories include those identifying themselves as Hispanic. *Those of Hispanic Origin may be of any race. Source: U.S. Census.

Public Assistance

According to the 2000 Census, 24,866 households or 2.2 percent of all households in Maricopa County received public assistance. The mean or average amount of public assistance income for 1999 was $2,609, a decrease from the 1989 average of $3,765 and $3,803 in 1979. Participation levels in the Food Stamp and Temporary Assistance to Needy Families (TANF) programs serve as indicators of the extent of poverty. In 2000, 100,685 people or 3.3 percent of the population received food stamps. At the same time, 14,866 or 1.9 percent of families were enrolled in TANF.

Public Assistance (PA)	Base Year	1990	2000	% Change 1990-2000	% Change Base Yr-2000
Households receiving PA (1980)	24,516	39,958	24,866	-37.8%	1.4%
Persons Food Stamps (1985*)	75,758	146,366	100,685	-31.2%	32.9%
Families AFDC-TANF (1985*)	11,220	22,457	14,866	-33.8%	32.5%

NOTE: Base year in parentheses. *April figures. Source U.S. Census and Arizona Department of Economic Security.

Self-Sufficiency

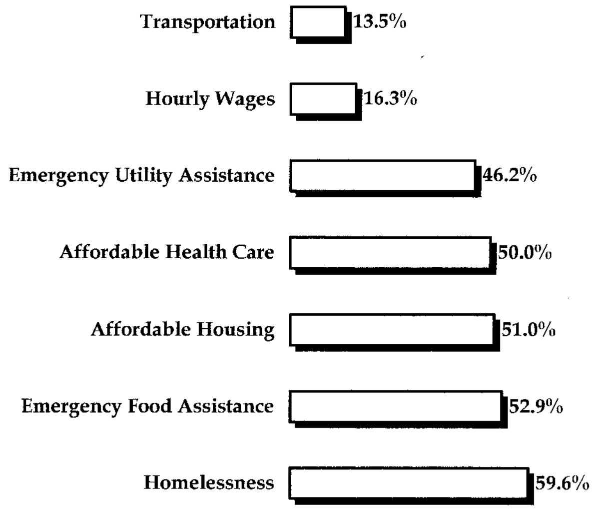
According to an Arizona Children's Action Alliance report completed in 2002, "The Self-Sufficiency Standard for Arizona," a single parent with an infant and a preschool-age child needs to earn a minimum of $40,153 annually to cover basic expenses in Maricopa County. In comparison, the following chart notes that a two parent household with an infant and a preschool-age child would need to make $47,495 annually, while a single adult would need $18,442 to cover basic living needs in Maricopa County.

Monthly Costs	Adult	Adult + Infant Preschooler	2 Adults + Infant Preschooler
Housing	605	760	760
Child Care	0	964	964
Food	176	345	496
Transportation	252	257	496
Health Care	105	299	367
Miscellaneous	114	262	308
Taxes	286	639	746
Earned Income Tax Credit (-)	0	0	0
Child Care Tax Credit (-)	0	-80	-80
Child Tax Credit	0	-100	-100
Self-Sufficiency Wage:			
Hourly	**$8.73**	**$19.01**	**$11.24 Per adult**
Monthly	**$1,537**	**$3,346**	**$3,958**
Annual	**$18,442**	**$40,153**	**$47,495**

NOTE: Numbers represent those living in Phoenix-Mesa only.

Perceptions from the Community

Seven meetings were held throughout Maricopa County to survey the perceived needs of those living in poverty and solutions for change. The chart below shows the percentage of participants surveyed who believe conditions have gotten ***worse*** in the following areas over the last ten years:



Of particular concern was the need for more quality child care with increased flexibility to serve working parents who work alternative shifts. Participants also called for an increase in child care subsidies to help the working poor.

Mohave County

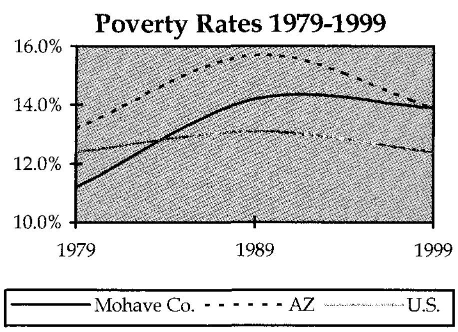
The 2000 Census revealed 155,032 people living in Mohave County, a 65.8 percent increase from the 1990 Census of 93,497. In 1999, Mohave County had close to 14 percent of its population or 21,252 people living below the poverty level. While the overall percentage of people in poverty slightly decreased over the last ten years, the number of people in poverty did not. Mohave County experienced a 62.9 percent increase since 1989 when 13,049 people or 14.2 percent of the county's population lived in poverty.

Poverty in Selected Communities

Number of Persons Below Poverty Level (Poverty Rate)	1989	1999	% Change
Bullhead City	2,749 (12.8%)	5,074 (15.1%)	84.6%
Kingman	1,167 (9.4%)	2,207 (11.6%)	89.1%
Lake Havasu City	1,958 (8.1%)	3,946 (9.5%)	101.5%
Reservations	NA	670 (29.8%)	NA
Mohave County	13,049 (14.2%)	21,252 (13.9%)	62.9%
Arizona	564,362 (15.7%)	698,669 (13.9%)	23.8%

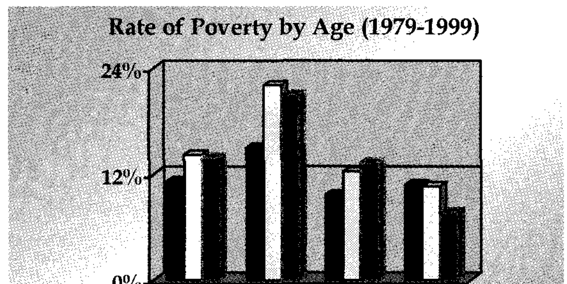
Source: U.S. Census and Research Advisory Services, Inc.

When you compare poverty rates over the last twenty years, Mohave County's poverty rate increased from 11.2 percent in 1979 to 13.9 percent in 1999, 6,207 to 21,252 people respectively. In 1999, Mohave County's poverty rate is equal to the state average of 13.9 percent and higher than the national average of 12.4 percent.



Poverty and Age

In 1999, among all age categories examined, children under 18 years of age experienced the highest rate of poverty at 21 percent, while those 65 and older had the lowest rate at 7.7 percent. Over the last twenty years, the rate of poverty has increased for all age groups, except those over 65 who experienced an improvement from 10.8 percent in 1979 to 7.7 percent in 1999.

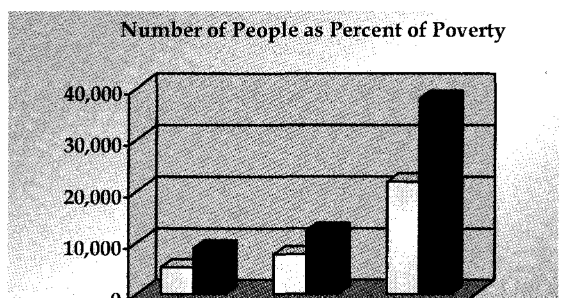


	All	<18	18-64	65+
1979	11.2%	15.0%	9.7%	10.8%
1989	14.2%	22.1%	12.3%	10.6%
1999	13.9%	21.0%	13.3%	7.7%

Source: U.S Census.

Poverty and Income Levels

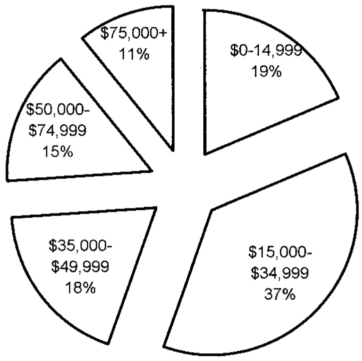
Examination of the income to poverty ratio reveals that 8,954 people or 42.1 percent of those below the poverty rate in Mohave County were ***very poor***, with incomes less than 50 percent of the poverty threshold. Another 37,993 people had incomes equal to or above the poverty level, but less than 199 percent (ACAA's definition of "working poor"). ***In total, there are 59,245 people in Mohave County who are poor or "working poor," 38.7 percent of the county's total population.***



	<50%	50-99%	100-199%
1989	5,270	7,779	21,876
1999	8,954	12,298	37,993

Source: U.S Census.

1999 Household Income Distribution – Mohave County



Source: U.S Census. Note: The median household income in Mohave County was $31,521 in 1999 compared to $24,002 in 1989 (31.3 percent increase).

From 1990 to 1999, local total personal income in Mohave County increased nearly 88.5 percent compared to the state's roughly 90 percent (according to the Arizona Department of Economic Security). Mohave County per capita income was $20,199 in 1999, about 80.2 percent of the state average, down from 87.8 percent in 1990. Average earnings per job were $23,948 in 1999 compared to $31,307 for the state.

Poverty and Families

In 1999, the poverty rate among all families with children under 18 years of age living in Mohave County was 16.5 percent. The rates for families with children headed by single females were 36.1 percent and even higher with younger children (less than 5 years) at 45.8 percent. Married couple families with children experienced a much lower rate at 10 percent.

Number Below Poverty Level (Poverty Rate)	1979	1989	1999	% Change '79-'99
All	1,470 (8.7%)	2,335 (8.7%)	4,277 (9.8%)	191.0%
With children under 18	808 (11.5%)	1,589 (15.2%)	2,944 (16.5%)	264.4%
Female-headed with children under 18	288 (34.0%)	503 (31.0%)	1,412 (36.1%)	390.3%
Female headed with children under 5*	141 (47.5%)	214 (42.3%)	709 (45.8%)	402.8%

*1979 numbers include 5 year olds. Source: U.S. Census.

Poverty and Race

Among racial/ethnic groups, other races, those of Hispanic Origin, and Blacks experienced the highest poverty rate at 22.9 percent, 20.3 percent, and 20.2 percent respectively. Whites had the lowest at 12.9 percent. Blacks, Other races and those of Hispanic Origin in Mohave County saw an increase in poverty rates from 1989.

Race Ethnicity	% of Total Population 1999	% of Poverty Population 1999	Poverty Rate by Race 1999	Poverty Rate by Race 1989
White	90.1%	84.4%	12.9%	13.5%
Black	0.5%	0.8%	20.2%	19.9%
American Indian	2.4%	3.7%	21.1%	35.0%
Asian/PI	0.9%	0.8%	13.3%	21.6%
Other	6.1%	10.2%	22.9%	20.4%
Hispanic Origin*	11.1%	16.4%	20.3%	19.4%

NOTE: Categories include those identifying themselves as Hispanic. *Those of Hispanic Origin may be of any race. Source: U.S. Census.

Public Assistance

According to the 2000 Census, 2,254 households or 3.6 percent of all households in Mohave County received public assistance. The mean or average amount of public assistance income for 1999 was $2,546, a decrease from the 1989 average of $3,764 and $4,051 in 1979. Participation levels in the Food Stamp and Temporary Assistance to Needy Families (TANF) programs serve as indicators of the extent of poverty. In 2000, 12,150 people or 7.8 percent of the population received food stamps. At the same time, 1,202 or 2.8 percent of families were enrolled in TANF.

Public Assistance (PA)	Base Year	1990	2000	% Change 1990-2000	% Change Base Yr-2000
Households receiving PA (1980)	711	1,969	2,254	14.5%	217.0%
Persons Food Stamps (1985*)	4,016	6,998	12,150	73.6%	202.5%
Families AFDC-TANF (1985*)	347	789	1,202	52.3%	246.4%

NOTE: Base year in parentheses. *April figures. Source U.S. Census and Arizona Department of Economic Security.

Self-Sufficiency

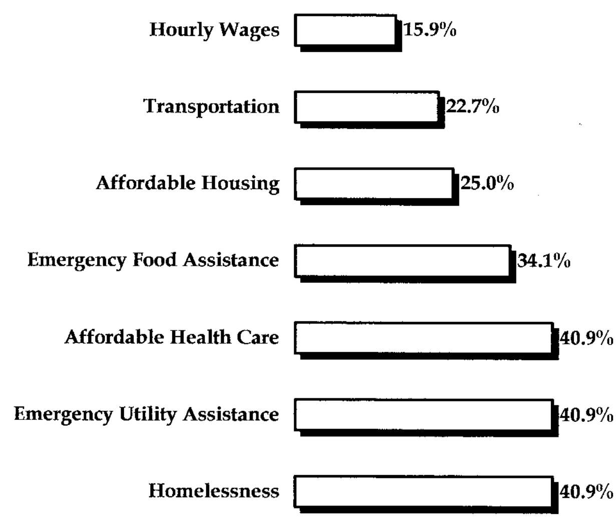
According to an Arizona Children's Action Alliance report completed in 2002, "The Self-Sufficiency Standard for Arizona," a single parent with an infant and a preschool-age child needs to earn a minimum of $36,174 annually to cover basic expenses in Mohave County. In comparison, the following chart notes that a two parent household with an infant and a preschool-age child would need to make $43,053 annually, while a single adult would need $14,175 to cover basic living needs in Mohave County.

Monthly Costs	Adult	Adult + Infant Preschooler	2 Adults + Infant Preschooler
Housing	658	783	783
Child Care	0	781	781
Food	176	345	496
Transportation	214	220	425
Health Care	101	283	352
Miscellaneous	115	241	284
Taxes	289	541	648
Earned Income Tax Credit (-)	0	0	0
Child Care Tax Credit (-)	0	-80	-80
Child Tax Credit	0	-100	-100
Self-Sufficiency Wage:			
Hourly	**$6.71**	**$17.13**	**$10.19 Per adult**
Monthly	**$1,181**	**$3,015**	**$3,588**
Annual	**$14,175**	**$36,174**	**$43,053**

NOTE: Mohave County is considered part of the Las Vegas, Nevada MSA in calculating housing costs.

Perceptions from the Community

Three community meetings were held in Mohave County to discuss poverty issues and solutions. The chart below shows the percentage of participants surveyed who believe conditions have gotten ***worse*** in the following areas over the last ten years:



More specifically, participants made the following comments:

- There are large numbers of working poor and pockets of poverty in the community.
- Resort communities tend to draw low paying jobs. Typical jobs are at the casinos.
- Increased education and training are needed to boost employment opportunities.
- Transportation and living wage jobs are needed throughout the county.
- Healthcare benefits are needed with more jobs -- many employers hire part-time people and offer no health benefits.
- Dental and vision benefits are needed with AHCCCS.
- Child care costs consume wages for low-income people.
- More activities are needed for children to reduce drug use and crime.

Navajo County

The 2000 Census revealed 97,470 people living in Navajo County, a 25.5 percent increase from the 1990 Census of 77,658. Forty-five percent of all people in the county lived on reservation lands (Fort Apache, Hopi and Navajo). In 1999, Navajo County had almost 30 percent of its population or 28,054 people living below the poverty level. While the overall percentage of people in poverty decreased over the last ten years, the number of people in poverty did not. Navajo County experienced a 6.0 percent increase since 1989 when 26,458 people or 34.7 percent of the county's population lived in poverty. In 1999, the poverty rate for those not living on reservation lands was 15.6 percent.

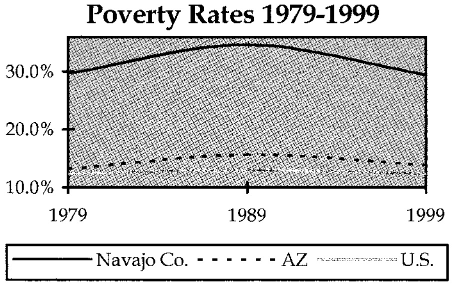
Poverty in Selected Communities

Number of Persons Below Poverty Level (Poverty Rate)	1989	1999	% Change
Holbrook	803 (17.3%)	957 (20.1%)	19.2%
Pinetop-Lakeside	241 (10.0%)	355 (10.1%)	47.3%
Show Low	927 (18.5%)	1,134 (15.0%)	22.3%
Reservations	19,823 (53.0%)	19,908 (46.4%)	0.4%
Navajo County	26,458 (34.7%)	28,054 (29.5%)	6.0%
Arizona	564,362 (15.7%)	698,669 (13.9%)	23.8%

Source: U.S. Census and Research Advisory Services, Inc.

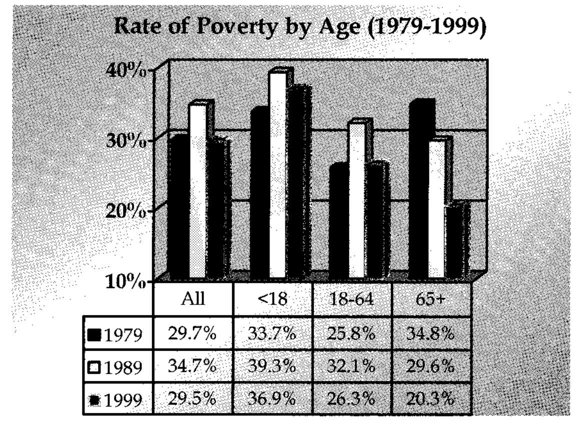
When you compare the number of people in poverty over the last twenty years, Navajo County's added 8,091 people, up from 19,963 in 1979. In 1999, Navajo County's poverty rate is more than double the state and national average of 13.9 percent and 12.4 percent respectively.

Poverty Rates 1979-1999



Poverty and Age

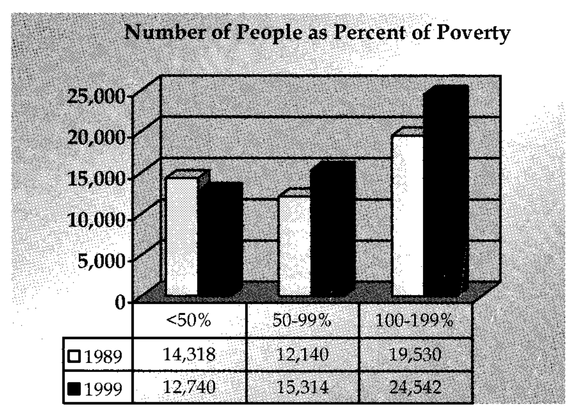
In 1999, among all age categories examined, children under 18 years of age experienced the highest rate of poverty at 36.9 percent, while those 65 and older had the lowest rate at 20.3 percent. Over the last twenty years, the rate of poverty has increased for all age groups, except those over 65 who experienced an improvement from 34.8 percent in 1979 to 20.3 percent in 1999.



Source: U.S Census.

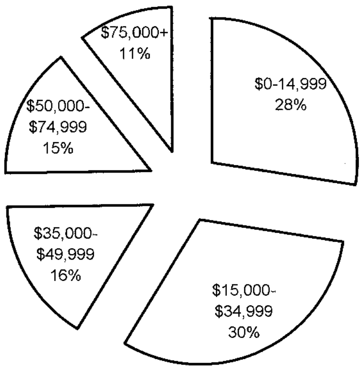
Poverty and Income Levels

Examination of the income to poverty ratio reveals that 12,740 people or 45.4 percent of those below the poverty rate in Navajo County were ***very poor***, with incomes less than 50 percent of the poverty threshold. Another 24,542 people had incomes equal to or above the poverty level, but less than 199 percent (ACAA's definition of "working poor"). ***In total, there are 52,596 people in Navajo County who are poor or "working poor," 55.3 percent of the county's total population.***



Source: U.S Census.

1999 Household Income Distribution – Navajo County



Source: U.S Census. Note: The median household income in Navajo County was $28,569 in 1999 compared to $19,452 in 1989 (46.9 percent increase).

From 1990 to 1999, local total personal income in Navajo County increased 68.6 percent compared to the state's roughly 90 percent (according to the Arizona Department of Economic Security). On a per capita basis, the gain of 33.7 percent was 12.6 percent below the state's growth of 46.3 percent. Navajo County per capita income was $13,440 in 1999, about 53.4 percent of the state average, down from 58.4 percent in 1990. Average earnings per job for 1999 were $24,170 compared to $31,307 for the state.

Poverty and Families

In 1999, the poverty rate among all families with children under 18 years of age living in Navajo County was 30.6 percent. The rates for families with children headed by single females were 52.5 percent and even higher with younger children (less than 5 years) at 65.7 percent. Married couple families with children experienced a lower rate at 20.2 percent.

Number Below Poverty Level (Poverty Rate)	1979	1989	1999	% Change '79-'99
All	3,694 (24.1%)	5,498 (30.3%)	5,410 (23.4%)	46.5%
With children under 18	3,015 (27.6%)	4,305 (35.4%)	4,380 (30.6%)	45.3%
Female-headed with children under 18	980 (55.8%)	1,612 (60.9%)	2,067 (52.5%)	110.9%
Female headed with children under 5*	605 (67.9%)	931 (70.7%)	1,069 (65.7%)	76.7%

*1979 numbers include 5 year olds. Source: U.S. Census.

Poverty and Race

Among racial/ethnic groups, American Indians experienced the highest poverty rate at 45.4 percent. They also were represented at a disproportionately higher rate among those in poverty than in the overall population. All races saw an improvement in poverty rates from 1989 except Asian/Pacific Islanders and those of other races.

Race Ethnicity	% of Total Population 1999	% of Poverty Population 1999	Poverty Rate by Race 1999	Poverty Rate by Race 1989
White	45.9%	19.0%	11.9%	13.7%
Black	0.9%	0.6%	18.7%	25.3%
American Indian	47.7%	75.3%	45.4%	52.8%
Asian/PI	0.4%	0.2%	12.8%	11.5%
Other	5.1%	4.9%	27.8%	26.8%
Hispanic Origin*	8.2%	6.7%	23.5%	26.4%

NOTE: Categories include those identifying themselves as Hispanic. *Those of Hispanic Origin may be of any race. Source: U.S. Census.

Public Assistance

According to the 2000 Census, 2,794 households or 9.3 percent of all households in Navajo County received public assistance. The mean or average amount of public assistance income for 1999 was $2,969, a decrease from the 1989 average of $3,578 and $3,884 in 1979. Participation levels in the Food Stamp and Temporary Assistance to Needy Families (TANF) programs serve as indicators of the extent of poverty. In 2000, 16,189 people or 16.6 percent of the population received food stamps. At the same time, 2,345 or 10.1 percent of families were enrolled in TANF.

Public Assistance (PA)	Base Year	1990	2000	% Change 1990-2000	% Change Base Yr-2000
Households receiving PA (1980)	2,117	3,738	2,794	-25.3%	32.0%
Persons Food Stamps (1985*)	12,134	14,589	16,189	11.0%	33.4%
Families AFDC-TANF (1985*)	1,316	1,593	2,345	47.2%	78.2%

NOTE: Base year in parentheses. *April figures. Source U.S. Census and Arizona Department of Economic Security.

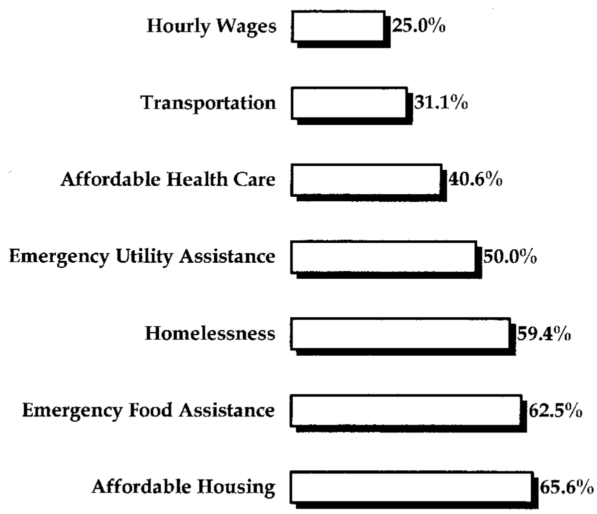
Self-Sufficiency

According to an Arizona Children's Action Alliance report completed in 2002, "The Self-Sufficiency Standard for Arizona," a single parent with an infant and a preschool-age child needs to earn a minimum of $32,206 annually to cover basic expenses in Navajo County. In comparison, the following chart notes that a two parent household with an infant and a preschool-age child would need to make $38,947 annually, while a single adult would need $14,168 to cover basic living needs in Navajo County.

Monthly Costs	Adult	Adult + Infant Preschooler	2 Adults + Infant Preschooler
Housing	396	503	503
Child Care	0	825	825
Food	176	345	496
Transportation	221	227	437
Health Care	102	289	358
Miscellaneous	90	219	262
Taxes	196	456	545
Earned Income Tax Credit (-)	0	0	0
Child Care Tax Credit (-)	0	-80	-80
Child Tax Credit	0	-100	-100
Self-Sufficiency Wage:			
Hourly	**$6.71**	**$15.25**	**$9.22 Per adult**
Monthly	**$1,181**	**$2,684**	**$3,246**
Annual	**$14,168**	**$32,206**	**$38,947**

Perceptions from the Community

Two community meetings were held in Navajo County to address solutions to poverty. The chart below shows the percentage of participants surveyed who believe conditions have gotten *worse* in the following areas over the last ten years:



More specifically, participants discussed the need for less isolation and more community support of low-income people. Other comments included:

- More individualized, targeted training is needed for job readiness.
- Better quality housing.
- Mentoring and exposure of children to industry opportunities.
- Increased discipline to promote accountability in schools.
- Increased money to create opportunities for higher education.
- Language barriers (Native American and Spanish) exist.
- The need for more medical services especially dental, and increasing the availability of child care services.

Pima County

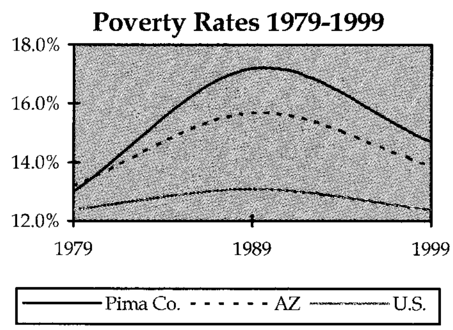
The 2000 Census revealed 843,746 people living in Pima County, a 26.5 percent increase from the 1990 Census of 666,880. In 1999, Pima County had almost 15 percent of its population or 120,778 people living below the poverty level. The poverty rate for those living on the Pascua Yaqui and Tohono O'odham Reservations is significantly higher at 44.9 percent. While the overall percentage of people in poverty decreased over the last ten years, the number of people in poverty did not. Pima County experienced an 8.0 percent increase since 1989 when 111,880 people or 17.2 percent of the county's population lived in poverty.

Poverty in Selected Communities

Number of Persons Below Poverty Level (Poverty Rate)	1989	1999	% Change
Oro Valley	355 (5.3%)	929 (3.1%)	161.7%
Tucson	79,287 (20.2%)	86,532 (18.4%)	9.1%
Reservations	6,987 (64.6%)	5,656 (44.9%)	-19.0%
Pima County	111,880 (17.2%)	120,778 (14.7%)	8.0%
Arizona	564,362 (15.7%)	698,669 (13.9%)	23.8%

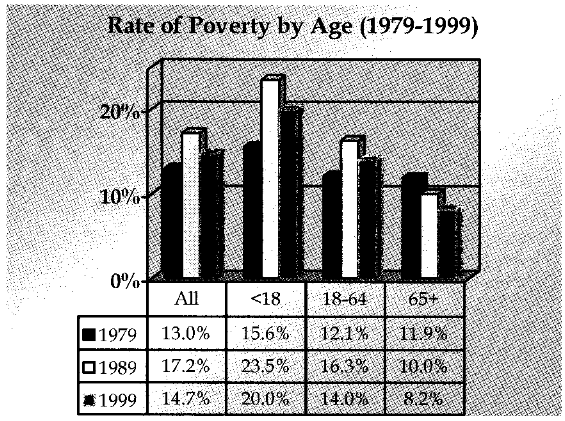
Source: U.S. Census and Research Advisory Services, Inc.

When you compare poverty rates over the last twenty years, Pima County's poverty rate increased from 13.0 percent in 1979 to 14.7 percent in 1999, 67,739 to 120,778 people respectively. In 1999, Pima County's poverty rate still remains higher than the state average of 13.9 percent and the national average of 12.4 percent.



Poverty and Age

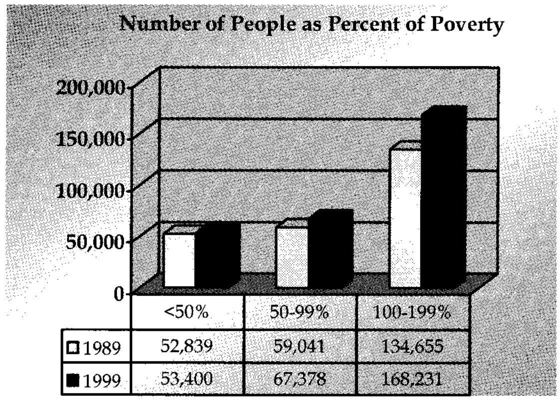
In 1999, among all age categories examined, children under 18 years of age experienced the highest rate of poverty at 20 percent, while those 65 and older had the lowest rate at 8.2 percent. Over the last ten years, the rate of poverty has decreased for all age groups, but is still higher than the 1979 rate except those in the over 65 age group which continued to decline.



Source: U.S Census.

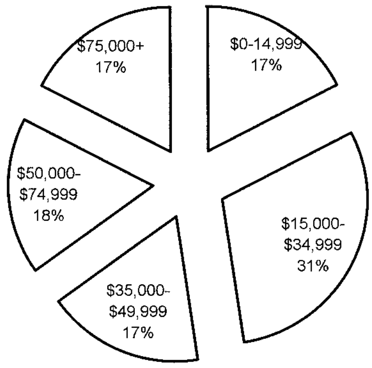
Poverty and Income Levels

Examination of the income to poverty ratio reveals that 53,400 people or 44.2 percent of those below the poverty rate in Pima County were ***very poor***, with incomes less than 50 percent of the poverty threshold. Another 168,231 people had incomes equal to or above the poverty level, but less than 199 percent (ACAA's definition of "working poor"). ***In total, there are 289,009 people in Pima County who are poor or "working poor," 35.1 percent of the county's total population.***



Source: U.S Census.

1999 Household Income Distribution – Pima County



Source: U.S Census. Note: The median household income in Pima County was $36,758 in 1999 compared to $25,401 in 1989 (44.7 percent increase).

From 1990 to 1999, local total personal income in Pima County increased 77 percent compared to the state's nearly 90 percent (according to the Arizona Department of Economic Security). On a per capita basis, the gain of 47.3 percent is slightly greater than the state's growth of 46.3 percent. Pima County per capita income was $23,911 in 1999, less than the state average of $25,173, or roughly 95 percent of the state average. Average earnings per job for 1999 was $28,378 compared to $31,307 for the state.

Poverty and Families

In 1999, the poverty rate among all families with children under 18 years of age living in Pima County was 16.4 percent. The rates for families with children headed by single females were 35.2 percent and even higher with younger children (less than 5 years) at 46.9 percent. Married couple families with children experienced a much lower rate at 9.1 percent.

Number Below Poverty Level (Poverty Rate)	1979	1989	1999	% Change '79-'99
All	12,516 (9.1%)	20,495 (12.0%)	22,432 (10.5%)	79.2%
With children under 18	9,021 (12.8%)	16,201 (18.9%)	17,740 (16.4%)	96.7%
Female-headed with children under 18	4,066 (34.2%)	7,812 (40.4%)	9,297 (35.2%)	128.7%
Female headed with children under 5*	1,935 (48.0%)	4,003 (57.8%)	4,507 (46.9%)	132.9%

*1979 numbers include 5 year olds. Source: U.S. Census.

Poverty and Race

Among racial/ethnic groups, American Indians experienced the highest poverty rate at 34.4 percent and Whites had the lowest at 11.3 percent. American Indians, Other races and those of Hispanic Origin were represented at a disproportionately higher rate among those in poverty than in the overall population. All races in Pima County saw an improvement in poverty rates from 1989.

Race Ethnicity	% of Total Population 1999	% of Poverty Population 1999	Poverty Rate by Race 1999	Poverty Rate by Race 1989
White	75.1%	59.0%	11.3%	12.8%
Black	3.0%	3.7%	17.3%	27.5%
American Indian	3.2%	7.7%	34.4%	52.4%
Asian/PI	2.2%	2.4%	16.0%	21.5%
Other	16.5%	27.1%	23.5%	32.3%
Hispanic Origin*	29.3%	46.3%	22.6%	28.2%

NOTE: Categories include those identifying themselves as Hispanic. *Those of Hispanic Origin may be of any race. Source: U.S. Census.

Public Assistance

According to the 2000 Census, 10,254 households or 3.1 percent of all households in Pima County received public assistance. The mean or average amount of public assistance income for 1999 was $2,353, a decrease from the 1989 average of $3,752 and $3,860 in 1979. Participation levels in the Food Stamp and Temporary Assistance to Needy Families (TANF) programs serve as indicators of the extent of poverty. In 2000, 45,092 people or 5.3 percent of the population received food stamps. At the same time, 5,725 or 2.7 percent of families were enrolled in TANF.

Public Assistance (PA)	Base Year	1990	2000	% Change 1990-2000	% Change Base Yr-2000
Households receiving PA (1980)	9,727	15,877	10,254	-35.4%	5.4%
Persons Food Stamps (1985*)	40,491	59,261	45,092	-23.9%	11.4%
Families AFDC-TANF (1985*)	5,055	7,782	5,725	-26.4%	13.3%

NOTE: Base year in parentheses. *April figures. Source U.S. Census and Arizona Department of Economic Security.

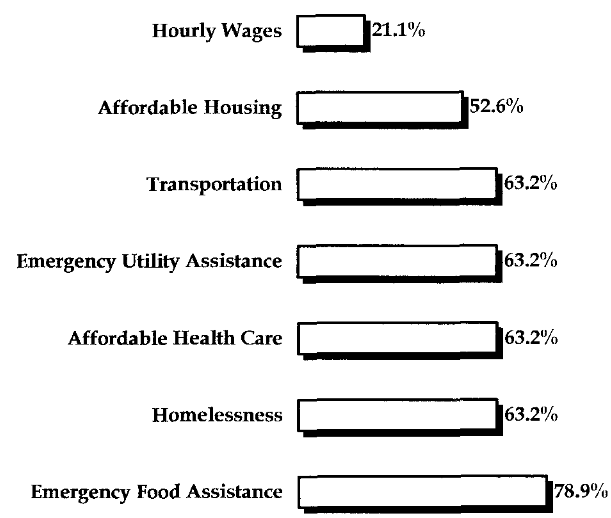
Self-Sufficiency

According to an Arizona Children's Action Alliance report completed in 2002, "The Self-Sufficiency Standard for Arizona," a single parent with an infant and a preschool-age child needs to earn a minimum of $36,166 annually to cover basic expenses in Pima County. In comparison, the following chart notes that a two parent household with an infant and a preschool-age child would need to make $43,440 annually, while a single adult would need $16,098 to cover basic living needs in Pima County.

Monthly Costs	Adult	Adult + Infant Preschooler	2 Adults + Infant Preschooler
Housing	486	647	647
Child Care	0	893	893
Food	176	345	496
Transportation	238	244	471
Health Care	101	283	352
Miscellaneous	100	241	286
Taxes	240	540	656
Earned Income Tax Credit (-)	0	0	0
Child Care Tax Credit (-)	0	-80	-80
Child Tax Credit	0	-100	-100
Self-Sufficiency Wage:			
Hourly	**$7.62**	**$17.12**	**$10.28 Per adult**
Monthly	**$1,341**	**$3,014**	**$3,620**
Annual	**$16,098**	**$36,166**	**$43,440**

Perceptions from the Community

One community meeting was held in Pima County to discuss issues and solutions to poverty. The chart below shows the percentage of participants surveyed who believe conditions have gotten ***worse*** in the following areas over the last ten years:



More specifically, participants identified the lack of access to transportation, especially in rural areas; the need for livable wage jobs; increasing health care benefits; and a better economic base in the rural parts of Pima County. The county is also experiencing more people moving into the area in need of assistance

Pinal County

The 2000 Census revealed 179,727 people living in Pinal County, a 54.4 percent increase from the 1990 Census of 116,379. In 1999, Pinal County had almost 17 percent of its population or 27,816 people living below the poverty level. Those living on reservations (Gila River, Ak Chin, Tohono O'odham) experienced a much higher rate at 46.7 percent. While the overall percentage of people in poverty decreased over the last ten years, the number of people in poverty did not. Pinal County experienced a 6.4 percent increase since 1989 when 26,152 people or 23.6 percent of the county's population lived in poverty.

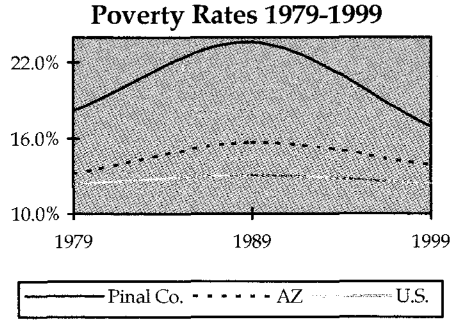
Poverty in Selected Communities

Number of Persons Below Poverty Level (Poverty Rate)	1989	1999	% Change
Casa Grande	3,274 (17.4%)	4,024 (16.0%)	22.9%
Eloy	2,631 (36.7%)	2,796 (31.9%)	6.3%
Florence	576 (17.6%)	372 (7.0%)	-35.4%
Reservations	5,009 (62,9%)	4,510 (46.7%)	-10.0%
Pinal County	26,152 (23.6%)	27,816 (16.9%)	6.4%
Arizona	564,362 (15.7%)	698,669 (13.9%)	23.8%

Source: U.S. Census and Research Advisory Services, Inc.

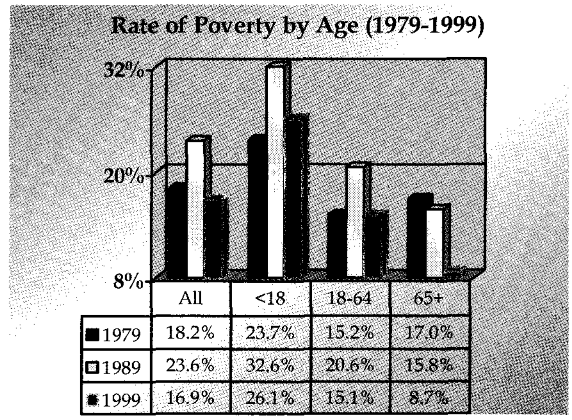
When you compare the number of people in poverty over the last twenty years, Pinal County added 11,816 persons. In 1999, Pinal County's poverty rate still remains higher than the state and national average of 13.9 percent and 12.4 percent respectively.

Poverty Rates 1979-1999



Poverty and Age

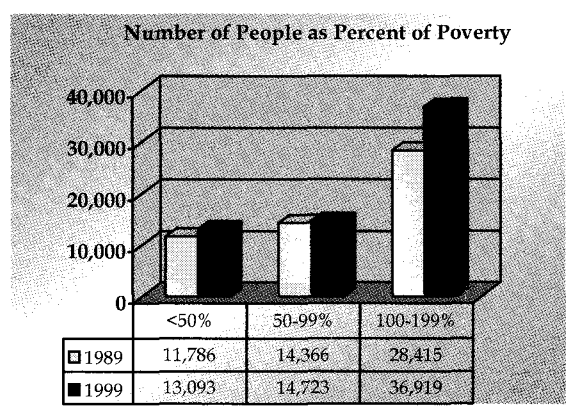
In 1999, among all age categories examined, children under 18 years of age experienced the highest rate of poverty at 26.1 percent, while those 65 and older had the lowest rate at 8.7 percent. While poverty among children under 18 years of age has improved over the last ten years, the rate is still higher than in 1979.



Source: U.S Census.

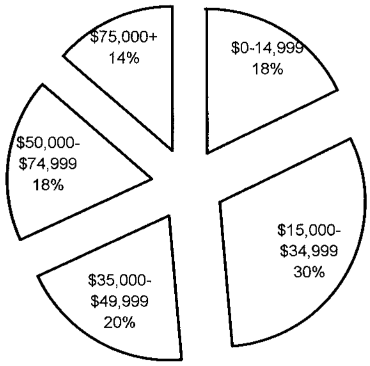
Poverty and Income Levels

Examination of the income to poverty ratio reveals that 13,093 people or 47.1 percent of those below the poverty rate in Pinal County were *very poor,* with incomes less than 50 percent of the poverty threshold. Another 36,919 people had incomes equal to or above the poverty level, but less than 199 percent (ACAA's definition of "working poor"). ***In total, there are 64,735 people in Pinal County who are poor or "working poor," 39.4 percent of the county's total population.***



Source: U.S Census.

1999 Household Income Distribution - Pinal County



Source: U.S Census. Note: The median household income in Pinal County was $35,856 in 1999 compared to $21,301 in 1989 (68.3 percent increase).

From 1990 to 1999, local total personal income in Pinal County increased 77 percent compared to the state's roughly 90 percent (according to the Arizona Department of Economic Security). On a per capita basis, the gain of 35.4 percent was 10.9 percent below the state's growth of 46.3 percent. Pinal County per capita income was $16,563 in 1999, about 65.8 percent of the state average, down from 71 percent in 1990. The average earnings per job was $28,394 compared to $31,307 for the state, or 90.7 percent of the state.

Poverty and Families

In 1999, the poverty rate among all families with children under 18 years of age living in Pinal County was 21 percent. The rates for families with children headed by single females were 40.7 percent and even higher with younger children (less than 5 years) at 50.8 percent. Married couple families with children experienced a much lower rate at 12.1 percent.

Number Below Poverty Level (Poverty Rate)	1979	1989	1999	% Change '79-'99
All	3,310 (14.3%)	5,593 (18.7%)	5,486 (12.1%)	65.7%
With children under 18	2,568 (19.5%)	4,193 (26.5%)	4,369 (21.0%)	70.1%
Female-headed with children under 18	1,051 (57.0%)	2,118 (63.1%)	2,162 (40.7%)	105.7%
Female headed with children under 5*	652 (65.9%)	1,122 (77.6%)	1048 (50.8%)	60.7%

*1979 numbers include 5 year olds. Source: U.S. Census.

Poverty and Race

Among racial/ethnic groups, American Indians experienced the highest poverty rate at 36.8 percent and Whites had the lowest at 11.3 percent. American Indians, Other races and those of Hispanic Origin were represented at a disproportionately higher rate among those in poverty than in the overall population. All races in Pinal County saw an improvement in poverty rates from 1989.

Race Ethnicity	% of Total Population 1999	% of Poverty Population 1999	Poverty Rate by Race 1999	Poverty Rate by Race 1989
White	70.4%	51.6%	11.3%	16.5%
Black	2.8%	2.9%	16.0%	39.3%
American Indian	7.8%	18.6%	36.8%	61.0%
Asian/PI	0.7%	0.6%	13.9%	16.9%
Other	18.3%	26.4%	22.3%	35.5%
Hispanic Origin*	29.9%	43.5%	22.6%	28.6%

NOTE: Categories include those identifying themselves as Hispanic. *Those of Hispanic Origin may be of any race. Source: U.S. Census.

Public Assistance

According to the 2000 Census, 2,547 households or 4.1 percent of all households in Pinal County received public assistance. The mean or average amount of public assistance income for 1999 was $2,647, a decrease from the 1989 average of $3,873 and $4,191 in 1979. Participation levels in the Food Stamp and Temporary Assistance to Needy Families (TANF) programs serve as indicators of the extent of poverty. In 2000, 12,638 people or 7 percent of the population received food stamps. At the same time, 1,613 or 3.5 percent of families were enrolled in TANF.

Public Assistance (PA)	Base Year	1990	2000	% Change 1990-2000	% Change Base Yr-2000
Households receiving PA (1980)	2,305	3,753	2,547	-32.1%	10.5%
Persons Food Stamps (1985*)	13,549	18,037	12,638	-29.9%	-6.7%
Families AFDC-TANF (1985*)	1,821	2,814	1,613	-42.7%	-11.4%

NOTE: Base year in parentheses. *April figures. Source U.S. Census and Arizona Department of Economic Security.

Self-Sufficiency

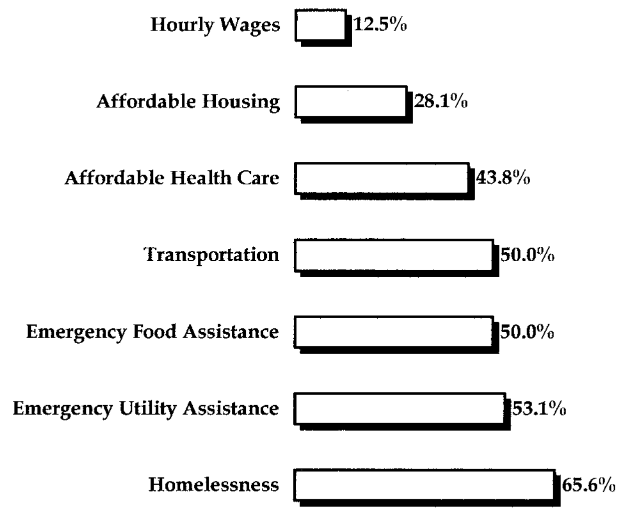
According to an Arizona Children's Action Alliance report completed in 2002, "The Self-Sufficiency Standard for Arizona," a single parent with an infant and a preschool-age child needs to earn a minimum of $36,818 annually to cover basic expenses in Pinal County. In comparison, the following chart notes that a two parent household with an infant and a preschool-age child would need to make $44,060 annually, while a single adult would need $17,213 to cover basic living needs in Pinal County.

Monthly Costs	Adult	Adult + Infant Preschooler	2 Adults + Infant Preschooler
Housing	551	692	692
Child Care	0	880	880
Food	176	345	496
Transportation	237	242	467
Health Care	102	287	356
Miscellaneous	107	245	289
Taxes	263	557	672
Earned Income Tax Credit (-)	0	0	0
Child Care Tax Credit (-)	0	-80	-80
Child Tax Credit	0	-100	-100
Self-Sufficiency Wage:			
Hourly	**$8.15**	**$17.43**	**$10.43 Per adult**
Monthly	**$1,434**	**$3,068**	**$3,672**
Annual	**$17,213**	**$36,818**	**$44,060**

NOTE: Pinal County is considered part of the Phoenix-Mesa MSA in calculating housing costs.

Perceptions from the Community

Two meetings were held in Pinal County to discuss major concerns and solutions to poverty. The chart below shows the percentage of participants surveyed who believe conditions have gotten ***worse*** in the following areas over the last ten years:



More specifically, participants identified:

- Lack of literacy and basic skills.
- The need for relationship training to curb domestic violence, elder abuse and child abuse.
- Teenage pregnancy issues.
- Health and public transportation issues.
- Low wages due to agriculture and service industry.

Possible solutions raised at the meeting were to use any business tax plan to increase wages and/or attract employers that pay reasonable wages (higher than the minimum wage). The plan should also provide incentives at places of employment for GED and higher education. Participants also thought that too much money was spent on corrections and prisons and not enough on prevention and education. A discussion also occurred regarding the need for improved interagency communication to increase awareness of resources.

Santa Cruz County

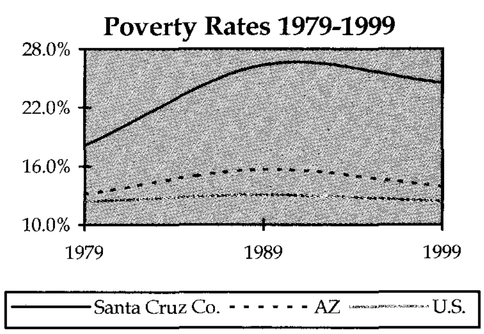
The 2000 Census revealed 38,381 people living in Santa Cruz County, a 29.3 percent increase from the 1990 Census of 29,676. In 1999, Santa Cruz County had close to one-fourth of its population or 9,356 people living below the poverty level. While the overall percentage of people in poverty decreased over the last ten years, the number of people in poverty did not. Santa Cruz County experienced a 20.0 percent increase since 1989 when 7,796 people or 26.4 percent of the county's population lived in poverty.

Poverty in Selected Communities

Number of Persons Below Poverty Level (Poverty Rate)	1989	1999	% Change
Nogales	6,051 (31.2%)	7,019 (33.9%)	16.0%
Patagonia	285 (30.9%)	214 (25.1%)	-24.9%
Santa Cruz County	7,796 (26.4%)	9,356 (24.5%)	20.0%
Arizona	564,362 (15.7%)	698,669 (13.9%)	23.8%

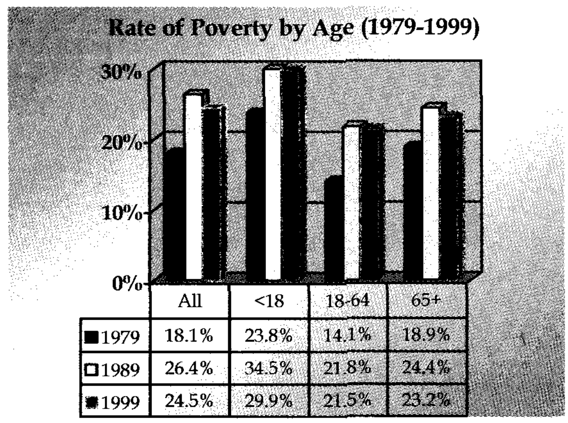
Source: U.S. Census and Research Advisory Services, Inc.

When you compare poverty rates over the last twenty years, Santa Cruz County's poverty rate increased from 18.1 percent in 1979 to 24.5 percent in 1999, 3,700 to 9,356 people respectively. In 1999, Santa Cruz County's poverty rate still remains significantly higher than the state average of 13.9 percent and the national average of 12.4 percent.



Poverty and Age

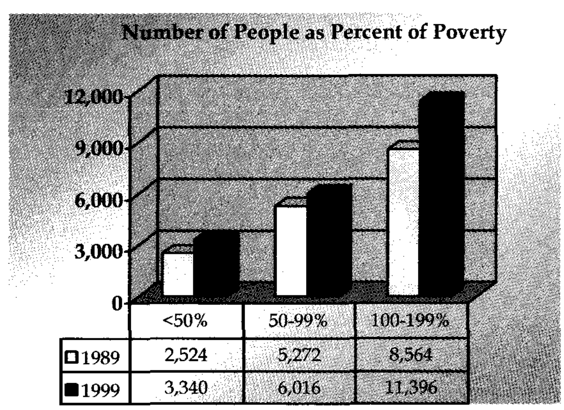
In 1999, among all age categories examined, children under 18 years of age experienced the highest rate of poverty at 29.9 percent, while those between age 18 and 64 had the lowest rate at 21.5 percent. Over the last twenty years, the rate of poverty has increased for all age groups with those between age 18 and 64 years of age increasing the most.



Source: U.S Census.

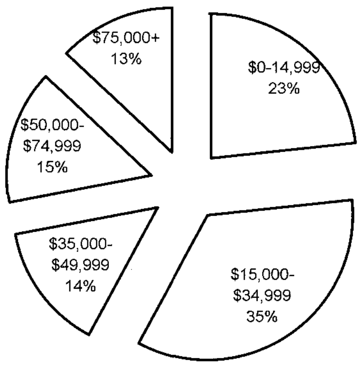
Poverty and Income Levels

Examination of the income to poverty ratio reveals that 3,340 people or over one-third of those below the poverty rate in Santa Cruz County were ***very poor***, with incomes less than 50 percent of the poverty threshold. Another 11,396 people had incomes equal to or above the poverty level, but less than 199 percent (ACAA's definition of "working poor"). ***In total, there are 20,752people in Santa Cruz County who are poor or "working poor," 54.3 percent of the county's total population.***



Source: U.S Census.

1999 Household Income Distribution – Santa Cruz County



Source: U.S Census. Note: The median household income in Santa Cruz County was $29,710 in 1999 compared to $22,066 in 1989 (34.6 percent increase).

From 1990 to 1999, local total personal income in Santa Cruz County increased 78.1 percent compared to the state's nearly 90 percent (according to the Arizona Department of Economic Security). Santa Cruz County per capita income was $16,496 in 1999, about 65.5 percent of the state average, down from 70 percent in 1990. The average earnings per job was $27,807 for the county compared to the state's $ 31,307, or 11.2 percent below the state.

Poverty and Families

In 1999, the poverty rate among all families with children under 18 years of age living in Santa Cruz County was 26 percent. The rates for families with children headed by single females were 46.6 percent and even higher with younger children (less than 5 years) at 55.7 percent. Married couple families with children experienced a lower rate at 20.6 percent.

Number Below Poverty Level (Poverty Rate)	1979	1989	1999	% Change '79-'99
All	681 (13.4%)	1,618 (22.0%)	2,056 (21.4%)	201.9%
With children under 18	604 (18.1%)	1,334 (28.2%)	1,620 (26.0%)	168.2%
Female-headed with children under 18	234 (46.3%)	465 (45.8%)	589 (46.6%)	151.7%
Female headed with children under 5*	102 (47.9%)	194 (46.2%)	246 (55.7%)	141.2%

*1979 numbers include 5 year olds. Source: U.S. Census.

Poverty and Race

Among racial/ethnic groups, those of Hispanic Origin experienced the highest poverty rate at 27.9 percent. They also represented most of all people below the poverty rate in Santa Cruz County. Since 1989, the poverty rate for those of Hispanic Origin decreased by almost four percentage points.

Race Ethnicity	% of Total Population 1999	% of Poverty Population 1999	Poverty Rate by Race 1999	Poverty Rate by Race 1989
White	76.0%	77.4%	24.8%	24.7%
Black	0.4%	0.0%	0.0%	53.0%
American Indian	0.7%	0.7%	25.5%	21.4%
Asian/PI	0.6%	0.2%	8.1%	6.4%
Other	22.4%	21.7%	23.7%	31.8%
Hispanic Origin*	80.8%	92.4%	27.9%	31.6%

NOTE: Categories include those identifying themselves as Hispanic. *Those of Hispanic Origin may be of any race. Source: U.S. Census.

Public Assistance

According to the 2000 Census, 549 households or 4.6 percent of all households in Santa Cruz County received public assistance. The mean or average amount of public assistance income for 1999 was $2,310, a decrease from the 1989 average of $2,990 and $3,313 in 1979. Participation levels in the Food Stamp and Temporary Assistance to Needy Families (TANF) programs serve as indicators of the extent of poverty. In 2000, 3,408 people or 8.9 percent of the population received food stamps. At the same time, 287 or 3 percent of families were enrolled in TANF.

Public Assistance (PA)	Base Year	1990	2000	% Change 1990-2000	% Change Base Yr-2000
Households receiving PA (1980)	599	844	549	-35.0%	-8.3%
Persons Food Stamps (1985*)	3,568	3,722	3,408	-8.4%	-4.5%
Families AFDC-TANF (1985*)	224	274	287	4.7%	28.1%

NOTE: Base year in parentheses. *April figures. Source U.S. Census and Arizona Department of Economic Security.

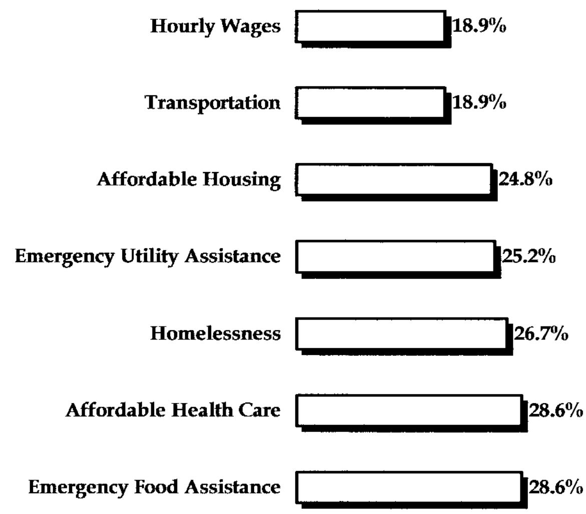
Self-Sufficiency

According to an Arizona Children's Action Alliance report completed in 2002, "The Self-Sufficiency Standard for Arizona," a single parent with an infant and a preschool-age child needs to earn a minimum of $32,300 annually to cover basic expenses in Santa Cruz County. In comparison, the following chart notes that a two parent household with an infant and a preschool-age child would need to make $39,278 annually, while a single adult would need $14,761 to cover basic living needs in Santa Cruz County.

Monthly Costs	Adult	Adult + Infant Preschooler	2 Adults + Infant Preschooler
Housing	416	517	517
Child Care	0	803	803
Food	176	345	496
Transportation	235	240	463
Health Care	102	289	358
Miscellaneous	93	219	264
Taxes	208	458	553
Earned Income Tax Credit (-)	0	0	0
Child Care Tax Credit (-)	0	-80	-80
Child Tax Credit	0	-100	-100
Self-Sufficiency Wage:			
Hourly	**$6.99**	**$15.29**	**$9.30 Per adult**
Monthly	**$1,230**	**$2,692**	**$3,273**
Annual	**$14,761**	**$32,300**	**$39,278**

Perceptions from the Community

One meeting was held in Santa Cruz County to discuss solutions to poverty. The chart below shows the percentage of participants surveyed who believe conditions have gotten ***worse*** in the following areas over the last ten years:



More specifically, participants discussed the following:

- Basic job skills are needed, including English.
- Need to attract employers.
- Unemployment insurance and job training for seasonal employees to seek new careers are needed.
- Government agencies, especially Border Patrol hire but bring people from other areas of the state rather than hiring within the community.
- Medical costs are too high, especially prescription drugs and medicine for behavioral health issues.
- Result of high medical costs force people to provide services at home which increases stress on the family.

Yavapai County

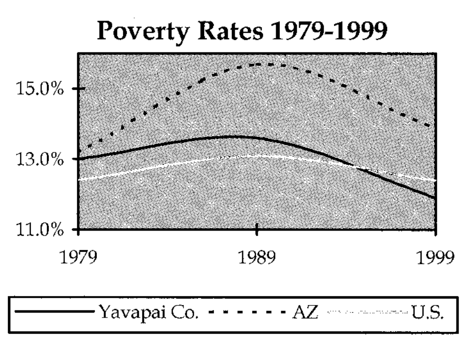
The 2000 Census revealed 167,517 people living in Yavapai County, a 55.5 percent increase from the 1990 Census of 107,714. In 1999, Yavapai County had almost 12 percent of its population or 19,552 people living below the poverty level. The poverty rate more than doubles on the Yavapai-Apache and Yavapai-Prescott Reservations with 28.2 percent living in poverty. While the overall percentage of people in poverty decreased over the last ten years, the number of people in poverty did not. Yavapai County experienced a 36.7 percent increase since 1989 when 14,308 people or 13.6 percent of the county's population lived in poverty.

Poverty in Selected Communities

Number of Persons Below Poverty Level (Poverty Rate)	1989	1999	% Change
Cottonwood	1,312 (22.7%)	1,211 (13.5%)	-7.7%
Prescott	3,354 (13.3%)	4,256 (13.1%)	26.9%
Sedona	681 (8.9%)	986 (9.7%)	44.8%
Reservations	NA	268 (28.2%)	NA
Yavapai County	14,308 (13.6%)	19,552 (11.9%)	36.7%
Arizona	564,362 (15.7%)	698,669 (13.9%)	23.8%

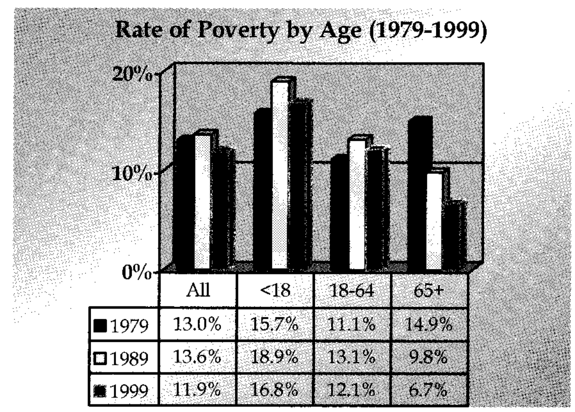
Source: U.S. Census and Research Advisory Services, Inc.

Yavapai County more than doubled the number of people in poverty over the last twenty years going from 8,652 in 1979 to 19,552 in 1999. In 1999, Yavapai County's poverty rate dropped below the national average of 12.4 percent and remains lower than the state average of 13.9 percent.



Poverty and Age

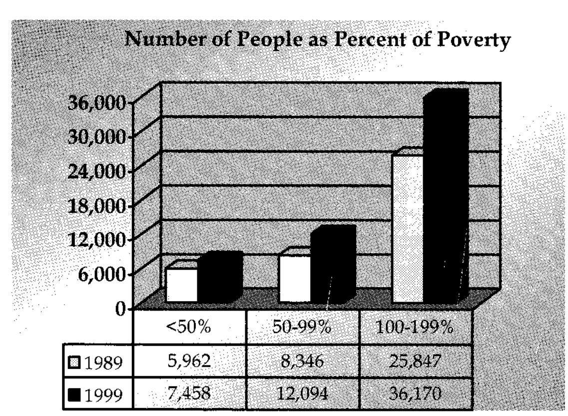
In 1999, among all age categories examined, children under 18 years of age experienced the highest rate of poverty at 16.8 percent, while those 65 and older had the lowest rate at 6.7 percent. Over the last ten years, the rate of poverty has decreased for all age groups. Those over 65 experienced a significant improvement over the last twenty years going from 14.9 percent in 1979 to 6.7 percent in 1999.



Source: U.S Census.

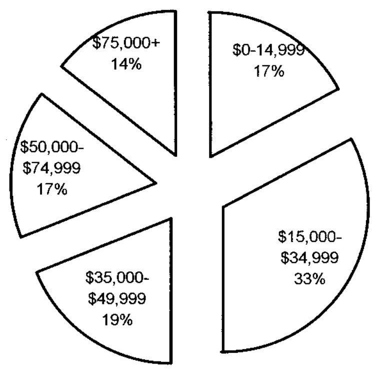
Poverty and Income Levels

Examination of the income to poverty ratio reveals that 7,458 people or 38.1 percent of those below the poverty rate in Yavapai County were ***very poor***, with incomes less than 50 percent of the poverty threshold. Another 36,170 people had incomes equal to or above the poverty level, but less than 199 percent (ACAA's definition of "working poor"). ***In total, there are 55,722 people in Yavapai County who are poor or "working poor," 34 percent of the county's total population.***



Source: U.S Census.

1999 Household Income Distribution – Yavapai County



Source: U.S Census. Note: The median household income in Yavapai County was $34,901 in 1999 compared to $22,060 in 1989 (58.2 percent increase).

Personal income grew in the county by 98.1 percent from 1990 to 1999 compared to the state's roughly 90 percent growth (according to the Arizona Department of Economic Security). Yavapai lags behind the state in the rest of the income figures. Per capita income in 1999 was $21,545 compared to the state's $25,173, or 14.4 percent below the state. The rate of growth of per capita income from 1990 to 1999 was 40.7 percent compared to the state's 46.3 percent. The average earnings per job in 1999 was $22,378 compared to $31,307 at the state level.

Poverty and Families

In 1999, the poverty rate among all families with children under 18 years of age living in Yavapai County was 14.5 percent. The rates for families with children headed by single females were 31.1 percent and even higher with younger children (less than 5 years) at 44 percent. Married couple families with children experienced a much lower rate at 9.2 percent.

Number Below Poverty Level (Poverty Rate)	1979	1989	1999	% Change '79-'99
All	1,886 (9.4%)	3,104 (9.8%)	3,703 (7.9%)	96.3%
With children under 18	1,042 (12.5%)	2,020 (16.8%)	2,653 (14.5%)	154.6%
Female-headed with children under 18	317 (29.2%)	908 (44.8%)	1,097 (31.1%)	246.1%
Female headed with children under 5*	149 (37.1%)	442 (71.1%)	538 (44.0%)	261.1%

*1979 numbers include 5 year olds. Source: U.S. Census.

Poverty and Race

Among racial/ethnic groups, American Indians experienced the highest poverty rate at 25.1 percent and Whites had the lowest at 10.7 percent. American Indians, Other races and those of Hispanic Origin were represented at a disproportionately higher rate among those in poverty than in the overall population. Those who experienced an increase in the poverty rate from 1989 included Asian/Pacific Islanders, Other races and those of Hispanic Origin.

Race Ethnicity	% of Total Population 1999	% of Poverty Population 1999	Poverty Rate by Race 1999	Poverty Rate by Race 1989
White	91.9%	83.9%	10.7%	13.0%
Black	0.4%	0.8%	23.8%	40.0%
American Indian	1.6%	3.4%	25.1%	36.2%
Asian/PI	0.6%	0.9%	18.1%	13.6%
Other	5.5%	10.9%	23.1%	20.3%
Hispanic Origin*	9.8%	18.7%	22.3%	17.2%

NOTE: Categories include those identifying themselves as Hispanic. *Those of Hispanic Origin may be of any race. Source: U.S. Census.

Public Assistance

According to the 2000 Census, 1,452 households or 2.1 percent of all households in Yavapai County received public assistance. The mean or average amount of public assistance income for 1999 was $2,887, a decrease from the $4,222 average of 1989 and $4,964 in 1979. Participation levels in the Food Stamp and Temporary Assistance to Needy Families (TANF) programs serve as indicators of poverty. In 2000, 5,456 people or 3.3 percent of the population received food stamps. At the same time, 574 or 1.2 percent of families were enrolled in TANF.

Public Assistance (PA)	Base Year	1990	2000	% Change 1990-2000	% Change Base Yr-2000
Households receiving PA (1980)	1,169	2,359	1,452	-38.4%	24.2%
Persons Food Stamps (1985*)	4,093	6,768	5,456	-19.4%	33.3%
Families AFDC-TANF (1985*)	392	836	574	-31.3%	46.4%

NOTE: Base year in parentheses. *April figures. Source U.S. Census and Arizona Department of Economic Security.

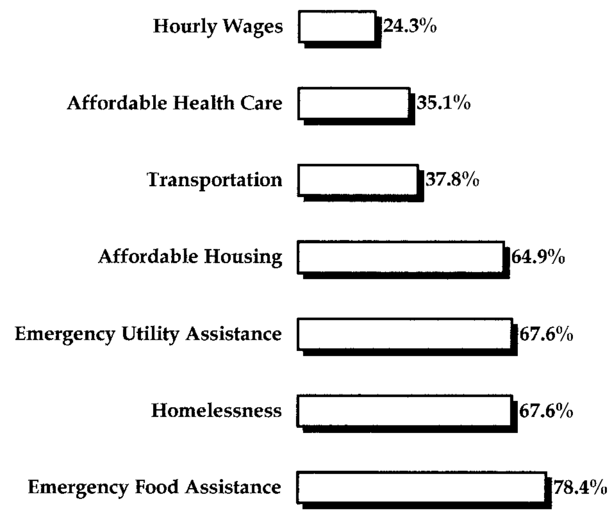
Self-Sufficiency

According to an Arizona Children's Action Alliance report completed in 2002, "The Self-Sufficiency Standard for Arizona," a single parent with an infant and a preschool-age child needs to earn a minimum of $33,276 annually to cover basic expenses in Yavapai County. In comparison, the following chart notes that a two parent household with an infant and a preschool-age child would need to make $40,023 annually, while a single adult would need $14,552 to cover basic living needs in Yavapai County.

Monthly Costs	Adult	Adult + Infant Preschooler	2 Adults + Infant Preschooler
Housing	416	557	557
Child Care	0	825	825
Food	176	345	496
Transportation	221	227	437
Health Care	104	294	363
Miscellaneous	92	225	268
Taxes	204	480	570
Earned Income Tax Credit (-)	0	0	0
Child Care Tax Credit (-)	0	-80	-80
Child Tax Credit	0	-100	-100
Self-Sufficiency Wage:			
Hourly	**$6.89**	**$15.76**	**$9.48 Per adult**
Monthly	**$1,213**	**$2,773**	**$3,335**
Annual	**$14,552**	**$33,276**	**$40,023**

Perceptions from the Community

Two meetings were held in Yavapai County to discuss the issues around poverty. The chart below shows the percentage of participants surveyed who believe conditions have gotten ***worse*** in the following areas over the last ten years:



More specifically, participants comments included:

- Increasing medical insurance and prescription medicine plans.
- A new belief system about the poor is needed.
- The need to create a sense of community.
- Increasing car donations to help low income people get to jobs, keep jobs, and go to college.
- Provide job coaches to assist people find opportunities across social classes.
- Give people in poverty a sense of hope.

Yuma County

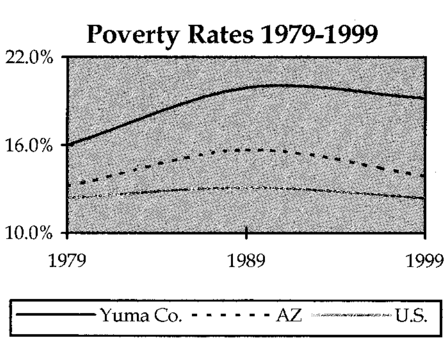
The 2000 Census revealed 160,026 people living in Yuma County, a 49.7 percent increase from the 1990 Census of 106,895. In 1999, Yuma County had over 19 percent of its population or 29,670 people living below the poverty level. The rate increases to 33.5 percent for those living on the Cocopah and Fort Yuma Reservations. While the overall percentage of people in poverty remained virtually the same over the last ten years, the number of people in poverty increased significantly. Yuma County experienced a 44.4 percent increase since 1989 when 20,552 people or 19.9 percent of the county's population lived in poverty.

Poverty in Selected Communities

Number of Persons Below Poverty Level (Poverty Rate)	1989	1999	% Change
San Luis	1,648 (34.9%)	4,645 (35.8%)	181.9%
Somerton	2,320 (44.0%)	1,928 (26.6%)	-16.9%
Yuma	8,621 (16.0%)	10,910 (14.7%)	26.6%
Reservations	335 (56.4%)	364 (33.5%)	8.7%
Yuma County	20,552 (19.9%)	29,670 (19.2%)	44.4%
Arizona	564,362 (15.7%)	698,669 (13.9%)	23.8%

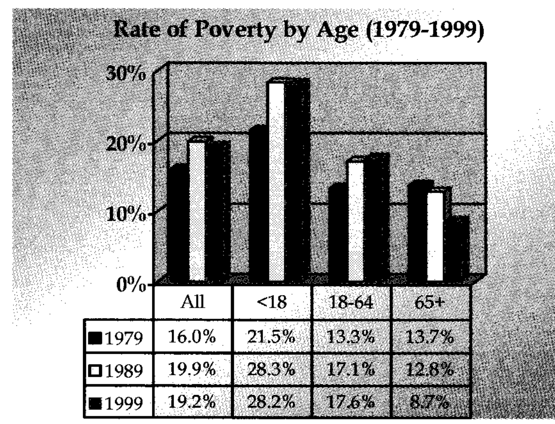
Source: U.S. Census and Research Advisory Services, Inc.

Over the last twenty years, Yuma County doubled the number of people below the poverty rate from 13,987 in 1979 to 29,670 in 1999. In 1999, Yuma County's poverty rate continues to be higher than the state average of 13.9 percent and the national average of 12.4 percent.



Poverty and Age

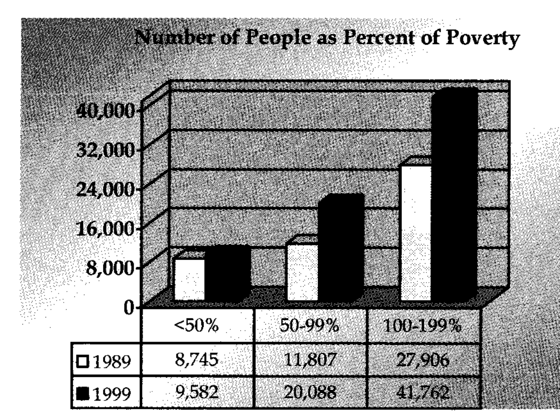
In 1999, among all age categories examined, children under 18 years of age experienced the highest rate of poverty at 28.2 percent, while those 65 and older had the lowest rate at 8.7 percent. Over the last ten years, the rate of poverty has stayed basically the same for all age groups, except those over 65 who experienced an improvement from 12.8 percent in 1989 to 8.7 percent in 1999.



Source: U.S Census.

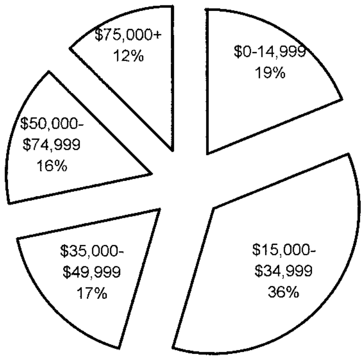
Poverty and Income Levels

Examination of the income to poverty ratio reveals that 9,582 people or one-third of those below the poverty rate in Yuma County were ***very poor,*** with incomes less than 50 percent of the poverty threshold. Another 41,762 people had incomes equal to or above the poverty level, but less than 199 percent (ACAA's definition of "working poor"). ***In total, there are 71,432 people in Yuma County who are poor or "working poor," 46.3 percent of the county's total population.***



Source: U.S Census.

1999 Household Income Distribution - Yuma County



Source: U.S Census. Note: The median household income in Yuma County was $32,182 in 1999 compared to $23,635 in 1989 (36.2 percent increase).

From 1990 to 1999, local total personal income in Yuma County increased 72.2 percent compared to the state's roughly 90 percent (according to the Arizona Department of Economic Security). On a per capita basis, the gain of 36.7 percent was 9.6 percent below the state's growth of 46.3 percent. Yuma County per capita income was $18,452 in 1999, about 73.3 percent of the state average, down from 78.4 percent in 1990. Average earnings per job increased 0.6 percent in 1999 - less than the state's gain of 4.1 percent.

Poverty and Families

In 1999, the poverty rate among all families with children under 18 years of age living in Yuma County was 24.4 percent. The rates for families with children headed by single females were 45.1 percent and even higher with younger children (less than 5 years) at 52.6 percent. Married couple families with children experienced a lower rate at 18.5 percent.

Number Below Poverty Level (Poverty Rate)	1979	1989	1999	% Change '79-'99
All	2,942 (12.3%)	4,341 (15.4%)	6,490 (15.5%)	120.6%
With children under 18	2,163 (16.5%)	3,593 (23.7%)	5,278 (24.4%)	144.0%
Female-headed with children under 18	780 (46.0%)	1,397 (54.7%)	1,903 (45.1%)	144.0%
Female headed with children under 5*	382 (51.5%)	719 (69.7%)	828 (52.6%)	116.8%

*1979 numbers include 5 year olds. Source: U.S. Census.

Poverty and Race

Among racial/ethnic groups, other races, American Indians and those of Hispanic Origin experienced the highest poverty rates at 29.1 percent, 28.9 percent and 28.2 percent. Other races and those of Hispanic Origin were represented at a disproportionately higher rate among those in poverty than in the overall population. All races saw an improvement in rates from 1989 except Asian/Pacific Islanders.

Race Ethnicity	% of Total Population 1999	% of Poverty Population 1999	Poverty Rate by Race 1999	Poverty Rate by Race 1989
White	68.3%	53.1%	14.4%	16.5%
Black	2.2%	1.9%	15.7%	16.5%
American Indian	1.6%	2.6%	28.9%	40.6%
Asian/PI	1.1%	0.4%	7.6%	6.1%
Other	26.8%	42.0%	29.1%	33.2%
Hispanic Origin*	50.5%	76.9%	28.2%	33.4%

NOTE: Categories include those identifying themselves as Hispanic. *Those of Hispanic Origin may be of any race. Source: U.S. Census.

Public Assistance

According to the 2000 Census, 1,878 households or 3.5 percent of all households in Yuma County received public assistance. The mean or average amount of public assistance income for 1999 was $2,408, a decrease from the 1989 average of $3,398 and $3,571 in 1979. Participation levels in the Food Stamp and Temporary Assistance to Needy Families (TANF) programs serve as indicators of the extent of poverty. In 2000, 12,095 people or 7.6 percent of the population received food stamps. At the same time, 923 or 2.2 percent of families were enrolled in TANF.

Public Assistance (PA)	Base Year	1990	2000	% Change 1990-2000	% Change Base Yr-2000
Households receiving PA (1980)	1,476	2,654	1,878	-35.0%	9.2%
Persons Food Stamps (1985*)	6,727	12,083	12,095	0.1%	79.8%
Families AFDC-TANF (1985*)	584	1,179	923	-21.7%	58.0%

NOTE: Base year in parentheses. *April figures. Source U.S. Census and Arizona Department of Economic Security.

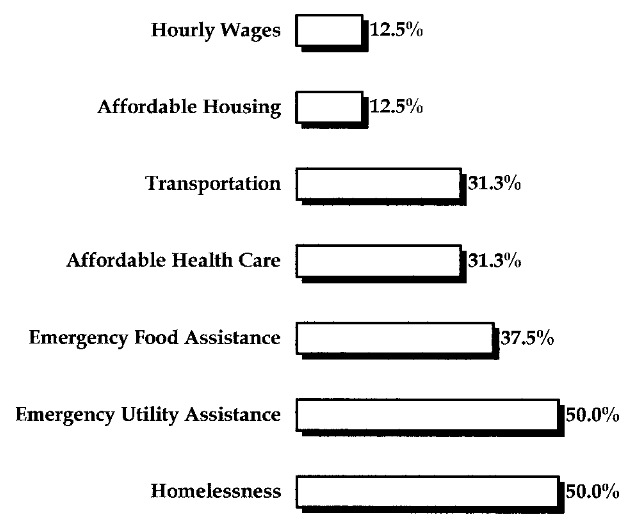
Self-Sufficiency

According to an Arizona Children's Action Alliance report completed in 2002, "The Self-Sufficiency Standard for Arizona," a single parent with an infant and a preschool-age child needs to earn a minimum of $33,410 annually to cover basic expenses in Yuma County. In comparison, the following chart notes that a two parent household with an infant and a preschool-age child would need to make $40,308 annually, while a single adult would need $15,350 to cover basic living needs in Yuma County.

Monthly Costs	Adult	Adult + Infant Preschooler	2 Adults + Infant Preschooler
Housing	453	603	603
Child Care	0	781	781
Food	176	345	496
Transportation	230	235	453
Health Care	103	290	359
Miscellaneous	96	225	269
Taxes	222	484	578
Earned Income Tax Credit (-)	0	0	0
Child Care Tax Credit (-)	0	-80	-80
Child Tax Credit	0	-100	-100
Self-Sufficiency Wage:			
Hourly	**$7.27**	**$15.82**	**$9.54** Per adult
Monthly	**$1,279**	**$2,784**	**$3,359**
Annual	**$15,350**	**$33,410**	**$40,308**

Perceptions from the Community

Participants attending the community meeting held in Yuma County discussed major concerns regarding poverty and solutions for change. The chart below shows the percentage of participants surveyed who believe conditions have gotten *worse* in the following areas over the last ten years:



More specifically, participants discussed:

- Transportation concerns and the inability of low-income people to afford a car.
- Literacy concerns and the accessibility of classes.
- Citizenship issues are present and many workers need guidance and support.
- Job training and economic development needs beyond low-wage agriculture.

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Eloy, AZ 85231
(520) 466-1112 FAX (520) 466-0013

Coconino County Community Services Department
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Flagstaff, AZ 86004
(928) 522-7979 FAX (928) 522-7965

Gila County Division of Health and Community Services
5515 S. Apache Avenue
Globe, AZ 85501
(928) 425-7631 FAX (928) 425-9468

Maricopa County Human Services Department
Community Services Division
234 N. Central Suite 300
Phoenix, AZ 85009
(602) 506-5911 FAX (602) 506-8789

City of Mesa Community Revitalization Division
20 E. Main Street, Suite 250
Mesa, AZ 85211-1466
(480) 644-2968 FAX (480) 644-4842

Northern Arizona Council of Governments (NACOG)
119 East Aspen Avenue
Flagstaff, AZ 86001
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City of Phoenix, Human Services Department
200 W. Washington, 18th Floor
Phoenix, AZ 85003-1611
(602) 262-6666 FAX (602) 495-0870

Pima County Community Action Agency
406 N. Church Ave.
Tucson, AZ 85701
(520) 884-4265 FAX (520) 884-5076

Southeastern Arizona Community Action Program (SEACAP)
283 West 5th Street
Safford, AZ 85546
(928) 428-4653 Fax (928) 428-1559

Western Arizona Council of Governments (WACOG)
224 South 3rd Avenue
Yuma, AZ 85364
(928) 782-1886 Fax (928) 329-4248

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BEFORE THE ARIZONA CORPORATION COMMISSION

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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

ARIZONA COMMUNITY ACTION ASSOCIATION'S RESPONSE TO
UNS, GAS, INC'S FIRST SET OF DATA REQUESTS

February 27, 2007

UNSG 1-1: Among utility rate increases, should low income customers be shielded from increases in:

a. water rates?

b. electricity rates?

EXHIBIT
tabbies
ACAA-2
admitted

c. telephone rates?

d. other utility rates?

ANSWER: The short answer is yes, low income customers should be shielded from increases in water, electricity, telephone and other utility rates. In fact, in most instances, low income customers are currently provided a discounted rate by the major electric companies, many private and municipal water companies, and telecommunications companies through two programs referred to as LIFELINE and Telephone Assistance Program or TAP.

ACAA believes that low income customers, at the level defined as 150% of poverty, need to have reduced utility rates for essential services. Essential services include heating, cooling, basic levels of electricity usage, basic telephone service and access to clean water services. ACAA is even more concerned however with utility services that can reach $300 per month, consuming 15% or 20% of the monthly income just for one utility service alone. This can easily happen with both gas and electric service in Arizona, whereas other utility services can provide basic service for $30-40 per month throughout the year.

UNS Gas customers currently living at 100% of poverty, families of three making less than $17,170 a year, are already going without important needs. Access to basic utility services should not be among them.

UNSG 1-2: Who should fund low-income assistance programs to shield low income customers from utility rate increases? How should those funding mechanisms operate?

ANSWER: ACAA suggests that all remaining customers fund the low income assistance programs. In this way, the impact on these remaining customers is minimized.

The funding mechanism should continue as presented in this case, that is the CARES customers continue to have a revenue contribution consistent with maintaining their costs at current levels. The revenue requirement for the remaining customer groups is calculated with what will be a minor addition to provide the subsidy to the limited number of CARES customers.

UNSG 1-3: Ms. Scheier recommends rejection of UNS Gas' proposed discounted customer charge under the low income discount program in favor of the current program of discounts based on sales. In colder climates, Ms. Scheier states that the current method will result in a larger discount – because the discount applies to the amount of gas used. Would the current rate design – with higher volumetric charges and lower customer charges – result in a higher bill because of the higher consumption associated with colder climates (before applying the discounts)? Do you agree that UNS Gas' proposed rate design avoids having customers in colder climates subsidize those in warmer climates?

ANSWER: It is ACAA's position that higher bills will be incurred by users in warmer and colder climates if their usage increases. When comparing the current and proposed rate design, low users will contribute a higher margin under the proposed rates than under the current rates – about $100 per year more for a 200 therm user. Users at 1053 therms per year will contribute an equal margin under the proposed and current rates. Users above this level will contribute less to this margin. While usage is generally higher in colder climates, usage also depends on house size and quality of housing stock, including the energy efficiency of the home and appliances, and we believe it is likely there are numerous cases where factors other than climate substantially impact usage. Furthermore, there are numerous low income residents in the coldest climates who have usage under 1053 who experience higher costs under the proposed rate increase.

Attached to this response is a spreadsheet that reflects data pulled from the UNS filing that shows the annual increases that will be incurred with the increase proposed, compared with the current rates. As we have previously stated, any increase in a low income home is too much. Additionally, though the annual bill reduction a customer using 2000 therms annually may receive under the proposed rates is beneficial, it is still a problem for that household, and assistance still needs to be available. An annual bill of approximately $2000 (for a 2000 therm user) is still too high for a low income customer to manage, and therefore those households still needs a usage base discount. The idea of providing the same discount for a customer in Lake Havasu as a customer in Flagstaff really makes no sense.

Additionally, ACAA feels very strongly that the discount on the CARES program should increase from 100 therms to at least 250 therms per month in order to cover the actual usage of the low income customer.

As to the question of whether ACAA agrees that the proposed rate design avoids having customers in colder climates subsidize those in warmer climates, we have not undertaken that analysis in this case except in the context of the large versus lower consumer of gas. And as we have previously stated, for a low income customer, any increase will be difficult at best for a low income family to manage, and if they are unable to make regular payments to the Company, the Company also suffers.

RESPECTFULLY SUBMITTED this 28th day of February 2007

By [signature]

Cynthia Zwick, Executive Director for
Miquelle Scheier
Arizona Community Action Association
2700 N. Third St., Suite 3040
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ANNUAL BILLS BY USAGE
UNS GAS, INC.

Annual bills by usage

Usage	Present	proposed	Change $	Change %
200	$304	$401	$97	32.0%
300	$414	$500	$86	20.7%
400	$524	$598	$74	14.2%
500	$634	$697	$63	9.9%
600	$744	$796	$52	6.9%
700	$854	$894	$40	4.7%
800	$964	$993	$29	3.0%
900	$1,074	$1,091	$17	1.6%
1000	$1,184	$1,190	$6	0.5%
1100	$1,294	$1,289	-$5	-0.4%
1200	$1,404	$1,387	-$17	-1.2%
1300	$1,514	$1,486	-$28	-1.9%
1400	$1,624	$1,584	-$40	-2.4%
1500	$1,734	$1,683	-$51	-2.9%
1600	$1,844	$1,782	-$62	-3.4%
1700	$1,954	$1,880	-$74	-3.8%
1800	$2,064	$1,979	-$85	-4.1%
1900	$2,174	$2,077	-$97	-4.4%
2000	$2,284	$2,176	-$108	-4.7%

assumes gas cost of $.80/therm for base gas cost +PGA, no surcharge
excludes taxes, which range from about 8-11%

1045	$1,233.50	$1,234.37	0.1%
1046	$1,234.60	$1,235.36	0.1%
1047	$1,235.70	$1,236.34	0.1%
1048	$1,236.80	$1,237.33	0.0%
1049	$1,237.90	$1,238.31	0.0%
1050	$1,239.00	$1,239.30	0.0%
1051	$1,240.10	$1,240.29	0.0%
1052	$1,241.20	$1,241.27	0.0%
1053	**$1,242.30**	**$1,242.26**	**0.0%**
1054	$1,243.40	$1,243.24	0.0%

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON, CHAIRMAN
JEFF HATCH-MILLER, Commissioner
KRISTIN K. MAYES, Commissioner
WILLIAM MUNDELL, Commissioner
GARY PIERCE, Commissioner

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

Surrebuttal Testimony of

Miquelle Scheier

On Behalf of

Arizona Community Action Association

March 30, 2007

EXHIBIT
ACAA-3
admitted

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Miquelle Scheier. My business address is Coconino County Community Services, 2625 N. King St., Flagstaff, Arizona 86004.

Q. Are you the same Miquelle Scheier who filed Direct Testimony in this case?

A. Yes, I am.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide a response to the Rebuttal Testimony filed by James S. Pignatelli, Gary Smith and Denise Smith in this case. Arizona Community Action Association disagrees with some of the Rebuttal Testimony offered and intends to clarify several items that appear to be misunderstandings.

II. RATE DESIGN AND LOW INCOME PROGRAMS

Q. James P. Pignatelli indicates that he was disturbed to learn that UNS Gas is somehow referring customers to "predatory lenders," and believes you to be mistaken. Would you like to clarify your concern?

A. Yes. I would refer Mr. Pignatelli to the UNS website, a printout from which was attached to our initial filing. The web site clearly offers pay-day loan facilities as an option for those customers who need to pay their UNS Gas or Electric bill in cash. The website also includes an indication that there will be an additional charge for use of some of those sites. In conversations with UNS Gas staff, I was not told that the Company was picking up those costs if the pay-day loan facility was not near an alternative UNS Gas facility. Regardless, we believe that it is an irresponsible practice to send customers to predatory lenders in order to meet their payment obligations.

Q. Gary Smith, in his Rebuttal Testimony on page 2, describes the Company's efforts to enroll eligible customers in the CARES program. Do you believe this is adequate?

A. No. We know that there are many more customers eligible for the CARES program. While the Company has engaged in some outreach, it is clearly not hitting the mark as enrollment is still too low. Additional resources need to be allocated to support an effective outreach and enrollment program, including the automatic enrollment of LIHEAP elgible customers, which I suggested in my Direct Testimony.

Q. Gary Smith, in his Rebuttal Testimony on page 9, states, "With regard to the suggestion that UNS Gas is somehow encouraging customers to enter into agreements with pay day loan operations, we are not doing so." Is this an accurate characterization of your Direct Testimony?

A. No. Arizona Community Action Association is concerned that customers are being referred to predatory lenders as an option for paying their bills. As previously stated, we believe this is an irresponsible practice. We have spoken with low-income clients who, upon presenting their bill for payment at pay day loan facilities, have been encouraged to take out a loan. While this may not be UNS Gas intention, it is a very real consequence.

Q. Gary Smith, in his Rebuttal Testimony on page 10 indicates that CAA's need time to ramp up in order to utilize an increase in weatherization funds, and expresses a willingness to work with CAA's prior to its next rate case. Do you have any response to this offer?

A. Yes. I believe this response to be inappropriate. While we appreciate the Company's willingness to work with us, waiting to increase funding and therefore service to the low-income community until the filing of the next rate increase is inadequate. The need exists today, the funding is currently inadequate, and it is irresponsible to suggest that the families be put on hold. Additionally, while the homes are not weatherized, the energy efficiency of those homes continues to go unattended, resulting in wasted energy, and unnecessarily high bills. ACAA is happy to work with the Company in the design of the program that will facilitate the efficient expenditure of funds, and with the CAA's so they may be prepared to assist a larger number of families.

Q. In Denise Smith's testimony on page 10, she indicates that the marketing of the low income weatherization program is currently handled by the agencies administering the program. Is that your understanding as well?

A. Well, I think we need to define marketing. The agencies administering the weatherization program receive no funding to conduct any kind of marketing. They are engaged in referring clients to the program through agency brochures that they have created independently, and through agency referrals when clients come into their offices with extremely high energy bills – a common indication that perhaps a home is not energy efficient. If provided funding to conduct a meaningful marketing or outreach strategy, and if the Company was actually involved in marketing the availability of the weatherization program along with the CARES program, many more families could be served, and there would be increased awareness about the program and its benefits community-wide.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes it does, thank you.

RESPECTFULLY SUBMITTED this 20th day of March 2007

By ______________________

Cynthia Zwick, Executive Director for
Miquelle Scheier
Arizona Community Action Association
2700 N. Third St., Suite 3040
Phoenix, AZ 85004

Copy of the foregoing hand-delivered/mailed
This 20th day of March 2007 to:

Original and 17 copies to:
Arizona Corporation Commission
Docket Control
1200 West Washington
Phoenix, AZ 85007

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ROSHKA DeWULF & PATTEN, PLC
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Michelle Livengood
Tucson Electric Power Company
One South Church Avenue
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Scott Wakefield
Chief Counsel
Residential Utility Consumer Office
1110 West Washington Street, Suite 200
Phoenix, AZ 85007

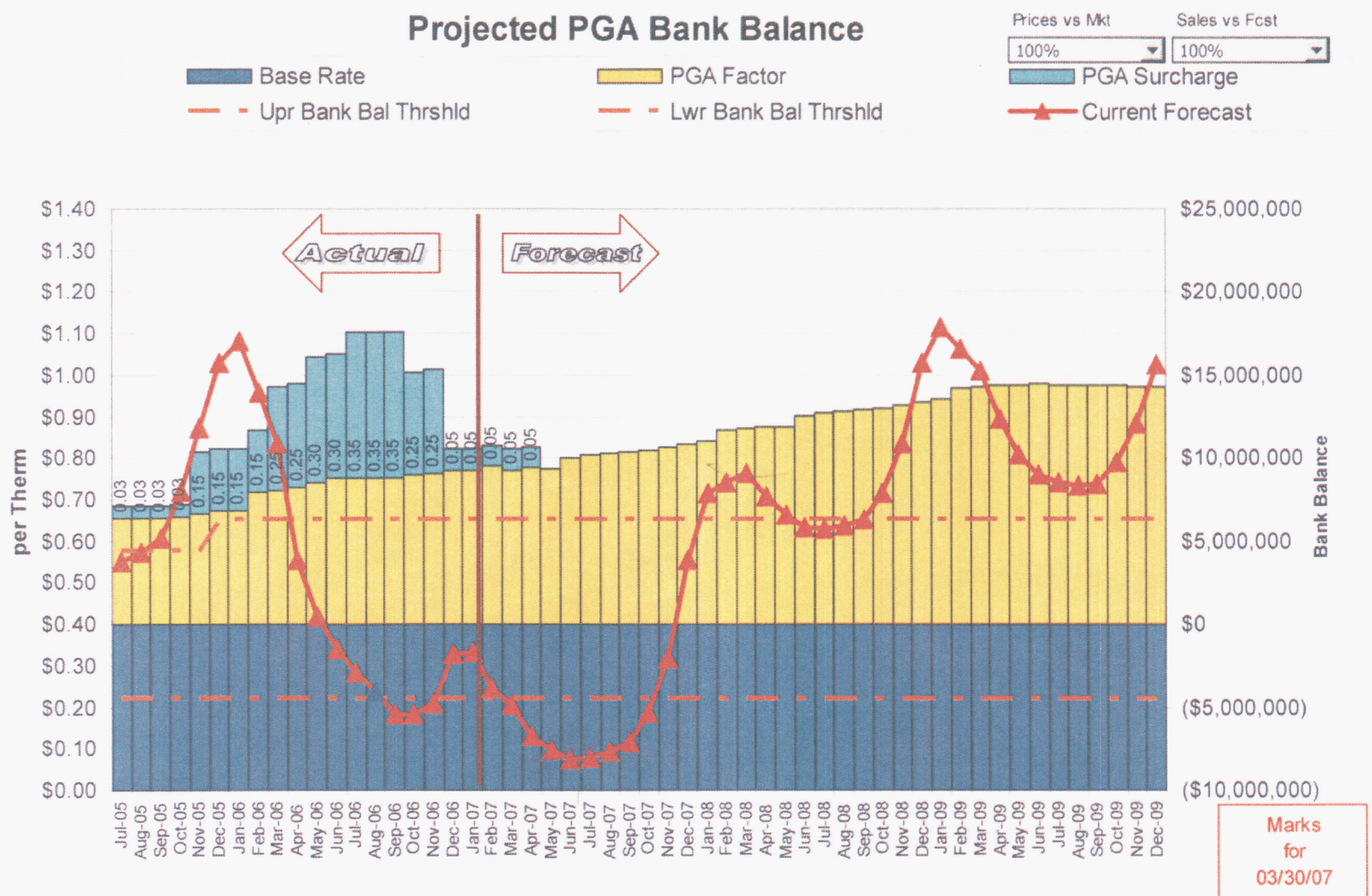
EXHIBIT

tabbies

Mayes-1

Admitted

Projected PGA Bank Balance



Feb ~ -4.2 ✓

MAr - -4.7

Summer'0ED - 8 M

Winter ok → +8 M

AZ Daily Star, 30 Mar 2007

Owe utilities? Earlier shutoff, deposits lurk

By Shelley Shelton
ARIZONA DAILY STAR

Here comes the sun.

And if you're not careful, here also come disconnect notices from Tucson Electric Power Co. a month sooner than a year ago if you don't pay your electric bill on time.

As we leave behind a winter that brought snow and record heating bills for many, folks should be looking at ways to prevent the financial crunch from continuing as they switch from gas heating to electric cooling, according to a longtime consumer-advocate group.

Miss a gas or electric payment twice in a year — during any consecutive 12 months for the gas company, and during the calendar year for the electric company — and you could be stuck paying deposits as high as your two highest bills, depending on the utility.

The relatively recent change to watch out for is the not-quite-year-old TEP policy regarding disconnect notices.

Before April of last year, TEP customers could accumulate two unpaid bills before a disconnect notice was issued, leaving 10 days to pay before their service was shut off.

But then in April the rule changed so a 10-day disconnect notice is issued

See UTILITIES, A4

On StarNet: Learn different ways to conserve energy and reduce your heating and cooling bills at azstarnet.com/earth911

PAYMENT HELP

To set up payment arrangements, get on the equal-payment plan or arrange for automatic withdrawal from your bank account for your electric or gas bills, call:

- Tucson Electric Power Co. **623-7711**
- Southwest Gas Corp. **889-1888**

EXHIBIT
tabbies
Magruder-1
Admitted

UTILITIES

Continued from Page A1

after one bill remains unpaid when the next month's bill goes out, said Joe Salkowski, TEP spokesman.

"If customers have more than two payments that are late within a calendar year, under those circumstances we will ask for a deposit," Salkowski said.

The deposit is an estimate of two months' worth of your electric bill, based mainly on actual billed history at that address. But if you haven't lived there for very long, it is based on your history with the company as well as other usage at that address, he said.

After 12 months of paying your TEP bill on time, you get the deposit back, plus 6 percent interest.

Deposit can be a hardship

But for people who live from paycheck to paycheck, paying the bill by the exact due date each month on top of putting down a hefty deposit for late payments can be a hardship, said Al Sterman, vice president of the Arizona Consumers Council, a 40-year-old statewide consumer-advocate group.

"It becomes very difficult for a large segment of the population to keep up with their utility bills," he said. "It seems that they're making it much more difficult for those who are on the edge to stay on the edge" without going over it.

At Southwest Gas Corp., late means the new bill comes when the old one hasn't been paid, but that's nothing new, said Libby Howell, company spokeswoman.

And when customers rack up three or more late payments in any consecutive 12-month period, they are asked to pay a deposit equal to twice their highest bill, she said.

"What's different this year is, everybody's bill is very much higher. That may have triggered someone to be late that isn't normally late," she said.

As of Monday, 2,814 Pima County customers were projected to be "Did Not Pays" — Southwest Gas customers who have reached the delinquency point and were scheduled to be turned off by April 1.

Last year's Did Not Pays for the same period totaled 1,217, Howell said. However, this year's numbers are projected, and a large number of those people likely will pay before April 1, she said.

Protecting paying customers

The disconnect and deposit policies may seem coldhearted, but it's the best way for TEP to keep costs under control so paying customers don't have to foot the bill for those who don't pay, Salkowski said.

Historically, when TEP has gone before the Arizona Corporation Commission to set its rates — which are frozen until 2009 — the cost of unpaid bills is figured into the rates the company charges, he said.

"It is in there, and we're always trying to manage our costs on behalf of our customers, and this is one of them that we ought to be able to reduce as best we can."

Howell said the Southwest Gas deposit is based on the two highest bills because people should always be able to pay their highest bill.

"We're not like other businesses. We let you use our product first before you pay for it," she said. "You can't eat the groceries first and then pay for them."

Salkowski and Howell each emphasized the need for customers to call their utility companies right away when it looks like a bill might be too large.

Both companies have several options for working with customers to get the bills paid rather than turning off service, including setting up payment arrangements, low-income payment plans and equal-payment plans for future bills.

That's the customer's best bet, said consumer advocate Sterman.

"The biggest advice is, try if you possibly can, to put away today the equivalent of what a monthly bill might be during the summertime," he said. "Before you get into trouble and are not able to pay the bill, or at the time you can't pay the bill, call the company and say, 'Can we make payment arrangements?' and see if that works."

Contact reporter Shelley Shelton at 434-4086 or sshelton@azstarnet.com.

EXHIBIT

Magruder-2
admitted

UniSourceEnergy SERVICES

SECTION NO. 10
BILLING AND COLLECTION
(continued)

C. Billing Terms

1. All bills for gas service are due and payable no later than ten (10) days from the date the bill is rendered. Any payment not received within this time-frame shall be considered past due and may be subject to a late payment penalty charge. If the tenth (10th) day falls on a weekend or holiday, then the past due date is extended to the next business day.

2. For purposes of this rule, the date the bill is rendered shall be the latest of the following:

   a. The postmark date;

   b. The mailing date; or

   c. The billing date shown on the bill (however, the billing date shall not differ from the postmark or mailing date by more than two (2) days.

3. All past due bills for gas service are due and payable within fifteen (15) days. Any payment not received within this time-frame shall be considered delinquent and will be issued a suspension of service notice. For Customers under the jurisdiction of a bankruptcy court, a more stringent payment or prepayment schedule may be required, if allowed by that court.

   a. The amount of the late payment penalty shall not exceed one and one-half percent (1.5%) of the delinquent bill, applied on a monthly basis.

4. All delinquent bills for which payment has not been received within five (5) days shall be subject to the provisions of the Company's suspension of service procedures.

5. All payments shall be made at or mailed to the office of the Company or to the Company's duly authorized representative.

EXHIBIT
3 Magruder
admitted

UNS GAS, INC.'S RESPONSES TO
MR. MAGRUDER'S SECOND SET OF DATA REQUESTS
DOCKET NO. G-04204A-06-0463
March 29, 2007

MM DR 2-9 How many CARES customers received LIW funds from UNS Gas for each year since 2002?

a. If this data are recorded monthly, then monthly data for CARES customers.
b. How may of these CARES customers lived in Santa Cruz County for each year or by month?
c. What are the total annual CARES costs to UNS Gas since 2002?
d. What are the total annual CARES distributions to customers since 2002?

RESPONSE: UNS Gas can assume that all LIW customers are eligible to be CARES customers. However, there is no cross-reference data to determine how many CARES customers also received LIW funds from UNS Gas.

a. There is no data available.

b. There is no data available.

c.-d. See Bates Nos. UNSG(0463)06020 to UNSG(0463)06023 for the available annual CARES costs and discounts to customers.

RESPONDENT: Linda Douglas-Worthey

WITNESS: Denise Smith

UNS Gas, Inc. CARES Discount Program - Summary of Total Program Expenses

July - December 2006

	Participation	Discount	PGA Surcharge Forfeit	Avg. Discount	Administrative Expenses	Marketing Expenses
July	5,836	$ (1.05)	$ 25,377.80	$ 4.35	$ 2,402.04	$ -
August	5,788	$ -	$ 24,742.55	$ 4.27	$ 1,332.82	$ 6,119.38
September	5,835	$ -	$ 28,978.25	$ 4.97	$ 1,021.22	$ 18,249.70
October	5,976	$ -	$ 30,977.00	$ 5.18	$ 608.13	$ 1,444.57
November	6,037	$ 33,938.85	$ 57,739.00	$ 15.19	$ 330.35	$ 5,227.87
December	6,233	$ 59,503.65	$ 21,999.15	$ 13.08	$ 476.87	$ -
Total	**35,705**	**$ 93,441.45**	**$ 189,813.75**	**$ 7.93**	**$ 6,171.43**	**$ 31,041.52**

Total Discount and Expenses July 06-Dec 06	Avg. Monthly Customer Participation July 06-Dec 06	Avg. Discount July 06-Dec 06
$ 320,468.15	**5,950**	**$ 53.86**

UNS Gas, Inc. CARES Discount Program - Summary of Total Program Expenses

January 2006- June 2006

2006	Discount	Avg Discount	Participation	Administrative Expenses	Marketing Expenses
January	$ 53,937.20	$ 9.51	5,670	$ 286.01	$ 304.71
February	$ 58,098.60	$ 10.10	5,754	$ 302.67	$ 97.50
March	$ 55,371.00	$ 9.34	5,930	$ 450.38	$ -
April	$ 47,070.15	$ 7.85	5,994	$ 1,582.72	$ 831.98
May	$ 14.70	$ -	5,929	$ 1,130.54	$ 211.50
June	$ 4.35	$ -	5,845	$ 1,180.79	$ 6,070.72
TOTAL	**$ 214,496.00**	**$ 6.11**	**-**	**$ 4,933.11**	**$ 7,516.41**

Total Discount and Expenses Jan 06 - June 06	Avg. Monthly Customer Participation Jan 06 - June 06	Avg. Discount Jan 06 - June 06
$ 214,496.00	5,520	$ 6.11

Notes:

1) Basic Cost of Service Rate: first 100 therms or less per month will be discounted by $0.1500 per therm for the billing months November through April

UNSG0463/06021

UNS Gas, Inc. CARES Discount Program - Summary of Total Program Expenses

July 2005 - December 2005

2005	Discount	Avg Discount	Participation	Administrative Expenses	Marketing Expenses
Jul	$ -	$ -	5,475	$ 1,006.85	$ -
Aug	$ -	$ -	5,536	$ 490.76	$ 5,744.28
Sep	$ -	$ -	5,428	$ 415.58	$ 8,365.45
Oct	$ -	$ -	5,401	$ 154.09	$ 6,060.17
Nov	$ 24,123.00	$ 4.37	5,523	$ 346.86	$ 8,244.60
Dec	$ 50,613.00	$ 9.01	5,618	$ 238.90	$ 32.50
TOTAL	**$ 74,736.00**	**$ 6.70**	**32,981**	**$ 2,653.04**	**$ 28,447.00**

Total Discount and Expenses July 05 - Dec 05	Avg. Monthly Customer Participation July 05 - Dec 05	Avg. Discount July 05 - Dec 05
$ 74,736.00	5,571	$ 6.70

Notes:

1) Basic Cost of Service Rate: first 100 therms or less per month will be discounted by $0.1500 per therm for the billing months November through April

UNS Gas, Inc. CARES Discount Program - Summary of Total Program Expenses

July 2004 - December 2004

2004	Discount	Avg. Discount	Customer Participation	Administrative Expenses	Marketing Expenses
July	$ -	$ -	3,075	$ 750.00	$ 12,200.00
August	$ -	$ -	3,101	$ 750.00	$ 12,200.00
September	$ -	$ -	3,385	$ 750.00	$ 12,200.00
October	$ -	$ -	3,746	$ 750.00	$ 12,200.00
November	$ 26,986.95	$ 6.35	4,251	$ 750.00	$ 12,200.00
December	$ 47,445.30	$ 10.24	4,630	$ 750.00	$ 12,200.00
TOTAL	**$ 74,432.25**	**$ 8.30**		**$ 4,500.00**	**$ 73,200.00**

Total Discount and Expenses July 04 - Dec 04	Avg. Monthly Customer Participation July 04 - Dec 04	Avg. Discount Per Customer July 04 - Dec 04
$ 152,132.25	3,698	$ 8.30

Total Discount and Expenses Jan 04 - Jun 04	Avg. Monthly Customer Participation Jan 04 - Jun 04	Avg. Discount Per Customer Jan 04 - Jun 04
$ 109,754.39	2,883	$6.35

Total Discount and Expenses Jan 04 - Dec 04	Avg. Monthly Customer Participation Jan 04 - Dec 04	Avg. Discount Per Customer Jan 04 - Dec 04
$ 261,886.64	3,290	$ 7.32

Notes:

1) Basic Cost of Service Rate: first 100 therms or less per month will be discounted by $0.1500 per therm for the billing months November through April
2) Marketing expenses were not included in the January through June 2004 CARES report. Marekting expenses will be included in all subsequent filings.

The standard cost effectiveness analysis may not be appropriate for certain types of DSM programs.

1. ***Market Transformation Programs: Cost effectiveness shall be measured by the success of a program in achieving results, such as market effects compared to its costs.***

2. ***Educational Programs: Utilities shall attempt to estimate the energy and peak demand savings that result from educational efforts that raise awareness about energy use and opportunities for saving energy.***

3. ***R&D and Pilot Programs: Individual research and development and pilot programs do not have to demonstrate cost-effectiveness.***

4. ***Low Income Programs: Measures included in low-income programs shall be generally cost-effective.***

The following table illustrates the differences between the various cost-effectiveness tests.

Comparison of Cost-Effectiveness Tests

	Participant Test	*Utility Cost Test*	*Total Resource Cost Test*	*Societal Test*
Benefits	• *incentives received* • *bill reductions*	• *avoided utility costs*	• *avoided utility costs*	• *avoided utility costs* • *avoided environmental impacts*
Costs	• *bill increases* • *incremental participant costs*	• *incremental utility costs, including incentives paid by utility*	• *incremental utility costs, excluding incentives paid by utility* • *incremental participant costs*	• *incremental utility costs, excluding incentives paid by utility* • *incremental participant costs*

The *Cost-Effectiveness* section describes the process by which the cost-effectiveness of the overall DSM portfolio and each individual DSM program will be evaluated. Both the overall DSM portfolio and each individual DSM program must be cost-effective.

There are several recognized methods to test for cost-effectiveness including the Participant Test, Utility Cost Test, Total Resource Cost Test, Ratepayer Impact Measure, and the Societal Test. Each method varies in the types of costs and/or benefits that are considered. The

BEFORE THE ARIZONA CORPORATION COMMISSION

<u>COMMISSIONERS</u>

Jeff Hatch-Miller, Chairman
William A. Mundell
Mike Gleason
Kristin K. Mayes
Barry Wong

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**

A MOTION TO INTERVENE FOR MARSHALL MAGRUDER

As provided by the Procedural Order for these cases of 8 September 2006, Marshall Magruder, a Santa Cruz County UNS Gas, Inc. customer, respectfully requests to intervene in these combined cases. Some of the areas of interest include:

a. The proposed residential Service Charge increase of 340% in less than four years from $60.00 per year prior to 11 August 2003, to the present $84.00 per year, and a proposed $204.00 per year.

b. The proposed natural gas rates for many Schedules that show customer savings for higher monthly usage per therm instead of a rate increase which is counter-initiative to both Demand Reduction and basic conservation principles.

EXHIBIT
tabbies
Magruder 5
admitted

c. The proposed natural gas rates policy to lower rates for customers in colder climates and penalize customers in warmer climates with lower demands, which directly impacts the separate service area in Santa Cruz County, compared to the other UNS Gas, Inc. customers in counties with colder climates and higher demands.

d. The proposed policies for rates and charges may blur separation of "cost of service" and "cost of natural gas" differences as only the first provides profit to the company.

e. The potential for customers to pay any costs for the transition of ownership from Citizens to UNS Gas, Inc., customarily borne by a company and not by its customers.

f. The potential for UNS Gas, Inc. customers to pay multiple "general and administrative" (pancake) charges to various subsidiaries and to UniSource Energy.

I have a copy of effective Procedural Order and UNS Gas, Inc., filings to date in these cases. I understand the procedural schedule and will comply with the required filing dates.

Early approval of this Motion is requested as a better understanding of the various issues involved should be attainable during discovery.

I certify that this filing has been mailed to all known and interested parties and the company as shown in the Distribution List below.

Respectfully submitted on this 16th day of November 2006

MARSHALL MAGRUDER

By ______________________________

Marshall Magruder
PO Box 1267Tubac, Arizona 85646
(520) 398-8587
marshall@magruder.org

Distribution List

Original and 20 copies of the foregoing are filed this date with:

Docket Control (17 copies)
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007-2927

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Ernest G. Johnson, Director Utilities Division (1 copy)
Christopher Kempley, Chief Counsel (1 copy)

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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

Jeff Hatch-Miller, Chairman
William A. Mundell
Mike Gleason
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** **Notice of Filing of Testimony of Marshall Magruder**
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**

As directed in the Procedural Order of 8 September 2006, modified on 10 January 2007, the prefiled Testimony of Marshall Magruder is submitted to all Parties as of this date.

Respectfully submitted on this 7th day of February 2007 to all parties.

MARSHALL MAGRUDER

By ______________________________

Marshall Magruder

EXHIBIT
tabbies
Magruder 6
admitted

Distribution List

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Manny Ruiz
John Maynard
George Silva, Santa Cruz County Attorney
Santa Cruz County Complex
2150 North Congress Drive
Nogales, Arizona 85621-1090

City of Nogales City Hall
City Attorney
777 North Grand Avenue
Nogales, Arizona 8562-2262

DIRECT

TESTIMONY

OF

MARSHALL MAGRUDER

FEBRUARY 7, 2007

In

ACC Docket No. G-04204A-06-0463
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,

and

ACC Docket No. G-04204A-06-0013
In the Matter of the Application of UNS Gas, Inc. to Review and Revise its Purchased Gas Adjustor

and

ACC Docket No. G-04204A-05-0831
In the Matter of the Inquiry into Prudence of the Gas Procurement Practices of UNS Gas, Inc.

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Testimony

Exhibit

TESTIMONY OF MARSHALL MAGRUDER

Part I – Background and Introduction

1.1 Introduction.

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

A. My name is Peyton Marshall Magruder, Jr. I am a customer of UNS Gas and UNS Electricity, two energy public service companies that serve Santa Cruz County. I was Vice Chairman of the Santa Cruz County/City of Nogales Energy Commission, and have been active in various community projects including the Tubac Community Center Foundation and the AARP tax aide program.

I have several jobs including Senior Scientist and Information Systems Architect for Integrated Systems Improvement Services (ISIS), Inc. in Sierra Vista, Arizona, working with information warfare, systems architectures, electronic and communications intelligence systems test plans, information assurance, cryptologic systems management, and information technology services. I am Systems Engineer and Training Systems consultant for Imagine CBT, Inc., at Raytheon Naval and Maritime Systems in San Diego doing systems engineering work with US and Royal Navy aircraft carriers and amphibious warfare ship's command, control, communications, computers, intelligence, surveillance and reconnaissance systems, and training systems. January through April, I also work as Tax Advisor Level 3 for H&R Block, Inc, in Tucson, Arizona. I retired from Raytheon/Hughes Aircraft Company as a Senior Systems Engineer after nearly 18 years and as an Officer in the US Navy for 25 years. Please see Exhibit A for additional work experience.

As an instructor in the University of Phoenix MBA programs, I taught courses on "Operations Management for Total Quality" and "Managing R&D and Innovation Processes" in the Nogales, Arizona, where all the students were from Mexico, and in Tucson, Arizona. I am preparing a course on the DOD architecture framework systems engineering process. In addition, I am the Vice President of the Martin B-26 Marauder Historical Society and served as Fund Raising Chairman for an ongoing five-million dollar "Lasting Legacy" fund drive to endow the MHS International Archives and the restoration of a B-26 Marauder aircraft at the Pima Air and Space Museum/Arizona Aerospace Foundation, Tucson.

My business address is PO Box 1267, Tubac, Arizona, 85646-1267.

Q. Have you previously testified before this Commission?

A. Yes, in appearances at ACC Open and Special Meetings and as a party in the following ACC Dockets:

a. Arizona Power Plant and Transmission Line Siting Case No. 111[1] (TEP's CEC Application);

b. Docket No. E-01032C-00-0951[2], the Citizens Purchase Power and Fuel Adjustment Clause (PPFAC) hearings;

c. Docket Nos. E-1033A/E-01032C/G-01032C-02-0914[3], the UniSource-Citizens Acquisition hearings;

d. Docket No. E-04230-03-0933[4], the UniSource-Sahuaro Acquisition hearings.

e. Reopened and ongoing Docket No. E-01032A-99-0401, the Santa Cruz County service quality, analysis of transmission and proposed Plan of Action case, and

f. Reopened Arizona Power Plant and Transmission Line Siting Case No. 111,[5] and which may reconvene depending upon the resolution of the E-01032A-99-0401 Docket.[6]

The testimonies presented with these filings are totally mine and are not for another.

Q. What is your educational background?

A. My latest degree is a Master of Science in System Management (MSSM) with majors in human factors and R&D from the University of Southern California with 'A's' in all courses. I

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[1] This case was before the Arizona Power Plant and Transmission Line Siting Committee, Case No. 111, and ACC Docket Nos. L-00000C-01-0111 and L-00000F-01-0111 was for "the matter of the joint Application of Tucson Electric Power Company and Citizens Communications Company, or their Assignee(s) for a Certificate of Environmental Compatibility for a proposed 345 kV transmission line ystem from Tucson Electric Power Company's existing South 345 kV Substation in ...Sahuarita, Arizona, to the proposed Gateway 345/115 kV Substation in ... Nogales Arizona, with a 115 kV interconnection to the Citizens Communications Company's 115 kV Valencia Substation in Nogales, Arizona, with a 345 kV transmission line from the proposed Gateway Substation to the International Border ...," submitted on 1 March 2001." This case resulted in ACC Decision No. 64356. I was an Intervenor and Party. Siting Case No. 111 has been reopened including ACC Decision No. 82011 that previously closed ACC Docket No. E-01032A-99-0401.

[2] This case was before the ACC "in the matter of the Application of the Arizona Electric Division of Citizens Communications Company to change the current purchase power and fuel adjustment clause rate, to establish a new purchase power and fuel adjustment clause bank, and to request approval of guidelines for the recovery and cost Incurred in connection with energy risk management initiatives," on 28 September 2000.This was reflected in ACC Decision No. 66028 of 18 December 2002. I was an Intervenor and Party.

[3] This case was before the ACC "in the matter of the joint Application of Citizens Communications Company and UniSource Energy Corporation for the approval of the sale of certain electric utility and gas utility Certificates of Convenience and Necessity from Citizens Communications Company to UniSource Energy Corporation the approval of the financing for the transactions and other related matters." This case was combined with the Citizens PPFAC Case in ACC Decision No. 66028 filed on 18 December 2002. I was an Intervenor and Party.

[4] This case was before the ACC "in the matter of the reorganization of the UniSource Energy Corporation." I was an Intervenor and Party.

[5] This re-opened case is before the ACC. I am an Intervenor and Party in the reopened case.

[6] This re-opened case is before the ACC. I am an Intervenor and Party in the reopened case.

also hold an MS degree from the Naval Postgraduate School, in Physical Oceanography for the study of the physics of the ocean with several electrical engineering courses involving underwater acoustics. In addition, I took advanced graduate-level EE courses at the University of Rhode Island involving acoustic array design, and electronic beam forming and steering. A Bachelor of Science Degree and Commission in the United States Navy was awarded by the United States Naval Academy with extra courses in Operations Research/Analysis and the History of Russian Naval Tactics. I am a long-time member of the American Society of Naval Engineers, the premier naval shipbuilding organization. I am a life member of the Naval Academy Alumni Association, the United States Naval Institute, the Navy League, and the Naval Surface Warfare Association and a member of the Armed Forces Communications-Electronics Association and the Naval Submarine League.

See Exhibit A for further details.

Q. Could you explain what you do as a Systems Engineer?

A. A Systems Engineer coordinates, plans, schedules, integrates and manages engineers of various other disciplines. The Systems Engineer is the technical lead or director for projects. The Systems Engineer determines the customer's need and analyzes the requirements, leads and/or writes the system and subsystem technical specifications, prepares and makes trade-off technical and economic (best and cost of ownership values) decisions, manages the entire system development process and leads system and subsystem tests to ensure the system accomplishes the customer's requirements and satisfies the need and requirements within budget and schedule. The integration and synthesis of this discipline use inputs from mechanical, electrical, civil, safety, life-cycle, and human factors engineers; integrated logistics, financial, maintenance, structural, and reliability data, operator and maintenance training development, aerospace, acoustic, computer systems, software, hardware, production, test and test equipment engineers and other specialist disciplines.

As the Systems Engineer for dozens of different and diverse projects summarized in Exhibit A, the Santa Cruz service area gas system is a simple, straightforward system for me to review.

Q. How long have you been interested in the matter in this hearing?

A. In the late summer of 2006, when reading the mail insert with my UNS Gas bill, I learned that a new UNS Gas rate case had been filed. The extraordinary increase in the proposed residential Service Charge from $60 in 2003 to $204 per year seemed unjustifiable, as there have been almost no significant projects in this county during the time span covered. This 340% rate increase turns out to be over 100% per year. Many natural gas ratepayers in

Santa Cruz County are struggling to pay today's gas bills. Most customers are not aware of the proposed increase because few customers read bill inserts. After reviewing the on-line filing, additional areas of concern were included in my Motion to Intervene.

My subsequent, more detailed review seems to indicate that a realistic rate case has not been presented the Commission. The UNS Gas Application has significant flaws in its structure and these will confuse anyone's understanding of what is needed.

Since then, I have been actively interested in this matter.

Part II – Purpose of this Testimony

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

A. The purpose of this testimony is to present the significant concerns with respect to the following areas:

1. The Proposed Significant Service Charge (Part III),
2. Restructured cost including product cost within the Service Charge (Part IV), and
3. Additional transition capital and personnel costs from Citizens to UNS Gas (Part V).

This testimony contains conclusions and recommendations for consideration by the Administrative Law Judge and the Commission.

Q. What is the basis of the recommendations in your testimony?

A. An analysis of the Application shows significant and potential structural rate design flaws resulting in a proposed new rate design that is both unfair and discriminatory to some customer classes in Santa Cruz County.

Part III – The Proposed Significant Service Charge Increase

Q. Why are you concerned with the proposed increase in Service Charge?

A. First, the Service Charge (or Cost of Service) is one of the three major components of a utility bill. The Cost of the Product, in this case, natural gas, is the second component; taxes and miscellaneous regulatory fees are the third. In general, public service companies receive their revenue from the Service Charge. The product costs are in the second part, a "pass through" to the customers in the distribution utility. UNS is a distribution utility, and its revenue for capital and cost of business expenses is separate from the cost of gas delivered to customers. For decades this separation has been observed and is well understood by those who can read and understand their utility bills. Many customers do not understand this process. Mixing these two components will not be beneficial as discussed in Part IV below.

Service Charges for residential customers since 2003 are shown in Table III-1 below:

Table III-1 Service Charge History and Proposed New Service Charge

Dates	Monthly Service Charge	Annual	Company
Prior to August 2003	$ 5.00	**$ 60.00**	Citizens
August 2003 – ~July 2007	$ 7.00	**$ 84.00**	UNS Gas
After July 2007 (if approved in this case)	December – March $ 9.00 April – November $22.00	**$ 204.00**	UNS Gas

The August, 2003 Service Charge was increased by 40% when the company transitioned from Citizens to UNS Gas. At that time there was also a 22% rate increase for cost of natural gas to cover the cost of raising natural gas prices. The **<u>proposed 340% Service Charge increase</u>** over the 3 to 4 years under UNS Gas ownership is not justified or explainable to ANY ratepayer. There has not been that amount of significant capital improvements. In Pignatelli Testimony, he states "we project that the number of UNS Gas customers will increase as much as 5-10% annually." [*Pignatelli Testimony*, 1 at 26] At best, capital costs in a Service Charge based on this kind of growth and increased productivity generally should be less than 30%. Since inflation has been less than 5% each year, when combined to determine Service Cost, using the existing rate structure process (see Part IV), there is absolutely no justification for such a large increase. It also should be remembered that customers needing to be connected for gas service pay for their service lines; therefore most of the capital costs for new service lines are not UNS Gas costs

Q. Using the existing rate structure, what might be a reasonable Service Charge?

A. The seasonal rate scheme, with higher Service Charges in the summer, only benefits selective rate payers, in particular those who have higher usage costs in the winter. Let us look at the benefits and costs of such a scheme as shown in Table III-2 below:

Table III-2, Based on Season, the Full and Summer/Winter Residential Impacts of the Seasonal Service Charge Rate Changes.

Season / Resident	Winter	Spring/Fall	Summer
Full year	Lower Monthly rate to reduce winter bill	Rate adjusted to lower winter bill	Higher Monthly rate reduce winter bill
Summer only	Higher Monthly rate without gas consumed	Rate adjusted without consumption	Higher Monthly rate when gas is consumed
Winter only	Lower Monthly rate to reduce winter bill	Rate adjusted without consumption	Lower Monthly rate without consumed

In Table III-2 we see that some will have higher rates without consumption, some lower rates without consumption, some have adjusting rates without consumption and further changes. This would not reasonable for the winter-only and summer-only residents, a high percentage of the UNS Gas service customers in Santa Cruz County.

In Santa Cruz County, in some neighborhoods, nearly 50% of the residents are winter-only residents. Contrary to the Pignatelli Testimony, not all summer (or winter) homes are "luxury" [*Ib.,* 20 at 26]. Winter only residents, with higher/lower Service Charge in Table III-, are not considered at all.

The factors mentioned in Part IX of the Pignatelli Testimony are extremely detrimental to residents in warmer parts of the UNS Gas service area, in particular Santa Cruz County, which is warmer due to its geographic location. Cost of utilities is an important factor for potential new customers, those considering moving in the area. By deliberately designing a rate structure that goes against the climate reality of southern Arizona is contrary to fair and just treatment of consumers. Suppose I want to live in Snowflake. It is obvious utility bills will be higher there due to its geographic location when compared to Santa Cruz County. Proposing a rate structure to penalize such logic should not even be considered. The higher-use customers are not being used "to subsidize the true cost of serving lower-usage customers." [*Ib.,* 20 at 21] The "higher-use" customers should know they live in colder areas. It was their decision to live there and it should not be paid for by those in warmer parts of our state.

Mr. Pignatelli testified, that "higher than expected usage can increase margin revenues beyond anticipated levels, while lower usage can result in an under-recovery of the utility's costs." [*Ib.* 20 at 5] It is not the Commission's responsibility to manage risk for seasonal variations. Weather temperature risk factors are foreseen, expected, and predicable; good management always takes all factors into account when making decisions. Any rate structure, based on passing the responsibility of risk management of seasonal variations to the Commission should not be considered. In other hearings, I have asked his employees if there were a meteorologist on staff at UniSource. The response has been that there is not been one, but that staff did check the Internet for weather information. Without such expertise used daily for risk management decisions, this corporation will continue to be ill-informed about the operational environment in both short- and long-term planning and decision making.

Also, UNS Gas is proposing that the Commission "approve" UNS Gas' Price Stabilization Policy. This is an internal policy, under internal control. It could be modified at any time by the company; no assurance that this will not be the case is given. Exhibit DGH-1 is for 2006 thus is already outdated by a newer 2007 version. Their Application needs updating. The mandatory compliance verb "shall" is used once in the entire document. Exhibit DGH-1 is vague, for example, in paragraph 2.1 on page 3, this pricing strategy is "used by UNS to stabilize gas prices." Does this imply that UNS Gas purchases natural gas for UniSource Energy (UNS) including Tucson Electric and Power Company (TEP) and UNS Electricity or just for UNS Gas? This could be more significant. Without mandatory provisions, an internal practice such as this is unsatisfactory and definitely should not replace the detailed audits accomplished by ACC Staff and RUCO in all rate proceedings. In fact, suggesting that this weak document replace the prudency audit has no merit. If the Commission allows this document to replace their reviews, liability for any poor decisions or losses based on this practice could cause significant liabilities to the Commission instead of shareholders. Shareholders are the ones who should absorb losses.

Most of the testimony presented in this Application is from TEP personnel, perhaps on some kind of "loan" to a separate, independent public service company, regulated by the Commission. Without very close accounting, such as strict time card practices, separation of which UNS subsidiary "pays" for services from another is challenging at the least. In my decades of Department of Defense contracting work, this issue is always at the forefront of management to manage and control. This concern is also discussed in Part IV below.

Part IV – Restructured Cost Structure including Product Cost in the Service Charge

Q. What are your concerns about the proposed Rate Structure?

A. The proposed rate structure combines both natural gas transmission and distribution cost and the cost of service. The mixing of product and cost of service costs is contrary to prior business practices in this industry but more significant is the loss of traceability to product cost and to service cost, a key element of this rate case If traceability is lost or muddled, future rate cases will not be able to track costs to either rates or expenses of this regulated public service company.

For a practicable example, I can see from my window the El Paso Natural Gas (EPNG) line easement and the interconnecting substation to the local UNS Gas main and service lines for my home. EPNG is paid by UNS Gas to supply natural gas to the substation for local distribution. When natural gas is consumed it is reasonable to pay EPNG transmission and distribution charges for the volume of natural gas delivered to my home. Conversely, it is not reasonable, fair or just to charge for transporting gas via EPNG's line when I use no natural gas. It is false charging to require one to pay EPNG transportation and distribution volumetric charges when a customer does not use any natural gas. The combining of any transportation (or volumetric charges) that are not absolutely fixed UNS Gas infrastructure expenses in the "fixed" part of the billing mixes and muddles the entire billing process which then will not be objective, auditable, or traceable.

Continuing in Part IX of the Pignatelli Testimony, these proposed policies confirm the above. See page 20 for non-explicit expressions such as "more closely", "very significantly", "typically", "<u>most</u> transmission and distribution costs", etc. Prudent cost of management and operations of its distribution and transmission system is a reimbursable fixed cost of service expense. The cost of transmission and distribution of natural gas is a volumetric expense and is related to product usage. Please maintain a clear, objective separation between service and product costs.

Q. Using the extreme case, why should any customer pay for the actual transmission of natural gas, when they are not using any?

A. The proposed rate structure charges customer for more than the value of the infrastructure required to deliver the product. This is unfair to the customer. The only benefit of such an approach would be to UNS. This approach would destroy any ability to protect future customer's rights in future rate cases.

Keeping Cost of Service independent of Cost of Product is a critical accounting and ratemaking concept being clearly violated by this proposal. One flaw in this conceptual approach is that without demand, there are minimal operational transmission and distribution costs, thus there is a relationship between volumetric demand and product cost.

Using the proposed mechanism, a Throughput Adjustment Mechanism (TAM), UNS Electric states that the TAM "will allow UNS Gas to implement the comprehensive energy conservation program proposed in this filing." This statement is without merit. Customers notice higher and lower bills and when too high, conservation is the easiest way to lower bills. Lowering the thermostat, full loads in gas clothes dryers, less hot water usage are all understood. UNS Gas can't expect customers to understand TAM or anything equivalent. They understand "cost of service" and "cost of natural gas" and the present billing makes that distinction; however the PGA and surcharges are not very clear. Mr. Voge's Testimony also failed to resolve these difficulties.

The existing residential bill has three volumetric charges, Distribution Margin, PGA Cost and PGA Surcharge.

The Distribution Margin should include the cost of transportation for the basic amount of natural gas and be based usage. Customers can understand this charge. Several data requests were submitted on this issue which maybe resolved in later filings.

The Adjustment charge, as requested in this application, will need to be redefined in order to account for price swings. No evidence presented shows how TAM reduces swings or the second adjustment, the PGA Surcharge.

The proposed "product cost" process is not satisfactory nor will it be understood by customers. Without customer understanding and support, there will be complaints.

Part V – Additional Transition Capital and Personnel Cost from Citizens to UNS Gas ownership and continued operations (Third Issue)

Q. Why are you concerned about transition and personnel costs?

A. There are two concerns. The first is the Pignatelli Testimony reference to the customer benefits due to the "negative acquisition premium" [*Ib.,* 16 at 20] needs to be watched closely as the ACC Staff and RUCO review the accounting details associated with this rate case to ensure these benefits are not lost.

The second "transition" concern is related to personnel costs and accounting. As pointed out above, most of the testimony provided in this case is from Tucson Electric and Power Company (TEP) employees, a separate public service utility company, regulated by the Commission. The TEP employees have worked for UNS Gas, another, separate, and independent public service utility, with its own and separate accounts. Tracking charges to UNS Gas from TEP to ensure that the correct labor and other associated charges are include for each of this two companies is a major challenge, made even complicated by the two holding companies, UNS Energy and UniSource Energy Services (UES) and the third public service company UNS Electricity, Inc. In my decades of DoD contractor experiences, where such costs are accurately accounted, management of this process is very challenging, strict, and requires continual monitoring of daily time cards (or equivalent), specific tasks being charged to the appropriate entity by personnel authorized to charge to that account, budget plans per task to prevent overruns, and sorting associated overhead, General and Administrative (G&A), and profits among different organizations.

Several open data requests have been submitted to help clarify this issue in future filings. If the personnel labor accounting practices are as weak at the Price Stabilization Policy, this issue requires further and detailed review by ACC Staff and RUCO. The wrong public service company could be charged or, worse yet, charges may be made to both, three or more organizations. Obviously ratepayers would be the ultimate losers.

Part VI – Conclusions

Q. Do you have any conclusions?

A. Yes, but these initial conclusions might change as responses to data requests are received.

Q. Have you come to any conclusions about the Increased Service Charge?

A. 1. The proposed Service Charge increase is clearly too high.

2. The season choice should not be mandatory. Only an "annual" rate should be approved by the Commission with the Company authorized to charge higher "summer" or "winter" or "level" or "actual" monthly charges. The result is the same; let the customers chose how they prefer to pay the bill.
3. Mandated seasonal charges discriminate against a large number of customers in warmer areas to benefit others who choose to live where it is colder.
4. UNS Gas needs support from a qualified utility meteorologist or equivalent.
5. UNS Gas takes all risks due to hot and cold seasons, not the ratepayer.
6. The proposed internal "UNS Gas Price Stabilization Policy" is under total UNS Gas control; therefore, any Commission approval might incur inappropriate liability to the Commission. Further, significant clarification as to the applicability of this policy is missing.
7. Such a policy should not be substituted for any ACC and RUCO audits during rate cases.
8. Cross-charging internally within the various UniSource Energy (UNS) entities requires strict auditing to account for labor hours and other charged to other UNS entities,

Q. What are your conclusions about the Restructured Cost Structure?

A. 1. Mixing cost of service and product cost is contrary to best business practices, common sense and will make tracking costs too difficult.

2. The Applicant's proposed rate structure process is not clear, objective or traceable; there are many vague assumptions.
3. Transmission and distribution operational costs are dependent upon volumetric demand.
4. The conceptual process presented is without merit.
5. The proposed rate structure using Throughput Adjusted Mechanism (TAM) is not sound.
6. There is no relationship between TAM and conservation.
7. Distribution Margin needs to be reviewed to account for the operational costs that were proposed as part of Service Cost in the discussion of increased service charge.
8. The TAM does not dampen the swing of natural gas prices.
9. The proposed approach for product cost is unsatisfactory.
10. The use of TAM will make billing costs less comprehensible than the present process.

Q. Do you have any conclusions about Transition and Personnel Cost?

A. 1. The negative acquisition premium from the Citizens Acquisition case must remain intact to protect customer's benefits from that transaction.

2. Cross-charging labor and other costs must be continuously monitored to prevent abuse with severe penalties imposed to ensure compliance.

Part VII – Recommendations

Q. Do you have any recommendations?

A. Yes. Based on the above initial conclusions, the following are recommended in an Amended Application:

1. Reduce the proposed Service Charge to the order of $100 per year or less.
2. Make the seasonal charge differential adjustment voluntary and not compulsory.
3. Remove all discrimination in rates between the Northern and Southern Counties.
4. Remove all seasonal risk from ratepayers.
5. Make major changes to the UNS Gas Price Stability Policy including adding an ACC reasonableness process review.
6. Eliminate any indication that the ACC will approve the UNS Gas Price Stability Policy.
7. Provide proof that "cross-" or "multiple-" labor charging does not exist at all UNS entities.
8. Eliminate any mixing of the cost of service and the cost of product and continue separation of service and product charges.
9. Delete the Throughput Adjusted Mechanism (TAM) concept.
10. Consider using Distribution Margin to include specific, measurable, and defined fixed costs that are NOT related to the volume of natural gas.
11. Revise the PGA and Surcharge eliminating TAM.

In addition, the ACC and RUCO should monitor the negative acquisition premium to ensure the same benefits remain in force when UNS Gas was established, continue the prudency review process, ensure seasonal variation risks are company and not ratepayer risks, and retain separation of cost of service and product cost in the resultant rate structure.

Part VIII – Summary

Q. Would you please summarize your testimony?

A. The recommendations in Part VII show there are major changes required by the Applicant. Without these changes, unfair and unreasonable rates will result for customers. The deliberate discrimination against the warmer, e.g., Santa Cruz, counties is an inappropriate way to lower rates in colder areas. The mixing of cost of service with product costs will make correct accounting impossible. Risks are borne by the company and not the ratepayers. These and other substantive changes are needed and to be expected in updates to this flawed Application.

This application is so confusing that there must be other significant flaws not discussed that require correction as soon as possible.

Unanswered data requests might change this Testimony.

Q. Does this conclude your direct testimony?

A. Yes.

Exhibit A

Resume of Marshall Magruder

Education

MS in Systems Management, University of Southern California, Los Angles, California (1981)
MS in Physical Oceanography, Naval Postgraduate School, Monterey, California (1970)
BS, US Naval Academy, Annapolis, Maryland (1962)

Experience

Over 25 years as Senior Systems Engineer with and an associated contractor, consultant to Raytheon-Hughes in systems engineering, training and naval systems, simulation and modeling in C4I; with over 20 years of service with the US Navy, a total over 40 years experience in this field

- **Large-system development** at all levels
  From pursuit, analysis, winning strategy, Request for Proposal evaluation, proposal management, system requirements analysis, architectures, specifications, design synthesis, trade-off studies, requirements allocation tracking,
  To system, level test planning, deployment, implementation, through sign-off, and
  For technical systems of all complexities.

- **Developed** Antisubmarine Warfare (ASW), Electronic Warfare (EW), Command, Control, Communications, Computers, Intelligence, Surveillance, and Reconnaissance (C4ISR) operational concepts, procedures, and tactical employment.

- **Used, operated, and planned** Navy, Army, Air Force, Coast Guard, Joint systems, world-wide.

- **Coordinated multi-platform employment** from sensor to unit to Battle Force to Theater levels.

- **Qualified systems engineer/manager** for trainers, artillery, Command and Control (C2), countermeasures, for any platform.

- **Specialties:** environmental analysis, documentation, sensor/weapon predictions, C4ISR, Electromagnetic and Emission Control decision criteria.

- **Battle Force/Group Tactical Action Officer** (TAO) on 8 aircraft carriers, TAO Instructor for 4 years, 20 months combat experience.

Recent Positions
at ImagineCBT Inc., ISIS Inc., Raytheon and Hughes Aircraft Company

C4I Architect and **C4I Support Plan Lead** for the Carrier for the 21st Century (CVNX) Task Order.
- Completed *CVX C4I Support Plan, v1.0,* Joint Operational Architecture development for Joint and Naval staff space allocations for CVX (1999) and Joint Command and Control ship (2002).
- Drafted *CVN 77 Electronics System Integrator Statement of Work (SOW)* for WBS Group 400 tasks and IPTs (1999), *Integrated Management Plan*; Royal Navy CVF WBS proposal (2002)

Lead Systems Engineer, Operations Analyst and **Site Survey Leader** for Saudi Arabian Minister of Defense National Operational Command Centers and C4I System (completed August 1997).
- Completed *System Specification, System Description Document, Site Survey, Interface Requirements Documents*

Proposal Technical Volume Manager for the following **winning proposals**:

- Vessel Traffic Service 2000 system, US Coast Guard command center for surface surveillance using radar, visual, communications links. (proposal evaluated A++, won Phase I, Phase II delayed then restructured)
- Anti-submarine Warfare Team Trainer (Device 20A66), an integrated, multi-ship, submarine and aircraft training system for Naval Task Groups. ($56M contract, best technical, lowest cost)
- Electronic Warfare Coordination Module, an Intelligence/EW spectrum planning and management system for Task Force Command Centers. (won Phase I, best technical)

Assistant Program Manager for the Training Effectiveness Subsystem, Device 20A66

- Performance Measurement Subsystem, observed real-time performance of operators, teams, multi-ship and aircraft units during exercises and compared to the standard

Senior Systems Engineer responsible for writing **specifications** in following **proposals**:

- Fire Support Combined Arms Team Trainer (FSCATT) *System Specification*, a US Army artillery multiple cannon and battery training system. (awarded $118M contract, still under contract)
- Warfighter's Simulation 2000 (WARSIM 2000) *System Specification*, a US Army Force XXI Century battalion to theater levels, and training system with actual C4I systems. (won Phase I)
- Tactical Combat Training System, *Exercise Execution Software Requirements Specification* (SRS) for simulation and computer models to run real-time, driving sensors, weapons and links on 35 ships, 100 aircraft and submarines (won Phase I contract, wrote SRS in Phase 2 proposal)

Detailed Descriptions of Experience

The following are more information, arranged chronologically, with dates, duration, position title, program name, followed by accomplishments, and then an overview of the project.

April 2000 to present – ISIS, Inc., primarily as Senior Scientist, Information System Architect, Systems Engineer, Training Systems Analyst and **Requirements Analyst.**

General Accounting Office (GAO) (May 2005 – June 2006), reviewed and prepared training system development and professional engineering services (PES processes and job descriptions for category 69 (training) proposal.

Strategic Services and Support (April 2005-Sept. 2006), attended pre-solicitation conference for the Army Communications-Electronics Command (CECOM), Ft. Monmouth, New Jersey, waiting for formal request for a part of this $19.25 billion program proposal.

Department of Interior Management, Organization and Business Improvement Services (MOBIS) and Professional Engineering Services (PES) proposal analysis (June 2005), prepared a detailed requirements and tasks analysis of the RFP) and proposal plan.

Total Engineering Information Services (TEIS) (Feb. – March, 2005), participated as proposal writer, pink and red team member with another company which is prime for an approximately $12 million, multi-year, contract for the Army Information Systems Engineering Command, Ft. Huachuca, Arizona. Prepared TEIS Risk Management Plan for prime contractor. Presently ISIS is waiting for announcement of selected winners.

Networthiness Certification (Jan. 2005 – Sept. 2006), prepared proposal for the Army Network Command (NETCOM), awaiting RFP to respond for this several million dollar program involving over 3,200 Army computer programs at all Army installations, worldwide. Prepared Quality Control (QC) and Risk Management Plan.

Cryptologic Support and Logistic Analysis (Oct. 2004 – Sept. 2006), prepared proposal for the Army Communications-Electronics Command (CECOM), Ft. Huachuca, Arizona, waiting for formal request for proposal.

Information Warfare Training (2001 - 2005), USAF Small Innovative Business R&D (SBIR) Phase I contract, to determine IW training requirements and measure performance in an intelligence, wargaming system, awaiting possible award for development of an Information Warfare training system for the USAF Information Warfare Aggressor Squadron.

US Army Virtual Proving Ground (2001-2002) - Performed *C4ISR Architecture Framework* development, implementation and documentation using the DoD *C4ISR Architecture Framework, v2.0* and for Operational, Technical and Systems architecture products.

Prepared C4ISR architecture framework proposals for US South Command (USSOUTHCOM) Command Center (2003), DoD Threat Reduction Agency (DTRA) Operational Command Center at an Army Command, Virginia (2002), and Government Enterprise Architecture development for Department of Health and Human Services Command Center (2002) programs.

Raytheon Naval and Maritime Systems, San Diego, California, for various programs, a consultant for ImagineCBT, systems engineer.

April 2001 to June 2005 – C4I Architect, Operations Analyst/Systems Engineer for Minister of Defence (UK) Future Aircraft Carrier (CVF) program, Raytheon Naval and Maritime Ship Systems, San Diego.

Prepared for Raytheon Naval Ship & Integrated Systems (San Diego) proposals in April and June 2003 with Statement of Work (SOW), Data Item Descriptions (DIDs) and CDRLs for Architecture Assessments (Requirements, Testing) for ten functional mission areas, Global Information Grid Evaluations in order for CVF to be interoperable with US forces, and Levels of Information System Interoperability (LISI) using DoD LISI PAID (procedures, applications, infrastructure, data) attributes to determine internal and external interoperability assessments

Prepared proposal and performed contract for Raytheon C3I Systems (Fullerton, CA) for the Joint Command and Control Ship (JCC) *JCC Interoperability Study*, including report drafting and preparation, conference presentations and making recommendations to JCC Program Office for ensuring over 400 tactical, logistic, administrative, C4ISR applications work. (2001-02)

Prepared proposal and performed contract for Raytheon NAMS (San Diego) for *JCC Reconfiguration Study* to determine requirements to most effectively manage command (C4ISR) onboard JCC. (2001-02)

Provided architecture framework proposal inputs and evaluation for US Army Landwarrior III (Future Combat System) for Raytheon C3I Systems (Plano Texas)

Provided C4ISR and engineering analysis and proposal preparation for LHA(R), JCC, CVF and other Raytheon, San Diego ship programs (2000-03)

October 2000 to present (inactive) – MBA Instructor, University of Phoenix, for "Operations Management for Total Quality" and "Managing R&D and Innovation Processes" courses.

Taught these courses in Nogales to Mexican maquilladores managers and in Tucson to Americans managers.

Qualified to teach "Program Management" course.

Plan to qualify as FlexNet (online) Instructor, presently inactive instructor status.

April 1998 to September 2000 – CVNX C4I Architect, **C4I Support Plan Leader** also **Lead Systems Engineer** and **Requirements Analyst** for CVN 77 and CVNX Programs, at Raytheon, San Diego, CA

Performed C4I Support analysis to prepare requirements for the DoD C4I Support Plan. Led several teams to understand the *DoD C4ISR Architecture Framework*, v2.0 and Operational, Technical and Systems architecture products.

Managed team for CVN 77 requirements analysis 3 months to draft and submit plan to NAVSEA (PMS-378) for two customer reviews.

Provided interface to combine CVNX and Joint Command and Control (JCCX) Ship architecture development for NAVSEA (PMS-377), drafted task schedule but funding then not provided.

Proposed an approved Technical Instruction for "Reconfigurable Joint and Naval Staff Space Allocations" in order to start the CVX/JCC *Operational Architecture* and *Mission Essential Tasks* processes – completed early 1999. (3 of 14 proposed were approved for study)

Coordinated the AFCEA "Architecture Implementation Course" at the Raytheon San Diego site.

Created and drafted CVN 77 *Electronic Systems Integrator (ESI) Statement of Work (SOW)* for the CVN 77 ESI role and RFP in Spring 1999.

Provided trade studies and options for performing this task for Newport News Shipbuilding.

Established a draft CVN 77/CVX "Total Ship Systems Engineering (TSSE) Plan for our team.

Implemented the Raytheon and Newport News Shipbuilding *Integrated Product and Process Development* processes to structure IPTs, tasks, and work descriptions.

Provided interoperability inputs to UK Future Aircraft Carrier (CVF) Raytheon Qualification letter.

Participated in establishing teaming arrangements with SPAWAR Systems Center, San Diego.

The CVN 77 is the transition aircraft carrier from the *Nimitz* class, to be commissioned in FY 2008. Two other evolutionary aircraft carriers, CVNX-1 and CVNX-2 are to be commissioned in FY 2013 and FY 2018, respectively. The tenth CVNX is planned for disposal in FY 2111. Overall manning will be reduced up to 1,740 personnel. Up to 12 Joint, Naval, Combined and Coalition staffs may embark up to 1,000 augmentation personnel beyond the present capabilities. CVNX can embark a Joint (Task) Force Commander with command and control systems for Operational-Theater and Tactical (service) levels. The ESI role involves integration of all C4ISR equipment, internal and external communications, navigation, sensors, fire control, weapons, and associated display and processing systems.

January 1998 to present – H&R Block, Tax Advisor Level 3, seasonal tax preparer (annually, January to April 15), AARP Tax Consulting for the Elderly (pro bono) tax preparer, IRS qualified, over 450 hours of H&R Block classroom and CBT training courses.

August 1997 to April 1998 – DD 21 Requirements IPT Lead, Systems Verification and Test IPT Lead, and **Initial Lead Systems Engineer** for the Hughes, then Raytheon, DD 21 Program for NAVSEA, PMS-500 – assigned the C VX Reduced Manning (Automation) Study that led to CVX C4I Support Plan after Raytheon sent "no bid" letter in April 1998.

Provided IPPD plans for all systems engineering functions, including workshop participation, for subsystem to total Ship System levels.

Managed two Integrated Product Teams (IPTs), as additional DD 21 personnel were assigned.

Conducted a weekly VTC with IPTs, issued Agenda, Minutes, and led team meetings.

Attended Risk Management course and recommended Raytheon's Prophet™ risk management software tool for DD 21 and other integration programs.

Provided the initial *DD 21 Total Ship Systems Engineering (TSSE) Plan*.

Coordinated systems engineering modeling and simulation planning.

The Future Surface Combatant of the 21st Century (SC-21) Program consisted of both destroyers and cruisers, with the Land Attack Destroyer (DD 21) to be commissioned in FY2009 and an Air Dominance Cruiser in FY2018. I participated in the program implementation and maintenance of collaborative and synergy with both CVNX and SC-21 programs and the emergent JCC and USCG Deep Water Programs. [SC 21 is DDGX Program]

June 1995 to August 1997 (26 months) – Operations Analyst and **Site Survey Team Leader** also **Naval Operations Analyst** and **Joint Training Analyst,** *C4I System for National Defense Operations Center and Area Command Centers Definition Study* **- completed August 1997.**

Performed pre-contract planning analysis for site survey from battalion to national level.

Managed budget for 3 months deployment for the 12 engineers in Saudi Arabia.

Conducted interviews and briefs with members of all joint Minister of Defense and Aviation (MODA) staff and all armed forces, including schools and topographic commands.

Provided reports, program reviews and TGMIRs for survey and design efforts for the 2 years, including the coordination of all Action Items and Program Management Review Minutes.

Created significant inputs to the *System Description Document, System Specification* as Lead Systems Engineer, emphasized operational concepts including staffing and workstation operator tasks; operations center and support facility layouts; specifications for a transportable operations center (TOC); system-level communications interfaces including ATM, SATCOM, PTT and RF communications; system hardware and software interfaces including JMCIS, TADIL-S and IDL; operator training; selected over 100 formatted messages (using USMTF) for integration, and overall system performance characteristics.
Drafted System Specification for Land Forces Operations Center, deemed excellent by customer.
Prepared *Site Survey Report* and participated in drafting the *Communications Interface Requirements Document*, presented multiple customer briefs.
Only engineer to start and complete this contract (over $10M), most of the others were replaced.
The MODA C4I System will provide 13 operations centers, nation-wide, to form a joint service, C4I system, integrating the four services through 3 command echelons and, for the Land Force will provide their digital command and control system through 4 echelons.

1995 – Systems Engineer, for an AirHawk Concept of Operations.
Drafted a preliminary "*Operations Concept Document (OCD) for the Air HAWK*" system for HMSC, provided a systems approach to integrate the subsystems with the missile, for the Command and Control Division, using the MIL-STD-498(B) DID as a guide.
AirHawk provides an air-launch system capability for the U.K. Tomahawk cruise missile.

1995 (five months) - Lead Systems Requirements Engineer, Warfighters' Simulation 2000 (WARSIM 2000), US Army training system.
Performed system functional requirements analysis for command and control levels from battalion through echelons above corps and Theater-levels
Responsible Engineer for the analysis and writing of the system specification for the entire system in accordance with MIL-STD-498(B) (System Engineering). (Hughes won Phase I)
WARSIM 2000 C4I training system to stimulate all present and emerging Force XXI digital C4I systems with operational data for entire staffs in their Tactical Operations Centers in the field, in classrooms and at the War Colleges. WARSIM 2000 integrates with other joint systems through protocol standardization and object-oriented design features.

1994 – System Requirements Compliance Engineer, Theater Battle Management Core System (TBMCS), US Air Force C4I system.
Ensured compliance with the contract and requirements documents integrating different systems into the TBMCS proposal, including the Global Command and Control System.
Drafted a compliance matrix with 200 pages in the Executive Volume to meet demanding RFP compliance requirements (Proposal vs. IFPP vs. SOW vs. CDRL vs. WBS vs CLIN vs. TRD).
TBMCS is the US Air Force Theater to squadron level C4I system. (Hughes lost)

1994 (seven months) – Proposal Technical Volume Manager for the Vessel Tracking Services 2000 (VTS 2000), US Coast Guard C3 system.
Led the technical and engineering proposal efforts to comply with the RFP and proposal requirements, based on Hughes themes and proposal strategy decisions.
Managed systems, hardware, communications, software, and logistics engineers writing the responsive proposal. (Ten corporate teams bid; Hughes won Phase I with two others including Raytheon, Hughes performed Phase I, Congress delayed Phase II, program later restructured)
VTS interfaces radar, visual surveillance, environmental, and voice communications data with differential Global Positioning System (dGPS) information from automated and human input to enhance safety and commerce on waterways and for major port regions.

1993-1994 (ten months) – Lead Systems Engineer, Fire Support Combined Arms Tactical Trainer (FSCATT), US Army training system.

Team Leader for the requirements analysis, design, and system engineering and proposal efforts.

Drafted and led several pre-RFP System Requirements Reviews for the System Specification.

Developed a technique with Distributed Interactive Simulation (DIS) protocols whereby a thousand or more cannons can perform exercises from multiple sites in same exercise.

FSCATT integrates artillery and fire control with a Forward Observer visual training system, provides Fire Direction Center simulation and stimulation interfaces with Close Combat Team Trainer (CCTT) M1 tank and M2 systems. (Hughes won $118M program, still ongoing)

1990-1991 (20 months) – Systems Requirements Engineer, Tactical Combat Training System (TCTS), US Navy C4I training system.

Led the simulation and modeling, system requirements analysis for all real-time operations for the proposal and Phase I development efforts. (Hughes won Phase I)

Wrote most of the *Exercise Execution CSCI SRS* for real-time system execution software for all simulations and sensor, weapons and platform models (over 100).

TCTS provides a task group training data link for 100 aircraft, 24 ships and submarines, 6 ashore installations and ranges, with real-time targets (to 780). TCTS uses participant "pods" with a data link between platforms; stimulates platform sensors with the real-time targets; maintains data link communications; collects data for feedback and rapid after action reviews. (Hughes team won Phase I, Raytheon Phase II)

1991 - Human Factors SE for Land Warrior 2000 proposal, US Army infantryman C4I system.

Human Factor Engineer for proposal effort for the helmet display overload analysis with computer text and graphic display resolution. Left to lead FSCATT Systems Engineering and Proposal teams.

Land Warrior 2000 system provides infantrymen with an integrated C4I System for an infantry brigade, with computer-driven displays, messages, GPS, and other C2 features. (Hughes won)

1988-1991 (4 years) – Assistant Program Manager for the Training Effectiveness Subsystem, Device 20A66.

Created Performance Measurement Subsystem, used subcontractor to provide analysis, documentation, and design details.

Managed subcontract ($1.2M), conducted subcontractor reviews, wrote SOWs, evaluated products and a subcontractor.

The Performance Measurement Subsystem determines operational performance (real time) for trainees from Admiral to sensor operators and for ship teams, multi-ship and tactical units.

1988-1991 (4 years) – Senior Systems Engineer, Device 20A66.

<u>Lead Systems Engineer</u>, provided significant inputs for models, simulations, communication data link interfaces, user displays, and I/O; consultant to software team as ASW expert.

Designed to real-time Links 4A/11/16 with ships in port and ships/aircraft at sea.

The Device 20A66 trains a Battle Group Commander in a Task Force Command Center (TFCC), staff and subordinate staffs (in 20 ships and submarines and 15 aircraft in 35 mockups using 186 different workstations with 61 large screen displays) to use data links, communications, and good decision making practices.

1986-1988 (1.5 years) – Proposal Technical Volume Manager, Device 20A66.

Evaluated Draft-RFP and System Specification, provided 229 change pages, and was acknowledged to be most significant pre-proposal action by any bidding contractor.

Led pre-proposal, technical design and development effort as the only engineer for 1 year.

Led, as Technical Volume Manager, team of systems, simulation, hardware, courseware, facility, logistics and software engineers in the synthesis and drafting of the 500-page technical volume, with final technical volume cost less than B&P estimate.

After proposal submittal, replied to questions, gave briefs. (Hughes won, beat 2 incumbents)

1987-1988 (6 months) – Proposal Manager, California Law Enforcement Driver Trainer System

Led pre-proposal and proposal team to develop a design for high-technology driver trainer systems for the Peace Officers and Safety Training (POST) Commission. (Hughes won)

Participated during contract, as systems engineer in-charge of design, to verify the POST training objective(s), standard(s) and criteria would be met for the drivers of the system.

1987 (4 months) – Lead Engineer, Advanced Fuels Auxiliaries Test System for USAF

Provided initial engineering requirements analysis leading to joint venture with Allison Gas Turbines to bid this major USAF test system.

Drafted initial System/Subsystem Design Document, the basis for design.

Hughes bid, after I left project; however, USAF declined to award contract.

1986-1987 (3 months) – Proposal Coordinator, USAF LANTIRN training system.

Led proposal compliance review for real-time video and infrared technical requirements using the Hughes RealScene™ 3-dimensional (voxel-based), interactive system instead of the Hughes (formerly Honeywell)-developed, GBU-15 training system.

LANTIRN trainer provides real-time displays of video and IR images to cockpit and weapons systems for F-15, F-16 flight simulators and the AGM-130 missile. (Hughes no-bid)

1985-1986 (9 months) – Senior System Engineer for the Electronic Warfare Coordination Module (EWCM) program with responsibility for the environmental effects design.

Led technical proposal effort, coordinated proposal outline, reviewed storyboards and topics, determined compliance, edited technical volume, and synchronized with other volumes.

Responsible engineer for atmospheric and acoustic effects on propagation and degradation from countermeasures, provided customer briefs and proposal topics.

EWCM provides full spectrum management capabilities for the Electronic Warfare Commander to coordinate operational and intelligence EW information and databases. (Hughes won Phase I, lost Phase II)

1982-1985 (2.5 years) – Systems Engineer for the training subsystem, Device 14A12 ASW Tactical Ship Training System.

Led technical proposal effort for the Performance Measurement and Monitoring training subsystem, sonar modeling and simulation, operator displays, fire control, data links, and sensor, weapon and platform modeling.

Designed PMM subsystem, pushing the state of the art, later implemented in Device 20A66.

All ASW ships and ASW aircraft were simulated in a single-ship, multi-dimensional (anti-air, anti-surface, anti-submarine) environment, as a C2 and sensor operator training system.

Papers

Presented papers to the <u>Industry/Inter-Service</u> <u>Training</u> <u>Systems</u> <u>Conferences</u> (I/ITSC):

"Design Concepts for a Performance Measurement System" [nominated for best paper top 5 of 105]

"A Performance Measurement System Design", based on Device 20A66 results.

Prepared and presented three reports to the <u>National</u> <u>Security</u> <u>Industrial</u> <u>Association</u> (NSIA), ASW Committee, as Vice-Chairman of Training and Interoperability Subcommittee; Study Leader for following Reports:

"Training Commonality for Oceanography and Acoustic Environment Study Results"

"Training Commonality for Detection and Classification Study Results"

"Proposed Standard Sonar Equation for Technical, Tactical, and Training Communities"

Received NSIA <u>Meritorious Award</u> for leading these ASW industry and government studies)

Presented paper to the Hughes Advanced Technology and Studies Group describing the use of "Distributed Interactive Simulation (DIS) Protocols in C4I Systems".

Raytheon and Hughes Aircraft Company Courses

Taught "Introduction to ASW Tactics" course, at Hughes (four times) and for the *Advanced Training Institute* at Naval Underwater Systems Center (New London and Newport RI) 10 times at the Naval Surface Weapons Center (White Oak), Naval Civil Engineering R&D Center (Oxnard), and others.

Attended "C4I Architecture Implementation" (4 days, AFCEA Course), "Risk Management" (3 days), "Front-End of the Business" (1 week), "Systems Engineering" (HITS/HMSC processes), "Global Command and Control Seminars" (APL)

Attended ATEP Courses:
Software Risk Analysis, Software Estimating and Prediction, Database Modeling, Object-Oriented Software Methodologies, Proposal Development, How to Interview Candidates, Microsoft Word, Creating a Web Browser, Netscape User's Courses

Participated in the NSIA Industry War Games at Naval War College (Newport RI) and Marine Corps Command and Development Center (Quantico).

Military Schools

Attended US Naval schools including Destroyer School Department Head Course, Gunnery Officer, Anti-submarine Warfare (ASW) Officer, Communications Security (COMSEC), Naval War College Wargaming Course, and Naval Tactical Data Systems User Courses.

Military Qualifications

Qualified for Command of Destroyer, Tactical Action Officer (Battle Group and Warship), Officer of the Deck (cruiser and destroyer), Ship Command Duty Officer, and Surface Warfare Officer.

Proven Subspecialist (post Master Degree) in Geophysics, Oceanography, and ASW Systems Technology, Board selected (about 10 in each of these subspecialties per year in US Navy).

Significant Military And Operational C4i Experience

Active duty commissioned officer in the US Navy serving in the following assignments (home ported twice with each of the four fleets):

<u>Area ASW Force, Sixth Fleet</u> (CTF 66) as <u>Staff Plans Officer</u> coordinated all surface ships, aircraft carriers, submarines and ASW/EW aircraft in the Sixth Fleet area on a daily basis; conducted operational ASW with real targets; coordinated (simulated) daily submarine, surface ship and air-launched anti-ship Harpoon attacks on targets. (Awarded Meritorious Service Medal for highest Fleet-level ASW performance ever)

<u>Fleet ASW Training Center</u>, Pacific Fleet, the lead Coordinated ASW Tactics Instructor and Staff Oceanographer, and at sea as an Anti-Submarine Warfare Commander Instructor and ASWC Watch Officer during Fleet Exercises, augmenting Destroyer Squadron staffs. Also taught coordinated ASW tactics at Fleet Combat Training Center (Point Loma) as a guest instructor to TAO classes for three years.

<u>Commander Carrier Group Three</u>, as staff <u>ASW Surface Operations</u> and <u>Geophysics/ Environment Officer</u>, deployed twice to Western Pacific and Indian Ocean; planned and conducted RIMPAC 77 with Japan, Australia, New Zealand, and Canadian ships, 3 aircraft carriers, 7 submarines and over 150 aircraft; planned Persian Gulf CENTO MIDLINK-77 with UK, Iran and Pakistan; qualified as Battle Force TAO on 5 different aircraft carriers.

<u>Naval Surface Warfare Officers Schools Command</u>/<u>Naval Destroyer School</u> as the <u>ASW Tactics</u> and <u>TAO Instructor</u> for Prospective COs, XOs, Department Heads and Free World Navies Courses for mid-grade officers from over 30 countries; co-developed Naval Tactical Analysis Wargame and used it to evaluate tactical concepts including Harpoon anti-ship tactical development; used ASW team and sonar trainers for exercises; trainers for anti-PT boat interactive team exercises; taught anti-submarine/anti-surface warfare tactics, EW, communications, and EMCON decision making classes. Taught surface ship ASW at Submarine School was a guest instructor at the

Naval War College and used the War College wargaming facilities to evaluate new systems and ship classes being designed by NAVSEA. (Awarded Navy Commendation Medal with Gold Star)

Commander Cruiser-Destroyer Flotilla Ten, as ASW Plans Officer, deployed to Sixth Fleet, embarked on 3 aircraft carriers and 2 cruisers including USS *Albany*. Planned and executed many Sixth Fleet and NATO exercises and a CENTO air defense exercise. Engaged in more than 50 Soviet bomber over-flights of the Battle Group, 100% successfully intercepted by fighters and missile lock –on prior to 100 miles from the aircraft carrier. (Awarded Meritorious Unit Commendation for validating anti-SSBN tactics and developing SSN direct support procedures)

USS *Hollister* (DD788), Operations Officer, deployed for 2 years, 19 months of consecutive combat operations off Vietnam in the Seventh Fleet, provided naval gunfire support (over 28,000 5/38 rounds), maritime surveillance, SAR, *Gemini VIII* NASA space craft rescue ship, and EW intelligence gathering and Korean operations. (Awarded Secretary of Navy Unit Commendation, Navy Commendation Medal with Combat "V")

USS *Robert L. Wilson* (DD748), ASW Officer, deployed to Sixth Fleet for ASW operations, UN rescue ship off Cyprus, NATO exercises, *Gemini IV* NASA space craft rescue ship, participated in the Dominican Republic operations. (Armed Forces Expedition Service Medal)

USS *Springfield* (CLG7), Main Battery Fire Control Officer and Missile Fire Control Officer, deployed in the Sixth Fleet Flagship, home ported in Villefranche-sur-Mer, France.

State of Arizona, Industry Association, Company, and Military Awards

Arizona Secretary of State "Arizona Golden Rule Citizen Certificate" and plaque from Janice K. Brewer, Secretary of State, for "exemplifying the spirit of the Golden Rule daily: "Treat others as you would like to be treated", nominated by former Santa Cruz County Supervisor Ron Morriss, for his work as a voluntary Energy Commissioner and his work for the county before the Arizona Corporation Commission. (2004)

National Security Industrial Association. (NSIA) Anti-Submarine Warfare Committee, Meritorious Award from the NSIA President, Admiral Hogg USN (Ret.), for leading several ASW training industry and government studies. (1992)

Merit Awards. Raytheon and Hughes, four times, for achievement and excellence in performance.

Military Awards include Meritorious Service Medal, Naval Commendation Medal with Combat "V" and Gold Star, Navy Unit Commendation, Navy Meritorious Unit Commendation, National Defense Medal, Armed Forces Expeditionary Medal (Dominican Republic), Vietnam Service Medal with three Bronze Stars, Vietnam Campaign Medal with "1960-", Overseas Service Ribbon (Italy).

Security Clearance

Secret (have held higher), last updated 2005, at ISIS, Inc.

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BEFORE THE ARIZONA CORPORATION COMMISSION

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** **Notice of Filing of** **Surrebuttal Testimony of Marshall Magruder, Intervenor** **4 April 2007**
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**

As directed in the Procedural Order of 8 September 2006, modified on 10 January 2007 and 15 February 2007, the Surrebuttal Testimony of Marshall Magruder is submitted to all Parties as of this date.

Respectfully submitted on this 4th day of April 2007 to all parties.

MARSHALL MAGRUDER

By ______________________________

Marshall Magruder

EXHIBIT
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Magruder 7
admitted

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SURREBUTTAL TESTIMONY

OF

MARSHALL MAGRUDER

April 4, 2007

In

ACC Docket No. G-04204A-06-0463
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,

and

ACC Docket No. G-04204A-06-0013
In the Matter of the Application of UNS Gas, Inc. to Review and Revise its Purchased Gas Adjustor

and

ACC Docket No. G-04204A-05-0831
In the Matter of the Inquiry into Prudence of the Gas Procurement Practices of UNS Gas, Inc.

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Surrebuttal Testimony by Marshall Magruder

SURREBUTTAL TESTIMONY BY MARSHALL MAGRUDER

Part I – Background and Key Issues

1.1 Background.

Q. What has been your involvement in this case to date?

A. On 10 January 2007, my Motion to Intervene of 16 November 2006 was approved and the Magruder Direct Testimony filed on 7 February 2007. Two sets of Data Requests were submitted to the Applicant. The first's data response was too late for the Direct Testimony and the response to the second set were received just prior to this Surrebuttal Testimony.

Q. How did the Applicants respond to your Direct Testimony?

A. No direct responses to my Direct Testimony[1] were in the Applicant's Rebuttal; however, in a reply to my second Data Request Set, the applicants indicated their rebuttal testimonies also pertained to mine and that the applicant's Rejoinder Testimony should address many the concerns in my Direct Testimony and, I would expect, issues in this Surrebuttal Testimony.

1.2 Key Concerns.

Q. Can you summarize the concerns in your Direct Testimony?

A. Yes, the following are some of the key concerns expressed in my Direct Testimony and expanded herein:

1. Residential Service (or customer) Charges to vary by season in 2.1 below.
2. Residential Service (or customer) Charge increases in 2.2 below.
3. Increased rates by Adding a Throughput Additional Mechanism (TAM) to shift some cost volumetric cost to the Service Charge in 2.3 below.
4. Usage charges in TAM when not using gas in 2.4 below
5. Internal UNS Gas "Price Stabilization Policy" to be adopted by the ACC to replace Prudency Purchase Audits for future rate cases in 2.5 below.

Q. Will you respond to ACAA's Direct Testimony and First Set Data Request Responses?

A. Yes. The Arizona Community Action Association's (ACAA) excellent Testimony and Data Request Response was located on the ACC website. The discussions in this Surrebutal Testimony, integrate ACAA's Testimony and its Response to UNS Gas' First Data Request

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[1] Direct Testimony by Marshall Magruder, dated 6 February 2007, hereafter "Magruder T." followed by page number and lines, when appropriate.

and concerns. Upon review of the ACAA Testimony; the following additional key concern was identified.

6. Changes in Past Due, Penalty, Suspension, Notice of Termination Dates after Billing in 2.6 below.

Q. Have you identified additional concerns in the Direct Testimony by the ACC Staff and RUCO?

A. Yes. These additional issues, from the Direct Testimonies of other Intervenors, pose additional concerts that have resulted in my response and are summarized as below: and numbered sequentially with those in my Direct Testimony, and summarized in Table 1 below of UNS Gas proposals in their Application:

7. Deletion of base cost of gas and only uses PGA for gas prices.
8. Change PGA bandwidth and then eliminate.
9. Recommended costs of natural gas at $**0.1862**/therm (with higher Service Charge) compared to the present $**0.3004**/therm.
10. Citizens Acquisition Adjustment: amortized charges.
11. Construction Work in Progress (CWIP) into base rate and CWIP property taxes.
12. Rate base expenses for GIS
13. Rate base working capital expenses.
14. Fleet fuel expenses with "early 2006" fuel prices.
15. Growth percentages being used instead of actual numbers.
16. Corporate expenses for the unsuccessful KKR, et al, acquisition.
18. Out of Test year charges that were added to base rate expenses.
19. Customer service cost increases by use of the TEP Call Center.

Q. Are their additional concerns that will be not be included in this Surrebutal Testimony.

A. The Applicants Rebuttal Testimony has resulted in the identification of additional concerns, in particular the proposed Demand Side Management (DSM) Plan, which was a Supplemental Exhibit to the Rebuttal Testimony of UNS Gas' Denise Smith.[2] Since this filing is for "informational purposes" it will not be reviewed herein as oral questions during the hearings should be all that is needed to respond to my concerns. Mostly, these concerns are about the limited approach being established and the lack of more programs, actions by the Company, and additional DSM coordination efforts.

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[2] "Supplemental Exhibit to the Rebuttal Testimony of Denise Smith," dated 23 March 2007, as Exhibit DAS-3, hereafter "UNSG-DSmith, SR., Exhibit DAS-3."

1.3 Organization of this Surrebuttal Testimony.

Q. How will your Surrebuttal Testimony be organized?

A. Each of the above key concerns will be presented and discussed in terms of

(1) Direct Testimony and proposals by the Applicant

(2) Direct Testimony by Intervenors, including

(a) RUCO,

(b) ACC Staff,

(c) ACAA, and

(d) Marshall Magruder

(3) Rebuttal Testimony by the Applicant to these Direct Testimonies.

(4) Recommendations for resolution of these concerns in this Surrebutal Testimony.

Q. Can you briefly summarize the differences between the Direct Testimony by the Applicant and Direct Testimony of Intervenors?

A. The Table below, in summary form, shows the results that are provided below (using the same numbers as above).

Table 1 – Areas of Concerned Discussed in Various Testimonies.

UNS Gas Direct Testimony Proposal Issue of Concern (numbered)	ACC Staff Testimony Response	RUCO Testimony Response	Magruder Testimony Response
Key Areas of Concern – Discussed in Part II			
1. Residential Service Charge to vary by season (Dec-Mar, Apr-Nov). Design rate structure so "warmer" counties (southern) cover costs in "colder" counties.	Seasonal cost differential was **not recommended**	**Not recommended,** levelized billing exists, seasonal cost differential **not recommended.**	**Not recommended** as unfair, unreasonable, inappropriate. Seasonal rates could be voluntary, not mandatory
2. Increase Residential Service Charge from $**84** per year to $**204** per year (Dec-Mar @ $**20**/mon, Apr-Oct @ $**11**/mon)	Recommended an annual $**102** Service Charge (raises from **$7.00** per month to **$8.50**)	Recommended $**8.13** per month ($**97.56** per year)	Less than $**100** per year (**<$8.33**) was recommended.
3. Increase rates by adding a Throughput Adjusted Mechanism TAM surcharge to shift some cost of natural gas to the Service Charge.	TAM process to protect company was **not recommended** due to being extremely unfair to consumers	**Recommend TAM be denied**; it increases rates for lowest income users, reduces revenue recovery risk to zero	TAM was **not recommended**, suggested using professional meteorologist
4. Charges for gas usage when not using gas (part of TAM)	**Not recommended**	**Not recommended**	**Not recommended**

Table 1 – Areas of Concerned Discussed in Various Testimonies.

UNS Gas Direct Testimony Proposal Issue of Concern (numbered)	ACC Staff Testimony Response	RUCO Testimony Response	Magruder Testimony Response
Key Areas of Concern – Discussed in Part II			
5. Adopt an internal UNS Gas "Price Stability Policy" and the ACC use it instead of prudency of purchases audit.	**Not recommended** to be adopted as prudent due to safe harbor and inability to follow market changes, Policy was not fully followed, only 20 purchases, most were higher than market.	**Not recommended.**	**Not recommended**, high liabilities for ACC if adopted, flawed policy as written
6. Change from **15** to **10** days before Late Fee is charged and Past Due to Cut-off from **30** to **15** days	**Recommended approval** after a six-month transition period	**NOT RECOMMENDED**	Not mentioned
Other Areas of Concern not discussed in Part II			
7. Delete basic cost of gas, use only PGA for gas prices	Agreed	Agree	Recommend a major revision to the PGA process.
8. Change PGA bandwidth and then eliminate	Need to check	Recommend twice BW do not delete	Not mentioned
9. Recommended costs of natural gas at $**0.1862**/therm (+higher SC) was $**0.3004**/therm	Residential at $**0.3217**/therm (+3.31% or $3.36 per month)	Residential at $**0.2892**/therm	Company always gets paid for gas costs, not discussed in detail
10. Citizens Acquisition Adjustment amortized ($248,000) of $30,7 million permanent reduction	Not located	Amortize not approved always **deny** ($248,000) (rate base adjustment #3), RBA #3	Warning in Part V that this adjustment must be watched closely to ensure the acquisition customer benefits are not lost.
11. Construction Work in Progress included in base rate and CWIP property taxes	Staff adjustment B-1 **remove** $7,189,000 from rate base, C-4 **reduce** expense by $363,150	**Delete** $7,189,000 as it was not used, delete $166,000 tax, RBA #4, OA #18	Not mentioned
12. Rate base expenses for GIS and amortization for deferred GIS cost	Staff adjustment B-2 **remove** $897,068 from rate base, C-5 **delete** $299,023	**Delete** $897,000 overcharge, RBA #5, remove $299,023 Operating Adjustment #12 (OA #12)	Not mentioned
13. Rate base working capital expenses	Staff adjustment B-3 **increase** rate base by $771,000.	**Add** $1.2 million (error), RBA #6	Not mentioned
14. Accumulated deferred Income Tax (ADIT)	Staff adjustment B-4 **increase** rate base by $195,336.	**Increased** expenses by $1,830,390, OA #22	Not mentioned.
15. Revenue Animalization	Staff adjustment C-1 **add** $102,433 more revenue	**Add** $110,006, OA #15	Not mentioned

Table 1 – Areas of Concerned Discussed in Various Testimonies.

UNS Gas Direct Testimony Proposal Issue of Concern (numbered)	ACC Staff Testimony Response	RUCO Testimony Response	Magruder Testimony Response
Key Areas of Concern – Discussed in Part II			
16. Weather Normalization	Staff adjustment C-2 **add** $1,962 to revenue	Not located	Not mentioned
17. Bad Debt Expense	Staff adjustment C-3 **increase** expense by $1,263	Not located	Not mentioned
18. Incentive Compensation and SERP	Staff adjustment C-6 **reduce** O&M expenses by $262,223	**Delete** $278,848, OA #2; SERP **decrease** $93,075, OA #11	Not mentioned
19. Emergency Bill Assistance Expense	Staff adjustment C-7 **shifted** $21,600 to op expenses from DSM	Not located	Not mentioned
20. Remove Nonrecurring Severance Payment Expenses	Staff adjustment C-8 removed $52,288 from **operating** expense	Not located	Not mentioned
21 Overtime Payroll Expenses	Staff adjustment C-9 **reduced** by $123, 010	Not located	Not mentioned
22. Payroll Tax expenses	Staff adjustment C-10 **reduced** by $13,356	Not located	Not mentioned
23. Nonrecurring FERC Rate Case Legal Expenses	Staff adjustment C-11 **reduced** by $311,051	**Delete** $311,051 as already recovered, OA #20	Not mentioned
24. Property Tax Expense	Staff adjustment C-12 **reduced** property tax by $80,290	**Decrease** $309,309, OA #7	Not mentioned
25. Worker's Compensation Expense	Staff adjustment C-13, **rejected** $34,234 as unjustified.	**Delete** $34,234, OA #1	Not mentioned
26. Membership and Industry Association Dues	Staff adjustment C-14 **removed** $26,868	**Decrease** $1,523, OA #9	Not mentioned
27. Fleet fuel expenses used early 2006 fuel prices	Staff adjustment C-15 reduced $52,439	**Delete** $67,000 overcharge, OA #17	Not mentioned
28 Postage Expense	Staff adjustment C-16 **increased** by $115,095	**Decrease** $153,379, OA #4	Not mentioned
29. Irate Case Expense	Not located	**Decrease** $116,333, OA #8	Not mentioned
30. Uses growth percentages instead of actual numbers	Not located	**Add** $110,000 to revenues	Not mentioned
31. Included corporate expenses for KKR acquisition	Not located	Replace $130.000 with $13,000 (error), OA #16	Not mentioned
32. Out of Test year charges to base expenses	Not located	**Delete** 3 invoices for $21,000	Not mentioned
33. Increase customer service costs from $18,000 to $76,000 per month at TEP call center	Not located	**Delete** $727,000 as services are same as under Citizens, OA #5	Not mentioned

Table 1 – Areas of Concerned Discussed in Various Testimonies.

UNS Gas Direct Testimony Proposal Issue of Concern (numbered)	ACC Staff Testimony Response	RUCO Testimony Response	Magruder Testimony Response
Key Areas of Concern – Discussed in Part II			
34. Out of Pocket Expenses	Not located	**Decrease** $21,120, OA #19	Not mentioned
35. Non-Recurring/Atypical Expenses	Not located	**Decrease** $2,584	Not mentioned
36. Depreciation Expenses	Not located	**Decrease** $324,083, OA #4	Not mentioned
37. Disallowance of Inappropriate and/or Unnecessary Expenses	Not located	**Deny** #233,347, OA #6	Not mentioned

1.4 Minor Errata to the Direct Testimony.

Q, Did you have any minor errors in your Direct Testimony that you would want to correct?

A. Yes. There as a minor error.

a. In the Table III-1, the proposed 'winter' Service charge in the second column, last line should have been "$21.00" instead of "$22.00". The annual Service Charge proposed by UNS Gas at $204 per year is correct. This table has the proposed rates from the customer flyer, while the Voge Testimony stated $11.00 for December-March and $20 for April to November.[3] Again, the annual Service Charge is correct. This table has been corrected, updated, and expanded and now is Table 2 in this surrebuttal testimony.

[3] Direct Testimony of Tobin L. Voge on Behalf of UNS Gas, Inc., of 13 July 2006, page 10 at 7 to 9, hereafter "UNS-Voge T.".

Part II – Response for Each Area of Concern.

2.1 Residential Service Charge to Vary by Season.

UNS Gas has proposed to raise summer rates and lower winter rates so that those in colder climates can stop subsidizing those who live in desert climates. This winter/summer rate structure philosophy is a discriminatory concern.

(a) Direct Testimony and Proposal by the Applicant

UNS Gas proposed seasonal residential Service Charge rates are mandated to vary by season. During the months of December to March the Service Charge will be $11.00 per month and during April to November raised to$20.00 per month.[4] UNS Gas' Voge stated

> "I recognize that customers in the warmer climates have grown accustomed to having their usage more steeply subsidized by customers in cold climates. Therefore, we have proposed setting the residential customer charge at $20.00 in the months of April through November and reducing that charge to $11.00 in the four remaining winter months. This would help levelize bills across all 12 months, allowing customers to more easily budget for their bills. Customers in colder regions also would benefit from a lower customer charge during months when the commodity portions of their bulls pose the largest problem."[5]

Further, UNS Gas Testimony stated

> "the average residential customer pays an annual margin of $292, $133 more than the $159 paid by the average residential customer in Lake Havasu... '[T]he Flagstaff customer is contributing a larger share of the cost."[6]

Mr. Voge stated that

> "[C]ross subsidization that occurs when usage within customer classes varies significantly based on geography and climate."[7]

(b) Direct Testimony by Intervenors, including RUCO, ACC Staff, ACAA, and Magruder

(1) RUCO stated that any seasonal rates could be voluntary, not mandatory. Ms Diez stated that the proposed Winter/Summer rate structure "

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[4] It should be noted that the August 2006 "billing insert" about this rate case sent to customers, stated $9.00 per month for the four winter months of December through March and $21.00 per month for the other eight months from April through November. The annual totals for both are the same at $204 or an average of $17.00 per month. The present rate is $7.00 per month, for an increase from $84.00 per year to the proposed $204.00 per year, an increase of 143% since the last Service Charge increase in August 2003 when the Service Charge was $5.00 per month or $60.00 per year and now $204.00 per year. Thus, from August 2003 to August 2007, the Service Charge will have been **increased 308% or 77% per year.** [emphasis added]

[5] UNSG-Voge T. 10 at 5 to 12"

[6] *Ibid,* 8 at 16 to 20.

[7] *Ibid.* 7 at 11 to 13.

"This aspect of he Company-proposed rate design further acerbates the perverse price signal that results from nearly doubling the percentage fixed revenue and decreasing the commodity charge.... The higher summer fixed charges will further flatten any price signal possible from the Company's rate design by equalizing summer and winter bills. UNS Gas already offers a levelized billing program and RUCO believes the choice of whether a customer prefers a levelized program should be left with the customer and UNS Gas should concentrate greater efforts to ensure that customers are aware of the availability and advantages of the levelized bill option.[8]" [Underlining added for emphasis.]

Further, RUCO recommended

"eliminate the Company-proposed summer and winter rate structure differential."[9]

(2) ACC Staff did not recommend seasonal rates, for example, Mr. Steven Ruback stated,

"The composite residential charge is $17.00 a month; this is a 143% increase the existing Residential charge of $7,00. The Commission should not accept the Company's proposals to increase the customer charges as UNS has requested, or to create a seasonal charge. The composite residential charge of $17.00 violates the basic rate design criterion of gradualism. The seasonal customer charges are also not appropriate because customer costs included in the customer charge do not change by season."[10]

Mr. Ruback recommended

"UNS proposed rate design process to recover more of its costs from higher fixed charges. I recommend that the rates proposed by UNS' be rejected."[11]

(3) ACAA stated:

"As to the question of whether ACC agrees that the proposed rate design avoids having customers in colder climates subsidize those in warmer climates, we have not undertaken that analysis in this case except in the context of large versus lower consumer of gas."[12]

The below ACAA statement shows all seasons are important to ratepayers:

"[U]tility bill assistance is the only resource available for a family to stay warm in the winter and cool in the summer."[13]

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[8] Direct Testimony of Marylee Diaz Cortez on Behalf of the Residential Utility Consumer Office, dated 9 February 2007, page 29 at 19 to page 30 at 6, hereafter "RUCO-Diaz-Cortez T.".
[9] *Ibid.* 33 at 19 and 20.
[10] Direct Testimony of Steven W. Ruback on Behalf of the Arizona Corporation Commission Utilities Division Staff, dated 23 February 2007, hereafter "ACC-Ruback T.".
[11] ACC-Ruback T. page [iii], at Executive Summary, first numbered paragraph.
[12] Arizona Community Action Association's Response to UNS, Gas, Inc's First Set of Data Requests, dated 27 February 2997, fourth page.
[13] Direct Testimony of Arizona Community Action Association. by Miquelle Scheier, dated 8 February 2007, page 7, third paragraph, hereafter "ACAA-Scheier T. "

(4) Marshall Magruder stated seasonal rates could be voluntary and the negative impacts of <u>mandatory</u> summer/winter rate differences, as only "those who have higher usage costs in the winter"[14] will benefit, thus the proposed rates discriminate against a selective group of ratepayers and those using energy efficiency measures. He also stated:

> "The factors mentioned in Part IX of the Pignatelli Testimony are extremely detrimental to residents in warmer parts of the UNS Gas service area, in particular Santa Cruz County, which is warmer due to its geographic location. Cost of utilities is an important factor for potential new customers, those considering moving in the area. By deliberately designing a rate structure that goes against the climate reality of southern Arizona is contrary to fair and just treatment of consumers. Suppose I want to live in Snowflake. It is obvious utility bills will be higher there due to its geographic location when compared to Santa Cruz County. Proposing a rate structure to penalize such logic should not even be considered."[15]

UNS Gas has a voluntary "level" rate plan for all residential ratepayers, thus a second "levelization" function fails to send a pricing signal to high-usage customers. He concluded

> "The season choice should not be mandatory. Only an "annual" rate should be approved by the Commission with the Company authorized to charge higher "summer" or "winter" or "level" or "actual" monthly charges. The result is the same; let the customers chose how they prefer to pay the bill... Mandated seasonal charges discriminate against a large number of customers in warmer areas to benefit other who choose to live where it is colder."[16]

(c) <u>Rebuttal Testimony by the Applicant</u>.

Mr. Pignatelli still wants to discriminate against his customers who chose to live in warmer climates by stating

> "[U]nder UNS Gas' current rate design, cold-weather customers – particularly high-use customers – subsidize warm-weather customers" show again this policy... the company's proposal seasonal rates so that cold-weather customers would not subsidize warm-weather customers to the degree that subsidization is now occurring now. We also want to send significantly more accurate price signals through rates.[17]"

UNS Gas Rebuttal Testimony by Mr. Erdwurn[18] missed the Magruder comments on the winter versus summer rates and continues Mr. Voge rate design philosophy:

> "[B]ecause the [UNS Gas] rate design proposals made by the company were aimed at helping reduce a grossly unfair subsidy to customer in low-use, desert

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[14] Magruder T. 9 at 22.
[15] *Ibid.* 10 at 6 to 16.
[16] *Ibid.* 14 at 7 to 12.
[17] Rebuttal Testimony by James S. Pignatelli on Behalf of UNS Gas, Inc. dated 16 March 2007, hereafter "UNSG-Pignatelli R.".
[18] Rebuttal Testimony of D. Bentley Erdwurm on Behalf of UNS Gas, dated 16 March 2007, hereafter "UNSG-Erdwurm R.".

communities from customers in higher use communities like Flagstaff. The public interest demand an end of this inequity."[19] ...
"This means that residents in the colder community of Flagstaff will end up paying more than the Company requires to serve them, because customers in desert communities use little gas, and pay less than the cost to serve them."[20]

The Erdwum Rebuttal Testimony responses to a question "

"Q. Did any intervenor witness address the geographic subsidy that you identified in your Direct Testimony?

A. No, neither Staff nor RUCO directly address this rate design inequity in their Direct Testimonies. Both RUCO and Staff state that their respective proposals generate more revenues through the customer charge than is currently generated. However, the proposed $1.50 per month increase by Staff and the $1.13 per month by RUCO for residential customers results in the continued subsidization of fixed costs by customers in cold climates."[21]

(d) Recommendations for resolution of these concerns.

The UNSG continues to discriminate against those who understand colder climates have higher winter energy costs. This was accounted when the ratepayer chose to live in the warm/cold climate; thus, no basis exists for the proposed rate structure. Concerns about seasonal rate discrimination in Magruder's Testimony[22] were omitted in UNS Gas' Rebuttal.

I know of no one in Santa Cruz County who would believe UNS Gas' saying they were being subsidized by those in colder climates. This geographic inequity issue and rate design philosophy is wrong and should be denied. This rate structure clearly sends the wrong signal to high-use customers by rewarding high-users by penalizing low-users.

Recommendations:

1. The proposed seasonal rate structure elements (including TAM), including mandatory summer/winter rates, should be denied.
2. An approved annual total Service Charge, if voluntary, could provide a seasonal option, the present level payments scheme, or the varying monthly service charge.

2.2. Residential Service Charge increases.

UNS Gas proposed removal of some "volumetric" charges from the cost of gas and transfer these cost to the Service Charge or fixed-part of the bill. Customers in colder climates have higher winter gas bills than those in warmer climates but UNS Gas proposed to lower the

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19 *Ibid,* 13 at 22 to 25,
20 *Ibid,* 4 at 2 to 6.
21 *Ibid,* 11 at 20 to 27
22 Magruder T. 8 at 24 to 11 at 14 clearly disputed the philosophy of seasonal and volumetric factors in the basic Customer Charge.

higher volume bills by increasing the Service Charge for the lower volume ratepayers. The opposite should be true. Natural gas is a limited natural resource. Those who use more should pay more that those who use less. This is a principle of energy efficiency, economics. and demand reduction programs.

(a) Direct Testimony and Proposal by the Applicant.

UNS Gas witness Voge Testimony stated:

"The proposed average customer charges of $17 for residential customers, $20 for commercial customers and $120 for industrial customers would align more closely to the true costs of providing monthly distribution costs of providing monthly distribution service to those classes. In this way, these higher charges would reduce the inequities borne by high usage customers. Under our proposed rate design, the average residential customer in Flagstaff would pay an annual margin of $333, while the average Lake Havasu customer would pay $250 – just $83 less than the Flagstaff customer. This represents a significant reduction from the cross subsidy that Flagstaff customers currently bear."[23]

(b) Direct Testimony by Intervenors, including RUCO, ACC Staff, ACAA, and Magruder.

(1) RUCO witness Ms. Diaz Cortez Testimony stated

"RUCO recommends the Commission reject the biased winter/summer rates, doubling of the revenue allocated to the fix charge, and the TAM."[24]

RUCO also proposed a new Service Charge rate schedule which stated

"An in-depth discussion of RUCO's proposed rate design is contained in the testimony of Ms Diaz Cortez. In summary, for residential customers, RUCO proposes a single basic service charge (not season differentiated) of $8.13 and a commodity based charge of $0.2892 per therm."[25]

(3) ACC Staff witness Mr. Ruback clearly stated

"The Company is proposing a staggering increase in the fixed customer charges for all classes of service. The most extreme customer charge proposal is the Company's request to increase the Residential customer charge by more than 185%, during the summer period and 57% percent in the winder period. "I recommended that UNS' rate design be rejected for the reasons stated in my testimony."[26]

ACC Staff witness Mr. Ruback also stated

"The purpose of my rate design testimony is to provide an overview as to why UNS' proposal should be rejected."[27]

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23 UNSG-Voge T. 9 at 18 to 25.
24 RUCO-Diaz-Cortez T. 34 at 2 to 4.
25 ACC-Ruback T. 3 at 9 to 11.
26 *Ibid* 11 at 5
27 *Ibid* 11 at 8 to 10.

ACC Staff witness Mr. Ralph Smith presented a new rate structure. For residential customers,

"[T]he recommended customer charge of $8.50 per month, would result in UNS Gas collecting approximately 36 percent of the revenue via fixed charges."[28]

(3) ACAA responded indirectly to the Service Charge concern; as the purpose of ACAA;s Testimony is

"[T]o urge the Commission .to hold low-income customers harmless in the rate case by increasing the R12 discount to an amount commensurate with an residential rate increase the Company may be awarded, and in particular to reject the Company's proposed structure for R12, which reduces the discount to larger, colder climate users."[29]

(4) The Magruder Testimony noted four years ago in August 2003, the

"Service Charge was increased by 40% [from $5.00 per month to $7.00 per month] when the company transitioned from Citizens UNS Gas. At that time there was also a 22% rate increase for the cost of natural gas."[30]

The applicant proposed Service Charge increases for all customers but are most significant for residential customers as summarized in Table 2 below:

Table 2 Residential Service Charge History and Proposed New Service Charges[31]

Effective Dates	Monthly Service Charge	Annual	Organization
Prior to August 2003	$ 5.00	**$ 60.00**	Citizens
August 2003 – ~July 2007	$ 7.00	**$ 84.00**	UNS Gas
After Approval, about August 2007			
<u>Proposed</u> by UNS Gas	December – March $11.00 April – November $20.00	**$ 204.00**	UNS Gas
Recommended by RUCO	$8.33 (R10)	**$99.96**	RUCO
Recommended by ACC Staff	$8.50 (R10)	**$102.00**	ACC Staff
Recommended by Magruder	<$8.00 (R10)	**<$100.00**	Magruder
CARES Recommendations	$7.00 (R12)	**$84.00**	All Parties

The Magruder Direct Testimony stated:

The **<u>proposed</u> <u>340%</u> <u>Service</u> <u>Charge</u> <u>increase</u>** over the 3 to 4 years under UNS Gas ownership is not justified or explainable to ANY ratepayer. There has not been that amount of significant capital improvements. In Pignatelli Testimony, he states

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28 Supplemental Direct Testimony of Ralph C. Smith on Behalf of The Arizona Corporation Commission, Utilities Division Staff, Concerning Rate Design and Bill Impact Analysis, dated 23 February 2007, page 6 at 9 to 10, hereafter "ACC-R-Smith ST.".

29 ACAA-Scheier T. 2 at first paragraph.

30 Magruder T. 9 at 7 to 9.

31 *Ibid,* 9 at 2 to 6, with proposed monthly Service Charge corrected with RUCO, ACC Staff, and Magruder recommended Service Charge.

'we project that the number of UNS Gas customers will increase as much as 5-10% annually.' [*Pignatelli Testimony*, 1 at 26]" [32] [emphasis in original]

Magruder concluded "the proposed Service Charge is clearly too high"[33] and recommended 'reduce the proposed Service Charge to the order of $100 per year or less."[34]

(c) Rebuttal Testimony by the Applicant.

UNS Gas' Mr. Erdwurm Rebuttal supported the proposed rate structure by stating: "The UNS Gas proposal to shift more cost recovery from a volumetric rate to a monthly customer charge is an attempt t send the appropriate price signal and alleviate the disparity that currently exists between our cold and warm climate customers."[35]

(d) Recommendations for Resolution of this concern.

It is obvious UNSG still is pressing to increase the Service Charge (customer charge) to $17.00, well above that recommended by RUCO, ACC Staff and Magruder for residential customers as summarized in Table 1. The proposal remains unacceptable, will NOT send a correct price signal to the customers, and will permit a higher rate of return to the utility, as this is calculated as a percentage of the fixed rate. This is a backdoor way to increase the company's profits. Nothing in the rate structure can reduce the rate disparity between cold and warm climates but the weather, which is beyond the control of this Commission.

It is recommended the Service Charge for residential customers (R10) be increased as shown by the consensus of RUCO, ACC Staff and Magruder about an increase of $1.50 per month. This results in an annual residential service charge between $99.96 and $102 per year, or about a 21.4% increase since the last August 2003 rate case and a 70.0% increase since before July 2003. This remains a high Service Charge increase.

The CARES (R12) Service Charge is recommended by all to stay at $7.00 a month.

2.3 Rate Increased by Adding a Throughput Additional Mechanism (TAM) to Shift Some volumetric Costs to the Fixed Service Charge.

(a) Direct Testimony and Proposal by the Applicant.

The UNS Gas Application in the rate case stated

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32 *Ibid,* 9 at 9 to 14.
33 *Ibid,* 14 at 6.
34 *Ibid,* 15 at 11.
35 UNSG-Erdwurm R. 10 at 20 to 23.

"[T]he proposed rate design and related Throughput Adjustor Mechanism ("TAM") will better align the fixed and variable costs of service with the rates paid by the customers causing those costs and is in the public interest."[36]

Mr. Pignatelli testified how TAM would work

"Just as the PGA fluctuates to account for variations in the cost of gas, the TAM would be adjusted to account for changes in usage per customer ("UPC"). The under-recovery of costs due to reduced UPC in any period would be "trued-up" in future periods through use of a volumetric surcharge. Similarly, any over-recovery would be refunded to customers through a volumetric credit on future bills. In this way, both the Company and its customers would enjoy a more equitable, reliable and balanced collection of volumetric costs."[37]

Mr. Voge testified

"The continued use of a volumetric charge to recover a portion of the Company's fixed costs carries another concern: the uncertainty of recovery. If actual usage strays from the anticipated level used t establish that volumetric rate, customers could end up paying too much or too little for that portion of their service. Since usage is driven largely by weather trends during home heating season, particularly cold winters typically produce a swell in UNS Gas' margin revenues. Meanwhile, warm weather, effective conservation efforts or anything else that reduces consumption below anticipated levels leads to an under-recovery of the Company's costs. Eliminating such uncertainty would benefit both the Company and its customers."[38]

Mr. Voge also testified the TAM "credit reimburses the customer for the non-commodity portion of the relatively high cold winter gas bill."[39]

(b) Direct Testimony by Intervenors, including RUCO, ACC Staff, ACAA, and Magruder.

(1) RUCO testified that

"The TAM would true-up customer usage to match the billing determinants authorized in this rate cast. In other words, customers would pay for a fixed amount of consumption regardless of how much they actually consumed. The Company claims it needs this mechanism to "mitigate" the risk of revenue recovery."[40]

And responding to would TAM "mitigate" the risk of revenue recover, stated:

"No. This mechanism would *entirely remove* any risk associated with revenue recovery, not just merely mitigate it. In combination with the proposed fixed charge shift, and the biased summer/winter rate proposal, it would also send a perverse price

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[36] UNS Gas "Application, dated 13 July 2007, ACC Docket No. G-04204A-06-0463, 4 at 20 to 22, hereafter "UNSG-Application." It is noted a Southwest "decoupling" mechanism (CMT) was rejected by the ACC as CMT was inconsistent with the public interest and was not sound regulatory policy (Southwest Gas; Decision No. 68487; Docket No. G-01551A-04-0876)." From ACC-Ruback T. 17 at 18 to 21.

[37] UNSG-Pignatelli T. 22 at 1 to 9.

[38] UNSG-Voge T. 11 at 3 to 14.

[39] *Ibid,* 14 at 21 to 23.

[40] RUCO-Diaz Cortez T. 30 at 15 to 20.

signal that tells customers they will pay the same whether they use large quantifies of gas or no gas at all. It also would guarantee UNS Gas' revenue recovery."[41]

In response to the appropriateness for the regulator of a monopoly public service company to "guarantee" revenues, RUCO's response was "No."[42] Also, RUCO stated "the Commission denied the proposed [Southwest Gas] decoupling mechanism" in ACC Decision No. 64887."[43]

RUCO recommended denial of the TAM decoupling mechanism.[44]

(2) ACC Staff witness Ruback Testimony summarized in the Executive Summary stated

"The Commission should reject the proposed Throughput Adjustment Mechanism ("TAM"), because it is inequitable to ratepayers. The TAM shifts the risk of declining usage attributable to weather, economics and conservation from UNS Gas to ratepayers. There is a precedent for rejection of a Rate Decoupling Mechanism such as TAM. I also recommend that the Commission reject the implementation of the TAM because it is piecemeal ratemaking."[45]

ACC Staff witness testified

"The proposed regulator mechanism [TAM] is risk-reducing to the company as its transfers a portion of the risk from shareholders to ratepayers."[46]

(3) ACAA testified

"[C]ustomers eligible for the R12 discount should also be held harmless from any increases in the Throughput Adjustor Mechanism (TAM)."[47]

(4) Magruder testified

"It is not the Commission's responsibility to manage risk for seasonal variations. Weather temperature risk factors are foreseen, expected, and predicable; good management always takes all factors into account when making decisions. Any rate structure, based on passing the responsibility of risk management of seasonal variations to the Commission should not be considered. In other hearings, I have asked his employees if there were a meteorologist on staff at UniSource. The response has been that there is not been one, but that staff did check the Internet for weather information. Without such expertise used daily for risk management

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41 *Ibid,* 31 at 2 to 7.
42 *Ibid,* 15 at 9 to 11.
43 *Ibid,* 32 at 18 to 22.
44 *Ibid,* 33 at 14 to 16.
45 ACC-Ruback T. Executive Summary, page iii, second paragraph.
46 Direct Testimony and Exhibit of David C. Parcell on Behalf of the Commission Staff, dated 9 February 2007, 15 at 6 to 11, hereafter "ACC-Purcell T."
47 ACAA-Scheier T. 10 at first paragraph.

decisions, this corporation will continue to be ill-informed about the operational environment in both short- and long-term planning and decision making."[48]

Magruder also testified

"Using the proposed mechanism, a Throughput Adjustment Mechanism (TAM), UNS Electric states that the TAM "will allow UNS Gas to implement the comprehensive energy conservation program proposed in this filing." This statement is without merit. Customers notice higher and lower bills and when too high, conservation is the easiest way to lower bills. Lowering the thermostat, full loads in gas clothes dryers, less hot water usage are all understood. UNS Gas can't expect customers to understand TAM or anything equivalent. They understand "cost of service" and "cost of natural gas" and the present billing makes that distinction; however the PGA and surcharges are not very clear. Mr. Voge's Testimony also failed to resolve these difficulties."[49]

Magruder's concluded that

"mixing cost of service and product cost is contrary to best practices, common sense, and will make tracking costs too difficult ... transmission and distribution operational costs are dependent upon volumetric demand ... the conceptual process presented is without merit ... the proposed rate structure using Throughput Adjustment Mechanism (TAM) is not sound ... there is no relationship between TAM an conservation ... TAM does not dampen the swing of natural gas prices ... use of TAM will make billing costs less comprehensible than the present process."[50]

Magruder recommended to

"[R]emove all seasonal risk from ratepayers .. eliminate any mixing of the cost of service and the cost of product and continue separation of service and product charges ... delete the Throughput Adjusted Mechanism (TAM) concept."[51]

(c) Rebuttal Testimony by the Applicant.

Mr. Pignatelli's Rebuttal Testimony stated

"UNS Gas has provided substantial evidence to justify approval of its proposed Throughput Adjustment Mechanism ("TAM") that decouples the Company's dependence on natural gas consumption to meet its revenue requirement and allows it the opportunity to earn its authorized rate of return."[52]

Mr. Erdwurm's Rebuttal Testimony has lots of words about "decoupling" but none were significant enough to quote.[53] He did state

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[48] Magruder T. 10 at 20 to 28.
[49] *Ibid,* 12 at 18 to 26.
[50] *Ibid,* 25 at 22 to 34.
[51] *Ibid,* 26 at 9 to 29.
[52] UNSG-Pignatelli R. 3 at 1 to 4.
[53] UNSG-Erdwurm R. 14 at 21 to 19 at 15.

"[T]he annual adjustment to the margin rate will likely be less than one cent per therm. The cost of natural gas at 60 to 70 cents per therm will continue to provide strong incentive for conservation."[54]

(d) Recommendations for Resolution of this concern.

UNS Gas still believes TAM is essential but weak arguments for decoupling si the Company can become more efficient through the implementation of customer conservation measures. I'm sorry, this is not logical. Mr. Erwum's Rebuttal Testimony also includes several exhibits from the gas industry and regulatory associations. After reading, UNSG conclusions are not convincing. The Arguments by RUCO and ACC Staff clearly show of the negative impacts that such a "decoupling" mechanism on UNS Gas' ratepayers.

It is recommended that any decoupling concept, such as TAM, be denied and that the RUCO or ACC Staff rate structure be adopted by the ACC for UNS Gas.

2.4 Gas Usage Charged with TAM When Not Using Gas.

(a) Direct Testimony and Proposal by the Applicant.

Not discussed.

(b) Direct Testimony by Intervenors, including RUCO, ACC Staff, ACAA, and Magruder.

(1) RUCO has proposed a rate design that

"[Q]ill not result in customers having to pay for therms they did not use and adheres to the undesirability of the proposed decoupling mechanism.[55]

(2) ACC Staff witness Ruback responded to the question "do customer charges impede the ability of customers to control their bills" using the proposed rate structure?" with

"Customer charges are inelastic. Inelasticity is an inappropriate concept to build into a tariff design. Unlike commodity charges, which provide customers the opportunity to control their bills by changing the amount of gas used or peak demand imposed on the system, a customer charge does not change with reduced consumption or less demand. The only way a customer can avoid customer charges is to discontinue all gas service."[56] [emphasis added]

He also quoted from the ACC Decision No. 68487 where the Commission disapproved the Southwest decoupling mechanism

"The likely effect of adopting the proposed CMT would be a disincentive to undertake conservation efforts because ratepayers would be required to pay for gas not used in prior years."[57] and "There is also concern that there could be a dramatic impact that could be experienced by customers faced with a surcharge for not using enough gas

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[54] *Ibid,* 16 at 5 to 7.
[55] RUCO-Diaz Cortez T. 34 at 23 to 35 at 3.
[56] ACC-Ruback T. 8 at 15 to 21.
[57] *Ibid,* 18 at 4 to 6.

the prior year."[58] And "The Company is requesting that customers provide a guaranteed method of recovering authorized revenues, thereby virtually eliminating the Company's attendant risk. Neither law nor sound public policy requires such a result and we decline to adopt the Company's CMT in this case."[59] [emphasis added]

(3) ACAA did not respond directly to this issue.

(4) The Magruder Testimony, in Table 3 showed some will have **higher rates** without consumption, some **lower rates** without consumption, some have **adjusting rates** without consumption and further changes. This is not reasonable for the winter-only or summer-only residents, as high percentage of the UNS Gas customers are part-year residents.[60]

Table 3, Impact of Service Charge Rate Change for Full Year and Seasonal Residents.[61]

Season / Resident	Winter	Spring/Fall	Summer
Full year	Lower Monthly rate to reduce winter bill	Rate adjusted to lower winter bill	Higher Monthly rate reduce winter bill
Summer only	Higher Monthly rate without gas consumed	Rate adjusted without consumption	Higher Monthly rate when gas is consumed
Winter only	Lower Monthly rate to reduce winter bill	Rate adjusted without consumption	Lower Monthly rate without consumed

Testimony also tried to make the easier to understand with an example:

For a practicable example, I can see from my window the El Paso Natural Gas (EPNG) line easement and the interconnecting substation to the local UNS Gas main and service lines for my home. EPNG is paid by UNS Gas to supply natural gas to the substation for local distribution. When natural gas is consumed it is reasonable to pay EPNG transmission and distribution charges for the volume of natural gas delivered to my home. Conversely, it is not reasonable, fair or just to charge for transporting gas via EPNG's line when I use no natural gas. It is false charging to require one to pay EPNG transportation and distribution volumetric charges when a customer does not use any natural gas. The combining of any transportation (or volumetric charges) that are not absolutely fixed UNS Gas infrastructure expenses in the "fixed" part of the billing mixes and muddles the entire billing process which then will not be objective, auditable, or traceable.[62]

(c) Rebuttal Testimony by the Applicant.

No response was noted to this issue.

(d) Recommendations for Resolution of this concern

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58 *Ibid,* 18 at 7 to 9.
59 *Ibid,* 18 at 12 to 13.
60 *Ibid,* 18 at 4 to 6.
61 Magruder T. at 9 at 25 to 31, where this table is labeled Table III-2 and with a slightly different title.
62 *Ibid,* 11 at 32 to 36.

Under no circumstances should a ratepayer pay for natural gas costs when the ratepayer is not using gas, such when on vacation, when only a fixed Service Charge applies.

It is recommended the resultant rate structure "Eliminate any mixing of the cost of service and the cost of product and continue separation of service and product charges."[63]

2.5 Internal UNS Gas "Price Stability Policy" to be Adopted by the ACC to Replace Prudency Purchase Audits during Future Rate Cases.

(a) Direct Testimony and Proposal by the Applicant.

The UNSG Application requested that

"The Company's Price Stabilization Policy concerning gas purchases should be prospectively approved to provide Commission guidance for the Company's gas procurement practices."[64]

And that the ACC

"Issue a final order approving UNS Gas' Price Stabilization Policy."[65]

Mr. Pignatelli testified why his Company wants this document approved by the ACC?

"We recommend that the Commission prospectively approve the Price Stabilization Policy. As I have indicated, prudence reviews are "after-the-fact" events that try to recreate the circumstances that existed at the time of the investment or expenditure. This can be very difficult when the period or activities in question were volatile and quickly unfolding. Rather than look at UNS Gas' procurement practices in hindsight, UNS Gas recommends that its Price Stabilization Policy be reviewed and approved by the Commission during this case for future implementation. This way the Commission can have input e r to UNS Gas incurring the costs for gas procurement rather than after the fact. And there will be <u>no need for a separate non rate case-related prudency review of gas acquired pursuant to the approved methodology</u>."[66] [Underlined for emphasis]

And Mr. Pignatelli further requested that

"A finding that UNS Gas' past gas procurement practices and current UNS Gas Price Stabilization Policy are <u>prudent</u>."[67] [Underlined for emphasis]

And Mr. Hutchens testified that

"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

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63 *Ibid,* 15 at 22 to 23.
64 UNSG-Application 5 at 1 to 3.
65 *Ibid* , 6 at 4.
66 UNSG-Pignatelli T. 14 at 25 to 15 at 8.
67 *Ibid,* 25 at 21 to 22.

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."[68] [Underlined for emphasis]

(b) Direct Testimony by Intervenors, including RUCO, ACC Staff, ACAA, and Magruder.

(1) RUCO did not directly discuss adoption of this plan as proof of prudent purchases.

(2) ACC Staff witness Mr. Jerry Mendl testified that

- "UNS Gas did not precisely carry out its 2005 Price Stabilization Policy.
- All the fixed price gas delivered during the 28-month audit period was purchased on only 20 days."[69]

And ACC Staff witness Mr. Mendl recommended that:

"The Commission should not approve UNS Gas' request to approve its 2006 Gas Price Stabilization Policy.

- The 2006 Price Stabilization Policy would allow UNS Gas to stabilize prices using call options and collars which could add to the cost without commensurate benefit to ratepayers.
- Approval of the Policy would create a safe harbor that would increase the resistance of UNS Gas to change policies when conditions warranted.
- If the Commission considers approving the Price Stabilization Policy, it should require UNS Gas to provide a detailed explanation of how it would monitor the markets and make changes for the ratepayers' benefit.
- If the Commission considers approving the Price Stabilization Policy, it should condition the approval to be valid only as long as the conditions underlying the policy are valid.
- If the Commission considers approving the Price Stabilization Policy, it should require UNS Gas to show that any premiums anticipated for hedging instruments are reasonable and serve the objectives of stabilizing prices while minimizing costs.
- If the Commission considers approving the Price Stabilization Policy, it should require UNS Gas to provide a corrected copy of the Policy."[70]

(3) AACA did not discuss adoption of this plan.

(4) Magruder testified that the Price Stabilization Policy

"UNS Gas is proposing that the Commission 'approve' UNS Gas' Price Stabilization Policy. This is an internal policy, under internal control. It could be modified at any time by the company; no assurance that this will not be the case is given. Exhibit DGH-1 is for 2006 thus is already outdated by a newer 2007 version. Their

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[68] Direct Testimony of David G. Hutchens on Behalf of UNS Gas, Inc. dated 13 July 2006, 7 at 3 to 8, hereafter 'UNSG-Hutchens T. page".

[69] Redacted Direct Testimony of Jerry E. Mundl on Behalf of Arizona Corporation Commission Staff, dated 16 February 2007, Executive Summary page 1, hereafter "ACC-Mendl T."

[70] *Ibid*, Executive Summary page 2.

Application needs updating. The mandatory compliance verb "shall" is used once in the entire document. Exhibit DGH-1 is vague..."[71]

And Magruder further testified

"Without mandatory provisions, an internal practice such as this is unsatisfactory and definitely should not replace the detailed audits accomplished by ACC Staff and RUCO in all rate proceedings. In fact, <u>suggesting that this weak document replace the prudency audit has no merit</u>. If the Commission allows this document to replace their reviews, liability for any poor decisions or losses based on this practice could cause significant liabilities to the Commission instead of shareholders. Shareholders are the ones who should absorb losses."[72] [Underlined for emphasis]

And Magruder concluded

"The proposed internal "UNS Gas Price Stabilization Policy" is under total UNS Gas control; therefore, <u>any</u> Commission approval might incur inappropriate liability to the Commission. Further, significant clarification as to the applicability of this policy is missing."[73]

And Magruder recommended:

"Make major changes to the UNS Gas Price Stability [*sic,* Stabilization] Policy including adding an ACC reasonableness process review. Eliminate any indication that the ACC will approve the UNS Gas Price Stability [*sic,* Stabilization] Policy."[74]

(c) <u>Rebuttal Testimony by the Applicant</u>.

Mr. Pignatelli's Rebuttal stated

"I am disappointed that Staff is recommending that UNS Gas' Price Stabilization Policy not be approved."[75]

And

"We would re-urge our original request that the Commission approve its Price Stabilization Policy."[76]

Mr. Hutchens' Rebuttal Testimony responded to ACC witness Mr. Mendl concern that approval of the Policy would put the Company on "autopilot" and not continually review its purchasing strategy was

"[T]his is inconsistent with the Company's behavior and the Policy itself" and he then describes interaction with Company's internal policies.[77]

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71 Magruder T. 10 at 29 to 34.
72 *Ibid,* 11 at 2 to 8.
73 *Ibid,* 14 at 15 to 17.
74 *Ibid,* 15 at 17 to 19.
75 UNSG-Pignatelli R. 11 at 16 and 17.
76 *Ibid*, 11 at 23 and 24.
77 Rebuttal Testimony of David G. Hutchens on Behalf of UNS Gas, Inc. dated 16 March 2007, page 10 at 18 to page 11 at 4, hereafter "UNSG-Hutchens R.".

(d) Recommendations for Resolution of this concern.

After reviewing the Pignatelli and Hutchens' Rebuttals, in summary, they say "Trust me.. Believe me ... Everything will be A-ok ...hurray, we don't have to do any more prudency audits.. This company plan will cover both us... if you approve.. we can sue.. if we lose money ... oh well... you approved it"

The Company has no profit interest in achieving the lowest gas prices for its customers. Cost of gas is about two-thirds of a customer's bill, then, as a customer and ratepayer, I expect and demand that the Commission continue its sound policy of holding prudency reviews and audits for all gas purchases that impact customer's rates. Anything else, in my opinion, is neither wise nor prudent.

The UNSG Rebuttals did not respond to the impact of "ACC approval" and potential liability for ratepayers and the Commission if and/or when the "policy" was not followed, as has already shown in ACC witness Mendl Testimony.[78]

I recommend the UNS Price Stabilization Policy be reviewed by the Commission for reasonableness and that this Company document should NEVER be approved or specified as a substitute for prudency audits of all gas purchases in future rate cases.

2.6 Changes in Past Due, Penalty, Suspension, Notice of Termination Dates after Billing.

Both RUCO and ACC testified this important change in the "Rules and Regulations* (R&R) will have serious impacts for lower income customers.

(a) Direct Testimony and Proposal by the Applicant.

The Testimony of UNS Gas witness Mr. Gary A. Smith stated "billing terms" were changed in the Rules and Regulations (R&R) in order to be aligned with the Arizona Administrative Code,[79] without reference. He included a clean and redline versions of the proposed the "Rules and Regulations" as Exhibit GAS-2.[80] Table 5 tries to show and compare the present and proposed policy changes. The result is a change from 40 days after a Bill Due date to 20 Days before termination of service, with other actions also occurring earlier as shown in Table 4.

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78 ACC-Mendl T. Executive Summary, 1 and 2,

79 Direct Testimony by Gary A. Smith on Behalf of UNS Gas, Inc, dated 13 July 2006, 19 at 15 to 1 and 20 at 1 to 3, hereafter "UNSG-GASmith T."

80 UNSG GASmith, T., Exhibit GAS-2, "Rules and Regulations" Sections 10.C and 11.E.

Table 4 – Changes in Proposed Termination Dates for UNS Customers.[81]

Action**	Notice	Present Policy	Proposed Policy	New R&R Reference
Bill Due	Bill	15 days after Due Date	10 days after Due Date	Sec. 10.C.1 page 51
Penalty Charge Assessed	None	15 days after Due Date	10 days after Due Date	Sec. 10.C.1 page 51
Bill is Past Due	None	No payment within 30 days after Due Date	15 days after Due Date	Sec. 10.C.3 page 51
Suspension of Service Notice/ Termination Notice	Written notice 1st Class Mail	No payment within 30 days after Due Date	No payment within 15 days after Due Date	Sec. 10.C.3 page 51
		10 days prior to Termination Date	5 days prior to Termination Date	Sec. 11.E page 62
Service can be Terminated	None	No payment within 40 days after Due Date	No payment within 20 days of Due Date	Sec. 10.C.4 page 51

* For practical purposes in this table, Due Date is defined at date bill is rendered, or later of (1) postmark date, (2) mailing date, or (3) billing date shown on bill; however the billing date shall not differ from postmark or billing date by more than 2 days.
** A bankruptcy court may require a more stringent schedule.

Also in the proposed Rules and Regulations (R&R) under "Termination of Service Without Notice" the fourth condition "d" was proposed to read as follows (in redline form):

"d. The Customer has failed to comply with the curtailment procedures imposed by the Company ~~during supply shortages~~ in accordance with Company's Pricing Plans ~~Tariffs~~."[82]

(b) Direct Testimony by Intervenors, including RUCO, ACC Staff, ACAA, and Magruder.

(1) RUCO stated the proposed Rules and Regulations

"Shortened the period of time customers have to pay their gas bills before a late fee is assessed from 15 days to 10 days and to short[en[the time customers have to pay a past due bill prior to notice of shut-off from 30-days to 15-days."[83]

RUCO proposed action for this concern was:

"The proposed changes are unreasonable. The proposed payment due dates are so short that a UNS Gas customer on vacation could forseeably come home and find their gas shut-off. Since gas is a vital service to many, a more flexible payment schedule should prevail. As a regulated utility UNS Gas already receives a working capital allowance to bridge differences between receipt of revenues and payment of expenses, and should not have to impose unreasonable payment terms on its customers.

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81 This table was derived by this party to try to understand these R&R sections, no simple timeline is in the R&R and word definitions are not consistent, thus it is very difficult to understand and violates basic principles for human factors engineering and public communications.
82 UNSG GASmith, T., Exhibit JAS-2, Section 11.B.1.d, page 59 of 81 (redlined version).
83 RUCO-Diaz Cortez T. 35 at 15 to 18.

"RUCO recommends the Commission deny the proposed changes in payment due dates.[84]

(2) ACC Staff witness Ralph Smith stated for the proposed changes to Section 10.C of the proposed R&R

"Staff agrees with the UNS Gas-proposed changes to Section 10.C. In order that these changes not present a hardship on UNS Gas customers, there should be a six month waiver in the late penalty charge. The company has proposed to reduce the number of days, from 15 to 10, as the period a customer may avoid a late payment penalty. For the first six months, the penalty should be waived for day 10. After the initial 6 months, the Company should be able to charge the penalty after day 10. This temporary six-month transition period should help alleviate any hardship on customers from this change in billing terms."[85]

And Mr. Smith also stated for the proposed changes in Section 11.E of R&R

"Staff supports the standardization of tariff provisions for rules and regulations from the UniSource Energy Companies, including UNS Gas. Staff does not object to the UNS Gas' proposed revision to Section 11.E; however, Staff is concerned that the shortening of notice time could present a hardship to customers. Therefore, Staff recommends that during the first six months after the notification provisions are approved, the Company allow affected customers the current ten calendar days to respond to a termination of service notice before actually disconnecting the customers. After six months, the new terms in Section 11.E would be enforceable as stated."[86]

(3) ACAA Direct Testimony, briefly summarized, stated lower income customers usually do not have a checking account or the ability to pay on-line. This schedule is a challenge for those who have to pay in cash and need to arrange transportation. This leads to the using "payday" loan services to drive even more customers to predatory, onerous lenders. "Twenty days is an absolutely reasonable timeframe in which to pay UES, ten days simply is not."[87]

(4) The Magruder Testimony did not discuss this concern.

(c) Rebuttal Testimony by the Applicant.

The Rebuttal Testimony by Gary Smith stated these due dates met the specifications of Arizona Administrative Code R-14-2-310.C. He testified one has10 days to pay the bill before it is late and another 15 days before a late fee applies.

"Only then would the bill be considered delinquent...and the Company would not commence suspension of service procedures unless it did not receive payment for a

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[84] *Ibid,* 35 at 20 to 36 at 6.
[85] Direct Testimony of Ralph C. Smith for the Arizona Corporation Commission, dated 9 February 2007 page 68, hereafter "ACC-RSmith T."
[86] *Ibid,* 70 at 4 to 12.
[87] ACAA-Scheier, T. 14.

delinquent bill after five days. So the Customer has a total of 30 days after a bill receipt to pay his or her bill before a notice to shut-off is issued."[88]

A.A.C R-14-2-310.C. is quoted below:

"C. Billing terms

1. All bills for utility services are due and payable no later than 10 days from the date the bill is rendered. Any payment not received within this time-frame shall be considered past due.
2. For purposes of this rule, the date a bill is rendered may be evidenced by:
   a. The postmark date
   b. The mailing date
   c. The billing date shown on the bill (however, the billing date shall not differ from the postmark or mailing date by more than two days).
3. All past due bills for utility services are due and payable within 15 days. Any payment not received within this time-frame shall be considered delinquent.
4. All delinquent bills for which payment has not been received within five days shall be subject to the provisions of the utility's termination procedures.
5. All payments shall be made at or mailed to the office of the utility's duly authorized representative."[89]

(d) <u>Recommendations for Resolution of this concern</u>.

The Rebuttal Testimony by Mr. Gary Smith appears not agree with the R&R schedule nor the Arizona Administrative Code. This section of the A.A.C was last updated in 1992, so the rationale for this change surely is not due to any recent Code changes. The Testimony by ACC witness Ralph Smith temporarily delays both Section 10C and 11E for six-months.

The other R&R change in Section 11.B.1.d is significant, in that it is significantly different from that part of the A.C.C, and gives broad "without" notification powers to the Company without rationale. The Code must read exactly as the original R&R and A.A.C. for deciding when service can be terminated <u>without</u> notification.

It is recommend that

(1) The Company writes a new, completely reader-friendly, plain language UNS Gas Rules and Regulations.[90] The present edition is misleading and almost impossible to understand. Recommend eight-grade reading level skills be used.[91]

(2) Consideration must be given to continue using the present schedule as it is known by the customers as there are so many below poverty-line customers who are struggling to make every utility, car, medical and rent payments, and if this is not possible, the

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88 UNSG-GASmith R. 4 at 7 to 5 at 2.

89 Arizona Administrative Code R-14-310.C, obtained 3 April 2007 from http://www.azsos.gov/public_services/Table_of_Contents.htm

90 I have two different insurance companies (automobile and home) policies with "plain English" policies that meet all legal requirements using simple, easy to understand English. Get the attorneys out of writing the rules for their less-educated customers to read and understand. This should lead to higher understanding and better compliance than what is now published and not comprehensible to most college graduates. Direct quotes from the A.A.C. are not acceptable for customers.

91 *National Geographic* magazine and most newspapers use eight grade reading skill levels.

implement the six-month temporarily delay while the Company notifies its customers several times of the new billing schedule.

(3) The proposed change to Section 11.B.1.d be denied and the original version remain for terminations without notification'

(4) A Spanish-version of the new R&R also be approved by the ACC, and.

(5) ALL customers receive a copy of the new R&R, within 30 days of ACC approval and all new customers prior to being accepted as a customer.

Part III – Summary

Q. Would you please summarize your testimony?

A. The surrebutal recommendations about key concerns in Part II show that the Applicant still agrees with its original Application in almost every significant concern raised by all the Intervenors. Without removal of the proposed rate structural flaws, customer rates will be unfair and unreasonable. Approval of the RUCO or ACC Staff rate structures and values are very reasonable and fair, to both the Company and the ratepayers. The deliberate and continuous discrimination campaigns in the Company's Application and Testimonies against the warmer counties, such a Santa Cruz, and Lake Havasu, is an inappropriate way to lower rates for colder areas. The mixing of cost of service with product costs will make correct accounting impossible. Risks must be borne by the company and not by the ratepayers in the monopolistic environment, especially for reasonable and predictable elements, such as weather.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

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** **Notice of Filing of** **Summary Testimony of Marshall Magruder, Intervenor** **23 April 2007**
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**

As directed in the Procedural Order of 8 September 2006, modified on 10 January 2007 and 15 February 2007, the Summary Testimony of Marshall Magruder is submitted to all Parties two days prior to oral testimony planned for 25 April 2007.

Respectfully submitted on this 23rd day of April 2007 to all parties,

MARSHALL MAGRUDER

By ______________________________

Marshall Magruder

EXHIBIT
tabbies
Magruder 8
admitted

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Marshall Magruder
Summary Testimony
23 April 2007

As my Motion to Intervene, Direct Testimony, Surrebuttal and this Summary Testimony, the issues have evolved, some deleted, during these hearings. Briefly these and recommendations are:

a. Proposed rate structure – Flawed, unfair, significantly reduces Company and shareholder risk, increases customer cost. RUCO and Staff propose acceptable, realistic rate structures.
b. Proposed $17 Monthly Service Cost – Not reasonable. Recommend either RUCO or Staff Cost of Service rate between $8.33 and $8.50 for commercial/residential and $7 for CARES.
c. Proposed Rates Adjusted for Location factors,– Not recommended as one rate schedule is for all in same rate category without cross-subsidies based on cold/warm climate locations,
d. Proposed Volumetric (TAM) mechanism – Not recommended having all volumetric costs in Cost of Service charge and move risk of seasonal weather to customers.
e. Proposed Mandatory Seasonal Rates – Not recommended as annual levelized rates exist.
f. Proposed Schedules – Not recommended to give greatest savings to higher consuming customers are expense of lower consuming customers.
g. Proposed Acquisition Adjustments – Not recommended, the Citizens-UniSource Settlement Agreement protects ratepayers.
h. Potential for "double recovery" – Staff has indicated this issue has not been fully resolved.
i. Proposed Billing Schedule – Not recommended to increase revenue to Company for late payments and re-connect fees that will be collected with much tighter billing schedule.
j. Proposed Rule & Regulation to Permit Cutoff without Notification – Do not change rule.
k. Proposed Price Stability Policy for ACC Approval – Reasonable policy, unreasonable for ACC to assume purchase gas risk in order to delete Prudency Audits in future rate cases.
l. Executive Severance Compensation at Retirement – A company, not customer cost.
m. Under-funding of CARES – About 15,000 low income ratepayers are not participating in UNS Gas CARES programs. Thus, a more vigorous program is required for funding.
n. UNS Demand Side Management Program – Fully support policy but proposed plan misses important DSM actions, participants and funding to meet society environmental factors and consider utility, customer and total resource cost-benefit in the Goals and Objectives for each DSM Program. Recommend conceptual program approval with a DSM Adjustor and go-head only for the proposed study. Each DSM program must to be planned detail, based on results of survey and budgeted with real, not "placeholders," as the customer will pay and submitted to ACC Staff and RUCO prior to Commission decision at an Open Meeting within 75 days of filing.

MAGRUDER Exhibit

NUMBER OF UNS CUSTOMERS
WHO ARE LIVING AT OR BELOW THE POVERTY LEVEL AND
WHO COULD BE POSSIBLE CARES PARTICIPANTS

County	Percent Living at or below the Federal Poverty Level (2007 Census Data)	Total UNS Gas Residential Customers (Jan 2007)	Number of UNS Gas Customers below Poverty Level and Possible CARES participants (est.)
Coconino/ Flagstaff	17.9%	28,360	**5,076**
Mohave	15.3%	22,723	**3,477**
Navajo/ Show Low	29.0%	15,940	**4,623**
Santa Cruz	24.5%	7,005	**1,716**
Yavapai / Prescott	12.8%	55,020	**7,042**
		Total	**21,934**
	Note 1	Note 2	Note 3

Notes:

1. From ACAA Testimony page 5, US Census Bureau for each county,
2. Total UNS Gas Residential Customers from UNS Gas Data Response to MM DR 1-10a (corrected), 29 March 2007 for number of residential customers on 1 January 2007. UNS Gas does not use County Lines in its statistics so some customers might actually live in a different county than shown.
3. Second Column X Third Column = Number below Poverty Level and as an estimate of possible CARES participants.

In response to Magruder Data Request 2-9, as of December 2006 there were **6,227** participants in the CARES program or 6227/21934 ~ **28.3%** participating. See Exhibit M-4.

EXHIBIT
tabbies
Magruder 9
admitted

UNS Gas, Inc.
Analysis of Plant
September 2002 - August 11, 2003

Description	12/31/2001	Jan. 2002	Feb. 2002	Mar. 2002	Apr. 2002	May 2002	June 2002	July 2002	Aug. 2002	Sept. 2002	Oct. 2002
Santa Cruz Gas:											
E.O.M. Balances-											
Plant in Service	13,449,373	13,450,646	13,509,851	13,486,273	13,711,832	13,639,115	13,645,482	13,664,074	13,741,425	14,332,913	14,342,075
So. Union Acq Adj.											
Total	13,449,373	13,450,646	13,509,851	13,486,273	13,711,832	13,639,115	13,645,482	13,664,074	13,741,425	14,332,913	14,342,075
CWIP	282,123	313,901	291,174	321,808	140,334	151,136	90,081	86,324	41,666	25,563	26,559
Capital Expenditures		31,798	33,550	7,477	44,017	9,838	15,912	14,802	32,693	(2,558)	16,409
No. Arizona Gas:											
E.O.M. Balances-											
Plant in Service	219,020,755	220,917,074	221,721,409	222,332,476	223,830,745	224,886,329	224,220,837	224,970,796	222,578,405	219,350,782	220,201,895
So. Union Acq. Adj.	21,316,577	21,316,577	21,316,577	21,316,577	21,316,577	21,316,577	21,316,577	21,316,577	21,316,577	21,316,577	21,316,577
Net P.I.S.	240,337,332	242,233,651	243,037,986	243,649,053	245,147,322	246,202,906	245,537,414	246,287,373	243,894,982	240,667,359	241,518,472
CWIP	2,045,445	964,858	1,714,535	2,661,369	2,805,433	3,183,909	2,756,310	3,337,879	4,152,011	3,683,363	4,159,350
Capital Expenditures		268,441	1,196,961	1,502,492	1,214,176	1,109,639	1,181,447	1,469,272	1,720,072	592,218	1,384,204
Total Arizona Gas											
E.O.M. Balances-											
Plant in Service	232,470,128	234,367,720	235,231,260	235,818,749	237,542,577	238,525,444	237,866,319	238,634,870	236,319,830	233,683,695	234,543,970
So. Union Acq. Adj.	21,316,577	21,316,577	21,316,577	21,316,577	21,316,577	21,316,577	21,316,577	21,316,577	21,316,577	21,316,577	21,316,577
		-	-	-	-	-	-	-	-	-	-
Net P.I.S.	253,786,705	255,684,297	256,547,837	257,135,326	258,859,154	259,842,021	259,182,896	259,951,447	257,636,407	255,000,272	255,860,547
CWIP	2,327,568	1,278,759	2,005,709	2,983,177	2,945,767	3,335,045	2,846,391	3,424,203	4,193,677	3,708,926	4,185,909
Capital Expenditures		300,239	1,230,511	1,509,969	1,258,193	1,119,477	1,197,359	1,484,074	1,752,765	589,660	1,400,613

EXHIBIT RUCO-1 Admitted

UNSG0463/00179

(1)

UNS Gas, Inc.
Analysis of Plant
September 2002 - Au

Description	Nov. 2002	Dec. 2002	Jan. 2003	Feb. 2003	Mar. 2003	Apr. 2003	May 2003	June 2003	July 2003	Aug. 2003
Santa Cruz Gas:										
E.O.M. Balances-										
Plant in Service	14,351,581	14,426,397	14,450,739	14,466,612	14,468,092	14,473,021	14,434,994	14,487,903		
So. Union Acq Adj.										
Total	14,351,581	14,426,397	14,450,739	14,466,612	14,468,092	14,473,021	14,434,994	14,487,903	-	-
CWIP	93,601	101	23,674	57,985	100,681	108,918	81,992	72,331		
Capital Expenditures	76,548	29,529	45,268							
No. Arizona Gas:										
E.O.M. Balances-										
Plant in Service	221,754,428	224,616,288	225,122,661	226,231,563	225,843,597	226,782,400	227,586,510	228,678,476		
So. Union Acq. Adj.	21,316,577	21,316,577	21,316,577	21,316,577	21,316,577	21,316,577	21,316,577	21,316,577		
Net P.I.S.	243,071,005	245,932,865	246,439,238	247,548,140	247,160,174	248,098,977	248,903,087	249,995,053	-	-
CWIP	3,568,116	1,571,383	1,788,442	1,324,382	1,834,424	1,814,395	2,384,269	2,581,074		
Capital Expenditures	936,539	622,822	309,259							
Total Arizona Gas										
E.O.M. Balances-										
Plant in Service	236,106,009	239,042,685	239,573,400	240,698,175	240,311,689	241,255,421	242,021,504	243,166,379	-	-
So. Union Acq. Adj.	21,316,577	21,316,577	21,316,577	21,316,577	21,316,577	21,316,577	21,316,577	21,316,577	-	-
	-	-	-	-	-	-	-	-	-	-
Net P.I.S.	257,422,586	260,359,262	260,889,977	262,014,752	261,628,266	262,571,998	263,338,081	264,482,956	-	-
CWIP	3,661,717	1,571,484	1,812,116	1,382,367	1,935,105	1,923,313	2,466,261	2,653,405	-	-
Capital Expenditures	1,013,087	652,351	354,527	431,888	1,065,664	574,536	1,260,911	1,082,300	1,395,976	290,449

UNSC0463/00180

2

Santa Cruz County Gas
Summary Trial Balance
by Reg Function
June ,2003

Company Code: 2001
Client Name: CU's Production
Client Number: 100
Date/Time: 07/16/2003/09:19:49

37
38

			Opening Balance	Debits	Credits	Net Change	Ending Balance
**				771,810.61	771,810.61-		
**	0101	PLANT IN SERVICE	14,434,993.93	53,243.49	334.75-	52,908.74	14,487,902.67
**	0107	CONSTRUCTION WORK IN PROG	81,992.12	49,248.12	58,908.91-	9,660.79-	72,331.33
**	0108	ACCUMULATED DEPRECIATION	7,482,318.68-	1,936.54	47,515.71-	45,579.17-	7,527,897.85-
**	0131	CASH		195,368.27	195,401.15-	32.88-	32.88-
**	0142	CUSTOMER ACCOUNTS RECEIVA	336,709.49	213,714.53	259,391.76-	45,677.23-	291,032.26
**	0143	OTHER ACCOUNTS RECEIVABLE					
**	0144	ACCUM PROVISION FOR UNCOL	5,183.96-	2,905.76	13,534.80-	10,629.04-	15,813.00-
**	0145	NOTES RECEIVABLE FROM ASS					
**	0146	Intercompany Receivable	8,082,166.26-	423,804.54	445,146.86-	21,342.32-	8,103,508.58-
**	0154	PLANT MAT & OPER SUPPLIES	48,160.72	17,322.05	13,609.96-	3,712.09	51,872.81
**	0155	MERCHANDISE M&S					
**	0163	STORES EXPENSE UNDISTRIBU					
**	0165	PREPAYMENTS	195.58	18,122.74	8,470.25-	9,652.49	9,848.07
**	0182	REGULATORY ASSET	60,159.83				60,159.83
**	0184	CLEARING ACCOUNT		14,920.97	14,920.97-		
**	0186	DEFERRED DEBITS	497,336.59	278,779.59	291,992.43-	13,212.84-	484,123.75
**	0190	ACCUM DEFERRED INCOME TAX	314,873.00				314,873.00
**	0216	UNAPPROPRIATED R/EARNINGS	706,999.38				706,999.38
**	0232	ACCOUNTS PAYABLE	46,901.37-	74,258.03	101,226.42-	26,968.39-	73,869.76-
**	0233	NOTES PAYABLE-ASSOC COMPA					
**	0235	CUSTOMER DEPOSITS	39,551.87-	2,030.00	800.00-	1,230.00	38,321.87-
**	0236	TAXES ACCRUED	222,369.45-	115,744.96	44,599.83-	71,145.13	151,224.32-
**	0237	INTEREST ACCRUED	1,218.20-		121.51-	121.51-	1,339.71-
**	0241	TAX COLLECTIONS PAYABLES					
**	0242	MISC CURRENT/ACCRUED LIAB					
**	0252	CUSTOMER ADVANCES FOR CON	167,037.00-	9,097.00	27,763.00-	18,666.00-	185,703.00-
**	0255	ACCUM DEFERRED ITC	35,292.00-	674.00		674.00	34,618.00-
**	0271	CONTRIB IN AID OF CONSTRU		9,569.00	9,569.00-		
**	0282	ACCUM DEFERRED INCOME TAX	538,989.00-				538,989.00-
**	0403	DEPRECIATION EXPENSE	229,796.13	47,907.20	1,936.54-	45,970.66	275,766.79
**	0408	TAXES OTHER THAN INCOME T	142,776.72	28,093.19	35.23-	28,057.96	170,834.68
**	0409	INCOME TAXES	97,780.00-		36,768.00-	36,768.00-	134,548.00-
**	0419	Interest & Dividend Incom	1,683.43-	268.17	473.02-	204.85-	1,888.28-
**	0420	INVESTMENT TAX CREDITS	1,975.00-		674.00-	674.00-	2,649.00-
**	0426	OTHER DEDUCTIONS	250.00		38,859.07-	38,859.07-	38,609.07-
**	0431	OTHER INTEREST EXPENSE	1,109.24	178.77		178.77	1,288.01
**	0480	RESIDENTIAL REVENUES	1,565,017.29-		132,375.71-	132,375.71-	1,697,393.00-
**	0481	COMMERCIAL/INDUSTRIAL	563,916.29-		64,281.80-	64,281.80-	628,198.09-
**	0488	MISC SERVICE REVENUES	987.61-		102.00-	102.00-	1,089.61-
**	0495	OTHER REVENUES	301.00-				301.00-
**	0807	PURCHASED GAS EXPENSES	1,395,997.92	292,058.31	172,245.34-	119,812.97	1,515,810.89
**	0874	MAINS & SERVICES EXP.S	103,216.75	16,582.44		16,582.44	119,799.19
**	0875	MEASUR/REGULAT STATN EXP-	4,567.85				4,567.85
**	0877	MEASUR/REGULAT STATION EX	538.00				538.00
**	0878	METER EXP.S	7,093.93	3,483.35		3,483.35	10,577.28
**	0879	CUSTOMER INSTALLATIONS EX	4,260.11	593.74		593.74	4,853.85
**	0880	OTHER EXPENSES	8,216.89	28.98		28.98	8,245.87
**	0881	RENTS	325.00				325.00
**	0886	MAINT. OF STRUCTURES	3,039.26				3,039.26
**	0887	MAINT. OF MAINS	71,001.56	12,594.42		12,594.42	83,595.98
**	0888		3,194.59	617.00		617.00	3,811.59
**	0889	MAINT. MEASU/REG STATION	133.97				133.97
**	0892	MAINT. OF SERVICES	10,085.61	1,257.13		1,257.13	11,342.74

3

UNSG0463/00197

Northern Arizona Gas
Summary Trial Balance
by Reg Function
June ,2003

Company Code: 2002
Client Name: CU's Production
Client Number: 100
Date/Time: 07/16/2003/09:19:49

			Opening Balance	Debits	Credits	Net Change	Ending Balance	
**				25,035,091.45	25,035,091.45-			
**	0101	PLANT IN SERVICE	227,586,510.22	1,235,270.41	143,304.33-	1,091,966.08	228,678,476.30	93
**	0105	PLANT HELD FOR FUTURE USE						
**	0107	CONSTRUCTION WORK IN PROG	2,384,269.49	1,672,633.70	1,475,828.96-	196,804.74	2,581,074.23	93
**	0108	ACCUMULATED DEPRECIATION	55,477,515.35-	156,802.28	739,244.32-	582,442.04-	56,059,957.39-	95
**	0114	PLT. ACQUISITION ADJ.	21,316,576.60				21,316,576.60	
**	0131	CASH	189,947.31	4,681,427.99	4,583,237.63-	98,190.36	288,137.67	
**	0135	WORKING FUNDS						
**	0136	TEMPORARY INVESTMENTS						
**	0142	CUSTOMER ACCOUNTS RECEIVA	9,274,025.48	10,901,994.41	12,752,755.07-	1,850,760.66-	7,423,264.82	
**	0143	OTHER ACCOUNTS RECEIVABLE	369,064.82				369,064.82	
**	0144	ACCUM PROVISION FOR UNCOL	10,202.14-	37,644.95	110,175.81-	72,530.86-	82,733.00-	
**	0145	NOTES RECEIVABLE FROM ASS						
**	0146	INTERCOMPANY RECEIVABLE	172,579,292.28-	9,265,655.01	10,826,275.57-	1,560,620.56-	174,139,912.84-	
**	0154	PLANT MAT & OPER SUPPLIES	969,615.18	87,340.83	124,329.70-	36,988.87-	932,626.31	
**	0163	STORES EXPENSE UNDISTRIBU						
**	0165	PREPAYMENTS	57,931.03	394,103.02	185,599.79-	208,503.23	266,434.26	
**	0174	OTHER CURRENT ASSETS	16,490.22	22,674.99		22,674.99	39,165.21	
**	0182	REGULATORY ASSET	403,058.96		1,040.00-	1,040.00-	402,018.96	
**	0184	CLEARING ACCOUNT		405,178.16	405,178.16-			
**	0186	DEFERRED DEBITS	8,282,535.20	6,593,460.01	7,121,351.14-	527,891.13-	7,754,644.07	
**	0190	ACCUM DEFERRED INCOME TAX	3,744,647.00				3,744,647.00	
**	0191	UNRECOVERED PURCHASED GAS						
**	0216	UNAPPROPRIATED R/EARNINGS	2,346,534.48				2,346,534.48	
**	0228	OTHER NONCURRENT LIABILIT						
**	0232	ACCOUNTS PAYABLE	6,198,430.46-	16,113,669.39	15,697,169.00-	416,500.39	5,781,930.07-	
**	0233	NOTES PAYABLE-ASSOC COMPA						
**	0235	CUSTOMER DEPOSITS	2,058,177.61-	48,032.68	48,536.00-	503.32-	2,058,680.93-	
**	0236	TAXES ACCRUED	6,053,267.78-	3,150,239.89	1,424,618.68-	1,725,621.21	4,327,646.57-	
**	0237	INTEREST ACCRUED	38,245.12-		6,268.27-	6,268.27-	44,513.39-	
**	0241	TAX COLLECTIONS PAYABLES	43,207.03-	297,979.43	230,691.26-	67,288.17	24,081.14	
**	0242	MISC CURRENT/ACCRUED LIAB	12,464,430.30-		41,854.07-	41,854.07-	12,506,284.37-	
**	0252	CUSTOMER ADVANCES FOR CON	5,684,751.73-	1,017,912.03	462,025.96-	555,886.07	5,128,865.66-	
**	0253	DEFERRED CREDITS						
**	0254	OTHER REGULATORY LIABILIT	104,431.00-				104,431.00-	
**	0265							
**	0271	CONTRIB IN AID OF CONSTRU		72,605.82	72,605.82-			
**	0282	ACCUM DEFERRED INCOME TAX	15,179,665.00-				15,179,665.00-	
**	0403	DEPRECIATION EXPENSE	3,266,415.02	671,726.31	64,129.81-	607,596.50	3,874,011.52	
**	0408	TAXES OTHER THAN INCOME T	2,336,549.94	459,359.59	539.22-	458,820.37	2,795,370.31	
**	0409	INCOME TAXES	716,400.00		195,958.00-	195,958.00-	520,442.00	
**	0419	Interest & Dividend Incom	12,167.49-	2,700.61	3,628.02-	927.41-	13,094.90-	
**	0421	MISC NON-OPERATING INCOME	500,685.05-	6,419,575.60	6,514,494.65-	94,919.05-	595,604.10-	
**	0426	OTHER DEDUCTIONS	3,766.12	3.81	826,009.15-	826,005.34-	822,239.22-	
**	0431	OTHER INTEREST EXPENSE	251,786.87	51,068.30		51,068.30	302,855.17	
**	0432	ALLOW FOR BORROWED FUNDS-	6,466.73-		1,496.27-	1,496.27-	7,963.00-	
**	0480	RESIDENTIAL REVENUES	29,268,030.61-		2,284,754.23-	2,284,754.23-	31,552,784.84-	
**	0481	COMMERCIAL/INDUSTRIAL	10,127,340.32-		1,175,919.18-	1,175,919.18-	11,303,259.50-	
**	0482	PUBLIC AUTHORITY	2,426,128.28-		149,912.25-	149,912.25-	2,576,040.53-	
**	0487	FORFIETED DISCOUNTS	148,820.31-		19,498.59-	19,498.59-	168,318.90-	
**	0488	MISC SERVICE REVENUES	197,332.56-	897.42	47,104.94-	46,207.52-	243,540.08-	
**	0489	TRANSPORT/STORING	1,046,457.39-	135,614.79	301,030.35-	165,415.56-	1,211,872.95-	
**	0495	OTHER REVENUES	15,101.81-	46.22	6,526.70-	6,480.48-	21,582.29-	
**	0520	STEAM EXPENSES	1,463.11				1,463.11	

(4)

UNS^0463/00214

Attachment No. 1

UniSource Energy Services

UNS Gas

Journal Entries for the Purchase of Citizens Gas Co. Assets

	FERC Acct	Debit	Credit
1			
Cash	131	150,000,000	
Common Stock Subscribed	202		10
Donations Received from Stockholders	208		49,999,990
Other Long-Term Debt	224		100,000,000
To record the debt and equity transactions for the purchase of the gas assets.			
2			
Gas Plant Purchased	102	137,186,838	
Cash	131		135,792,209
Cash	131		1,503,029
Customer Accounts Receivable	142	1,674,182	
Other Accounts Receivable	143	422,310	
Accumulated Provision for Uncollectible Accounts	144		248,812
Plant Materials and Operating Supplies	154	908,377	
Prepayments	165	353,427	
Accrued Utility Revenues	173	6,366,518	
Miscellaneous Current and Accrued Assets	174	27,422	
Other Regulatory Assets	182.3	383,765	
Unrecovered Purchase Gas Costs	191	5,623,892	
Donations Received from Stockholders	208		1,419,941
Other Long-Term Debt	224		486,820
Accumulated Provisioin for Pension and Benefits	228.3		778,422
Accounts Payable	232		8,613,075
Customer Deposits	235		2,083,759
Interest Accrued	237		61,070
Customer Advances for Construction	252		1,959,594
To record the acquisition of gas plant assets.			
3			
Gas Plant Purchased	102		206,265,427
Gas Plant in Service	101	I 248,032,644	
Construction Work in Progress - Gas	107	1,408,952	
Accumulated Provision for Depreciation of Gas Utility Plant	108		61,069,331
Accumulated Provision for Amortization and Depletion of Gas Utility Plant	111		378,187
Accumulated Provision for Amortization of Gas Plant Acquisition Adjustment	115		3,045,228
Gas Plant Acquisition Adjustment	114	21,316,577	
To record the original cost of the acquired gas plant assets.			
4			
Gas Plant Purchased	102	69,078,589	
Gas Plant Acquisition Adjustment	114		69,078,589
To close out the balance in account 102, Gas Plant Purchased, to account 114, Gas Plant Acquisition Adjustment.			
5			
Gas Plant Acquisition Adjustment	114	47,762,012	
Accumulated Provision for Depreciation of Gas Utility Plant	108		47,762,012
To reclass negative acquisition adjustment to account 108, Accumulated Provision for Depreciation of Gas Plant.			

EXHIBIT
RUCO-2
Admitted

UNS GAS INC.'S RESPONSES TO
STAFF'S TWENTY-SECOND SET OF DATA REQUESTS
DOCKET NO. G-04202A-06-0463
April 2, 2007

STF 22-15 Refer to Mr. Dukes' rebuttal testimony at pages 17-18 regarding legal expense.

a. At page 17, line 12, Mr. Dukes indicates that the Company had continuing legal expense for the El Paso Natural Gas FERC case in 2006 and 2007. Please provide the monthly 2005 and 2007 legal expense broken out between (1) legal expense for the El Paso Natural Gas FERC case and (2) other.

b. At page 18, lines 7-10, Mr. Dukes recommends using an average of 2004 and 2006 legal expense. Please provide the monthly Please provide the monthly 2004 and 2005 legal expense broken out between (1) legal expense for the El Paso Natural Gas FERC case and (2) other.

RESPONSE:

a. Please see STF 22-15 (a), Bates Nos. UNSG(0463)06387 to UNSG(0463)06552, on the enclosed CD. The file contains the monthly legal expenses for 2006 and 2007 and all of the related invoices that include the requested detail. Bates Nos. UNSG(0463)06387 to UNSG(0463)06552 contain confidential information and are being provided pursuant to the terms of the Protective Agreement.

b. Please see STF 22-15 (b), Bates Nos. UNSG(0463)06553 to UNSG(0463)06679, on the enclosed CD. The file contains the monthly legal expenses for 2004 and 2005 and all of the related invoices that include the requested detail. Bates Nos. UNSG(0463)06553 to UNSG(0463)06679 contain confidential information and are being provided pursuant to the terms of the Protective Agreement.

RESPONDENT: Mina Briggs

WITNESS: Dallas Dukes

* Confidential *

Transaction Detail - All Sources

GL Period Name: %06, Co: 032mpany, Account: 52010, &Subaccount, Co: 032st Center, &Task, &Project Number, &FERC Account

Legal Invoices 2006 - Request 22-15a

Co: 032	Acct: 52010	Ferc Account: 0923

GL Period	Query Source	Gl Je Source	Task Number	Gl JE Name	DR	CR	Net Amount	Vendor Name	Invoice Number
JAN-06	Payables		GTPA160	Purchase Invoices USD	39,128.51		39,128.51	FLEISCHMAN & WALSH LLP	534850
	Payables		GTPD160	Purchase Invoices USD	17,612.56		17,612.56	ROSHKA DEWULF & PATTEN PLC	1205 4752328
	General Ledger	Spreadsheet		J904 - Reverses "Reverses '	17,612.56		17,612.56		
	General Ledger	Spreadsheet		J925 - Reverses "J904 - Re\		17,612.56	<17,612.56>		
	General Ledger	Spreadsheet		J926 Reverses J1015 A/P A		17,612.56	<17,612.56>		
	General Ledger	Spreadsheet		J932 - Reverses "J1020 Ye		39,128.51	<39,128.51>		
	General Ledger	Spreadsheet		J962 Jan-06 Inv. With Feb A	41,062.23		41,062.23		
Sum					115,415.86	74,353.63	41,062.23		
FEB-06	Payables		GTPA160	Purchase Invoices USD	29,845.48		29,845.48	FLEISCHMAN & WALSH LLP	535137a
	Payables		GTP0923	Purchase Invoices USD	2,233.75		2,233.75	ROSHKA DEWULF & PATTEN PLC	0106 7052065
	Payables		GTPD160	Purchase Invoices USD	8,983.00		8,983.00	ROSHKA DEWULF & PATTEN PLC	0106 7052065
	General Ledger	Spreadsheet		J342 TEP/UNE/UNG Manua	41,441.06		41,441.06		
	General Ledger	Spreadsheet		J909 - Reverses "J962 Jan-(		41,062.23	<41,062.23>		
Sum					82,503.29	41,062.23	41,441.06		
MAR-06	Payables		GTPA160	Purchase Invoices USD	29,845.48		29,845.48	FLEISCHMAN & WALSH LLP	
	Payables		GTPA160	Purchase Invoices USD		29,845.48	<29,845.48>	FLEISCHMAN & WALSH LLP	535137
	Payables		GTPA160	Purchase Invoices USD	11,595.58		11,595.58	FLEISCHMAN & WALSH LLP	535137a
	Payables		G560930	Purchase Invoices USD	55.36		55.36	PETTY CASH	535457
	General Ledger	Spreadsheet		J343 - Reverses "J342 TEP/		41,441.06	<41,441.06>		RPC51257LUCERO
Sum					41,496.42	71,286.54	<29,790.12>		
APR-06	Payables		GTP0923	Purchase Invoices USD	71.45		71.45	LEWIS AND ROCA LLP	764891
	Payables		GTPA160	Purchase Invoices USD	6,050.00		6,050.00	LOCKE LIDDELL & SAPP LLP	578939
	Payables		GTP0923	Purchase Invoices USD	1,386.60		1,386.60	ROSHKA DEWULF & PATTEN PLC	0306 8497530
	Payables		GTPD160	Purchase Invoices USD	412.50		412.50	ROSHKA DEWULF & PATTEN PLC	0306 8497530
Sum					7,920.55		7,920.55		
MAY-06	Payables		GTPA160	Purchase Invoices USD	30,806.84		30,806.84	LOCKE LIDDELL & SAPP LLP	584116
	Payables		GTP0923	Purchase Invoices USD	453.20		453.20	ROSHKA DEWULF & PATTEN PLC	053106 5737731
	Payables		GTPD160	Purchase Invoices USD	508.50		508.50	ROSHKA DEWULF & PATTEN PLC	053106 5737731
Sum					31,768.54		31,768.54		
JUN-06	Payables		GTPF160	Purchase Invoices USD	1,575.00		1,575.00	BEALE MICHEAELS & SLACK PC	050906 40642
	Payables		GTPA160	Purchase Invoices USD	43,545.07		43,545.07	LOCKE LIDDELL & SAPP LLP	591248
	Payables		GTPA160	Purchase Invoices USD	43,278.93		43,278.93	LOCKE LIDDELL & SAPP LLP	588485
	General Ledger	Spreadsheet		J341 Legal Invoice Accrua A	43,000.00		43,000.00		
Sum					131,399.00		131,399.00		
JUL-06	Payables		GTPF160	Purchase Invoices USD	267.13		267.13	BEALE MICHEAELS & SLACK PC	071806 40642-0010
	Payables		GTPF160	Purchase Invoices USD	5,722.41		5,722.41	BEALE MICHEAELS & SLACK PC	406420010061206
	Payables		GTP0923	Purchase Invoices USD	115.45		115.45	LEWIS AND ROCA LLP	770751
	Payables		GTP0923	Purchase Invoices USD	26.62		26.62	ROSHKA DEWULF & PATTEN PLC	32803
	Payables		GTP0923	Purchase Invoices USD	709.90		709.90	THELEN REID BROWN RAYSMAN & STEINER LL	6937776
Sum					6,841.51		6,841.51		
AUG-06	Payables		GTP0923	Purchase Invoices USD	75.30		75.30	LEWIS AND ROCA LLP	773853

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Confidential UNSG0463/06387

Transaction Detail - All Sources

GL Period Name: %06, Co: 032mpany, Account: 52010, &Subaccount, Co: 032st Center, &Task, &Project Number, &FERC Account

Co: 032	Acct: 52010	Ferc Account: 0923

GL Period	Query Source	Gl Je Source	Task Number	Gl JE Name	DR	CR	Net Amount	Vendor Name	Invoice Number
AUG-06	Payables		GTPA160	Purchase Invoices USD	38,875.06		38,875.06	LOCKE LIDDELL & SAPP LLP	596069
	Payables		GTP0923	Purchase Invoices USD	2,589.90		2,589.90	THELEN REID BROWN RAYSMAN & STEINER LL	6940979
	General Ledger	Spreadsheet		J906 UNS/TEP/UES Credit ,		3,299.70	<3,299.70>		
	Purchasing	Purchasing		Accrual USD SEP-06	0.54		0.54		
Sum					41,540.80	3,299.70	38,241.10		
SEP-06	Payables		GTPF160	Purchase Invoices USD	2,091.35		2,091.35	BEALE MICHEAELS & SLACK PC	090606 209135
	Payables		GTPA160	Purchase Invoices USD	39,214.58		39,214.58	LOCKE LIDDELL & SAPP LLP	599777
	Payables		GTPA160	Purchase Invoices USD	38,130.60		38,130.60	LOCKE LIDDELL & SAPP LLP	603092
	Payables		GTP0923	Purchase Invoices USD	2,574.37		2,574.37	THELEN REID BROWN RAYSMAN & STEINER LL	6944323
	General Ledger	Spreadsheet		J907 Correct coding of le Ta		2,574.37	<2,574.37>		
	General Ledger	Spreadsheet		J341 Legal Invoice Accrua A	40,000.00		40,000.00		
	Purchasing	Purchasing		Accrual USD OCT-06	0.54		0.54		
	Purchasing	Purchasing		Reverses "Accrual USD SEI		0.54	<0.54>		
Sum					122,011.44	2,574.91	119,436.53		
OCT-06	Payables		GTPF160	Purchase Invoices USD	1,267.24		1,267.24	BEALE MICHEAELS & SLACK PC	092506 40642-0010
	Payables		GTPF160	Purchase Invoices USD	1,362.50		1,362.50	BEALE MICHEAELS & SLACK PC	101106 40642-0010
	Payables		GTP0923	Purchase Invoices USD	282.00		282.00	ROSHKA DEWULF & PATTEN PLC	32937
	Payables		GTP0923	Purchase Invoices USD	825.00		825.00	ROSHKA DEWULF & PATTEN PLC	33212
	Payables		GTPD160	Purchase Invoices USD	205.50		205.50	ROSHKA DEWULF & PATTEN PLC	32937
	Purchasing	Purchasing		Reverses "Accrual USD OC'		0.54	<0.54>		
	Purchasing	Purchasing		Accrual USD NOV-06	0.54		0.54		
Sum					3,942.78	0.54	3,942.24		
NOV-06	Payables		GTPF160	Purchase Invoices USD	802.97		802.97	INVESTIGATIVE RESEARCH INC	11581
	Payables		GTP0923	Purchase Invoices USD	52.88		52.88	LEWIS AND ROCA LLP	781384
	Payables		GTP0923	Purchase Invoices USD	903.10		903.10	ROSHKA DEWULF & PATTEN PLC	33350
	General Ledger	Spreadsheet		J342 TEP/UNE/UNG Manua	38,828.60		38,828.60		
	Purchasing	Purchasing		Accrual USD DEC-06	0.54		0.54		
	Purchasing	Purchasing		Reverses "Accrual USD NO'		0.54	<0.54>		
Sum					40,588.09	0.54	40,587.55		
DEC-06	Payables		GTPF160	Purchase Invoices USD	5,838.43		5,838.43	BEALE MICHEAELS & SLACK PC	111006 40640-0010
	Payables		GTP0923	Purchase Invoices USD	75.50		75.50	LEWIS AND ROCA LLP	785015
	Payables		GTPA160	Purchase Invoices USD	35,947.61		35,947.61	LOCKE LIDDELL & SAPP LLP	607369
	Payables		GTPA160	Purchase Invoices USD	38,828.60		38,828.60	LOCKE LIDDELL & SAPP LLP	611255
	Payables		GTP0923	Purchase Invoices USD	85.00		85.00	ROSHKA DEWULF & PATTEN PLC	33475
	General Ledger	Spreadsheet		J341 - Legal Accrual Accrua		49,400.00	<49,400.00>		
	General Ledger	Spreadsheet		J343 - Reverses "J342 TEP/		38,828.60	<38,828.60>		
	General Ledger	Spreadsheet		J960 Additional TEP/UNG/U	143.90		143.90		
	Purchasing	Purchasing		Accrual USD JAN-07	0.53		0.53		
	Purchasing	Purchasing		Reverses "Accrual USD DE(		0.54	<0.54>		
Sum					80,919.57	88,229.14	<7,309.57>		
Total					706,347.85	280,807.23	425,540.62		

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Confidential UNSG0463/06388

* Confidential *

Transaction Detail - All Sources

GL Period Name: %04, Co: 032mpany, Account: 52010, &Subaccount, Co: 032st Center, &Task, &Project Number, FERC: 0923 Account

Co: 032	Acct: 52010	FERC: 0923

Legal 2004 Invoices = Request 22-156

GL Period	Pa Task	Pa Expenditure Comment (Vendor)	Gl JE Name	DR	CR	Net Amount	Vendor Name	Invoice Number
JAN-04	G500923	003539 THELEN REID & PRIEST LLP		368.67		368.67		
	GTP0923	000290 FENNEMORE CRAIG		605.34		605.34		
	GTP0923	003058 FENNEMORE CRAIG		293.92		293.92		
	GTPA160	002051 FLEISCHMAN & WALSH, LLP		19,880.61		19,880.61		
	GTPA160	002561 TROUTMAN SANDERS LLP		622.50		622.50		
	GTPD160	000638 LEWIS AND ROCA LLP		2,520.80		2,520.80		
	GTPE160	000087 SNELL & WILMER LAW OFFICES		97.50		97.50		
			J342 LEGAL FEES Adjustmen	38,788.86		38,788.86		
			J908 - Reverses "J342 LEGAL		19,880.61	<19,880.61>		
			J936 Cor Cost Centers UNS A	0.00		0.00		
Sum				**63,178.20**	**19,880.61**	**43,297.59**		
FEB-04			J909 - Reverses "J342 LEGAL		38,788.86	<38,788.86>		
			J342 LEGAL FEES Adjustmen	1,720.24		1,720.24		
	GTPD160	006929 LEWIS AND ROCA LLP		4,040.38		4,040.38		
	GTPA160	008787 FLEISCHMAN & WALSH, LLP		6,882.74		6,882.74		
	GTPA160	006880 FLEISCHMAN & WALSH, LLP		16,197.34		16,197.34		
	G500923	006929 LEWIS AND ROCA LLP		1,049.82		1,049.82		
	G500923	005312 ROSHKA HEYMAN & DEWULF		22,591.52		22,591.52		
Sum				**52,482.04**	**38,788.86**	**13,693.18**		
MAR-04			J909 - Reverses "J342 LEGAL		1,720.24	<1,720.24>		
			J342 LEGAL FEES Adjustmen	1,569.00		1,569.00		
	GTPC160	015085 ROSHKA HEYMAN & DEWULF		315.80		315.80		
	GTPC160	010161 ROSHKA HEYMAN & DEWULF		125.50		125.50		
	GTPA160	013723 TROUTMAN SANDERS LLP		473.00		473.00		
	GTP0923	014505 LEWIS AND ROCA LLP		4,353.45		4,353.45		
	GTP0923	014485 THELEN REID & PRIEST LLP		437.83		437.83		
	GTP0923	011086 LEWIS AND ROCA LLP		962.25		962.25		
	G500923	011086 LEWIS AND ROCA LLP		1,121.74		1,121.74		
Sum				**9,358.57**	**1,720.24**	**7,638.33**		
APR-04			J940 - Reverses "J342 LEGAL		1,569.00	<1,569.00>		
			J342 LEGAL FEES Adjustmen	9,281.50		9,281.50		
	GTPE160	018353 SNELL & WILMER LAW OFFICES		984.00		984.00		
	GTPA160	019143 FLEISCHMAN & WALSH, LLP		6,811.56		6,811.56		
	GTPA160	018874 TROUTMAN SANDERS LLP		1,338.50		1,338.50		
	GTPA160	018354 TROUTMAN SANDERS LLP		585.00		585.00		
	GTPA160	017104 FLEISCHMAN & WALSH, LLP		21,636.80		21,636.80		
	GTP0923	019753 LEWIS AND ROCA LLP		5,930.55		5,930.55		
Sum				**46,567.91**	**1,569.00**	**44,998.91**		
MAY-04	GTP0923	024682 LEWIS AND ROCA LLP		4,659.54		4,659.54		
	GTP0923	024683 LEWIS AND ROCA LLP		490.08		490.08		
	GTPC160	021275 ROSHKA HEYMAN & DEWULF		835.50		835.50		

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Transaction Detail - All Sources
GL Period Name: %04, Co: 032mpany, Account: 52010, &Subaccount, Co: 032st Center, &Task, &Project Number, FERC: 0923 Account

Co: 032	Acct: 52010	FERC: 0923

GL Period	Pa Task	Pa Expenditure Comment	Gl JE Name	DR	CR	Net Amount	Vendor Name	Invoice Number
MAY-04	GTPE160	023094 SNELL & WILMER LAW OFFICES		8,446.00		8,446.00		
			J342 LEGAL FEES Adjustmen	26,738.71		26,738.71		
			J905 - Reverses "J342 LEGAL		9,281.50	<9,281.50>		
Sum				41,169.83	9,281.50	31,888.33		
JUN-04			J901 - Reverses "J342 LEGAL		26,738.71	<26,738.71>		
			J342 LEGAL FEES Adjustmen	4,780.36		4,780.36		
	GTPC160	026941 ROSHKA HEYMAN & DEWULF		505.90		505.90		
	GTPA160	027042 TROUTMAN SANDERS LLP		5,737.00		5,737.00		
	GTPA160	026885 FLEISCHMAN & WALSH, LLP		26,232.81		26,232.81		
	G500923	030387 JORDEN BISCHOFF MCGUIRE AND RO		257.83		257.83		
Sum				37,513.90	26,738.71	10,775.19		
JUL-04	GTP0923	031687 LEWIS AND ROCA LLP		4,715.37		4,715.37		
	GTPA160	033596 VOUCHER NOT FOUND			29,882.49	<29,882.49>		
	GTPA160	033598 FLEISCHMAN & WALSH, LLP		29,882.49		29,882.49		
	GTPA160	033656 FLEISCHMAN & WALSH, LLP		29,822.49		29,822.49		
	GTPA160	035250 TROUTMAN SANDERS LLP		2,393.00		2,393.00		
	GTPC160	033580 ROSHKA HEYMAN & DEWULF		65.00		65.00		
			J902 - Reverses "J342 LEGAL		4,780.36	<4,780.36>		
Sum				66,878.35	34,662.85	32,215.50		
AUG-04			J342 LEGAL FEES Adjustmen	2,030.46		2,030.46		
	GTPA160	043072 TROUTMAN SANDERS LLP		2,532.50		2,532.50		
	GTPA160	039662 FLEISCHMAN & WALSH, LLP		29,542.03		29,542.03		
	GTP0923	037914 LEWIS AND ROCA LLP		1,251.97		1,251.97		
Sum				35,356.96		35,356.96		
SEP-04	GTP0923		Purchase Invoices USD	1,310.46		1,310.46	LEWIS AND ROCA LLP	711879
	GTP0923		Purchase Invoices USD	9,143.80		9,143.80	SNELL & WILMER LAW OFFICES	1868427
	GTPA160		Purchase Invoices USD	720.00		720.00	THELEN REID BROWN RAYSMAN	351816
	GTPA160		Purchase Invoices USD	720.00		720.00	TROUTMAN SANDERS LLP	351816
			J925 UES Seyfarth Correct Ad	8,828.00		8,828.00		
			J929 - Reverses "J342 LEGAL		2,030.46	<2,030.46>		
			J963 Adjust/Create AP Acc Ad	15,344.13		15,344.13		
Sum				36,066.39	2,030.46	34,035.93		
OCT-04	GTPA160		Purchase Invoices USD	32,248.25		32,248.25	FLEISCHMAN & WALSH LLP	530528
	GTP0923		Purchase Invoices USD	2,030.38		2,030.38	THELEN REID BROWN RAYSMAN	6856235
	GTP0923		Purchase Invoices USD	160.54		160.54	THELEN REID BROWN RAYSMAN	6859849
			J909 - Reverses "J963 Adjust/		15,344.13	<15,344.13>		
Sum				34,439.17	15,344.13	19,095.04		
NOV-04	GTPB160		Purchase Invoices USD	7,057.63		7,057.63	BELL NUNNALLY & MARTIN LLP	705763
	GTPA160		Purchase Invoices USD	32,564.36		32,564.36	FLEISCHMAN & WALSH LLP	530796
	GTPA160		Purchase Invoices USD	19,611.84		19,611.84	FLEISCHMAN & WALSH LLP	531009
	GTP0923		Purchase Invoices USD	285.55		285.55	LEWIS AND ROCA LLP	713830

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Transaction Detail - All Sources

GL Period Name: %04, Co: 032mpany, Account: 52010, &Subaccount, Co: 032st Center, &Task, &Project Number, FERC: 0923 Account

Co: 032	Acct: 52010	FERC: 0923

GL Period	Pa Task	Pa Expenditure Comment	Gl/JE Name	DR	CR	Net Amount	Vendor Name	Invoice Number
NOV-04	GTP0923		Purchase Invoices USD	236.90		236.90	LEWIS AND ROCA LLP	716357
	GTPC160		Purchase Invoices USD	97.50		97.50	ROSHKA DEWULF & PATTEN PL(	12270364
	GTP0923		Purchase Invoices USD	237.30		237.30	ROSHKA DEWULF & PATTEN PL(	12270364
	GTP0923		Purchase Invoices USD	10,077.56		10,077.56	SNELL & WILMER LAW OFFICES	2196146
	GTP0923		Purchase Invoices USD	127.50		127.50	SNELL & WILMER LAW OFFICES	415370
	GTP0923		Purchase Invoices USD	163.77		163.77	THELEN REID BROWN RAYSMAN	14315555
	GTPA160		Purchase Invoices USD	495.00		495.00	TROUTMAN SANDERS LLP	11258927
	GTPA160		Purchase Invoices USD	1,035.00		1,035.00	TROUTMAN SANDERS LLP	6408956
Sum				71,989.91		71,989.91		
DEC-04	GTPA160		Purchase Invoices USD	~~18,217.95~~		~~18,217.95~~	~~FLEISCHMAN & WALSH LLP~~	531295
	GTP0923		Purchase Invoices USD	2,464.93		2,464.93	RODEY DICKASON SLOAN AKIN	968151
			J342 LEGAL FEES Adjustmen	349.93		349.93		
			J933 TEP/UNE/UNG Manual /	246,924.07		246,924.07		
			J967 UNSE and UNSG Correc		239,768.17	<239,768.17>		
Sum				267,956.88	239,768.17	28,188.71		
Total				762,958.11	389,784.53	373,173.58		

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UNS GAS, INC.

DOCKET NO. G-04204A-06-0463 et al.

DIRECT TESTIMONY

OF

RODNEY L. MOORE

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

FEBRUARY 9, 2007

EXHIBIT
tabbies
RUCO 3
admitted

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INTRODUCTION

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

A. Rodney L. Moore, Public Utilities Analyst V
Residential Utility Consumer Office ("RUCO")
1110 West Washington Street, Suite 220
Phoenix, Arizona 85007.

Q. Please state your educational background and qualifications in the utility regulation field.

A. Appendix 1, which is attached to this testimony, describes my educational background and includes a list of the rate case and regulatory matters in which I have participated.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present RUCO's recommendations regarding UNS Gas Corporation's ("Company" or "UNS") application for a determination of the current fair value of its utility plant and property and for increases in its rates and charges based thereon for gas service. The test year utilized by the Company in connection with the preparation of this application is the 12-month period that ended December 31, 2005.

BACKGROUND

Q. Please describe your work effort on this project.

A. I obtained and reviewed data and performed analytical procedures necessary to understand the Company's filing as it relates to operating income, rate base, the Company's overall revenue requirement and rate design. My recommendations are based on these analyses. Procedures performed include the in-house formulation and analysis of seven sets of data requests, the review and analysis of Company responses to Arizona Corporation Commission ("Commission" or "ACC") Staff data requests, conversations with Company personnel and the review of prior ACC dockets related to UNS.

In Decision No. 66028, dated July 03, 2003, the Commission approved a Settlement Agreement, which authorized UNS to acquire the electric and gas assets of Citizens Communications Company ("Citizens"). This Settlement Agreement is the basis for the Company's present rates and charges for utility service. The test year used in that proceeding was the 12-month period ending December 31, 2001.

Q. What areas will you address in your testimony?

A. I will address issues related to rate base, operating income, revenue requirements and rate design. RUCO's witness Mr. William Rigsby will provide an analysis of the cost of capital.

RUCO's witness Ms. Marylee Diaz Cortez will also address additional issues related to rate base, operating income, rate design and revenue requirements.

Q. Please identify the exhibits you are sponsoring.

A. I am sponsoring Schedules numbered RLM-1 through RLM-17.

SUMMARY OF ADJUSTMENTS

Q. Please summarize the adjustments to rate base, operating income and rate design issues addressed in your testimony.

A. My testimony addresses the following issues:

Rate Base

Fair Value Rate Base – This adjustment states the fair value rate base by giving equal weighting (50/50 split) to RUCO's adjusted original cost rate base and RUCO's calculation of the reconstruction cost new depreciated rate base.

Pre-Acquisition Unsubstantiated Gross Plant and Accumulated Depreciation – This adjustment disallows the value of plant UNS was unable to verify as part of the rate base acquired from Citizens on August 11, 2003.

Test-Year Accumulated Depreciation – This adjustment restates the accumulated depreciation value to reflect RUCO's recalculation using the authorized depreciation rates.

Construction Work In Progress – This adjustment is addressed by RUCO witness Ms. Diaz Cortez.

Acquisition Adjustment - This adjustment is addressed by RUCO witness Ms. Diaz Cortez.

Geographic Information System - This adjustment is addressed by RUCO witness Ms. Diaz Cortez.

Allowance For Working Capital - This adjustment is addressed by RUCO witness Ms. Diaz Cortez.

Southern Union Acquisition – No adjustment.

Griffith Power Plant – No adjustment.

Build-Out Plant – No adjustment.

Customer Assistance Residential Energy Support Expense Asset – No adjustment.

Operating Income

Worker's Compensation Expense – This adjustment converts the amount reflected in the test-year operating expense from a cash basis to an accrual.

Incentive Compensation Expense – This adjustment removes all incentive compensation expenses, because the awards were paid despite non-performance of goals and did not provide additional benefits to ratepayers.

Depreciation and Amortization Expense Annualization – This adjustment reflects the level of test-year depreciation expense based on RUCO's adjusted gross plant in service and the Company–proposed depreciation rates.

Postage Expense – This adjustment reflects the RUCO's annualization of the customer base and a known and measurable postal increase.

Customer Service Cost Allocations – This adjustment disallows the Company's increased customer service expenditures, because the additional costs were imprudent and did not provide additional benefits to ratepayers.

RUCO Adjustments To Test-Year Operating Expenses – This adjustment to operating expenses removes inappropriate expenditures not necessary in the provisioning of gas service.

Property Tax Expense – This adjustment reflects the appropriate level of property tax expense given RUCO's recommended level of net plant in service.

Rate Case Expense – This adjustment is based on RUCO's determination of the fair and reasonable cost to UNS ratepayers for this application process.

American Gas Association Dues – This adjustment removes the portion of the dues dedicated to marketing and lobbying.

Non-Recurring/Atypical Expenses – This adjustment removes costs not expected to recur and considered atypical for inclusion in test year expenses.

Pension and Benefit Expenses – This adjustment reflects RUCO's disallowance of the supplemental executive retirement plan.

Amortization of GIS Expenditures - This adjustment is addressed by RUCO witness Ms. Diaz Cortez.

Fleet Fuel Expense - This adjustment is addressed by RUCO witness Ms. Diaz Cortez.

Customer Annualization - This adjustment is addressed by RUCO witness Ms. Diaz Cortez.

Weather Normalization - This adjustment is addressed by RUCO witness Ms. Diaz Cortez.

Corporate Cost Allocations – This adjustment is addressed by RUCO witness Ms. Diaz Cortez.

Bad Debt Expense – This adjustment is addressed by RUCO witness Ms. Diaz Cortez.

Depreciation and Property Tax for Construction Work In Progress – This adjustment is addressed by RUCO witness Ms. Diaz Cortez.

Out of Period Expenses – This adjustment is addressed by RUCO witness Ms. Diaz Cortez.

Legal Expense - This adjustment is addressed by RUCO witness Ms. Diaz Cortez.

Griffith Plant Operations – No adjustment.

Purchased Gas Cost and Gas Cost Revenue – No adjustment.

NSP Revenue and Gas Costs – No adjustment.

Payroll Expense – No adjustment.

Payroll Tax Expense – No adjustment.

Post Retirement Medical Expense – No adjustment.

Interest on Customer Deposits – No adjustment.

Year-End Accruals – No adjustment.

Advertising and Donation Expenses – No adjustment.

Customer Assistance Residential Energy Support Expense – No adjustment.

Gain on Sale of Property – No adjustment.

Income Tax Expense – This adjustment reflects income tax expenses calculated on RUCO's recommended revenues and expenses.

REVENUE REQUIREMENTS

Q. Please summarize the results of RUCO's analysis of the Company's filing and state RUCO's recommended revenue requirement.

A. As outlined in Schedule RLM-1, RUCO is recommending that the increase in the Company's revenue requirement not exceed:

UNS	RUCO	DIFFERENCE
$9,615,767	$1,505,003	($8,110,764)

My recommended revenue requirement percentage increase versus the Company's proposal is as follows:

UNS	RUCO	DIFFERENCE
20.39 %	3.18 %	-17.21 %

RUCO's recommended decrease in Fair Value Rate Base ("FVRB") based on the equal weighting of a 50/50 split between Original Cost Rate Base ("OCRB") and Reconstruction Cost New Depreciated Rate Base ("RCND") is summarized on Schedule RLM-1:

UNS	RUCO	DIFFERENCE
$191,177,714	$171,223,175	($19,954,539)

The detail supporting RUCO's recommended rate base is presented on Schedules RLM-3, RLM-4, and RLM-5.

RUCO's recommended required operating income is shown on Schedule RLM-1 as:

UNS	RUCO	DIFFERENCE
$14,204,479	$11,480,374	($2,724,105)

Schedule RLM-1 presents the calculation of RUCO's recommended revenue requirement.

RATE BASE

Determination Of Fair Value Rate Base

Q. Please explain the basis for your determination of the FVRB as shown on Schedule RLM-1.

A. RUCO's determination of the FVRB consists of three elements. First, the value of the OCRB was restated to reflect RUCO's adjustment to the various rate base determinants. Second, the value of the RCND was computed. As shown on supporting Schedule RLM-2, RUCO computed RCND by multiplying RUCO's OCRB by the ratio of the Company's OCRB to its RCND as filed. Third, the FVRB was computed on an equally weighted basis (50/50 split) between RUCO's OCRB and RCND.

Q. Please elaborate on the first element of RUCO's FVRB determination.

A. The first element consists of several adjustments to the OCRB. The aggregate adjustment was corroborated between myself and RUCO witness Ms. Diaz Cortez. As shown on Schedule RLM-3, I was responsible for Adjustments No. 1 and No. 2. These adjustments established the initial level and subsequently calculated the present test-year level of gross plant in service and accumulated depreciation. Ms. Diaz Cortez analyzed the remaining adjustments.

<u>RUCO Rate Base Adjustment No. 1 – Remove Unsubstantiated Pre-Acquisition Gross Plant and Adjust Understated Accumulated Depreciation</u>

Q. Please provide the background to RUCO's adjustment.

A. The Settlement Agreement specifically states: "For ratemaking purposes and for the purposes of this Agreement, the Parties agree to a FVRB of $142,132,013 as of October 29, 2002." The components of this FVRB resulted from an OCRB of $117,661,030, including gross plant in service of $219,383,559 and accumulated depreciation of $52,018,971.

UNS states the value of the gross plant in service as of August 11, 2003 is $248,032,644 with a corresponding level of accumulated depreciation of $64,186,276. Thus, the Company contends the value of the plant increased $28,649,085 between the end of the test year utilized in the Settlement Agreement (December 31, 2001) and the date of the acquisition (August 11, 2003); while the accumulated depreciation balance increased by $12,167,305.

However, during discovery UNS was unable to provide records to substantiate the existence of $3,133,264 that it claimed Citizens invested in plant between the end of the test year in the prior case and the effective date of the acquisition.

Moreover, UNS has not supported its claimed accumulated depreciation balance and that balance is understated when compared to RUCO's application of the authorized plant balances to the authorized depreciation rates.

Q. Please continue and provide the explanation for RUCO's adjustment to remove unsubstantiated pre-acquisition plant and adjust accumulated depreciation.

A. This adjustment consists of two elements. As shown on supporting Schedule RLM-4 pages 1 through 3; first, I disallowed the unsubstantiated $3,133,264 of plant additions as represented by UNS; and second, I increased the level of accumulated depreciation.

Q. Please explain the first element of the adjustment to remove unsubstantiated pre-acquisition plan.

A. In the first element I reconstructed the plant addition and retirement activities as provided in the Company's response to RUCO data request 2.19.

The records submitted by UNS in data request 2.19 failed to account for $3,133,264 of gross plant in service that UNS has requested in this filing.

Thus, the Company has been unable to substantiate the existence of this level of plant. Without such evidence it cannot be afforded ratemaking treatment.

Q. Please explain the second element of the adjustment to increase the accumulated depreciation balance.

A. The second element is the difference in the level of accumulated depreciation as calculated by RUCO and the amount recorded by the Company as of December 31, 2003. RUCO's calculation applies the Commission-authorized depreciation rates to the Commission-authorized plant balances from the last rate case and substantiated plant additions and retirements in the current application. UNS has not supported its claimed accumulated depreciation balance and that balance is understated when compared to RUCO's application of the authorized depreciation rates to the current supported plant balances.

Q. Please summarize RUCO's adjustment to unsubstantiated pre-acquisition plant and understated accumulated depreciation.

A. As shown on Schedule RLM-3, column (B), this adjustment decreased the starting point of the net utility plant in service for this proceeding by removing $3,133,264 in gross plant and increasing the level of accumulated depreciation by $3,857,413 for a total reduction in the OCRB of $6,990,677.

<u>RUCO Rate Base Adjustment No. 2 – Reduce Test-Year Accumulated Depreciation</u>

Q. Please provide the background to RUCO's adjustment.

A. In the current case, UNS is attempting to use the depreciation rates that Citizens requested in its gas rate case (Docket No. G-01032A-02-0598); however, Citizens requested a suspension of that filing and instead filed a joint application with UNS for the sale of its assets. That joint application resulted in the Settlement Agreement.

The Settlement Agreement discussed specific terms to encompass a number of issues and was approved subject to the requirements and limitations discussed therein. However, the Settlement Agreement did not address plant depreciation rates; therefore, the Commission did not find, conclude or order a change in the depreciation rates. Thus, without a specific change being ordered by the Commission, the effective depreciation rates are those authorized by the Commission prior to this Settlement Agreement in Decision No. 58664, dated June 16, 1994.

Q. Please continue and provide the explanation for RUCO's adjustment to reduce the test-year accumulated depreciation.

A. In the Settlement Agreement, the Commission did not authorize a change in the depreciation rates it had established in Decision No. 58664. Therefore, since A.A.C. R14-2-102.C.4 states:

> "Changed depreciation rates shall not become effective until the Commission authorizes such changes."

RUCO's test-year accumulated depreciation reflects a calculation using the authorized rates stated in Decision No. 58664.

This adjustment decreased the test-year OCRB by $2,855,454.

OPERATING INCOME

<u>Operating Income Summary</u>

Q. Is RUCO recommending any changes to the Company's proposed operating expenses?

A. Yes. The Company proposed twenty-eight adjustments to its historical test-year operating income and RUCO analyzed the Company's adjustments and made several additional adjustments to the operating income as filed by the Company. RUCO witness Ms. Diaz Cortez testimony discusses fifteen of the adjustments, while I was responsible for reviewing thirteen of the adjustments the Company proposes to its test-year operating income, and finally, as a result of its discovery, RUCO recommends other adjustments. My review, analysis and adjustments are explained below.

Operating Income Adjustment No.1 – Worker's Compensation

Q. Please discuss the Company's proposed worker's compensation expense adjustment.

A. The Company has converted the amount reflected in the test-year operating expenses from an accrual to a cash basis.

Q. Please explain RUCO's treatment of the Company's proposed worker's compensation expense adjustment.

A. Absent a Commission ruling, RUCO does not consider it appropriate to arbitrarily change from an accrual to a cash basis. The UNS argument that since worker's compensation is a benefit provided to former or inactive employees it should receive the same treatment as post employment benefits is hollow. The Company failed to provide documentation segregating any worker's compensation benefits that are included in post employment benefit obligations. Furthermore, workers' compensation certainly is provided to active employees for which post-retirement accounting would not be applicable.

Therefore, as shown on Schedule RLM-7, column (B), I reversed the Company's cash treatment of worker's compensation expense to an accrual basis and decreased test-year operating expenses by $34,234.

Operating Income Adjustment No. 2 – Incentive Compensation

Q. Please provide the background for this adjustment.

A. In 2004, the Unisource Energy Corporation awarded incentive payments under the Performance Enhancement Plan ("PEP"). The PEP is only eligible for a select group of non-union employees and is paid after meeting certain performance goals, including certain financial goals.

In 2005, Unisource Energy Corporation did not meet the PEP financial goals; and therefore, no payments under the PEP program were awarded. Nevertheless, the Board of Directors authorized a Special Recognition Award to these non-union employees in recognition of their accomplishments; however, this special award was less of a payment as awarded in 2004.

The Company's adjusted test-year expense incorporates the average of the 2004 PEP bonus and the 2005 Special Recognition Award.

Q. Please continue and provide the explanation for RUCO's adjustment to the incentive compensation expenses.

A. After reviewing the Company's response to RUCO's data requests 1.14 and 6.10, it became apparent the ratepayers should not be burdened with the Board of Directors' arbitrary decision to authorize a Special Recognition Award to select UNS employees when they did not meet

Unisource Energy's 2005 financial performance goal. This "Special" award is unique and does not meet the criteria of a typical and recurring test-year expense; moreover, it rewards employees for non-performance.

RUCO does not generally vary from the strict implementation of the Historical Test-Year principle to avoid mismatches in the ratemaking elements. Therefore, RUCO dismisses the Company's proposal to average the 2005 Special Recognition Award with the 2004 PEP program.

Further to RUCO's objection to averaging the incentive compensation expenses over two years, the Company states that 60 percent of the PEP bonus is directly related to financial performance and operational cost containment. Stockholders are the beneficiaries of the achievement of these financial components. This is particularly true between rate cases. Any additional profit the Company is able to achieve between rate cases accrues solely to the Company's stockholders. Accordingly, since stockholders stand to gain from the achievement of the financial component, stockholders should bear all of the cost of this portion of the incentive compensation. These costs should not be considered for inclusion in rates.

Moreover, RUCO consistently scrutinizes any incentive compensation thoroughly to ensure ratepayers receive adequate benefit from the expense incurred. With the majority of a customer's interfacing with the Company done through the rank and file unionized employees who are not eligible for any PEP compensation, the perceived incremental increase in customer service generated by this incentive package would not be cost beneficial to ratepayers.

Therefore, RUCO disallows the Company's special test-year compensation bonus and would consider the PEP program (had it been implemented in the test year) discriminatory because the benefit is provided only to a subset of employees and it is of limited incremental benefit to the ratepayers because the benefit is offered to a class of employees that does not directly affect the service quality of customers.

As shown on Schedule RLM-7, column (C), my adjustment decreases adjusted test-year expenses by $278,748.

<u>Operating Income Adjustment No. 3 – Depreciation Expenses</u>

Q. Please explain your adjustment to reduce depreciation expenses.

A. The adjustment is primarily attributable to RUCO's rate base adjustment No. 1, which disallowed the unsubstantiated pre-acquisition plant and to rate base adjustment No. 3 disallowing construction work in progress ("CWIP") from rate base.

RUCO agrees with the new set of depreciation rates that UNS is proposing to implement on a going forward basis. I computed test-year depreciation by multiplying RUCO's level of test-year gross plant in service by the Company's proposed depreciation rates.

As shown on Schedule RLM-7, column (D) and supporting Schedule RLM-8, my adjustment decreases adjusted test-year expenses by $324,083.

Operating Income Adjustment No. 4 – Postage Expense

Q. Please explain your adjustment to reduce the postage expenses.

A. My adjustment consists of two elements. First, I annualized the test-year postage expense to match RUCO's annualized customer count.

Second, I increased the expense to recognize the change in postal rates, effective January 2006.

As shown on Schedule RLM-7, column (E) and supporting Schedule RLM-9, my adjustment decreases adjusted test-year expenses by $153,479.

Operating Income Adjustment No. 5 – Customer Service Cost Allocations

Q. Please provide the background for this adjustment.

A. Prior to May 1, 2005, the Call Center duties for UNS Gas were performed in-house by six UNS Gas Customer Service Representatives at a cost of approximately $17,636 per month for those four months.

After May 1, 2005, Unisource Energy consolidated the call center operations of UNS Gas, UNS Electric and TEP at an actual allocated cost to UNS Gas of $76,227 per month for those eight months, a 432 percent increase in cost.

Therefore, because of such a dramatic increase in costs for approximately the same service, RUCO does not agree with the Company's adjustment to allocate to UNS Gas a portion of the integrated call center and customer service functions which serves UNS Gas, UNS Electric and TEP.

Q. Please continue and provide an explanation for RUCO's adjustment to the allocated customer service costs.

A. In the Company's response to RUCO data request 6.13, UNS indicates that similar duties were initially provided by in-house customer service representatives at a much less cost.

RUCO is disallowing this imprudent expenditure which quadruples the annual cost for the provisioning of customer services simply because Unisource Energy choose to integrate similar job functions among its affiliates.

I determined the appropriate level of customer service costs from data provided by the Company, in which UNS stated actual customer service costs for the first four months of the test year (before integration) were $70,543.

I calculated the reasonable level of test-year customer service costs by annualizing the four-months of in-house actual costs to $211,629.

As shown on Schedule RLM-7, column (F) and supporting Schedule RLM-10, this adjustment decreased test-year expenses by $726,710.

Operating Income Adjustment No. 6 – Disallowance of Inappropriate and/or Unnecessary Expenses

Q. Please explain your analysis of the various operating expense accounts that result in your removal of inappropriate or unnecessary costs for the provisioning of gas service.

A After review of all the journal entries in various FERC accounts and the Company's response to a number of RUCO data requests, I determined there were numerous expenditures that were either questionable, inappropriate and/or unnecessary.

Therefore, as shown on Schedule RLM-11 and supporting workpapers attached, I have made an adjustment to remove test-year expenses related to payments to chambers of commerce, non-profit organizations, donations, club memberships, gifts, awards, extravagant corporate events, advertising and for various meals, lodging and refreshments, which are not necessary in the provisioning of gas service. The back-up documentation denoting each individual expense removed is recorded in my Workpaper Schedules: WP RLM-11-880, pages 1 to 4, WP RLM-11-921, pages 1 to 16, WP RLM-11-923, pages 1 and 2, WP RLM-11-926, page 1 and WP RLM-11-930, pages 1 to 5.

A sampling within the 1,995 questionable expenses submitted by RUCO includes invoices for: 1) $1,200.00 for two people to play in Flagstaff's 8th

Annual Golf Tournament; 2) $5,750.00 for an employee appreciation dinner in Prescott; 3) $1,000.00 for Toys for Tots; 4) $3,058.00 to the Flagstaff Chamber of Commerce, and 5) $1,246 for a chartered air flight.

RUCO expressed its concerns about the specific inappropriate/unnecessary expenditures and provided a copy of all questionable expenses to the Company in RUCO Data Request 4.01. However, UNS in its response stated:

> "UNS Gas has established practices, policies, procedures and internal controls in place to assure that expenses recorded in the identified FERC accounts are materially correct, prudent and properly classified. Implicit in that classification is the affirmation (belief of the Company) that the charges within those FERC accounts were incurred in the course of providing service to the gas customers in the period recorded."

The burden of proof is on the Company to substantiate the appropriateness of journal entries identified. The Company's mere avowal that the expenditures are prudent and necessary to provide gas service is not sufficient to satisfy that burden.

As shown on Schedule RLM-7, column (G), this adjustment decreased test-year expenses by $233,347.

Operating Income Adjustment No. 7 – Property Tax

Q. Do you agree with UNS's methodology for computing gas utility property taxes?

A. Yes. I have used the same methodology to compute RUCO's recommended level of property taxes.

The difference in the amount I have calculated versus the Company is a result of our respective levels of recommended net plant in service and RUCO's use of the assessment ratio of 24 percent that will be effective when the authorized rates in this case become effective.

The decreasing assessment ratios as authorized in the Arizona Revised Statues relating to property taxes states the effective rate from December 31, 2006 through December 31, 2007 to be 24 percent. The assessment ratio will continue to decline by one-half percent each year until it reaches 20 percent on December 31, 2014.

As shown on Schedule RLM-7, column (H) and supporting Schedule RLM-12, this adjustment decreased test-year expenses by $309,309.

Operating Income Adjustment No. 8 – Rate Case Expense

Q. Please explain your review of the Company's proposed rate case expenses.

A. Through the Company's responses to RUCO data requests 1.06, 6.11, 7.02 and Staff data requests 11.6 and 11.7, I have obtained a budget and copies of rate case billings to date, the total amount actually incurred in the instant case is not yet known. These documents showed a budgeted amount of $600,000 and an actual amount incurred through November 30, 2006 of $1,742,023.

RUCO has a concern over the reasonableness of such a large financial burden to the ratepayers from this requested adjustment. In comparison, Southwest Gas Corporation ("SWG") filed a rate application in 2004 with a requested and approved $235,000 in rate case expenses. The instant case has very similar characteristics to the SWG filing, with the majority of each application process being performed by in-house staff and both utilities requesting a fundamental shift in the ratemaking principles of de-coupling revenue from customer usage and extensive revisions to the PGA mechanism.

Moreover, UNS was able to refine its recommendations based on information cited in the Decision from SWG's groundbreaking application.

Nevertheless, UNS made no attempt to reconcile more than a two-fold increase in rate case expenses for processing a comparable filing to SWG's application. Thus, the appropriate level of rate case expense RUCO is recommending is $235,000 as authorized SWG in Decision No. 68487, dated February 23, 2006, then adjusted for inflation to $251,000.

Therefore, this adjustment reduces annual rate case expense from the Company's proposed level of $200,000 ($600,000 / 3 years) to RUCO's recommended level of $83,667 ($251,000 / 3 years).

As shown on Schedule RLM-7, Column (I), this adjustment decreased test-year expenses by $116,333.

Operating Income Adjustment No. 9 – American Gas Association Dues

Q. During the test year did the Company pay dues to the American Gas Association ("AGA")?

A. Yes. UNS paid $41,854 for its membership with the AGA during the test year.

Q. Has RUCO proposed an adjustment to remove a portion of the AGA dues paid during the test year from cost of service?

A. Yes. RUCO's adjustment represents the portion of UNS's dues that the AGA devoted to marketing and lobbying to promoting the use of gas.

Q. How did you identify the activities of the AGA?

A. As shown on RUCO Exhibit A, pages 1 and 2, the National Association of Regulatory Utility Commissioners ("NARUC") perform an audit of the 2003 expenditures of the AGA. The NARUC audit report identifies each category of AGA expenditures and the percentage of the AGA's annual expenditures that were devoted to each category during the audit year.

Q. Why should these categories of expenditures of the AGA be excluded from rates?

A. The marketing category represents costs to promote gas usage over other alternatives, which the Commission has previously rejected as not being an expenditure that is the best interests of the consumer.

Q. What was the Commission's rationale in disallowing these costs?

A. The Commission stated the following in Decision No. 57075, dated August 31, 1990 at page 54-55, regarding the rationale for its disallowances:

> Applicant's sales program is, without question, almost entirely motivated by the Company's perception of its competitive position vis-à-vis electric utilities for new and existing customers. This competition between energy providers requires us to evaluate the reasonableness and cost effectiveness of each competitor's marketing and advertising efforts in order to ensure that the ratepayers are not being forced to fund both sides of an escalating competition, without limitation and without realizing any discernible benefits in return.

Q. Who realizes the initial benefit from any increases in load resulting from these sales and marketing activities?

A. Any additional margin realized through these sales and marketing efforts accrues to shareholders between rate cases. Until such additional load is recognized in rates, the only beneficiary is the stockholder.

Q. Should ratepayers be required the bear the entire cost of these sales, marketing, and promotional activities?

A. No. The Commission has already recognized that these type of costs need to be contained. It has also recognized that ratepayers should not be forced to fund an escalating competition between the electric and gas industry. Furthermore, initially any increased sales arising out of these marketing efforts accrue solely to shareholders. Accordingly, ratepayers should not be required to fund the portion of AGA dues that pay for gas industry marketing and promotional activities.

The category of lobbying expenses should be excluded because it is utilized to represent the legislative interests of gas company stockholders. Further, lobbying expenses are typically reflected as below-the-line expenditures and not included in rates.

Q. What adjustment have you made?

A. As shown on the AGA/NARUC Oversight Committee report, the percentage of dues allocated to marketing was 1.54 percent; while the AGA incurred lobbying expenses of 2.10 percent of total member dues. Therefore, I have removed 3.64 percent of the Company's test year AGA dues. This represents the percentage of the AGA's expenditures that was used for marketing gas and legislative lobbying. This adjustment reduces operating expenses by $41,854 X 3.64 % = $1,523.

As shown on Schedule RLM-7, column (J), this adjustment decreased test-year expenses by $1,523.

Adjustments To Operating Expenses No. 10 – Non-Recurring/Atypical Expenses

Q. Please explain the basis for the adjustments you made to disallow non-recurring and/or atypical operating expenses.

A. Through discovery I reviewed and analyzed a sampling of test-year operating expense source documents. This review culminated in RUCO data request 4.01. In the Company's response to this data request was documentation indicating expenditures for "Union Training". After a further conversation with the Company there was agreement that this is not a recurring or typical test-year expense.

Therefore as shown on Schedule RLM-7, column (K) and supporting Schedule RLM-13, this adjustment decreased test-year expenses by $2,584.

Adjustments To Operating Expenses No. 11 – Supplemental Executive Retirement Plan

Q. Please explain the basis for the adjustment you made to the Pension and Benefits operating expenses.

A. I made an adjustment to the Supplemental Executive Retirement Plan ("SERP") portion of the pension and benefits operating expenses.

Q. Please explain your adjustment to the SERP.

A. As explained in the Company's response to Staff data request 5.72. a and b, UNS's test-year payroll loadings include the cost of a SERP. The Company's test-year operating expenses include $93,075 related to the SERP. The SERP is a retirement plan that is provided to a small select group of high-ranking officers of the Company. The high-ranking officers who are covered under the SERP receive these benefits in addition to the regular retirement plan.

Q. Should ratepayers be required to pay the cost of supplemental benefits for the high-ranking officers of the Company?

A. No. The cost of supplemental benefits for high-ranking officers is not a necessary cost of providing gas service. These individuals are already fairly compensated for their work and are provided with a wide array of benefits including a medical plan, dental plan, life insurance, long term disability, paid absence time, and a retirement plan. If the Company feels it is necessary to provide additional perks to a select group of employees it should do so at its own expense.

Q. In a recent ACC Decision did the Commissioners determine whether SERP expenses were recoverable?

A. Yes. In SWG's latest rate case (Decision No. 68487, dated February 23, 2006) the Commission agreed with RUCO that SERP should be excluded from operating expenses and it is not reasonable to place this additional burden on ratepayers. Therefore, I have removed the test-year cost of the SERP from operating expenses.

As shown on Schedule RLM-7, column (L), this adjustment decreased test-year expenses by $93,075.

<u>Operating Income Adjustment No. 22 – Income Tax Expense</u> – This adjustment reflects income tax expenses calculated on RUCO's recommended revenues and expenses.

As shown on Schedule RLM-7, column (W) and supporting Schedule RLM-14, this adjustment increased test-year expenses by $1,830,390.

RATE DESIGN

Q. Please explain your contribution to RUCO's recommended rate designs.

A. As shown on Schedule RLM-15, I was responsible for producing an accurate set of bill determinants (i.e. test-year customer bill counts and therms consumed). I adjusted the bill determinants to reflect the annualized customer count as calculated by Ms. Diaz Cortez in her workpapers. I made adjustments to remove the Company's proposed "Summer/Winter" basic service charge differential. However, I maintained the same percentage of revenue contribution from each class of service as is provided in the Company's current rates. An in-depth discussion of RUCO's proposed rate design is contained in the testimony of Ms. Diaz Cortez. In summary, for residential customers, RUCO proposes a single basic service charge (not season differentiated) of $8.13 and a commodity based charge of $0.2892 per therm.

Q. Please explain elements of the rate design.

A. Schedule RLM-15 illustrates the elements proposed by Ms. Diaz Cortez in her testimony, which are:

1. Provides a positive price signal to encourage energy efficient usage;
2. Consistent with the Cost of Service Study parameters, which established UNS's present rate design;
3. Recognition of the Company's need for revenue stabilization within the ratemaking principle of gradualism;
4. Shift 10 percent of the revenue requirement that is currently recovered from the commodity rates to the fixed monthly charges; and
5. Eliminate the Company-proposed summer and winter rate structure differential.

PROOF OF RECOMMENDED REVENUE

Q. Have you prepared a Schedule presenting proof of your recommended revenue?

A. Yes, I have. Proof that RUCO's recommended rate designs will produce the recommended required revenue as illustrated, is presented on Schedule RLM-15.

TYPICAL BILL ANALYSIS

Q. Have you prepared a Schedule representing the financial impact of RUCO's recommended rate design on the typical residential customer?

A. Yes, I have. A typical bill analysis for metered residential customers with various levels of usage is presented on Schedule RLM-16.

Q. Please provide an excerpt of RUCO's rate structure that illustrates RUCO's rate design goals as set forth in Ms. Diaz Cortez's testimony captures these fundamental changes in UNS's current rate design.

A. Schedule RLM-16 provides an extensive breakdown of the effects of RUCO's proposed rates on the R-10 Residential Customer. Below is a chart gleaned from Schedule RLM-16 comparing UNS's proposed rates to RUCO's proposed annual rates:

<u>UNS Proposed Rates and Charges</u>

Basic Monthly Service Charge	\$20.00/Summer & \$11.00/Winter
Commodity Charges (per Therm)	\$0.18625

<u>RUCO Proposed Rates and Charges</u>

Basic Monthly Service Charge	$8.13
Commodity Charges (per Therm)	$0.2862

RUCO's proposed rate design when compared to the Company's proposal:

1. Provides a clear price signal ($0.10 more per every therm used) that increased consumption will increase your monthly bill and reduced consumption will lower your monthly bill throughout the entire year in effort to promote conservation;
2. Maintains the same historical percentage (70 percent Residential vs. 30 percent Other) of revenue recovery among classes of service in recognition of the Company's Cost of Service Study; and
3. Shifts a significant amount (10 percent more than test year) of the revenue requirement from the variable commodity charge to the fixed basic service in recognition of the Company's concern over revenue stabilization.

COST OF CAPITAL

Q. Is RUCO proposing any adjustments to the Company proposed cost of capital?

A. Yes, it is. As shown on Schedule RLM-17, this adjustment decreases the Company's cost of common equity and therefore its weighted cost of capital by 86 basis points from 8.80 to 7.94 percent to reflect current market conditions. This adjustment is fully explained in the testimony of RUCO witness Mr. Rigsby.

Q. Does this conclude your direct testimony?

A. Yes, it does.

APPENDIX 1

APPENDIX 1

Qualifications of Rodney Lane Moore

EDUCATION: Athabasca University
Bachelor's Degree in Business Administration - 1993

EXPERIENCE: Public Utilities Analyst V
Residential Utility Consumer Office
Phoenix, Arizona 85007
May 2001 - Present

My duties include review and analysis of financial records and other documents of regulated utilities for accuracy, completeness, and reasonableness. I am also responsible for the preparation of work papers and Schedules resulting in testimony and/or reports regarding utility applications for increase in rates, financings, and other matters. Extensive use of Microsoft Excel and Word, spreadsheet modeling and financial statement analysis.

Auditor
Arizona Corporation Commission
Phoenix, Arizona 85007
October 1999 - May 2001

My duties include review and analysis of financial records and other documents of regulated utilities for accuracy, completeness, and reasonableness. I am also responsible for the preparation of work papers and Schedules resulting in testimony and/or reports regarding utility applications for increase in rates, financings, and other matters. Extensive use of Microsoft Excel and Word, spreadsheet modeling and financial statement analysis.

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.
Rio Verde Utilities, Inc	WS-02156A-00-0321
Black Mountain Gas Company	G-03703A-01-0283
Green Valley Water Company	W-02025A-01-0559
New River Utility Company	W-01737A-01-0662

Dragoon Water Company	W-01917A-01-0851
Roosevelt Lake Resort, Inc.	W-01958A-02-0283
Southwest Gas Company	G-01551A-02-0425
Arizona-American Water Company	W-01303A-02-0867 et al
Rio Rico Utilities, Inc.	WS-02676A-03-0434
Qwest Corporation	T-01051B-03-0454
Chaparral City Water Company	W-02113A-04-0616
Southwest Gas Company	G-01551A-04-0876
Arizona-American Water Company	W-01303A-05-0405
Far West Water and Sewer Company	WS-03478A-05-0801
Gold Canyon Sewer Company	SW-02519A-06-0015

UNS Gas Corporation
Docket No. G-04204A-06-0463
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Docket No. G-04204A-06-0463
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REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY ORIGINAL COST	(B) COMPANY RCND	(C) COMPANY FAIR VALUE	(D) RUCO ORIGINAL COST	(E) RUCO RCND	(F) RUCO FAIR VALUE
1	Adjusted Rate Base	$ 161,661,362	$ 220,694,068	$ 191,177,714	$ 144,680,196	$ 197,766,154	$ 171,223,175
2	Adjusted Operating Income (Loss)	$ 8,428,981	$ 8,428,981	$ 8,428,981	$ 10,560,998	$ 10,560,998	$ 10,560,998
3	Current Rate Of Return (Line 2 / Line 1)	5.21%	3.82%	4.41%	7.30%	5.34%	6.17%
4	Required Operating Income (Line 5 X Line 1)	$ 14,223,179	$ 14,223,179	$ 14,204,479	$ 11,480,374	$ 11,480,374	$ 11,480,374
5	Required Rate Of Return	8.80%	6.44%	7.43%	7.94%	5.81%	6.70%
6	Operating Income Deficiency (Line 4 - Line 2)	$ 5,794,198	$ 5,794,198	$ 5,775,498	$ 919,376		$ 919,376
7	Gross Revenue Conversion Factor (Schedule RLM-1, Page 3)	1.6649	1.6649	1.6649			1.6370
8	Increase In Gross Revenue Requirement (Line 7 X Line 6)	$ 9,646,901	$ 9,646,901	$ 9,615,767			$ 1,505,003
9	Adjusted Test Year Revenue			$ 47,169,528			$ 47,280,434
10	Proposed Annual Revenue Requirement (Line 8 + Line 9)			$ 56,785,295			$ 48,785,437
11	Required Percentage Increase In Revenue (Line 8 / Line 9)			20.39%			3.18%
12	Rate Of Return On Common Equity			11.39%			9.64%

References:
- Columns (A) Thru (C): Company Schedule A-1, C-1 And D-1
- Column (D): Schedules RLM-2, RLM-3, RLM-6 And RLM-17
- Column (E): Schedule RLM-2
- Column (F): Average Of Column (D) + Column (E)

UNS Gas Corporation
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GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	REFERENCE	(A)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:		
1	Revenue		1.0000
2	Less: Uncollectibles	Company Schedule C-3, Line 2	0.0051
3	Subtotal	Line 1 - Line 2	0.9949
4	Less: Combined Federal And State Tax Rate	Line 14	0.3840
5	Subtotal	Line 3 - Line 4	0.6109
6	**Revenue Conversion Factor**	Line 1 / Line 5	**1.6370**
	CALCULATION OF EFFECTIVE TAX RATE:		
7	Arizona Taxable Income		1.0000
8	Arizona State Income Tax Rate		0.0697
9	Federal Taxable Income	Line 7 - Line 8	0.9303
10	Applicable Federal Income Tax Rate		0.3400
11	Effective Federal Income Tax Rate	Line 9 X Line 10	0.3163
12	Subtotal	Line 8 + Line 11	0.3860
13	Revenue Less Uncollectibles	Line 3	0.9949
14	Combined Federal And State Income Tax Rate	Line 12 X Line 13	0.3840

UNS Gas Corporation
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FAIR VALUE RATE BASE - OCRB / RCND (50/50 SPLIT)

LINE NO.	DESCRIPTION	(A) COMPANY OCRB	(B) COMPANY RCND	(C) COMPANY FVRB	(D) OCRB/RCND % DIFF.	(E) RUCO OCRB	(F) RUCO RCND	(G) RUCO FVRB
1	Gross Utility Plant In Service	$ 279,169,694	$ 374,243,421	$ 326,706,558	134.06%	$ 268,847,200	$ 360,405,510	$ 314,626,355
2	Accumulated Depreciation	(72,006,708)	(97,114,865)	(84,560,787)	134.87%	(78,719,575)	(106,168,455)	(92,444,015)
3	Net Utility Plant In Service	$ 207,162,986	$ 277,128,556	$ 242,145,771		$ 190,127,625	$ 254,237,055	$ 222,182,340
4	Citizens Acquisition Discount	$ (30,709,738)	$ (41,822,562)	$ (36,266,150)	136.19%	$ (30,709,738)	$ (41,822,562)	$ (36,266,150)
5	Accumulated Amortization	1,876,981	2,560,308	2,218,645	136.41%	1,628,094	2,220,812	1,924,453
6	Net Citizens Acq. Disc.	$ (28,832,757)	$ (39,262,254)	$ (34,047,506)		$ (29,081,644)	$ (39,601,750)	$ (34,341,697)
7	Total Net Utility Plant	$ 178,330,229	$ 237,866,302	$ 208,098,266		$ 161,045,981	$ 214,635,305	$ 187,840,643
	Deductions:							
8	Cust. Advances For Const.	$ (7,283,595)	$ (7,786,962)	$ (7,535,279)	106.91%	$ (7,283,595)	$ (7,786,962)	$ (7,535,279)
9	Customer Deposits	(3,040,484)	(3,040,484)	(3,040,484)	100.00%	(3,040,484)	(3,040,484)	(3,040,484)
10	Acc. Deferred Income Taxes	(6,484,809)	(6,484,809)	(6,484,809)	100.00%	(6,484,809)	(6,484,809)	(6,484,809)
11	Total Deductions	$ (16,808,888)	$ (17,312,255)	$ (17,060,572)		$ (16,808,888)	$ (17,312,255)	$ (17,060,572)
12	Allowance - Working Capital	$ (1,045,146)	$ (1,045,146)	$ (1,045,146)	100.00%	$ 155,006	$ 155,006	$ 155,006
13	Regulatory Assets	$ 1,204,887	$ 1,204,887	$ 1,204,887	100.00%	$ 307,819	$ 307,819	$ 307,819
14	Regulatory Liability	$ (19,721)	$ (19,721)	$ (19,721)	100.00%	$ (19,721)	$ (19,721)	$ (19,721)
15	TOTAL TEST YEAR RATE BASE	$ 161,661,361	$ 220,694,067	$ 191,177,714		$ 144,680,196	$ 197,766,154	$ 171,223,175

References:
- Columns (A) (B) (C): Company Schedule B-1
- Column (D): Column (B) / Column (A)
- Column (E): Schedule RLM-3, Column (H)
- Column (F): Column (D) X Column (E)
- Column (G): Average Of Column (E) + Column (F)

UNS Gas Corporation
Docket No. G-04204A-06-0463
Test Year Ended December 31, 2005

SUMMARY OF ORIGINAL COST RATE BASE

LINE NO.	DESCRIPTION	(A) COMPANY FILED AS OCRB	(B) RUCO ADJUSTMENT NO. 1	(C) RUCO ADJUSTMENT NO. 2	(D) RUCO ADJUSTMENT NO. 3	(E) RUCO ADJUSTMENT NO. 4	(F) RUCO ADJUSTMENT NO. 5	(G) RUCO ADJUSTMENT NO. 6	(H) RUCO ADJUSTED AS OCRB
1	Gross Utility Plant In Service	$ 279,169,694	$ (3,133,264)	$ -	$ -	$ (7,189,230)	$ -	$ -	$ 268,847,200
2	Accumulated Depreciation	(72,006,708)	(3,857,413)	(2,855,454)	-	-	-	-	(78,719,575)
3	Net Utility Plant In Service	$ 207,162,986	$ (6,990,677)	$ (2,855,454)	$ -	$ (7,189,230)	$ -	$ -	$ 190,127,625
4	Citizens Acquisition Discount	$ (30,709,738)	$ -	$ -	$ -	$ -	$ -	$ -	$ (30,709,738)
5	Accumulated Amortization	1,876,981	-	-	(248,887)	-	-	-	1,628,094
6	Net Citizens Acq. Disc.	$ (28,832,757)	$ -	$ -	$ (248,887)	$ -	$ -	$ -	$ (29,081,644)
7	Total Net Utility Plant	$ 178,330,229	$ (6,990,677)	$ (2,855,454)	$ (248,887)	$ (7,189,230)	$ -	$ -	$ 161,045,981
	Deductions:								
8	Cust. Advances For Const.	$ (7,283,595)	$ -	$ -	$ -	$ -	$ -	$ -	$ (7,283,595)
9	Customer Deposits	(3,040,484)	-	-	-	-	-	-	(3,040,484)
10	Acc. Deferred Income Taxes	(6,484,809)	-	-	-	-	-	-	(6,484,809)
11	Total Deductions	$ (16,808,888)	$ -	$ -	$ -	$ -	$ -	$ -	$ (16,808,888)
12	Allowance - Working Capital	$ (1,045,146)	$ -	$ -	$ -	$ -	$ -	$ 1,200,152	$ 155,006
13	Regulatory Assets	$ 1,204,887	$ -	$ -	$ -	$ -	$ (897,068)	$ -	$ 307,819
14	Regulatory Liability	$ (19,721)	$ -	$ -	$ -	$ -	$ -	$ -	$ (19,721)
15	TOTAL OCRB	$ 161,661,361	$ (6,990,677)	$ (2,855,454)	$ (248,887)	$ (7,189,230)	$ (897,068)	$ 1,200,152	$ 144,680,196

References:
Column (A): - Company Schedule B-2
Column (B): - Adjustment No. 1 RUCO Adjustment To Pre-Acquisition Gross Plant And Accumulated Depreciation (See RLM-4, Page 3, Lines 38 & 39)
Column (C): - Adjustment No. 2 RUCO Adjustment To Test-Year Accumulated Depreciation (See RLM-4, Page 5, Line 40)
Column (D): - Adjustment No. 3 RUCO Adjustment To Restate Accumulated Amortization On Citizens Acquisition. (See MDC-1)
Column (E): - Adjustment No. 4 RUCO Adjustment To Remove CWIP From Test-Year Rate Base (See Testimony, MDC And RLM-5, Line 39)
Column (F): - Adjustment No. 5 RUCO Adjustment To The Geographical Information System (See Testimony, MDC)
Column (G): - Adjustment No. 6 Allowance For Working Capital (See MDC-2)
Column (H): - Sum Of Columns (A) Through (G)

TEST YEAR PLANT SCHEDULES
PRIOR TEST YEAR ENDED OCTOBER 29, 2002

LINE NO.	ACCT NO.	DESCRIPTION	(A) DEP. RATES AS FILING	(B) DEP. RATES PER 58664	(C) PROPOSED DEP. RATES	(D) PRIOR TOTAL PLANT SETTLEMENT	(E) PRIOR ACC. DEP. SETTLEMENT	(F) NET PLANT VALUE	(G) ACC ADJUSTMENT TO PLANT	(H) ACC ADJUSTMENT TO ACC. DEP.	(I) PER BOOKS ADJUSTED PRIOR TY PLT	(J) PER BOOKS ADJUSTED PRIOR ACC. DEP.
		Intangible:										
1	302	Franchises & Consents	3.95%	4.00%	3.95%	$ 371,375	$ (137,681)	$ 233,694	$ -	$ -	$ 371,375	$ (137,681)
2	303	Miscellaneous Intangible	5.84%	4.00%	5.84%	251,616	(151,955)	99,661	-	-	251,616	(151,955)
3		Total Intangible Plant				$ 622,991	$ (289,636)	$ 333,355	$ -	$ -	$ 622,991	$ (289,636)
		Transmission :										
4	365	Land & Rights	-	-	1.38%	$ 105,203	$ 5	$ 105,208	$ (33,897)	$ -	$ 71,306	$ 5
5	366	Structures & Improvements	7.27%	3.10%	1.55%	-	(5)	(5)	1,334	(1,329)	1,334	(1,334)
6	367	Mains	1.57%	2.57%	1.53%	11,080,124	(2,671,397)	8,408,727	2,900,215	84,706	13,980,339	(2,586,691)
7	369	Measuring And Reg. Equipment	1.61%	3.32%	1.54%	856,069	(270,221)	585,848	2,361,825	(88,596)	3,217,894	(358,817)
8	371	Other Equipment	5.00%	3.64%	2.49%	-	(7,910)	(7,910)	183,581	-	183,581	(7,910)
9		Total Transmission Plant				$ 12,041,396	$ (2,949,528)	$ 9,091,868	$ 5,413,058	$ (5,219)	$ 17,454,454	$ (2,954,747)
		Distribution:										
10	374	Land & Rights	-	-	0.93%	$ 134,581	$ -	$ 134,581	$ -	$ -	$ 134,581	$ -
11	375	Structures & Improvements	1.77%	3.35%	1.93%	8,247	(10,949)	(2,702)	1,366	3,123	9,613	(7,826)
12	376	Mains	2.08%	2.92%	2.07%	120,601,071	(21,816,051)	98,785,020	1,531,339	(83,498)	122,132,410	(21,899,549)
13	378	Meas. And Reg. Equip. - General	3.03%	5.73%	2.97%	1,813,831	(639,150)	1,174,681	62,680	(70,876)	1,876,511	(710,026)
14	379	Meas. And Reg. Equip. - City Gate	2.39%	5.52%	2.36%	1,719,751	(524,902)	1,194,849	247,482	(211,561)	1,967,233	(736,463)
15	380	Services	2.85%	4.75%	2.82%	49,751,369	(14,212,476)	35,538,893	830,520	(801,890)	50,581,889	(15,014,366)
16	381	Meters	2.05%	2.86%	2.02%	9,704,378	(3,838,309)	5,866,069	5,168	(50)	9,709,546	(3,838,359)
17	382	Meter Installation	2.42%	2.86%	2.36%	4,516,786	(465,155)	4,051,631	2,716	(234)	4,519,502	(465,389)
18	383	Regulators	2.63%	3.77%	2.56%	1,850,681	(785,543)	1,065,138	589,255	(587,980)	2,439,936	(1,373,523)
19	384	Regulator Installation	2.83%	3.77%	2.80%	284,404	(11,353)	273,051	257	(89)	284,661	(11,442)
20	385	Industrial Measuring Equipment	2.61%	3.82%	2.70%	785,500	(473,598)	311,902	90,723	(76,767)	876,223	(550,365)
21	387	Other Equipment	3.15%	3.64%	3.01%	724,235	(172,911)	551,324	677	(245)	724,912	(173,156)
22		Total Distribution Plant				$ 191,894,834	$ (42,950,397)	$148,944,437	$ 3,362,183	$ (1,830,067)	$ 195,257,017	$ (44,780,464)
		General:										
23	389	Land & Rights	-	-	4.93%	$ 194,035	$ -	$ 194,035	$ 496,357	$ 5,618	$ 690,392	$ 5,618
24	390	Structures & Improvements	3.75%	3.10%	4.89%	813,839	(187,270)	626,569	3,886,835	(545,882)	4,700,674	(733,152)
25	391	Office Furniture & Equipment	4.24%	4.82%	4.24%	8,083,824	(3,734,401)	4,349,423	627,732	(296,743)	8,711,556	(4,031,144)
26	392	Transportation Equipment	25.00%	0.00%	14.71%	2,528,039	(1,177,129)	1,350,910	138,927	(138,927)	2,666,966	(1,316,056)
27	393	Stores Equipment	3.03%	2.27%	3.03%	100,288	(13,725)	86,563	12,745	(12,745)	113,033	(26,470)
28	394	Tools, Shop And Garage Equip.	3.64%	5.76%	3.64%	1,411,184	(242,205)	1,168,979	341,273	(341,273)	1,752,457	(583,478)
29	395	Laboratory Equipment	9.29%	5.76%	9.29%	529,231	(78,858)	450,373	26,957	(26,957)	556,188	(105,815)
30	396	Power Operated Equipment	5.69%	24.60%	10.49%	362,259	(294,956)	67,303	25,601	(25,601)	387,860	(320,557)
31	397	Communication Equipment	6.11%	4.93%	6.11%	540,119	(38,388)	501,731	376,420	(102,703)	916,539	(141,091)
32	398	Miscellaneous Equipment	4.01%	5.43%	4.01%	261,520	(41,165)	220,355	11,374	(11,374)	272,894	(52,539)
33	399	Other Tangible Property	0.00%	3.64%	-	-	(21,313)	(21,313)	100,108	-	100,108	(21,313)
34		Total General Plant				$ 14,824,338	$ (5,829,410)	$ 8,994,928	$ 6,044,329	$ (1,496,587)	$ 20,868,667	$ (7,325,997)
35		TOTAL PLANT				$ 219,383,559	$ (52,018,971)	$167,364,588	$ 14,819,570	$ (3,331,873)	$ 234,203,129	$ (55,350,844)

References:
Columns (A) (B) (C) (D) (E) (F): Prior Rate Case And Company Response To RUCO Data Requests 1.08 & 2.19
Columns (G) (H): Company Response To RUCO Data Requests 1.08 & 2.19
Column (I): Column (D) + Column (G)
Column (J): Column (E) + Column (H)

UNS Gas Corporation
Docket No. G-04204A-06-0463
Test Year Ended December 31, 2005

TEST YEAR PLANT SCHEDULES - CONT'D
YEAR ENDED DECEMBER 31, 2002

LINE NO.	ACCT NO.	ACCOUNT NAME	(A) PLANT ADDITIONS	(B) PLANT ADJM'TS	(C) NET PLANT ADDITIONS	(D) PLANT RETIRM'TS	(E) TOTAL PLANT VALUE	(F) ACCURAL DEPRECIATION	(G) ACCUMULATED DEPRECIATION	(H) NET PLANT VALUE
		Intangible:								
1	302	Franchises & Consents	$ -	$ -	$ 10,422	$ (5,109)	$ 381,797	$ (14,961)	$ (147,533)	$ 234,264
2	303	Miscellaneous Intangible	-	-	7,061	(3,462)	258,677	(10,137)	(158,630)	100,047
3		Total Intangible Plant	$ -	$ -	$ 17,483	$ (8,571)	$ 640,474	$ (25,098)	$ (306,163)	$ 334,312
		Transmission :								
4	365	Land & Rights	$ -	$ -	$ 2,001	$ -	$ 73,307	$ -	$ 5	$ 73,312
5	366	Structures & Improvements	-	-	37	(18)	1,371	(42)	(1,357)	14
6	367	Mains	-	-	392,337	(192,344)	14,372,676	(361,865)	(2,756,212)	11,616,464
7	369	Measuring And Reg. Equipment	-	-	90,305	(44,272)	3,308,199	(107,598)	(422,143)	2,886,056
8	371	Other Equipment	-	-	5,152	(2,526)	188,733	(6,730)	(12,114)	176,619
9		Total Transmission Plant	$ -	$ -	$ 489,833	$ (239,160)	$ 17,944,287	$ (476,235)	$ (3,191,821)	$ 14,752,466
		Distribution:								
10	374	Land & Rights	$ -	$ -	$ 3,777	$ -	$ 138,358	$ -	$ -	$ 138,358
11	375	Structures & Improvements	-	-	270	(132)	9,883	(324)	(8,018)	1,865
12	376	Mains	-	-	3,427,462	(1,680,318)	125,559,872	(3,591,775)	(23,811,005)	101,748,866
13	378	Meas. And Reg. Equip. - General	-	-	52,661	(25,817)	1,929,172	(108,293)	(792,502)	1,136,671
14	379	Meas. And Reg. Equip. - City Gate	-	-	55,207	(27,066)	2,022,440	(109,368)	(818,765)	1,203,675
15	380	Services	-	-	1,419,504	(695,914)	52,001,393	(2,419,825)	(16,738,277)	35,263,116
16	381	Meters	-	-	272,484	(133,586)	9,982,030	(279,679)	(3,984,453)	5,997,577
17	382	Meter Installation	-	-	126,833	(62,180)	4,646,335	(130,182)	(533,391)	4,112,944
18	383	Regulators	-	-	68,473	(33,569)	2,508,409	(92,644)	(1,432,597)	1,075,812
19	384	Regulator Installation	-	-	7,989	(3,916)	292,650	(10,808)	(18,334)	274,316
20	385	Industrial Measuring Equipment	-	-	24,590	(12,055)	900,813	(33,711)	(572,021)	328,792
21	387	Other Equipment	-	-	20,344	(9,973)	745,256	(26,576)	(189,758)	555,497
22		Total Distribution Plant	$ -	$ -	$ 5,479,593	$ (2,684,527)	$ 200,736,610	$ (6,803,185)	$ (48,899,122)	$ 151,837,488
		General:								
23	389	Land & Rights	$ -	$ -	$ 19,375	$ -	$ 709,767	$ -	$ 5,618	$ 715,385
24	390	Structures & Improvements	-	-	131,917	(64,673)	4,832,591	(146,763)	(815,243)	4,017,349
25	391	Office Furniture & Equipment	-	-	244,477	(119,855)	8,956,033	(422,900)	(4,334,189)	4,621,843
26	392	Transportation Equipment	-	-	74,844	(36,693)	2,741,810	-	(1,279,363)	1,462,447
27	393	Stores Equipment	-	-	3,172	(1,555)	116,205	(2,584)	(27,499)	88,706
28	394	Tools, Shop And Garage Equip.	-	-	49,180	(24,111)	1,801,637	(101,664)	(661,031)	1,140,606
29	395	Laboratory Equipment	-	-	15,609	(7,652)	571,797	(32,266)	(130,428)	441,368
30	396	Power Operated Equipment	-	-	10,885	(5,336)	398,745	(96,096)	(411,317)	(12,572)
31	397	Communication Equipment	-	-	25,721	(12,610)	942,260	(45,509)	(173,990)	768,271
32	398	Miscellaneous Equipment	-	-	7,658	(3,755)	280,552	(14,924)	(63,709)	216,844
33	399	Other Tangible Property	-	-	2,809	(1,377)	102,917	(3,670)	(23,606)	79,312
34		Total General Plant	$ -	$ -	$ 585,648	$ (277,616)	$ 21,454,315	$ (866,376)	$ (7,914,756)	$ 13,539,558
35		TOTAL PLANT	$ -	$ -	$ 6,572,557	$ (3,209,875)	$ 240,775,686	$ (8,170,893)	$ (60,311,863)	$ 180,463,823

References:
Columns (A) (B) (C) (D): Company Response To RUCO Data Request 2.19
Column (E): Schedule RLM-4, Page 1, Column (I) + Column (C) + Column (D)
Column (F): [(Cl. (C) + Cl. (D)) X RLM-4, Pg 1, Cl. (B) X 1/2 yr. conv.] + [RLM-4, Pg 1, Cl. (I) + Cl. (D)) X RLM-4, Pg 1, Cl. (B)
Column (G): Schedule RLM-4, Page 1, Column (J) + Column (D) + Column (F)
Column (H): Column (E) + Column (G)

UNS Gas Corporation
Docket No. G-04204A-06-0463
Test Year Ended December 31, 2005

RATE BASE ADJUSTMENT NO. 1 - REMOVE UNSUBSTANTIATED PRE-ACQUISITION PLANT AND ACCUMULATED DEPRECIATION
TEST YEAR PLANT SCHEDULES - CONT'D
YEAR ENDED DECEMBER 31, 2003

LINE NO.	ACCT NO.	ACCOUNT NAME	(A) PLANT ADDITIONS	(B) PLANT ADJM'TS	(C) NET PLANT ADDITIONS	(D) PLANT RETIRM'TS	(E) TOTAL PLANT VALUE	(F) ACCURAL DEPRECIATION	(G) ACCUMULATED DEPRECIATION	(H) NET PLANT VALUE
		Intangible:								
1	302	Franchises & Consents	$ -	$ -	$ 6,539	$ (1,064)	$ 388,336	$ (15,381)	$ (161,850)	$ 226,486
2	303	Miscellaneous Intangible	-	-	4,430	(721)	263,108	(10,421)	(168,330)	94,777
3		Total Intangible Plant	$ -	$ -	$ 10,969	$ (1,785)	$ 651,444	$ (25,803)	$ (330,180)	$ 321,263
		Transmission :								
4	365	Land & Rights	$ -	$ -	$ 1,256	$ -	$ 74,563	$ -	$ 5	$ 74,568
5	366	Structures & Improvements	-	-	23	(4)	1,395	(43)	(1,396)	(1)
6	367	Mains	-	-	246,157	(40,059)	14,618,833	(372,026)	(3,088,179)	11,530,654
7	369	Measuring And Reg. Equipment	-	-	56,659	(9,220)	3,364,858	(110,620)	(523,542)	2,841,316
8	371	Other Equipment	-	-	3,232	(526)	191,965	(6,919)	(18,508)	173,458
9		Total Transmission Plant	$ -	$ -	$ 307,326	$ (49,809)	$ 18,251,613	$ (489,608)	$ (3,631,620)	$ 14,619,994
		Distribution:								
10	374	Land & Rights	$ -	$ -	$ 2,370	$ -	$ 140,727	$ -	$ -	$ 140,727
11	375	Structures & Improvements	-	-	169	(28)	10,052	(333)	(8,324)	1,728
12	376	Mains	-	-	2,150,427	(349,956)	127,710,298	(3,692,635)	(27,153,685)	100,556,614
13	378	Meas. And Reg. Equip. - General	-	-	33,040	(5,377)	1,962,213	(111,334)	(898,459)	1,063,754
14	379	Meas. And Reg. Equip. - City Gate	-	-	34,638	(5,637)	2,057,078	(112,439)	(925,568)	1,131,510
15	380	Services	-	-	890,612	(144,936)	52,892,006	(2,487,776)	(19,081,116)	33,810,889
16	381	Meters	-	-	170,959	(27,822)	10,152,989	(287,533)	(4,244,164)	5,908,825
17	382	Meter Installation	-	-	79,576	(12,950)	4,725,911	(133,838)	(654,279)	4,071,632
18	383	Regulators	-	-	42,961	(6,991)	2,551,370	(95,245)	(1,520,851)	1,030,519
19	384	Regulator Installation	-	-	5,012	(816)	297,662	(11,112)	(28,630)	269,031
20	385	Industrial Measuring Equipment	-	-	15,428	(2,511)	916,241	(34,658)	(604,168)	312,073
21	387	Other Equipment	-	-	12,764	(2,077)	758,019	(27,322)	(215,003)	543,017
22		Total Distribution Plant	$ -	$ -	$ 3,437,957	$ (559,100)	$ 204,174,567	$ (6,994,225)	$ (55,334,247)	$ 148,840,320
		General:								
23	389	Land & Rights	$ -	$ -	$ 12,156	$ -	$ 721,923	$ -	$ 5,618	$ 727,541
24	390	Structures & Improvements	-	-	82,766	(13,469)	4,915,358	(150,884)	(952,658)	3,962,700
25	391	Office Furniture & Equipment	-	-	153,387	(24,962)	9,109,420	(434,776)	(4,744,003)	4,365,417
26	392	Transportation Equipment	-	-	46,958	(7,642)	2,788,769	-	(1,271,722)	1,517,047
27	393	Stores Equipment	-	-	1,990	(324)	118,195	(2,657)	(29,832)	88,363
28	394	Tools, Shop And Garage Equip.	-	-	30,856	(5,021)	1,832,493	(104,518)	(760,528)	1,071,965
29	395	Laboratory Equipment	-	-	9,793	(1,594)	581,590	(33,172)	(162,006)	419,583
30	396	Power Operated Equipment	-	-	6,829	(1,111)	405,574	(98,794)	(509,000)	(103,426)
31	397	Communication Equipment	-	-	16,138	(2,626)	958,398	(46,786)	(218,150)	740,248
32	398	Miscellaneous Equipment	-	-	4,805	(782)	285,357	(15,343)	(78,270)	207,087
33	399	Other Tangible Property	-	-	1,763	(287)	104,680	(3,773)	(27,092)	77,588
34		Total General Plant	$ -	$ -	$ 367,442	$ (57,818)	$ 21,821,756	$ (890,704)	(8,747,642)	$ 13,074,114
35		TOTAL PLANT	$ -	$ -	$ 4,123,694	$ (668,513)	$ 244,899,380	$ (8,400,340)	$ (68,043,689)	$ 176,855,691
36		Total Plant As Per Company					$ 248,032,644		$ (64,186,276)	
37		Difference					$ (3,133,264)		$ (3,857,413)	
38		RUCO Adjustment To Pre-Aquisition Gross Plant In Service (See RLM-3, Column (B))					$ (3,133,264)			
39		RUCO Adjustment To Pre-Aquisition Accumulated Depreciation (See RLM-3, Column (B))							$ (3,857,413)	

References:

Columns (A) (B) (C) (D): Company Response To RUCO Data Request 2.19
Column (E): Schedule RLM-4, Page 2, Column (E) + Column (C) + Column (D)
Column (F): [(Cl. (C) + Cl. (D)) X RLM-4, Pg 1, Cl. (B) X 1/2 yr. conv.] + [RLM-4, Pg 2, Cl. (E) + Cl. (D)) X RLM-4, Pg 1, Cl. (B)
Column (G): Schedule RLM-4, Page 2, Column (G) + Column (D) + Column (F)
Column (H): Column (E) + Column (G)

TEST YEAR PLANT SCHEDULES - CONT'D
YEAR ENDED DECEMBER 31, 2004

LINE NO.	ACCT NO.	ACCOUNT NAME	(A) PLANT ADDITIONS	(B) PLANT ADJM'TS	(C) NET PLANT ADDITIONS	(D) PLANT RETIRM'TS	(E) TOTAL PLANT VALUE	(F) ACCURAL DEPRECIATION	(G) ACCUMULATED DEPRECIATION	(H) NET PLANT VALUE
		Intangible:								
1	302	Franchises & Consents	$ -	$ -	$ -	$ -	$ 388,336	$ (15,533)	$ (177,384)	$ 210,953
2	303	Miscellaneous Intangible	-	-	-	-	263,108	(10,524)	(178,854)	84,253
3		Total Intangible Plant	$ -	$ -	$ -	$ -	$ 651,444	$ (26,058)	$ (356,238)	$ 295,206
		Transmission :								
4	365	Land & Rights	$ -	$ -	$ -	$ -	$ 74,563	$ -	$ 5	$ 74,568
5	366	Structures & Improvements	-	-	-	-	1,395	(43)	(1,440)	(45)
6	367	Mains	3,184,658	-	3,184,658	-	17,803,491	(416,627)	(3,504,806)	14,298,685
7	369	Measuring And Reg. Equipment	159,602	-	159,602	-	3,524,460	(114,363)	(637,905)	2,886,555
8	371	Other Equipment	-	-	-	-	191,965	(6,988)	(25,495)	166,470
9		Total Transmission Plant	$ 3,344,260	$ -	$ 3,344,260	$ -	$ 21,595,873	$ (538,020)	$ (4,169,640)	$ 17,426,233
		Distribution:								
10	374	Land & Rights	$ -	$ -	$ -	$ -	$ 140,727	$ -	$ -	$ 140,727
11	375	Structures & Improvements	-	-	-	-	10,052	(337)	(8,661)	1,391
12	376	Mains	7,429,814	-	7,429,814	-	135,140,112	(3,837,616)	(30,991,301)	104,148,812
13	378	Meas. And Reg. Equip. - General	83,748	-	83,748	-	2,045,961	(114,834)	(1,013,293)	1,032,668
14	379	Meas. And Reg. Equip. - City Gate	4,948	-	4,948	-	2,062,026	(113,687)	(1,039,255)	1,022,771
15	380	Services	6,305,730	-	6,305,730	-	59,197,736	(2,662,131)	(21,743,248)	37,454,488
16	381	Meters	607,242	-	607,242	-	10,760,231	(299,059)	(4,543,223)	6,217,008
17	382	Meter Installation	-	-	-	-	4,725,911	(135,161)	(789,440)	3,936,471
18	383	Regulators	29,280	-	29,280	-	2,580,650	(96,739)	(1,617,590)	963,060
19	384	Regulator Installation	-	-	-	-	297,662	(11,222)	(39,852)	257,809
20	385	Industrial Measuring Equipment	85,105	-	85,105	-	1,001,346	(36,626)	(640,794)	360,552
21	387	Other Equipment	69,771	-	69,771	-	827,790	(28,862)	(243,864)	583,926
22		Total Distribution Plant	$ 14,615,638	$ -	$ 14,615,638	$ -	$ 218,790,205	$ (7,336,274)	$ (62,670,521)	$ 156,119,684
		General:								
23	389	Land & Rights	$ -	$ -	$ -	$ -	$ 721,923	$ -	$ 5,618	$ 727,541
24	390	Structures & Improvements	49,926	-	49,926	-	4,965,284	(153,150)	(1,105,808)	3,859,476
25	391	Office Furniture & Equipment	472,243	-	472,243	-	9,581,663	(450,455)	(5,194,458)	4,387,205
26	392	Transportation Equipment	1,365,147	-	1,365,147	(26,446)	4,127,470	-	(1,245,276)	2,882,194
27	393	Stores Equipment	4,162	-	4,162	-	122,357	(2,730)	(32,562)	89,795
28	394	Tools, Shop And Garage Equip.	72,784	-	72,784	-	1,905,277	(107,648)	(868,176)	1,037,102
29	395	Laboratory Equipment	39,228	-	39,228	-	620,818	(34,629)	(196,636)	424,182
30	396	Power Operated Equipment	-	-	-	-	405,574	(99,771)	(608,771)	(203,197)
31	397	Communication Equipment	80,571	-	80,571	-	1,038,969	(49,235)	(267,385)	771,584
32	398	Miscellaneous Equipment	-	-	-	-	285,357	(15,495)	(93,765)	191,593
33	399	Other Tangible Property	-	-	-	-	104,680	(3,810)	(30,902)	73,778
34		Total General Plant	$ 2,084,061	$ -	$ 2,084,061	$ (26,446)	$ 23,879,371	$ (916,924)	$ (9,638,120)	$ 14,241,251
35		TOTAL PLANT	$ 20,043,959	$ -	$ 20,043,959	$ (26,446)	$ 264,916,893	$ (8,817,276)	$ (76,834,519)	$ 188,082,374
36										
37										

References:
Columns (A) (B) (C) (D): Company Response To RUCO Data Request 1.08
Column (E): Schedule RLM-4, Page 3, Column (E) + Column (C) + Column (D)
Column (F): [(Cl. (C) + Cl. (D)) X RLM-4, Pg 1, Cl. (B) X 1/2 yr. conv.] + [RLM-4, Pg 3, Cl. (E) + Cl. (D)) X RLM-4, Pg 1, Cl. (B)
Column (G): Schedule RLM-4, Page 3, Column (G) + Column (D) + Column (F)
Column (H): Column (E) + Column (G)

UNS Gas Corporation
Docket No. G-04204A-06-0463
Test Year Ended December 31, 2005

RATE BASE ADJUSTMENT NO. 2 - REMOVE TEST-YEAR ACCUMULATED DEPRECIATION
TEST YEAR PLANT SCHEDULES - CONT'D
YEAR ENDED DECEMBER 31, 2005

LINE NO.	ACCT NO.	ACCOUNT NAME	(A) PLANT ADDITIONS	(B) PLANT ADJM'TS	(C) NET PLANT ADDITIONS	(D) PLANT RETIRM'TS	(E) TOTAL PLANT VALUE	(F) ACCURAL DEPRECIATION	(G) ACCUMULATED DEPRECIATION	(H) NET PLANT VALUE
		Intangible:								
1	302	Franchises & Consents	$ -	$ -	$ -	$ -	$ 388,336	$ (15,533)	$ (192,917)	$ 195,419
2	303	Miscellaneous Intangible	15,100	-	15,100	-	278,208	(10,826)	(189,681)	88,527
3		Total Intangible Plant	$ 15,100	$ -	$ 15,100	$ -	$ 666,544	$ (26,360)	$ (382,598)	$ 283,946
		Transmission :								
4	365	Land & Rights	$ -	$ -	$ -	$ -	$ 74,563	$ -	$ 5	$ 74,568
5	366	Structures & Improvements	-	-	-	-	1,395	(43)	(1,483)	(88)
6	367	Mains	5,001,194	-	5,001,194	-	22,804,685	(521,815)	(4,026,621)	18,778,064
7	369	Measuring And Reg. Equipment	806	-	806	-	3,525,266	(117,025)	(754,930)	2,770,336
8	371	Other Equipment	-	-	-	-	191,965	(6,988)	(32,483)	159,483
9		Total Transmission Plant	$ 5,002,000	$ -	$ 5,002,000	$ -	$ 26,597,873	$ (645,871)	$ (4,815,511)	$ 21,782,362
		Distribution:								
10	374	Land & Rights	$ -	$ -	$ -	$ -	$ 140,727	$ -	$ -	$ 140,727
11	375	Structures & Improvements	-	-	-	-	10,052	(337)	(8,997)	1,055
12	376	Mains	6,342,549	-	6,342,549	(607,106)	140,875,555	(4,029,829)	(34,414,023)	106,461,532
13	378	Meas. And Reg. Equip. - General	74,523	-	74,523	-	2,120,484	(119,369)	(1,132,662)	987,822
14	379	Meas. And Reg. Equip. - City Gate	303,733	-	303,733	-	2,365,759	(122,207)	(1,161,462)	1,204,297
15	380	Services	6,547,947	-	6,547,947	(22,405)	65,723,278	(2,966,874)	(24,687,717)	41,035,561
16	381	Meters	1,180,280	-	1,180,280	-	11,940,511	(324,621)	(4,867,844)	7,072,667
17	382	Meter Installation	981,154	-	981,154	-	5,707,065	(149,192)	(938,632)	4,768,434
18	383	Regulators	323,346	-	323,346	-	2,903,996	(103,386)	(1,720,975)	1,183,021
19	384	Regulator Installation	552,063	-	552,063	-	849,725	(21,628)	(61,480)	788,244
20	385	Industrial Measuring Equipment	162,566	-	162,566	-	1,163,912	(41,356)	(682,150)	481,762
21	387	Other Equipment	428,608	-	428,608	-	1,256,398	(37,932)	(281,797)	974,602
22		Total Distribution Plant	$ 16,896,769	$ -	$ 16,896,769	$ (629,511)	$ 235,057,463	$ (7,916,730)	$ (69,957,740)	$ 165,099,723
		General:								
23	389	Land & Rights	$ -	$ -	$ -	$ -	$ 721,923	$ -	$ 5,618	$ 727,541
24	390	Structures & Improvements	156,182	-	156,182	-	5,121,466	(156,345)	(1,262,152)	3,859,313
25	391	Office Furniture & Equipment	188,683	-	188,683	-	9,770,346	(466,383)	(5,660,842)	4,109,504
26	392	Transportation Equipment	3,091,785	-	3,091,785	(1,951,895)	5,267,360	-	706,619	5,973,979
27	393	Stores Equipment	-	-	-	(2,576)	119,781	(2,748)	(32,735)	87,047
28	394	Tools, Shop And Garage Equip.	66,811	-	66,811	-	1,972,088	(111,668)	(979,844)	992,244
29	395	Laboratory Equipment	33,550	-	33,550	-	654,368	(36,725)	(233,361)	421,007
30	396	Power Operated Equipment	93,549	-	93,549	-	499,123	(111,278)	(720,049)	(220,926)
31	397	Communication Equipment	-	-	-	(4,649)	1,034,320	(51,107)	(313,843)	720,477
32	398	Miscellaneous Equipment	-	-	-	-	285,357	(15,495)	(109,260)	176,098
33	399	Other Tangible Property	-	-	-	-	104,680	(3,810)	(34,713)	69,967
34		Total General Plant	$ 3,630,560	$ -	$ 3,630,560	$ (1,959,120)	$ 25,550,811	$ (955,559)	$ (8,634,560)	$ 16,916,252
35		TOTAL PLANT	$ 25,544,429	$ -	$ 25,544,429	$ (2,588,631)	$ 287,872,691	$ (9,544,520)	$ (83,790,408)	$ 204,082,283
36		Total Plant As Per Company							$ (77,077,541)	
37		Difference							$ (6,712,867)	
38		RUCO Adjustment To Pre-Aquisition Accumulated Depreciation (See RLM-4, Page 3, Lines 39)							(3,857,413)	
39										
40		RUCO Adjustment To Test-Year Accumulated Depreciation (See RLM-3, Column (C))							$ (2,855,454)	

References:

Columns (A) (B) (C) (D): Company Response To RUCO Data Request 1.08
Column (E): Schedule RLM-4, Page 4, Column (E) + Column (C) + Column (D)
Column (F): [(Cl. (C) + Cl. (D)) X RLM-4, Pg 1, Cl. (B) X 1/2 yr. conv.] + [RLM-4, Pg 4, Cl. (E) + Cl. (D)) X RLM-4, Pg 1, Cl. (B)
Column (G): Schedule RLM-4, Page 4, Column (G) + Column (D) + Column (F)
Column (H): Column (E) + Column (G)

UNS Gas Corporation
Docket No. G-04204A-06-0463
Test Year Ended December 31, 2005

RATE BASE ADJUSTMENT NO. 3 - REMOVE CWIP FROM TEST-YEAR RATE BASE
TEST YEAR PLANT SCHEDULES - CONT'D
PRO FORMA ADJUSTMENTS TO TEST YEAR ENDED DECEMBER 31, 2005

LINE NO.	ACCT NO.	ACCOUNT NAME	(A) GRIFFITH POWER PLANT PLANT ADJUSTMENTS	(B) GRIFFITH POWER PLANT ACC. DEP ADJUSTMENTS	(C) BUILD-OUT PLANT PLANT ADJUSTMENTS	(D) BUILD-OUT PLANT ACC. DEP ADJUSTMENTS	(E) RUCO ADJUSTED TOTAL PLANT VALUE	(F) RUCO ADJUSTED ACCUMULATED DEPRECIATION	(G) RUCO ADJUSTED NET PLANT VALUE
		Intangible:							
1	302	Franchises & Consents	$ -	$ -	$ -	$ -	$ 388,336	$ (192,917)	$ 195,419
2	303	Miscellaneous Intangible	-	-	-	-	278,208	(189,681)	88,527
3		Total Intangible Plant	$ -	$ -	$ -	$ -	$ 666,544	$ (382,598)	$ 283,946
		Transmission :							
4	365	Land & Rights	$ (10,075)	$ -	$ (7,441)	$ -	$ 57,047	$ 5	$ 57,052
5	366	Structures & Improvements	-	-	(1,222)	430	173	(1,053)	(880)
6	367	Mains	(3,421,025)	511,821	(1,606,936)	417,127	17,776,724	(3,097,673)	14,679,051
7	369	Measuring And Reg. Equipment	(2,557,112)	372,457	(259,186)	70,426	708,968	(312,047)	396,921
8	371	Other Equipment	(183,581)	44,626	(13,313)	4,641	(4,929)	16,784	11,856
9		Total Transmission Plant	$ (6,171,793)	$ 928,904	$ (1,888,098)	$ 492,624	$ 18,537,982	$ (3,393,983)	$ 15,143,999
		Distribution:							
10	374	Land & Rights	$ -	$ -	$ (18,709)	$ -	$ 122,018	$ -	$ 122,018
11	375	Structures & Improvements	-	-	(794)	1,016	9,258	(7,981)	1,277
12	376	Mains	-	-	(10,506,547)	3,424,497	130,369,008	(30,989,526)	99,379,482
13	378	Meas. And Reg. Equip. - General	-	-	(145,939)	98,248	1,974,545	(1,034,414)	940,131
14	379	Meas. And Reg. Equip. - City Gate	-	-	(169,292)	85,420	2,196,467	(1,076,042)	1,120,425
15	380	Services	-	-	-	-	65,723,278	(24,687,717)	41,035,561
16	381	Meters	-	-	-	-	11,940,511	(4,867,844)	7,072,667
17	382	Meter Installation	-	-	-	-	5,707,065	(938,632)	4,768,434
18	383	Regulators	-	-	-	-	2,903,996	(1,720,975)	1,183,021
19	384	Regulator Installation	-	-	-	-	849,725	(61,480)	788,244
20	385	Industrial Measuring Equipment	(12,609)	1,412	-	-	1,151,303	(680,738)	470,565
21	387	Other Equipment	-	-	(111,710)	38,712	1,144,688	(243,085)	901,604
22		Total Distribution Plant	$ (12,609)	$ 1,412	$ (10,952,991)	$ 3,647,893	$ 224,091,863	$ (66,308,435)	$ 157,783,428
		General:							
23	389	Land & Rights	$ -	$ -	$ -	$ -	$ 721,923	$ 5,618	$ 727,541
24	390	Structures & Improvements	-	-	-	-	5,121,466	(1,262,152)	3,859,313
25	391	Office Furniture & Equipment	-	-	-	-	9,770,346	(5,660,842)	4,109,504
26	392	Transportation Equipment	-	-	-	-	5,267,360	706,619	5,973,979
27	393	Stores Equipment	-	-	-	-	119,781	(32,735)	87,047
28	394	Tools, Shop And Garage Equip.	-	-	-	-	1,972,088	(979,844)	992,244
29	395	Laboratory Equipment	-	-	-	-	654,368	(233,361)	421,007
30	396	Power Operated Equipment	-	-	-	-	499,123	(720,049)	(220,926)
31	397	Communication Equipment	-	-	-	-	1,034,320	(313,843)	720,477
32	398	Miscellaneous Equipment	-	-	-	-	285,357	(109,260)	176,098
33	399	Other Tangible Property	-	-	-	-	104,680	(34,713)	69,967
34		Total General Plant	$ -	$ -	$ -	$ -	$ 25,550,811	$ (8,634,560)	$ 16,916,252
35		TOTAL PLANT	$ (6,184,402)	$ 930,316	$ (12,841,089)	$ 4,140,517	$ 268,847,200	$ (78,719,575)	$ 190,127,625
36		Total Plant As Per Company	$ -	$ (11,836,260)	$ (11,836,260)	$ -	$ 279,169,694	$ (72,006,708)	$ 213,928,413
37		Difference	$ (6,184,402)	$ 12,766,576	$ (1,004,829)	$ 4,140,517	$ (10,322,494)	$ (6,712,867)	$ (23,800,788)
38		RUCO Adjustment To Pre-Aquisition Gross Plant In Service (See RLM-4, Page 3, Lines 38)					(3,133,264)		
39		RUCO Adjustment To Pro-Forma Test-Year Gross Plant In Service (See RLM-3, Column (E))					$ (7,189,230)		

References:

Columns (A) (B) (C) (D): Company Workpapers
Column (E): Schedule RLM-4, Page 5, Column (E) + Column (A) + Column (C)
Column (F): Schedule RLM-4, Page 5, Column (G) + Column (B) + Column (D)
Column (G): Column (E) + Column (F)

UNS Gas Corporation
Docket No. G-04204A-06-0463
Test Year Ended December 31, 2005

OPERATING INCOME

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJ'TMENTS	(C) RUCO TEST YEAR AS ADJUSTED	(D) RUCO PROPOSED CHANGES	(E) RUCO AS RECOMMENDED
	Operating Revenues:					
1	Gas Retail Revenues	$ 45,689,224	$ 110,906	$ 45,800,130	$ 1,505,003	$ 47,305,133
2	Other Operating Revenue	1,480,304	-	1,480,304	-	1,480,304
3	TOTAL OPERATING REVENUES	$ 47,169,528	$ 110,906	$ 47,280,434	$ 1,505,003	$ 48,785,437
	Operating Expenses:					
4	Purchased Gas	$ 355,528	$ (54)	$ 355,474	$ -	$ 355,474
5	Other O & M Expense	24,459,038	(2,057,381)	22,401,657	-	22,401,657
6	Depreciation & Amortization	7,220,391	(646,479)	6,573,912	-	6,573,912
7	Taxes Other Than Income Taxes	4,730,093	(1,147,587)	3,582,506	-	3,582,506
8	Income Taxes	1,975,497	1,830,390	3,805,887	585,627	4,391,514
9	TOTAL OPERATING EXPENSES	$ 38,740,547	$ (2,021,111)	$ 36,719,436	$ 585,627	$ 37,305,063
10	OPERATING INCOME (LOSS)	$ 8,428,981		$ 10,560,998		$ 11,480,374

References:
- Column (A): Company Schedule C-1
- Column (B): Testimony, RLM And Schedule RLM-7, Pages 1 Thru 6
- Column (C): Column (A) + Column (B)
- Column (D): Testimony, RLM And Schedule RLM-1
- Column (E): Column (C) + Column (D)

UNS Gas Corporation
Docket No. G-04204A-06-0463
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SUMMARY OF OPERATING INCOME ADJUSTMENT
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJ. NO. 1 WORKERS COMP.	(C) ADJ. NO. 2 INCENTIVE COMP.	(D) ADJ. NO. 3 DEPRECIATION EXPENSE	(E) ADJ. NO. 4 POSTAGE EXPENSE	(F) ADJ. NO. 5 CUSTOMER SERVICE COSTS	(G) ADJ. NO. 6 UNNECESSARY EXPENSES	(H) ADJ. NO. 7 PROPERTY TAX
	Operating Revenue								
1	Net Sales to Ultimate Customers	$ 42,950,315	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Transportation of Gas	2,738,909	-	-	-	-	-	-	-
3	**Gas Retail Revenue**	$ 45,689,224	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Forfeited Discounts (Late Fees)	$ 398,966	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Miscellaneous Service Revenues	1,046,891	-	-	-	-	-	-	-
6	Other Gas Revenues	34,447	-	-	-	-	-	-	-
7	**Other Operating Revenue**	$ 1,480,304	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	**Total Operating Revenue**	$ 47,169,528	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Expense								
9	**Purchased Gas**	$ 355,528	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Transmision - Mains Expense	$ 11,280	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Transmision - Meas. and Reg. Station	(52,221)	-	-	-	-	-	-	-
12	Transmision - Maint. Compressor Stat. Equip.	19	-	-	-	-	-	-	-
13	Transmision - Oper. Super'n and Eng.	315,983	-	-	-	-	-	-	-
14	Distribution - Load Dispatching	162	-	-	-	-	-	-	-
15	Distribution - Mains and Services	1,337,349	-	(42,144)	-	-	-	(1,592)	-
16	Distribution - Meas. and Reg. Station - Gen.	244,463	-	-	-	-	-	-	-
17	Distribution - Meas. and Reg. Station - Ind.	150,536	-	-	-	-	-	-	-
18	Distribution - Meas. and Reg. Station - City	56,529	-	-	-	-	-	-	-
19	Distribution - Meter and House Regulator	1,349,114	-	(34,242)	-	-	-	-	-
20	Distribution - Customer Installations	539,082	-	-	-	-	-	-	-
21	Distribution - Other Expenses	1,090,666	-	-	-	-	-	(27,217)	-
22	Distribution - Rents	44,510	-	-	-	-	-	-	-
23	Distribution - Maint. Superv'n & Eng.	243,170	-	-	-	-	-	-	-
24	Distribution - Maintenance of Mains	1,084,194	-	(26,340)	-	-	-	-	-
25	Distribution - Maint. M & R Stat. Equip. - Gen.	25,623	-	-	-	-	-	-	-
26	Distribution - Maint. M & R Stat. Equip. - Ind.	2,072	-	-	-	-	-	-	-
27	Distribution - Maint. M & R Equip. - City Gate	850	-	-	-	-	-	-	-
28	Distribution - Maintenance of Services	465,066	-	-	-	-	-	-	-
29	Distribution - Maint. of Meters and Reg.	167,015	-	-	-	-	-	-	-
30	Distribution - Maintenance of Other Equip.	96,826	-	-	-	-	-	-	-
31	Customer Account - Supervision	74,309	-	-	-	-	-	-	-
32	Customer Account - Meter Reading	719,037	-	-	-	-	-	-	-
33	Customer Account - Records and Collection	5,462,173	-	(60,582)	-	(153,479)	(490,413)	-	-
34	Customer Account - Uncollectibles	722,634	-	-	-	-	-	-	-

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SUMMARY OF OPERATING INCOME ADJUSTMENT - CONT'D
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJ. NO. 1 WORKERS COMP.	(C) ADJ. NO. 2 INCENTIVE COMP.	(D) ADJ. NO. 3 DEPRECIATION EXPENSE	(E) ADJ. NO. 4 POSTAGE EXPENSE	(F) ADJ. NO. 5 CUSTOMER SERVICE COSTS	(G) ADJ. NO. 6 UNNECESSARY EXPENSES	(H) ADJ. NO. 7 PROPERTY TAX
	Continued								
35	Customer Account - Miscellaneous	$ 34,381	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36	Customer Account - Superv'n - Cust. Service	14,743	-	-	-	-	-	-	-
37	Customer Account - Assistance	(34,228)	-	-	-	-	-	-	-
38	Customer Account - Info and Instruct Advert.	65,794	-	-	-	-	-	-	-
39	Customer Account - Miscellaneous	22,602	-	-	-	-	-	-	-
40	Sales - Demonstrating and Selling	558	-	-	-	-	-	-	-
41	A & G - Salaries	1,529,696	-	(94,587)	-	-	(25,437)	-	-
42	A & G - Office Supplies and Expenses	1,365,974	-	-	-	-	(11,157)	(107,076)	-
43	A & G - Transferred - Credit	(152,817)	-	-	-	-	(133)	-	-
44	A & G - Outside Services Employed	2,696,531	-	-	-	-	(2,559)	(14,738)	-
45	A & G - Property Insurance	7,415	-	-	-	-	(1,329)	-	-
46	A & G - Injuries and Damages	574,128	(34,234)	-	-	-	(293)	-	-
47	A & G - Employee Pension and Benefits	2,452,071	-	-	-	-	(143,577)	(6,230)	-
48	A & G - Miscellaneous General Expenses	1,082,411	-	-	-	-	-	(76,494)	-
49	A & G - Rents	109,053	-	-	-	-	-	-	-
50	A & G - Maintenance of General Plant	169,826	-	-	-	-	-	-	-
51	A & G - Rate Case Expense	200,000	-	-	-	-	-	-	-
52	Interest On Customer Deposits	170,459	-	-	-	-	-	-	-
53	**Other Oper. and Maint. Expense**	$ 24,459,038	$ (34,234)	$ (257,895)	$ -	$ (153,479)	$ (674,898)	$ (233,347)	$ -
54	Dep. & Amort. - Citizens Acq. Discount	$ (729,791)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55	Dep. & Amort. - Intangible Plant	929,602	-	-	(57,341)	-	-	-	-
56	Dep. & Amort. - Transmission Plant	285,187	-	-	(1,618)	-	-	-	-
57	Dep. & Amort. - Distribution Plant	5,631,142	-	-	(427,753)	-	-	-	-
58	Dep. & Amort. - General Plant	1,104,251	-	-	162,629	-	(23,373)	-	-
59	**Depreciation and Amortization**	$ 7,220,391	$ -	$ -	$ (324,083)	$ -	$ (23,373)	$ -	$ -
60	Property Tax	$ 4,103,375	$ -	$ -	$ -	$ -	$ (28,439)	$ -	$ (309,309)
61	Payroll Tax - FUTA, SUTA, FICA & Medicare	537,877	-	(20,853)	-	-	-	-	-
62	Medical and Dental	86,130	-	-	-	-	-	-	-
63	Other	2,711	-	-	-	-	-	-	-
64	**Taxes Other Than Income Taxes**	$ 4,730,093	$ -	$ (20,853)	$ -	$ -	$ (28,439)	$ -	$ (309,309)
65	**Income Taxes**	$ 1,975,497	$ -	$ -	$ -	$ -	$ -	$ -	$ -
66	**Total Operating Expense**	$ 38,740,547	$ (34,234)	$ (278,748)	$ (324,083)	$ (153,479)	$ (726,710)	$ (233,347)	$ (309,309)
67	**Operating Income**	$ 8,428,981	$ 34,234	$ 278,748	$ 324,083	$ 153,479	$ 726,710	$ 233,347	$ 309,309

UNS Gas Corporation
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SUMMARY OF OPERATING INCOME ADJUSTMENT - CONT'D
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	DESCRIPTION	(I) ADJ. NO. 8 RATE CASE EXPENSE	(J) ADJ. NO. 9 AGA DUES	(K) ADJ. NO. 10 ATYPICAL EXPENSES	(L) ADJ. NO. 11 SERP	(M) ADJ. NO. 12 AMORTIZATION GIS O&M	(N) ADJ. NO. 13 FLEET FUEL EXPENSE	(O) ADJ. NO. 14 CUSTOMER ANNUALIZ'N	(P) ADJ. NO. 15 CUSTOMER WEATHERIZ'N
	Operating Revenue								
1	Net Sales to Ultimate Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ 110,006	$ 900
2	Transportation of Gas	-	-	-	-	-	-	-	-
3	**Gas Retail Revenue**	$ -	$ -	$ -	$ -	$ -	$ -	$ 110,006	$ 900
4	Forfeited Discounts (Late Fees)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Miscellaneous Service Revenues	-	-	-	-	-	-	-	-
6	Other Gas Revenues	-	-	-	-	-	-	-	-
7	**Other Operating Revenue**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	**Total Operating Revenue**	$ -	$ -	$ -	$ -	$ -	$ -	$ 110,006	$ 900
	Operating Expense								
9	**Purchased Gas**	$ -	$ -	$ -	$ -	$ -	$ (54)	$ -	$ -
10	Transmision - Mains Expense	$ -	$ -	$ -	$ -	$ -	$ (69)	$ -	$ -
11	Transmision - Meas. and Reg. Station	-	-	-	-	-	(1)	-	-
12	Transmision - Maint. Compressor Stat. Equip.	-	-	-	-	-	-	-	-
13	Transmision - Oper. Super'n and Eng.	-	-	-	-	-	(1,907)	-	-
14	Distribution - Load Dispatching	-	-	-	-	-	-	-	-
15	Distribution - Mains and Services	-	-	-	-	-	(5,801)	-	-
16	Distribution - Meas. and Reg. Station - Gen.	-	-	-	-	-	(1,095)	-	-
17	Distribution - Meas. and Reg. Station - Ind.	-	-	-	-	-	(834)	-	-
18	Distribution - Meas. and Reg. Station - City	-	-	-	-	-	(123)	-	-
19	Distribution - Meter and House Regulator	-	-	-	-	-	(6,218)	-	-
20	Distribution - Customer Installations	-	-	-	-	-	(2,502)	-	-
21	Distribution - Other Expenses	-	-	-	-	-	(1,956)	-	-
22	Distribution - Rents	-	-	-	-	-	-	-	-
23	Distribution - Maint. Superv'n & Eng.	-	-	-	-	-	(1,358)	-	-
24	Distribution - Maintenance of Mains	-	-	-	-	-	(3,330)	-	-
25	Distribution - Maint. M & R Stat. Equip. - Gen.	-	-	-	-	-	(19)	-	-
26	Distribution - Maint. M & R Stat. Equip. - Ind.	-	-	-	-	-	(1)	-	-
27	Distribution - Maint. M & R Equip. - City Gate	-	-	-	-	-	(1)	-	-
28	Distribution - Maintenance of Services	-	-	-	-	-	(2,229)	-	-
29	Distribution - Maint. of Meters and Reg.	-	-	-	-	-	(366)	-	-
30	Distribution - Maintenance of Other Equip.	-	-	-	-	-	(169)	-	-
31	Customer Account - Supervision	-	-	-	-	-	(415)	-	-
32	Customer Account - Meter Reading	-	-	-	-	-	(3,799)	-	-
33	Customer Account - Records and Collection	-	-	-	-	-	(7,985)	-	-
34	Customer Account - Uncollectibles	-	-	-	-	-	-	-	-

SUMMARY OF OPERATING INCOME ADJUSTMENT - CONT'D
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	DESCRIPTION	(I) ADJ. NO. 8 RATE CASE EXPENSE	(J) ADJ. NO. 9 AGA DUES	(K) ADJ. NO. 10 ATYPICAL EXPENSES	(L) ADJ. NO. 11 SERP	(M) ADJ. NO. 12 AMORTIZATION GIS O&M	(N) ADJ. NO. 13 FLEET FUEL EXPENSE	(O) ADJ. NO. 14 CUSTOMER ANNUALIZ'N	(P) ADJ. NO. 15 CUSTOMER WEATHERIZ'N
	Continued								
35	Customer Account - Miscellaneous	$ -	$ -	$ -	$ -	$ -	$ (9)	$ -	$ -
36	Customer Account - Superv'n - Cust. Service	-	-	-	-	-	(66)	-	-
37	Customer Account - Assistance	-	-	-	-	-	(71)	-	-
38	Customer Account - Info and Instruct Advert.	-	-	-	-	-	(3)	-	-
39	Customer Account - Miscellaneous	-	-	-	-	-	-	-	-
40	Sales - Demonstrating and Selling	-	-	-	-	-	-	-	-
41	A & G - Salaries	-	-	-	-	-	-	-	-
42	A & G - Office Supplies and Expenses	-	-	(2,584)	-	-	(8,981)	-	-
43	A & G - Transferred - Credit	-	-	-	-	-	-	-	-
44	A & G - Outside Services Employed	-	-	-	-	-	-	-	-
45	A & G - Property Insurance	-	-	-	-	-	-	-	-
46	A & G - Injuries and Damages	-	-	-	-	-	(3)	-	-
47	A & G - Employee Pension and Benefits	-	-	-	(93,075)	-	-	-	-
48	A & G - Miscellaneous General Expenses	-	(1,523)	-	-	-	(65)	-	-
49	A & G - Rents	-	-	-	-	-	-	-	-
50	A & G - Maintenance of General Plant	-	-	-	-	-	(120)	-	-
51	A & G - Rate Case Expense	(116,333)	-	-	-	-	-	-	-
52	Interest On Customer Deposits	-	-	-	-	-	-	-	-
53	**Other Oper. and Maint. Expense**	$ (116,333)	$ (1,523)	$ (2,584)	$ (93,075)	$ -	$ (49,493)	$ -	$ -
54	Dep. & Amort. - Citizens Acq. Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55	Dep. & Amort. - Intangible Plant	-	-	-	-	-	-	-	-
56	Dep. & Amort. - Transmission Plant	-	-	-	-	(299,023)	-	-	-
57	Dep. & Amort. - Distribution Plant	-	-	-	-	-	-	-	-
58	Dep. & Amort. - General Plant	-	-	-	-	-	-	-	-
59	**Depreciation and Amortization**	$ -	$ -	$ -	$ -	$ (299,023)	$ -	$ -	$ -
60	Property Tax	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
61	Payroll Tax - FUTA, SUTA, FICA & Medicare	-	-	-	-	-	-	-	-
62	Medical and Dental	-	-	-	-	-	-	-	-
63	Other	-	-	-	-	-	-	-	-
64	**Taxes Other Than Income Taxes**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
65	**Income Taxes**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
66	**Total Operating Expense**	$ (116,333)	$ (1,523)	$ (2,584)	$ (93,075)	$ (299,023)	$ (49,547)	$ -	$ -
67	**Operating Income**	$ 116,333	$ 1,523	$ 2,584	$ 93,075	$ 299,023	$ 49,547	$ 110,006	$ 900

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SUMMARY OF OPERATING INCOME ADJUSTMENT - CONT'D
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	DESCRIPTION	(Q) ADJ. NO. 16 CORP. COST ALLOCATION	(R) ADJ. NO. 17 UNCOL'TIBLES	(S) ADJ. NO. 18 CWIP PROP. TAXES	(T) ADJ. NO. 19 OUT OF PERIOD EXPENSES	(U) ADJ. NO. 20	(V) ADJ. NO. 21	(W) ADJ. NO. 22 INCOME TAX	(X) RUCO AS ADJUSTED
	Operating Revenue								
1	Net Sales to Ultimate Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 43,061,221
2	Transportation of Gas	-	-	-	-	-	-	-	2,738,909
3	**Gas Retail Revenue**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 45,800,130
4	Forfeited Discounts (Late Fees)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 398,966
5	Miscellaneous Service Revenues	-	-	-	-	-	-	-	1,046,891
6	Other Gas Revenues	-	-	-	-	-	-	-	34,447
7	**Other Operating Revenue**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,480,304
8	**Total Operating Revenue**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 47,280,434
9	**Purchased Gas**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 355,474
10	Transmision - Mains Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,211
11	Transmision - Meas. and Reg. Station	-	-	-	-	-	-	-	(52,222)
12	Transmision - Maint. Compressor Stat. Equip.	-	-	-	-	-	-	-	19
13	Transmision - Oper. Super'n and Eng.	-	-	-	-	-	-	-	314,076
14	Distribution - Load Dispatching	-	-	-	-	-	-	-	162
15	Distribution - Mains and Services	-	-	-	-	-	-	-	1,287,812
16	Distribution - Meas. and Reg. Station - Gen.	-	-	-	-	-	-	-	243,368
17	Distribution - Meas. and Reg. Station - Ind.	-	-	-	-	-	-	-	149,702
18	Distribution - Meas. and Reg. Station - City	-	-	-	-	-	-	-	56,406
19	Distribution - Meter and House Regulator	-	-	-	-	-	-	-	1,308,654
20	Distribution - Customer Installations	-	-	-	-	-	-	-	536,580
21	Distribution - Other Expenses	-	-	-	-	-	-	-	1,061,493
22	Distribution - Rents	-	-	-	-	-	-	-	44,510
23	Distribution - Maint. Superv'n & Eng.	-	-	-	-	-	-	-	241,812
24	Distribution - Maintenance of Mains	-	-	-	-	-	-	-	1,054,524
25	Distribution - Maint. M & R Stat. Equip. - Gen.	-	-	-	-	-	-	-	25,604
26	Distribution - Maint. M & R Stat. Equip. - Ind.	-	-	-	-	-	-	-	2,071
27	Distribution - Maint. M & R Equip. - City Gate	-	-	-	-	-	-	-	849
28	Distribution - Maintenance of Services	-	-	-	-	-	-	-	462,837
29	Distribution - Maint. of Meters and Reg.	-	-	-	-	-	-	-	166,649
30	Distribution - Maintenance of Other Equip.	-	-	-	-	-	-	-	96,657
31	Customer Account - Supervision	-	-	-	-	-	-	-	73,894
32	Customer Account - Meter Reading	-	-	-	-	-	-	-	715,238
33	Customer Account - Records and Collection	-	-	-	-	-	-	-	4,749,714
34	Customer Account - Uncollectibles	-	(95,583)	-	-	-	-	-	627,051

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SUMMARY OF OPERATING INCOME ADJUSTMENT - CONT'D
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	DESCRIPTION	(Q) ADJ. NO. 16 CORP. COST ALLOCATION	(R) ADJ. NO. 17 UNCOL'TIBLES	(S) ADJ. NO. 18 CWIP PROP. TAXES	(T) ADJ. NO. 19 OUT OF PERIOD EXPENSES	(U) ADJ. NO. 20 LEGAL EXPENSE	(V) ADJ. NO. 21	(W) ADJ. NO. 22 INCOME TAX	(X) RUCO AS ADJUSTED
	Continued								
35	Customer Account - Miscellaneous	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 34,372
36	Customer Account - Superv'n - Cust. Service	-	-	-	-	-	-	-	14,677
37	Customer Account - Assistance	-	-	-	-	-	-	-	(34,299)
38	Customer Account - Info and Instruct Advert.	-	-	-	-	-	-	-	65,791
39	Customer Account - Miscellaneous	-	-	-	-	-	-	-	22,602
40	Sales - Demonstrating and Selling	-	-	-	-	-	-	-	558
41	A & G - Salaries	-	-	-	-	-	-	-	1,409,672
42	A & G - Office Supplies and Expenses	-	-	-	-	-	-	-	1,236,177
43	A & G - Transferred - Credit	-	-	-	-	-	-	-	(152,950)
44	A & G - Outside Services Employed	-	-	-	-	(311,051)	-	-	2,368,183
45	A & G - Property Insurance	-	-	-	-	-	-	-	6,086
46	A & G - Injuries and Damages	-	-	-	-	-	-	-	539,598
47	A & G - Employee Pension and Benefits	-	-	-	-	-	-	-	2,209,189
48	A & G - Miscellaneous General Expenses	(12,765)	-	-	(21,120)	-	-	-	970,444
49	A & G - Rents	-	-	-	-	-	-	-	109,053
50	A & G - Maintenance of General Plant	-	-	-	-	-	-	-	169,706
51	A & G - Rate Case Expense	-	-	-	-	-	-	-	83,667
52	Interest On Customer Deposits	-	-	-	-	-	-	-	170,459
53	**Other Oper. and Maint. Expense**	$ (12,765)	$ (95,583)	$ -	$ (21,120)	$ (311,051)	$ -	$ -	$ 22,401,657
54	Dep. & Amort. - Citizens Acq. Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (729,791)
55	Dep. & Amort. - Intangible Plant	-	-	-	-	-	-	-	872,261
56	Dep. & Amort. - Transmission Plant	-	-	-	-	-	-	-	(15,454)
57	Dep. & Amort. - Distribution Plant	-	-	-	-	-	-	-	5,203,389
58	Dep. & Amort. - General Plant	-	-	-	-	-	-	-	1,243,507
59	**Depreciation and Amortization**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,573,912
60	Property Tax	$ -	$ -	$ (166,884)	$ -	$ -	$ -	$ -	$ 3,598,743
61	Payroll Tax - FUTA, SUTA, FICA & Medicare	-	-	-	-	-	-	-	517,024
62	Medical and Dental	-	-	-	-	-	-	-	86,130
63	Other	-	-	-	-	(622,102)	-	-	(619,391)
64	**Taxes Other Than Income Taxes**	$ -	$ -	$ (166,884)	$ -	$ (622,102)	$ -	$ -	$ 3,582,506
65	**Income Taxes**	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,830,390	$ 3,805,887
66	**Total Operating Expense**	$ (12,765)	$ (95,583)	$ (166,884)	$ (21,120)	$ (933,153)	$ -	$ 1,830,390	$ 36,719,436
67	**Operating Income**	$ 12,765	$ 95,583	$ 166,884	$ 21,120	$ 933,153	$ -	$ (1,830,390)	$ 10,560,998

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OPERATING INCOME ADJUSTMENT NO. 3
TEST-YEAR DEPRECIATION EXPENSE ON GROSS PLANT IN SERVICE

LINE NO.	ACCT. NO.		(A) RUCO TOTAL PLANT AS ADJUSTED	(B) CO. PROPOSED DEPRECIATION RATE	(C) TEST YEAR DEPREC'N EXPENSE
		Intangible:			
1	302	Franchises & Consents	$ 388,336	3.95%	$ 15,339
2	303	Miscellaneous Intangible	278,208	5.84%	16,247
3		Total Intangible Plant	$ 666,544		$ 31,587
4		Company As Filed (Company Workpapers)			88,927
5		Difference (Line 4 - Line 3)			$ (57,341)
6		RUCO Adjustment To Depreciation Expense - Intangibles (Line 5) (See RLM-7, Page 2, Column (D))			$ (57,341)
		Transmission :			
7	365	Land & Rights	$ 57,047	1.38%	$ 787
8	366	Structures & Improvements	173	1.55%	3
9	367	Mains	$ 17,776,724	1.53%	271,984
10	369	Measuring And Reg. Equipment	708,968	1.54%	10,918
11	371	Other Equipment	$ (4,929)	2.49%	(123)
12		Total Transmission Plant	$ 18,537,982		$ 283,569
13		Company As Filed (Company Workpapers)			285,187
14		Difference (Line 13 - Line 12)			$ (1,618)
15		RUCO Adjustment To Depreciation Expense - Transmission (Line 14) (See RLM-7, Page 2, Column (D))			$ (1,618)
		Distribution:			
16	374	Land & Rights	$ 122,018	0.93%	$ 1,135
17	375	Structures & Improvements	9,258	1.93%	179
18	376	Mains	130,369,008	2.07%	2,698,638
19	378	Meas. And Reg. Equip. - General	1,974,545	2.97%	58,644
20	379	Meas. And Reg. Equip. - City Gate	2,196,467	2.36%	51,837
21	380	Services	65,723,278	2.82%	1,853,396
22	381	Meters	11,940,511	2.02%	241,198
23	382	Meter Installation	5,707,065	2.36%	134,687
24	383	Regulators	2,903,996	2.56%	74,342
25	384	Regulator Installation	849,725	2.80%	23,792
26	385	Industrial Measuring Equipment	1,151,303	2.70%	31,085
27	387	Other Equipment	1,144,688	3.01%	34,455
28		Total Distribution Plant	$ 224,091,863		$ 5,203,389
29		Company As Filed (Company Workpapers)			5,631,142
30		Difference (Line 29 - Line 28)			$ (427,753)
31		RUCO Adjustment To Depreciation Expense - Distribution (Line 30)(See RLM-7, Page 2, Column (D))			$ (427,753)
		General:			
32	389	Land & Rights	$ 721,923	4.93%	$ 35,591
33	390	Structures & Improvements	5,121,466	4.93%	252,488
34	391	Office Furniture & Equipment	9,770,346	4.89%	477,770
35	392	Transportation Equipment	5,267,360	4.24%	223,336
36	393	Stores Equipment	119,781	14.71%	17,620
37	394	Tools, Shop And Garage Equip.	1,972,088	3.03%	59,754
38	395	Laboratory Equipment	654,368	3.64%	23,819
39	396	Power Operated Equipment	499,123	9.29%	46,369
40	397	Communication Equipment	1,034,320	10.49%	108,500
41	398	Miscellaneous Equipment	285,357	6.11%	17,435
42	399	Other Tangible Property	104,680	4.01%	4,198
43		Total General Plant	$ 25,550,811		$ 1,266,880
44		Company As Filed (Company Workpapers)			1,104,251
45		Difference (Line 44 - Line 43)			$ 162,629
46		RUCO Adjustment To Depreciation Expense - General (Line 45) (See RLM-7, Page 2, Column (D))			$ 162,629
44		TOTAL ADJUSTMENT			$ (324,083)

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OPERATING INCOME ADJUSTMENT NO. 4
NORMALIZATION OF POSTAGE EXPENSES

LINE NO.	DESCRIPTION	REFERENCE		(A) POSTAGE
1	Actual Test-Year Costs	Company Workpapers	$	367,603
2	Actual Number Of Test-Year Customer Bills	Company Schedule H-2		1,632,576
3	Cost Per Customer Bill	Line 1 / Line 2	$	0.2252
4	RUCO Annualized Number Of Test-Year Customer Bills	RLM-15, Column (C)		1,669,426
5	RUCO Adjusted Cost	Line 3 X Line 4	$	375,901
6	Postage Increase			5.00%
7	RUCO Adjusted Cost		$	394,696
8	Company As Filed	Company Workpapers	$	529,380
9	Difference	Line 7 - Line 8	$	(153,479)
10	RUCO Adjustment (See RLM-7, Pages 1 & 2, Column (E))	Line 9	$	(153,479)

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OPERATING INCOME ADJUSTMENT NO. 5
CUSTOMER SERVICE COST ALLOCATION

LINE NO.	ACCT NO.	ACCOUNT DESCRIPTION	(A) COMPANY AS FILED	(B) ALLOCATION FACTOR	(C) RUCO AS ADJUSTED	(D) RUCO ADJUSTMENT
1	403	Depreciation Expense	$ 30,202	3.23%	$ 6,830	$ (23,373)
2	408	Taxes Other Than Income Tax	33,577	3.59%	7,593	(25,984)
3	903	Customer Records & Collection Expenses	633,713	67.71%	143,300	(490,413)
4	920	A & G - Salaries	32,869	3.51%	7,433	(25,437)
5	921	Office Supplies & Expenses	14,416	1.54%	3,260	(11,157)
6	922	Administrative Expenses Transferred	172	0.02%	39	(133)
7	923	Outside Services	3,307	0.35%	748	(2,559)
8	924	Property Insurance	1,717	0.18%	388	(1,329)
9	925	Injuries & Damages	379	0.04%	86	(293)
10	926	Pensions & Benefits	185,531	19.82%	41,954	(143,577)
11	408	Co. Wp's "Property Tax" page 2, As Per Note				(2,455)
12		TOTAL	$ 935,884	100.00%	$ 211,629	$ (726,710)
13		RUCO Adjustment (See RLM-7, Pages 1 & 2, Column (F) For Distribution)				$ (726,710)

NOTE:
RUCO Calculated The Annual Customer Service Costs Of $211,629 By Multiplying the Company's Four-Month Test-Year Expenses As Stated In Its Response To RUCO Data Request 6.13 Of $70,543 By 3 To Equal $211,629 Annually (See Column (C), Line 11)

References:
Column (A): Company Workpapers
Column (B): Individual Account Allocation Based On Percentage Of Each Account To Total
Column (C): RUCO Adjusted Customer Service Cost Allocated By Allocation Factors In Column (B)
Column (D): Column (C) - (A)

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OPERATING INCOME ADJUSTMENT NO. 6
RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES

LINE NO.	DESCRIPTION	REFERENCE	(A) AMOUNT
	Expenses Removed		
1	Account 874 - Distribution Expense - Mains & Services:	Co. Response To STAFF Data Request 5.58	$ (1,592)
2	Account 880 - Distribution Expense - Other:	RUCO Workpapers - "WP RLM-11-880 (1 - 4)"	(27,217)
3	Account 921 - A & G Expense - Office Supplies:	RUCO Workpapers - "WP RLM-11-921 (1 - 16)"	(107,076)
4	Account 923 - A & G Expense - Outside Services Employed:	RUCO Workpapers - "WP RLM-11-923 (1 - 2)"	(14,738)
5	Account 926 - A & G Expense - Pension & Benefits	RUCO Workpapers - "WP RLM-11-926 (1)"	(6,230)
6	Account 930 - A & G Expense - Miscellaneous General Expenses:	RUCO Workpapers - "WP RLM-11-930 (1 - 5)"	(76,494)
7	Total Expenses Removed	Sum Of Lines 1 Thru 6	$ (233,347)
8	RUCO Adjustment (See RLM-7, Pages 1 & 2, Column (G) For Distribution)	Line 7	$ (233,347)

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WORKPAPER FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
EXPENSES REMOVED FROM ACCOUNT 880

LINE NO.	GENERAL LEDGER PERIOD	PA EXPENDITURE COMMENT	INVOICE NUMBER	NET AMOUNT
1	JUN-05	7 ELEVEN 18383		$ 6.06
2	APR-05	ABC BUFFET		18.50
3	SEP-05	ALBERTSONS #953 S9H		12.21
4	MAY-05	ALL STAR SPORTS CENTER		77.85
5	JUN-05	ANNIE S GIFT SHOP & TE		26.28
6	APR-05	APPLEBEES #511		12.22
7	JUN-05	APPLEBEES #511		29.84
8	AUG-05	APPLEBEES #511		551.40
9	SEP-05	APPLEBEES #511		85.69
10	OCT-05	APPLEBEE'S #513		40.33
11	DEC-05	APPLEBEE'S #516		14.11
12	MAY-05	ARIZONA DAILY SUN-CLAS		153.00
13	JUN-05	ARIZONA DAILY SUN-CLAS		425.19
14	AUG-05	AUDIO ADVANTAG00018424		129.71
15	NOV-05	AUDIO ADVANTAG00018424		18.44
16	DEC-05	AUDIO ADVANTAG00018424		43.23
17	APR-05	AZ REPUBLIC SUBSCRIPTI		156.00
18	OCT-05	BARNES & NOBLE #2102		62.79
19	DEC-05	BASHA S 18 SYW		18.01
20	APR-05	BASHAS 91 SYW		6.64
21	NOV-05	BEST WESTERN HOTELS		349.08
22	SEP-05	BGI-BUDGET RAC-RYDER T		159.08
23	FEB-05	BIFF'S BAGELS, INC		13.85
24	NOV-05	BIG APPLE GOODYEAR		31.40
25	MAY-05	BIG FOOT BARBEQUE		20.90
26	FEB-05	BIG JOHNS STEAK & PUB		16.26
27	JUL-05	BLACK BEAR DINER N		20.52
28	MAY-05	BLUE HILLS MARKET SPRI		38.00
29	FEB-05	BURGER KING #8615		5.37
30	JAN-05	CABLE ONE *		80.95
31	FEB-05	CABLE ONE *		80.95
32	MAR-05	CABLE ONE *		80.95
33	APR-05	CABLE ONE *		80.95
34	MAY-05	CABLE ONE *		80.95
35	JUN-05	CABLE ONE *		80.95
36	JUL-05	CABLE ONE *		80.95
37	AUG-05	CABLE ONE *		41.20
38	SEP-05	CABLE ONE *		125.85
39	OCT-05	CABLE ONE *		80.95
40	NOV-05	CABLE ONE *		80.95
41	DEC-05	CAFE DE MANUEL		12.52
42	NOV-05	CAPPELLOS ITALIAN		30.00
43	NOV-05	CARL'S JR #75100175Q58		11.46
44	OCT-05	CARTERS TRVL C00781Q65		10.00
45	NOV-05	CARTERS TRVL C00781Q65		39.49
46	MAR-05	CASA BONITA II		34.74
47	MAR-05	CHARIOT PIZZA		16.42
48	MAY-05	CHILI'S GRI04600010462		15.09
49	DEC-05	CHILI'S GRI04600010462		20.23
50	AUG-05	CHILI'S GRI41600004168		75.78
51	APR-05	CHINA BUFFET		12.85
52	MAY-05	CHINA BUFFET		19.67
53	FEB-05	CHIPOTLE MEXICAN #0085		31.47
54	JUL-05	CIRCLE K 00226		7.67
55	AUG-05	CIRCLE K 00226		8.80
56	FEB-05	CIRCLE K 00701		11.53
57	FEB-05	CIRCLE K 00817		14.54
58	OCT-05	CIRCLE K 01840		36.41
59	JUN-05	CIRCLE K 02907		7.44
60	DEC-05	CORRAL WEST #15		43.13
61	MAY-05	CORRAL WEST #31		64.68
62	OCT-05	CORRAL WEST #31		43.03
63	APR-05	CORRAL WEST #62		193.40
64	FEB-05	COUNTRY KITCHEN		11.82
65	MAR-05	COWBOY COOKIN		32.64
66	SEP-05	CRYSTAL CREEK SANDWICH		8.20
67	JAN-05	CUSTERS COWBOY CAFE		9.95
68	DEC-05	DAYS INN		53.70
69	JUL-05	DAYS INNS		177.86
70	MAY-05	DENNYS 00265454		13.42
71	OCT-05	DENNY'S #6671 Q67		13.59
72	JUN-05	DENNY'S #7297 Q67		12.55
73	JUN-05	DENNY'S INC Q67		12.46
74	OCT-05	DENNY'S INC Q67		33.92
75	JUN-05	DIAMOND 1616 SHAMROCK		2.98
76	AUG-05	D'LANO'S ITALIAN RESTA		19.96
77	OCT-05	D'LANO'S ITALIAN RESTA		125.00
78	MAY-05	DOUBLETREE HOTELS REID		194.16
79	NOV-05	EDGEWATER HOTEL F/B		41.84
80	JAN-05	EL CHAPARRAL		36.85
81	JAN-05	EL MARCOS BAR & GRILL		81.69

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WORKPAPER FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
EXPENSES REMOVED FROM ACCOUNT 880

LINE NO.	GENERAL LEDGER PERIOD	PA EXPENDITURE COMMENT	INVOICE NUMBER	NET AMOUNT
82	APR-05	ENTERPRISE RENT-A-CAR		$ 79.16
83	APR-05	FAZOLIS RESTAURANT NO		6.15
84	FEB-05	FRYS-FOOD-DRG #104 SXN		7.66
85	MAR-05	FRYS-FOOD-DRG #104 SXN		17.89
86	JUN-05	FRYS-FOOD-DRG #104 SXN		21.58
87	JUN-05	FRYS-FOOD-DRG #116 SXN		181.79
88	AUG-05	GARCIAS MEXICA00700021		25.76
89	SEP-05	GOLDEN CORRAL 29724Q15		52.29
90	NOV-05	GOLDEN NUGGET-RIVER CA		20.78
91	MAY-05	GURLEY STREET GRILL		49.48
92	FEB-05	HAMPTON INN HAVASU 51		229.47
93	OCT-05	HIROS SUSHI BAR & REST		23.71
94	SEP-05	HOLIDAY INN EXPRES		111.54
95	OCT-05	HOLIDAY INN EXPRESS		166.02
96	DEC-05	HOLIDAY INN TUCSON		286.05
97	FEB-05	HOLIDAY INN-AIRPORT		195.66
98	MAR-05	HOLIDAY INN-AIRPORT		99.83
99	MAY-05	HOLIDAY INN-AIRPORT		181.96
100	JUN-05	HOLIDAY INN-AIRPORT		365.12
101	JAN-05	HOLIDAY INNS		123.03
102	SEP-05	HOLIDAY INNS		170.32
103	NOV-05	HOLIDAY INNS		86.39
104	JAN-05	HOLIDAY INNS EXPRESS		268.56
105	MAR-05	HOLIDAY INNS EXPRESS		85.73
106	MAY-05	HOLIDAY INNS EXPRESS		88.92
107	NOV-05	HOLIDAY INNS EXPRESS		1,181.82
108	NOV-05	HOMETOWN BUFFE00103291		22.54
109	FEB-05	HOUSE OF BREAD		26.00
110	APR-05	HOWARD JOHNSON EXPRESS		387.40
111	JAN-05	HUNAN WEST		17.49
112	MAR-05	IHOP #1524 21815246		10.57
113	MAY-05	JACK INTHE BOX05615Q43		7.14
114	JAN-05	JACK INTHE BOX06911Q43		14.47
115	JAN-05	JB'S RESTAURANT 11		25.85
116	FEB-05	KACHINA DOWNTOWN		147.52
117	JUN-05	KACHINA DOWNTOWN		35.18
118	SEP-05	KACHINIA DOWNTOWN		31.71
119	NOV-05	KFC #6		15.62
120	AUG-05	KINGMAN DELI, THE		359.86
121	DEC-05	KMART 00037077		202.21
122	DEC-05	KMART 00048801		13.67
123	JAN-05	LA CABANA		13.85
124	FEB-05	LA CASITA CAFE		24.00
125	APR-05	LAQUINTA_FLAGSTAFF PAA		73.34
126	NOV-05	LAS VIGAS STEAK RANCH		37.57
127	SEP-05	LICANO'S MEXICAN F		12.32
128	SEP-05	LODGE ON ROUTE 66		137.88
129	OCT-05	LODGE ON ROUTE 66		551.52
130	SEP-05	LOTUS GARDEN CHINESE R		21.20
131	DEC-05	LOVE S COUNTRY00002Q01		31.80
132	JUN-05	MAGPIES GOURMET PIZZA		14.03
133	FEB-05	MALONES BAKERY & D		17.90
134	MAR-05	MARTINS'S ON SCOTT		14.74
135	SEP-05	MCDONALD'S F25162 Q17		4.31
136	DEC-05	MI NIDITO		30.00
137	NOV-05	MICHAELS #2747		35.58
138	FEB-05	NILES RADIO		102.84
139	MAR-05	NILES RADIO		117.97
140	APR-05	NILES RADIO		187.72
141	MAY-05	NILES RADIO		933.01
142	JUN-05	NILES RADIO		67.49
143	JUL-05	NILES RADIO		65.00
144	AUG-05	NILES RADIO		54.36
145	SEP-05	NILES RADIO		78.53
146	OCT-05	NILES RADIO		149.21
147	NOV-05	NILES RADIO		149.34
148	DEC-05	NILES RADIO		94.38
149	FEB-05	OREGANOS		44.30
150	SEP-05	ORIENTAL TRADING CO		159.20
151	OCT-05	OSCO DRUG #9343		10.78
152	FEB-05	OUR DAILY BREAD DELI		95.31
153	APR-05	OUTBACK #0317		43.13
154	JAN-05	OUTBACK #0319		54.99
155	JUN-05	PANCHO'S #075		15.74
156	MAR-05	PANDA EXPRESS 00008Q42		16.15
157	DEC-05	PAPA JOHNS #2844		7.58
158	MAR-05	PAPPADEAUX SEAFOOD KIT		33.10
159	SEP-05	PAYPAL *IRWAKACHINA		285.00
160	APR-05	PINE COUNTRY RESTA		8.05
161	OCT-05	PINE COUNTRY RESTAURAN		52.97
162	APR-05	PIZZA FACTORY		19.05
163	MAY-05	PIZZA FACTORY		18.10
164	SEP-05	PIZZA FACTORY		69.70

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EXPENSES REMOVED FROM ACCOUNT 880

LINE NO.	GENERAL LEDGER PERIOD	PA EXPENDITURE COMMENT	INVOICE NUMBER	NET AMOUNT
165	NOV-05	PIZZA H006705 16800Q34		$ 28.04
166	APR-05	PIZZA H010725 17500Q34		55.07
167	JUN-05	PIZZA HUT #10657500Q34		24.67
168	APR-05	PIZZA HUT #22 55700Q34		17.15
169	SEP-05	PIZZA HUT #22 55700Q34		15.40
170	JUN-05	PRESCOTT FRONTIER DAYS		350.00
171	SEP-05	PRETTY PARTY PLACE PR		22.06
172	JUL-05	QUALITY INNS LAS CAMPA		66.32
173	AUG-05	QUALITY INNS LAS CAMPA		480.80
174	JUN-05	QUIK MART #33		3.45
175	AUG-05	R & R PIZZA EXPRESS		17.99
176	SEP-05	RA SUSHI #0655		59.65
177	JAN-05	RADIO SHACK		21.66
178	APR-05	RADIO SHACK		43.13
179	MAR-05	RADIO SHACK 00134718		27.02
180	MAY-05	RADIO SHACK 00134718		51.32
181	MAY-05	RADIO SHACK 00139303		32.55
182	JUL-05	RADIOSHACK DEA01902659		6.02
183	SEP-05	RADIOSHACK DEA01902659		32.33
184	OCT-05	RADISSON HOTELS-WOODLA		50.35
185	NOV-05	RANGER RESOURCES		392.08
186	AUG-05	RASKIN JEWELERS LT		8.67
187	OCT-05	RED LOBSTER US00008458		54.32
188	MAY-05	RED ROBIN NO 309		13.52
189	OCT-05	RENTS AND TENTS		35.57
190	MAR-05	RODEO VIDEO		30.00
191	OCT-05	RODS STEAK HOUSE		47.68
192	SEP-05	RON'S MARKET SIH		8.91
193	MAY-05	ROSA'S CANTINA		23.76
194	JUN-05	ROSA'S MEXICAN FOOD		17.08
195	AUG-05	SAFEWAY STORE00002394		11.68
196	FEB-05	SAFEWAY STORE00017335		9.48
197	SEP-05	SAFEWAY STORE00017335		5.14
198	FEB-05	SAFEWAY STORE00020289		24.38
199	OCT-05	SAFEWAY STORE00020289		47.33
200	DEC-05	SAFEWAY STORE00020289		9.98
201	AUG-05	SAFEWAY STORE00020529		13.36
202	MAR-05	SCOTTYS BROASTED CHICK		53.83
203	APR-05	SEARS DEALER 3089		288.82
204	MAR-05	SEARS ROEBUCK 2218		153.84
205	NOV-05	SEARS ROEBUCK 2218		65.00
206	NOV-05	SHOWLOW #40		6.78
207	DEC-05	SILVER SADDLE STEAKHOU		21.41
208	MAY-05	SONIC #1077 Q63		6.59
209	AUG-05	SONIC #3385 Q63		44.59
210	NOV-05	SONIC DRIVE IN #483Q63		21.93
211	MAY-05	SOTO'S P/K OUTPOST		78.22
212	JAN-05	SOUPER SALAD #152		15.99
213	JUN-05	STREETS OF NEW YORK #1		24.41
214	AUG-05	STROMBOLLIS RESTAURANT		54.86
215	FEB-05	SU CASA OF CLARKDALE		10.53
216	MAY-05	SUBWAY 16276		26.11
217	AUG-05	SUBWAY 21530 Q16		8.36
218	MAY-05	SUBWAY 2296 Q16		11.99
219	AUG-05	SUBWAY 27912 Q16		18.48
220	NOV-05	SWEET & SUBS		19.68

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WORKPAPER FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
EXPENSES REMOVED FROM ACCOUNT 880

LINE NO.	GENERAL LEDGER PERIOD	PA EXPENDITURE COMMENT	INVOICE NUMBER	NET AMOUNT
221	MAY-05	SZECHUAN RESTAURANT		$ 8.10
222	SEP-05	SZECHUAN RESTAURANT		84.00
223	SEP-05	TEMPE 00001701		71.38
224	SEP-05	TEMPE HOOTERS INC		31.70
225	SEP-05	TEMPE MISSION PALMS HO		220.70
226	OCT-05	TEXAS ROADHOUSE #2204		53.52
227	JUL-05	THE CARPET WORKS I		14.15
228	MAY-05	THE COPPER PLATE		15.60
229	MAY-05	TOPOCK MARINA ON HISTO		24.90
230	MAY-05	VERDE LEA MARKET		13.94
231	JAN-05	WAL MART		10.69
232	OCT-05	WALGREEN 00025Q39		7.76
233	NOV-05	WALGREEN 00025Q39		11.46
234	JUL-05	WALGREEN 00052Q39		22.70
235	NOV-05	WALGREEN 00052Q39		4.51
236	JUN-05	WALGREEN 00055Q39		7.14
237	JUN-05	WAL-MART #1230 SE2		8.29
238	JUL-05	WAL-MART #1299 SE2		18.77
239	NOV-05	WAL-MART #1299 SE2		5.38
240	JUN-05	WAL-MART #1328		20.67
241	JUL-05	WAL-MART #1328		9.69
242	MAY-05	WAL-MART #1417 SE2		6.75
243	NOV-05	WAL-MART #1417 SE2		107.44
244	JUL-05	WAL-MART #2051 SE2		14.97
245	DEC-05	WAL-MART #2051 SE2		73.84
246	SEP-05	WAL-MART #5303 SE2		22.59
247	OCT-05	WAL-MART #5303 SE2		42.25
248	DEC-05	WAL-MART #5303 SE2		21.11
249	MAR-05	WAL-MART STORES, INC		29.95
250	NOV-05	WENDYS		10.51
251	DEC-05	WENDYS NO 413 Q50		4.21
252	SEP-05	WEST SIDE INN		15.70
253	JUL-05	WESTSIDE LILO'S CA		18.52
254	AUG-05	WESTSIDE LILO'S CA		15.00
255	OCT-05	WESTSIDE LILO'S CA		9.64
256	MAY-05	WHATABURGER #775		5.65
257	OCT-05	WHATABURGER 775 Q26		12.95
258	JUN-05	WIENERSCHNITZEL #692		4.38
259	MAR-05	WM SUPERCENTER SE2		14.02
260	APR-05	WM SUPERCENTER SE2		60.43
261	MAY-05	WM SUPERCENTER SE2		32.49
262	JUN-05	WM SUPERCENTER SE2		17.71
263	JUL-05	WM SUPERCENTER SE2		58.71
264	SEP-05	WM SUPERCENTER SE2		55.56
265	NOV-05	WM SUPERCENTER SE2		132.27
266	DEC-05	WOODLANDS PLAZA HOTEL		616.01
267	MAY-05	ZEKE'S EATIN PLACE		38.80
268	FEB-05	IBEW LOCAL #1116	021805 18675	186.75
269	APR-05	JACK POTS PORTABLES INC	12927	65.00
270	NOV-05	NAU ATHLETICS	110805 15000	150.00
271	NOV-05	NAU ATHLETICS	110805 15000A	150.00
272	JAN-05	NILES RADIO	230899	555.00
273	FEB-05	NILES RADIO	231185	555.00
274	MAR-05	NILES RADIO	231456	555.00
275	MAY-05	NILES RADIO	231731	555.00
276	AUG-05	NILES RADIO	232059a	555.00
277	MAY-05	NILES RADIO	232059A	555.00
278	JUN-05	NILES RADIO	232313	555.00
279	JUL-05	NILES RADIO	232691	555.00
280	AUG-05	NILES RADIO	232965	165.00
281	AUG-05	NILES RADIO	233059	555.00
282	SEP-05	NILES RADIO	233338	555.00
283	OCT-05	NILES RADIO	233595	555.00
284	DEC-05	NILES RADIO	234124	555.00
285	MAY-05	NILES RADIO	423902	20.54
286	NOV-05	NILES RADIO	425727	113.53
287	NOV-05	PETTY CASH	RPC-ADAMS30614	27.75
288	AUG-05	PETTY CASH	RPC27987ADAMS	5.50
289	TOTAL			$ 27,217.36

UNS Gas Corporation
Docket No. G-04204A-06-0463
Test Year Ended December 31, 2005

WORKPAPER FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
EXPENSES REMOVED FROM ACCOUNT 921

LINE NO.	GENERAL LEDGER PERIOD	PA EXPENDITURE COMMENT	INVOICE NUMBER	NET AMOUNT
1	JAN-05	3 MARGARITAS CASA BONI		$ 21.04
2	FEB-05	3 MARGARITAS CASA BONI		28.38
3	OCT-05	3 MARGARITAS CASA BONI		70.87
4	NOV-05	3 MARGARITAS CASA BONI		94.54
5	JUL-05	ABC BUFFET		12.40
6	AUG-05	AGNT FEE 89050521279672		28.00
7	FEB-05	AIR FARE		8.05
8	APR-05	AIR FARE		7.70
9	OCT-05	AIR FARE		18.47
10	JAN-05	ALBERTSONS #1027 S9H		4.48
11	JAN-05	ALBERTSONS #953 S9H		23.08
12	APR-05	ALBERTSONS #953 S9H		70.07
13	JUN-05	ALBERTSONS #953 S9H		38.92
14	JUL-05	ALBERTSONS #953 S9H		19.64
15	AUG-05	ALBERTSONS #953 S9H		49.14
16	OCT-05	ALBERTSONS #953 S9H		25.19
17	AUG-05	ALBERTSONS #965 S9H		13.93
18	MAY-05	ALBERTSONS #967 S9H		24.73
19	OCT-05	ALBERTSONS #967 S9H		32.28
20	NOV-05	ALBERTSONS #967 S9H		22.16
21	FEB-05	ALFONSO S MEXICAN FOOD		19.03
22	MAR-05	ALFONSO S MEXICAN FOOD		40.68
23	APR-05	ALFONSO S MEXICAN FOOD		118.48
24	JUL-05	ALFONSO'S MEXICAN FQ01		14.91
25	AUG-05	ALFONSO'S MEXICAN FQ01		31.16
26	OCT-05	ALFONSO'S MEXICAN FQ01		65.74
27	DEC-05	ALTITUDES BAR AND		26.76
28	SEP-05	AM CANCER SOC - SS		35.00
29	FEB-05	AMERICAN 00106191484482		175.00
30	AUG-05	AMERICAN 00113184653293		326.80
31	MAR-05	AMERICANA MOTOR HOTEL		18.00
32	JUN-05	AMERICAW 40121675337133		271.30
33	JUL-05	AMERICAW 40121692035854		277.30
34	DEC-05	AMERICAW 40121734713185		737.30
35	OCT-05	AMERISUITES - FF		59.46
36	NOV-05	AMERISUITES - FF		59.46
37	DEC-05	AMERISUITES - FF		59.46
38	FEB-05	ANGIES FLOWERS		28.68
39	JAN-05	APPLEBEES #511		189.12
40	APR-05	APPLEBEES #511		23.34
41	NOV-05	APPLEBEES #511		120.52
42	JUN-05	ARABIAN CAMPER&TRAILER		286.54
43	JAN-05	ARBY'S #1180 Q52		10.76
44	FEB-05	ARBY'S #1180 Q52		17.63
45	MAR-05	ARBY'S #1180 Q52		44.65
46	MAY-05	ARBY'S #1180 Q52		34.11
47	JUN-05	ARBY'S #1180 Q52		12.49
48	JUN-05	ARBY'S #1246 Q52		14.18
49	JAN-05	ARBY'S #1997 Q52		14.02
50	MAR-05	ARBY'S #1997 Q52		9.98
51	JUN-05	ARBY'S #5581 Q52		8.35
52	JUL-05	ARBY'S #5581 Q52		12.35
53	SEP-05	ARBY'S #7077 Q52		6.79
54	OCT-05	ARBY'S #7077 Q52		7.12
55	DEC-05	ARBY'S #7077 Q52		6.37
56	MAR-05	ARBYS OF SHOW LOW		6.57
57	DEC-05	ARBYS OF SHOW LOW		6.04
58	JUN-05	ARIZONA FAMILY RESTAUR		28.08
59	AUG-05	ARIZONA FAMILY RESTAUR		9.53
60	FEB-05	AUGIES PLACE		36.93
61	JAN-05	BABE'S ROUND UP		4,014.47
62	AUG-05	BABE'S ROUND UP		20.12
63	DEC-05	BARNES & NOBLE #2102		138.96
64	JUN-05	BARRO S PIZZA		7.05
65	APR-05	BASHA S 18 SYW		56.90
66	MAY-05	BASHA S 18 SYW		3.56
67	OCT-05	BASHA S 18 SYW		14.00
68	DEC-05	BASHA S 18 SYW		4.99
69	MAR-05	BASHA S 30 SYW		9.98
70	MAY-05	BASHA S 30 SYW		9.98
71	OCT-05	BASHA S 57 SYW		6.74
72	JAN-05	BASHAS #116 SYW		40.26
73	JUN-05	BASHAS #116 SYW		9.85
74	MAR-05	BASHAS 37 SYW		8.16
75	APR-05	BASHAS 37 SYW		47.22
76	JUN-05	BASHAS 37 SYW		32.38
77	OCT-05	BASHAS 37 SYW		16.32
78	NOV-05	BASHAS 37 SYW		8.16
79	OCT-05	BASHAS 53 SYW		2.84
80	JUN-05	BASHAS 67 SYW		27.46
81	AUG-05	BAY BEACH CAFE		24.36
82	SEP-05	BEAVER STREET BREW		57.75
83	OCT-05	BEAVER STREET BREW		47.41

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WORKPAPER FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
EXPENSES REMOVED FROM ACCOUNT 921

LINE NO.	GENERAL LEDGER PERIOD	PA EXPENDITURE COMMENT	INVOICE NUMBER	NET AMOUNT
84	FEB-05	BEAVER STREET BREWERY		$ 34.57
85	JUN-05	BEAVER STREET BREWERY		54.59
86	AUG-05	BEAVER STREET BREWERY		50.00
87	OCT-05	BELL CANYON HOOTERS IN		30.80
88	MAR-05	BELLA MIA RESTAURANT		21.21
89	AUG-05	BELLA MIA RESTAURANT		24.42
90	OCT-05	BEST WESTERN		74.48
91	AUG-05	BEST WESTERN BAYSIDE I		164.65
92	JAN-05	BEST WESTERN HOTELS		449.61
93	FEB-05	BEST WESTERN HOTELS		530.25
94	MAR-05	BEST WESTERN HOTELS		892.53
95	MAY-05	BEST WESTERN HOTELS		922.18
96	JUN-05	BEST WESTERN HOTELS		122.95
97	AUG-05	BEST WESTERN HOTELS		64.77
98	SEP-05	BEST WESTERN HOTELS		267.04
99	NOV-05	BEST WESTERN HOTELS		453.39
100	DEC-05	BEST WESTERN HOTELS		232.72
101	OCT-05	BEST WESTERN PRESCOTTO		17.05
102	MAR-05	BEST WESTERN SIESTA MT		225.78
103	NOV-05	BIFF'S BAGELS, INC		10.39
104	SEP-05	BIG 5 SPORTING #258		15.52
105	JAN-05	BIG DADDY'S PLACE		51.20
106	DEC-05	BIG LOTS #043000043059		48.39
107	DEC-05	BIGFOOT BARBECUE		400.96
108	JUL-05	BLACK BARTS STEAKHOUSE		43.09
109	JAN-05	BLACK BEAR DINER #40		28.07
110	AUG-05	BLACK BEAR DINER N		20.98
111	MAR-05	BLIMPIE SUBS & SALADS		5.79
112	JAN-05	BLUE MOON CAFE		20.58
113	JAN-05	BOARDWALK HOTEL - ADV		70.85
114	FEB-05	BOARDWALK HOTEL - ADV		(70.85)
115	JAN-05	BOB'S BIG BOY		34.48
116	JUL-05	BOWLINS PICACHO PEAK P		11.23
117	FEB-05	BRANDING IRON STKHSE		64.69
118	MAR-05	BRANDING IRON STKHSE		25.50
119	APR-05	BRANDING IRON STKHSE		76.38
120	MAY-05	BRANDING IRON STKHSE		50.88
121	JUN-05	BRANDING IRON STKHSE		46.11
122	JUL-05	BRANDING IRON STKHSE		21.34
123	AUG-05	BRANDING IRON STKHSE		33.00
124	OCT-05	BRANDING IRON STKHSE		139.24
125	NOV-05	BRANDING IRON STKHSE		36.00
126	JAN-05	BROOKLYN CAFE		96.69
127	JUN-05	BUFFALO WILD WINGS PRE		105.00
128	AUG-05	BUFFALO WILD WINGS PRE		25.00
129	APR-05	BUN HUGGERS EAST		96.46
130	MAY-05	BUN HUGGERS EAST		94.71
131	FEB-05	BUN HUGGERS WEST		80.01
132	MAR-05	BUN HUGGERS WEST		25.13
133	MAY-05	BUN HUGGERS WEST		15.58
134	JUN-05	BUN HUGGERS WEST		94.16
135	OCT-05	BUN HUGGERS WEST		108.20
136	NOV-05	BUN HUGGERS WEST		57.29
137	DEC-05	BUN HUGGERS WEST		71.00
138	NOV-05	BUNS N DOGS INC		98.79
139	MAY-05	BURGER KING #14442 Q07		30.24
140	MAY-05	BURGER KING #2305 Q07		4.95
141	APR-05	BURGER KING #4600		7.33
142	JUL-05	BURGER KING #4600 Q07		6.37
143	OCT-05	BURGER KING #6716 Q07		5.25
144	DEC-05	BURGER KING #6716 Q07		5.68
145	FEB-05	BUSTER S RESTAURANT		42.03
146	APR-05	BUSTER S RESTAURANT		22.67
147	MAY-05	BUSTER S RESTAURANT		97.07
148	JUN-05	BUSTER S RESTAURANT		53.58
149	JUL-05	BUSTER S RESTAURANT		188.13
150	AUG-05	BUSTER S RESTAURANT		41.13
151	SEP-05	BUSTER S RESTAURANT		122.32
152	APR-05	CACTUS JACK'S GRILL AN		46.56
153	NOV-05	CAFE DLANOS		17.38
154	DEC-05	CAFE DLANOS		31.95
155	FEB-05	CAFE D'LANOS		20.36
156	MAR-05	CAFE D'LANOS		90.93
157	APR-05	CAFE D'LANOS		75.65
158	MAY-05	CAFE D'LANOS		28.66
159	JUL-05	CAFE D'LANOS		69.82
160	SEP-05	CAFE D'LANOS		79.37
161	DEC-05	CAFE JOSE INC		18.38
162	JAN-05	CAFE 'N SALAD		68.79
163	SEP-05	CALICOS RESTAURANT		16.21
164	JAN-05	CANTON DRAGON		26.30
165	JUN-05	CANTON DRAGON		26.00
166	AUG-05	CARAMBA #2		10.47

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WORKPAPER FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
EXPENSES REMOVED FROM ACCOUNT 921

LINE NO.	GENERAL LEDGER PERIOD	PA EXPENDITURE COMMENT	INVOICE NUMBER	NET AMOUNT
167	NOV-05	CARL'S JR #75100175Q58		$ 12.00
168	MAY-05	CARLS JR 827		12.25
169	JUN-05	CASA BLANCA CAFE		50.84
170	JUL-05	CASA BLANCA CAFE		23.13
171	FEB-05	CASA BONITA II		51.85
172	MAR-05	CASA BONITA II		57.37
173	APR-05	CASA BONITA II		177.90
174	JUN-05	CASA BONITA II		63.17
175	JUL-05	CASA BONITA II		171.52
176	AUG-05	CASA BONITA II		39.27
177	APR-05	CASA CARDENAS		92.13
178	MAY-05	CASA CARDENAS		55.79
179	JUL-05	CASA DEL FOOD SERVICES		4.72
180	MAY-05	CASA GRANDE		116.88
181	JUN-05	CASA GRANDE		254.17
182	OCT-05	CASA GRANDE		43.97
183	FEB-05	CASA GRANDE RESTAURANT		47.57
184	APR-05	CASA SERRANO OF LAKE H		19.20
185	JUL-05	CASA SERRANO OF LAKE H		11.69
186	OCT-05	CASA SERRANO OF LAKE H		14.59
187	NOV-05	CASA SERRANO OF LAKE H		17.59
188	JAN-05	CATTLEMANS BAR & GRILL		27.00
189	FEB-05	CATTLEMANS BAR & GRILL		22.75
190	JUN-05	CATTLEMANS BAR & GRILL		48.75
191	SEP-05	CATTLEMANS BAR & GRILL		26.00
192	JAN-05	CHARLIE CLARKS RESTAUR		1,125.89
193	FEB-05	CHARLIE CLARKS RESTAUR		106.22
194	JUL-05	CHARLIE CLARKS RESTAUR		22.74
195	AUG-05	CHARLIE CLARKS RESTAUR		58.83
196	OCT-05	CHARLIE CLARKS RESTAUR		16.50
197	DEC-05	CHARLIE CLARKS RESTAUR		1,594.32
198	JUN-05	CHICO S TACOS		227.45
199	FEB-05	CHILI'S GRI04600010462		65.83
200	APR-05	CHILI'S GRI04600010462		88.30
201	MAY-05	CHILI'S GRI04600010462		53.35
202	JUN-05	CHILI'S GRI04600010462		48.89
203	JUL-05	CHILI'S GRI04600010462		162.30
204	AUG-05	CHILI'S GRI04600010462		111.14
205	OCT-05	CHILI'S GRI04600010462		17.00
206	NOV-05	CHILI'S GRI04600010462		87.57
207	DEC-05	CHILI'S GRI04600010462		24.94
208	MAR-05	CHILI'S GRI04900010496		18.00
209	JUN-05	CHILI'S GRI04900010496		45.43
210	JUL-05	CHILI'S GRI04900010496		35.96
211	OCT-05	CHILI'S GRI04900010496		35.48
212	NOV-05	CHILI'S GRI04900010496		22.38
213	AUG-05	CHILI'S GRI17000001701		55.43
214	JAN-05	CHILI'S GRI41600004168		135.69
215	FEB-05	CHILI'S GRI41600004168		84.85
216	MAR-05	CHILI'S GRI41600004168		62.43
217	APR-05	CHILI'S GRI41600004168		29.62
218	MAY-05	CHILI'S GRI41600004168		109.23
219	JUN-05	CHILI'S GRI41600004168		132.24
220	JUL-05	CHILI'S GRI41600004168		86.49
221	OCT-05	CHILI'S GRI41600004168		54.84
222	NOV-05	CHILI'S GRI41600004168		90.13
223	DEC-05	CHILI'S GRI41600004168		45.57
224	MAR-05	CHILI'S GRI56300005637		20.19
225	DEC-05	CHILI'S GRI56300005637		107.59
226	AUG-05	CHILI'S GRI77100007716		42.47
227	JUN-05	CHINA BUFFET		122.76
228	SEP-05	CHINA BUFFET		28.37
229	NOV-05	CHINA BUFFET		25.09
230	JAN-05	CHINA BUFFET - LH		12.79
231	MAR-05	CHINA BUFFET - LH		12.69
232	SEP-05	CHINA BUFFET - LH		11.79
233	FEB-05	CHINA STAR		6.92
234	MAR-05	CHINA STAR CHINESE RES		18.84
235	MAR-05	CHINA STAR SUPER BUFFE		7.58
236	OCT-05	CHINESE BAMBOO BUFFET		8.99
237	JAN-05	CHUYS MESQUITE BROILER		20.77
238	FEB-05	CHUYS MESQUITE BROILER		90.67
239	MAR-05	CHUYS MESQUITE BROILER		47.83
240	APR-05	CHUYS MESQUITE BROILER		66.65
241	MAY-05	CHUYS MESQUITE BROILER		76.56
242	JUN-05	CHUYS MESQUITE BROILER		26.90
243	FEB-05	CIRCLE K 00251		39.75
244	MAR-05	CIRCLE K 00251		10.89
245	MAY-05	CIRCLE K 00251		6.24
246	JUN-05	CIRCLE K 00251		6.24
247	MAR-05	CIRCLE K 01576		12.94
248	MAY-05	CIRCLE K 01576		19.48
249	JUN-05	CIRCLE K 01576		10.82

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WORKPAPER FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
EXPENSES REMOVED FROM ACCOUNT 921

LINE NO.	GENERAL LEDGER PERIOD	PA EXPENDITURE COMMENT	INVOICE NUMBER	NET AMOUNT
250	JUL-05	CIRCLE K 01576		$ 3.30
251	JAN-05	CIRCLE K 05326		88.12
252	FEB-05	CIRCLE K 05326		82.28
253	MAR-05	CIRCLE K 05326		96.43
254	APR-05	CIRCLE K 05326		63.90
255	MAY-05	CIRCLE K 05326		25.38
256	FEB-05	CIRCLE K 06362		4.60
257	JUL-05	CIRCLE K 06665		6.08
258	APR-05	CIRCLE K 08692		6.95
259	OCT-05	CIRCLE K 08838		5.90
260	JUL-05	CLAIM JUMPER #25		39.48
261	AUG-05	CLARKDALE CLASSIC STAT		10.50
262	JAN-05	COCOS BAKERY RESTAURAN		13.34
263	AUG-05	COCOS BAKERY RESTAURAN		33.49
264	NOV-05	COCOS BAKERY RESTAURAN		43.21
265	JAN-05	CODE 7		18.64
266	FEB-05	CODE 7		34.15
267	JAN-05	COLD STONE CREAMERY #6		24.95
268	JAN-05	COMFORT INN		121.00
269	OCT-05	COMFORT INNS		222.18
270	JUN-05	CONFETTIS GIFT & PARTY		14.62
271	MAR-05	COPALA RESTAURANT		18.47
272	MAR-05	COW PALACE RESTAURANT		78.69
273	JUN-05	COWBOY CLUB		41.98
274	APR-05	COWBOY COOKIN		31.96
275	SEP-05	CRACKER BARREL #277		19.06
276	APR-05	CRACKER BARREL #297		26.82
277	FEB-05	CRACKER BARREL #334		20.70
278	NOV-05	CRACKER BARREL #334		10.95
279	OCT-05	CRACKER BARREL #388		9.54
280	FEB-05	CRACKER BARREL #416		19.69
281	JUL-05	CRACKER BARREL #416		13.08
282	NOV-05	CRACKER BARREL #416		84.70
283	DEC-05	CRACKER BARREL #416		28.97
284	OCT-05	CRACKER BARREL #555		13.21
285	OCT-05	CRAZY BILLS SALON & ST		46.00
286	JUN-05	CROWN CITY INN		150.66
287	AUG-05	CROWN CITY INN		635.62
288	FEB-05	DAMBAR & STEAK HOUSE		59.76
289	MAR-05	DAMBAR & STEAK HOUSE		128.07
290	MAY-05	DAMBAR & STEAK HOUSE		129.92
291	AUG-05	DAMBAR & STEAKHOUSE		57.51
292	OCT-05	DAMBAR & STEAKHOUSE		28.00
293	NOV-05	DAMBAR & STEAKHOUSE		417.61
294	DEC-05	DAMBAR & STEAKHOUSE		123.93
295	JAN-05	DANONE WATERS OF NORTH		18.56
296	FEB-05	DANONE WATERS OF NORTH		15.07
297	MAR-05	DANONE WATERS OF NORTH		23.99
298	MAY-05	DANONE WATERS OF NORTH		30.86
299	JUL-05	DANONE WATERS OF NORTH		37.72
300	SEP-05	DANONE WATERS OF NORTH		30.86
301	OCT-05	DANONE WATERS OF NORTH		29.17
302	NOV-05	DANONE WATERS OF NORTH		8.56
303	NOV-05	DARA THAI RESTAURANT		41.96
304	NOV-05	DENNYS 00265454		13.51
305	JAN-05	DENNYS 00267559		30.37
306	APR-05	DENNYS 00267559		31.13
307	DEC-05	DENNYS 00267559		12.92
308	JAN-05	DENNY'S #6741 Q67		8.44
309	APR-05	DENNY'S #6741 Q67		9.92
310	DEC-05	DENNY'S INC		17.49
311	JAN-05	DENNY'S INC Q67		16.68
312	APR-05	DENNY'S INC Q67		10.52
313	MAY-05	DENNY'S INC Q67		10.49
314	JUN-05	DENNY'S INC Q67		13.48
315	NOV-05	DESERT DIAMOND CASINO		17.70
316	FEB-05	DINER INC		30.00
317	JAN-05	D'LANO'S ITALIAN RESTA		27.72
318	JUN-05	D'LANO'S ITALIAN RESTA		50.75
319	JUL-05	D'LANO'S ITALIAN RESTA		19.65
320	NOV-05	D'LANO'S ITALIAN RESTA		282.00
321	OCT-05	DLX BUSINESS 800328030		33.06
322	JAN-05	DOMINO'S PIZZA		45.42
323	MAR-05	DOMINO'S PIZZA		37.86
324	APR-05	DOMINO'S PIZZA		118.68
325	MAR-05	DOMINO'S PIZZA #7625		20.94
326	JAN-05	DOREEN'S BACKSTREE		46.70
327	MAY-05	DOREEN'S BACKSTREE		26.78
328	OCT-05	DOUBLETREE HOTELS REID		95.91
329	NOV-05	DOWNTOWN DINER		17.00
330	MAR-05	DRY GULCH STEAKHOUSE		41.71

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WORKPAPER FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
EXPENSES REMOVED FROM ACCOUNT 921

LINE NO.	GENERAL LEDGER PERIOD	PA EXPENDITURE COMMENT	INVOICE NUMBER	NET AMOUNT
331	NOV-05	DTV*DIRECTV SERVICE		$ 442.88
332	DEC-05	DUNTON HOUSE RESTA		8.30
333	APR-05	DYNASTY SUITES REDLAND		82.45
334	MAY-05	DYNASTY SUITES REDLAND		164.90
335	MAY-05	EASTERN CLASSIC RESTAU		19.55
336	JUN-05	EL CAPITAN FRESH MEXIC		35.18
337	AUG-05	EL CAPITAN FRESH MEXIC		68.81
338	OCT-05	EL CAPITAN FRESH MEXIC		74.26
339	DEC-05	EL CAPITAN FRESH MEXIC		20.57
340	FEB-05	EL CHAPARRAL		19.04
341	MAR-05	EL CHAPARRAL		24.25
342	APR-05	EL CHAPARRAL		8.75
343	APR-05	EL CHARRO CAFE		35.40
344	MAY-05	EL CHARRO CAFE		34.90
345	JUN-05	EL CHARRO CAFE		18.34
346	JUL-05	EL CHARRO CAFE		20.34
347	AUG-05	EL CHARRO CAFE		16.59
348	SEP-05	EL CHARRO CAFE		36.93
349	OCT-05	EL CHARRO CAFE		33.30
350	FEB-05	EL CHARRO RESTAURANT		20.53
351	APR-05	EL CHARRO RESTAURANT		46.63
352	OCT-05	EL CHARRO RESTAURANT		30.00
353	NOV-05	EL CHARRO RESTAURANT		21.69
354	OCT-05	EL MARCOS BAR & GRILL		41.12
355	MAR-05	EL MARIACHI		8.00
356	FEB-05	EL PALACIO OF KINGMAN		16.64
357	JUL-05	EL PALACIO OF KINGMAN		28.03
358	NOV-05	EL PALACIO OF KINGMAN		103.56
359	DEC-05	EL PALACIO OF KINGMAN		10.61
360	MAR-05	EL POLLO LOCO #3427		5.93
361	FEB-05	EL RANCHO		44.52
362	AUG-05	EL RANCHO		11.40
363	DEC-05	EL RANCHO		16.30
364	JUN-05	EL SARAPE MEXICAN REST		18.83
365	NOV-05	EL ZARAPE		5.07
366	JAN-05	ELKS LODGE #468		54.84
367	FEB-05	ELKS LODGE #468		151.25
368	MAR-05	ELKS LODGE #468		43.21
369	APR-05	ELKS LODGE #468		64.72
370	MAY-05	ELKS LODGE #468		157.85
371	JUN-05	ELKS LODGE #468		139.22
372	JUL-05	ELKS LODGE #468		26.08
373	OCT-05	ELKS LODGE #468		49.13
374	OCT-05	EMBASSY SUITES FLAGTIP		312.05
375	NOV-05	ENOTECA PIZZARIA WINE		13.83
376	DEC-05	ENTERPRISE RENT-A-CAR		127.57
377	NOV-05	EXQUISITO RESTAURANT		39.05
378	OCT-05	FAMOUS SAMS #10		21.22
379	JAN-05	FAMOUS SAMS #30		21.61
380	FEB-05	FAMOUS SAMS #30		19.25
381	FEB-05	FARR S SERVICE		26.50
382	FEB-05	FAZOLIS RESTAURANT NO		11.23
383	JUN-05	FAZOLIS RESTAURANT NO		7.55
384	AUG-05	FAZOLIS RESTAURANT NO		90.20
385	APR-05	FIESTA CHARRA INC		106.51
386	SEP-05	FIESTA CHARRA INC		30.66
387	OCT-05	FIESTA CHARRA INC		36.99
388	DEC-05	FIESTA CHARRA INC		32.02
389	FEB-05	FIESTA MEXICANA #7		18.59
390	APR-05	FIESTA MEXICANA #7		39.94
391	JUL-05	FIESTA MEXICANA #7		16.84
392	FEB-05	FLAGSTAFF CHAMBER OF C		300.00
393	FEB-05	FLAGSTAFF FAMILY YMCA		250.00
394	JAN-05	FLAMING WOK		8.63
395	APR-05	FLAMING WOK		15.10
396	DEC-05	FLAMINGO HILTON LASTIP		310.20
397	NOV-05	FLAMINGO HILTON LV TIP		125.35
398	APR-05	FLOWERS BY DOROTHY		37.84
399	OCT-05	FLOWERS BY DOROTHY		79.36
400	MAR-05	FLYING J THAD'S REST		16.43
401	MAR-05	FORMOSA CHINESE RESTAU		8.98
402	JAN-05	FRANCISCO'S MEXICAN RE		49.50
403	APR-05	FRANCISCO'S MEXICAN RE		20.88
404	APR-05	FRATELLI PIZZA		57.74
405	JUL-05	FRATELLI PIZZA		58.06
406	JAN-05	FRYS-FOOD-DRG #103 SXN		10.20
407	APR-05	FRYS-FOOD-DRG #103 SXN		106.78
408	JUN-05	FRYS-FOOD-DRG #103 SXN		45.29

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WORKPAPER FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
EXPENSES REMOVED FROM ACCOUNT 921

LINE NO.	GENERAL LEDGER PERIOD	PA EXPENDITURE COMMENT	INVOICE NUMBER	NET AMOUNT
409	JUL-05	FRYS-FOOD-DRG #103 SXN		$ 15.50
410	FEB-05	FRYS-FOOD-DRG #104 SXN		54.92
411	MAR-05	FRYS-FOOD-DRG #104 SXN		26.01
412	APR-05	FRYS-FOOD-DRG #104 SXN		106.01
413	MAY-05	FRYS-FOOD-DRG #104 SXN		218.24
414	JUL-05	FRYS-FOOD-DRG #104 SXN		52.62
415	AUG-05	FRYS-FOOD-DRG #104 SXN		54.24
416	SEP-05	FRYS-FOOD-DRG #104 SXN		78.19
417	OCT-05	FRYS-FOOD-DRG #104 SXN		26.97
418	NOV-05	FRYS-FOOD-DRG #104 SXN		27.78
419	DEC-05	FRYS-FOOD-DRG #104 SXN		74.95
420	JAN-05	FRYS-FOOD-DRG#0077 SXN		150.61
421	MAR-05	FRYS-FOOD-DRG#0077 SXN		6.68
422	APR-05	FRYS-FOOD-DRG#0077 SXN		17.95
423	OCT-05	FTD*FLORAL ARTS LTD OF		80.00
424	APR-05	FTD*PRESCOTT VALLEY FL		37.33
425	DEC-05	FUEGO MEXICAN GRILL &		19.41
426	JUN-05	GABBY'S KITCHEN		20.61
427	JUL-05	GABBY'S KITCHEN		29.86
428	NOV-05	GABBY'S KITCHEN		41.52
429	APR-05	GALAXY DINER 605		16.52
430	OCT-05	GALAXY DINER 605		24.21
431	FEB-05	GOLDEN CORRAL 29724Q15		63.87
432	MAR-05	GOLDEN CORRAL 29724Q15		37.34
433	APR-05	GOLDEN CORRAL 29724Q15		17.86
434	MAY-05	GOLDEN CORRAL 29724Q15		25.50
435	JUN-05	GOLDEN CORRAL 29724Q15		14.21
436	JUL-05	GOLDEN CORRAL 29724Q15		35.20
437	AUG-05	GOLDEN CORRAL 29724Q15		12.92
438	SEP-05	GOLDEN CORRAL 29724Q15		38.75
439	OCT-05	GOLDEN CORRAL 29724Q15		17.21
440	NOV-05	GOLDEN CORRAL 29724Q15		11.30
441	DEC-05	GOLDEN CORRAL 29724Q15		24.85
442	NOV-05	GOLDEN DRAGON REST		20.91
443	JAN-05	GOLDEN GATE RESTAURANT		74.98
444	FEB-05	GURLEY STREET GRILL		81.75
445	APR-05	GURLEY STREET GRILL		191.21
446	JUL-05	GURLEY STREET GRILL		102.85
447	AUG-05	GURLEY STREET GRILL		89.29
448	SEP-05	GURLEY STREET GRILL		131.04
449	OCT-05	GURLEY STREET GRILL		140.54
450	NOV-05	GURLEY STREET GRILL		29.58
451	DEC-05	GURLEY STREET GRILL		82.39
452	MAR-05	HAMPTON INN HAVASU 51		688.41
453	MAY-05	HAMPTON INN HAVASU 51		305.96
454	JUN-05	HAMPTON INN HAVASU 51		152.98
455	SEP-05	HAMPTON INN HAVASU 51		229.47
456	NOV-05	HAMPTON INN HAVASU 51		660.16
457	NOV-05	HAMPTON INN TUCSON 61		111.39
458	OCT-05	HAMPTON INNS TIP		426.60
459	JUN-05	HAMPTON INNS & SUITTIP		287.91
460	AUG-05	HARBOR HOUSE RESTAURAN		63.02
461	OCT-05	HARKINS PRESCOTT VALLE		25.00
462	OCT-05	HASSAYAMPA HOTEL LLC		577.45
463	FEB-05	HASTINGS-ENTERTAINME #		43.87
464	JUN-05	HERTZ RENT-A-CAR		449.64
465	JUL-05	HIDDEN VALLEY INN		77.05
466	AUG-05	HIRO S SUSHI BAR		22.11
467	DEC-05	HIROS SUSHI BAR & REST		89.40
468	DEC-05	HMS HOST-ORD AIRPT #81		9.10
469	AUG-05	HMSHOST SAN AIRPT #00		18.81
470	AUG-05	HMSHOST-PHX-AIR #00		37.95
471	OCT-05	HMSHOST-PHX-AIR #00		31.02
472	AUG-05	HMSHOST-PHX-AIR #01		8.64
473	MAY-05	HOBO JOE'S		17.60
474	JAN-05	HOBO JOES COFFEE S		16.39
475	FEB-05	HOBO JOES COFFEE S		14.02
476	AUG-05	HOLIDAY INN EXPRES		345.76
477	FEB-05	HOLIDAY INN EXPRESS PR		325.45
478	OCT-05	HOLIDAY INN EXPRESS TU		121.54
479	APR-05	HOLIDAY INN EXPRESSTIP		1,106.53
480	JUN-05	HOLIDAY INN EXPRESSTIP		520.72
481	NOV-05	HOLIDAY INN EXPRESSTIP		195.27
482	JUN-05	HOLIDAY INN FLAGSTAFF		238.52
483	AUG-05	HOLIDAY INN TUCSON		73.10
484	SEP-05	HOLIDAY INN TUCSON		91.38
485	OCT-05	HOLIDAY INN TUCSON		190.71
486	DEC-05	HOLIDAY INN TUCSON		156.96
487	FEB-05	HOLIDAY INN-AIRPORT		194.58
488	APR-05	HOLIDAY INN-AIRPORT		204.06
489	MAY-05	HOLIDAY INN-AIRPORT		25.33
490	JUN-05	HOLIDAY INN-AIRPORT		491.21
491	JUL-05	HOLIDAY INN-AIRPORT		188.19
492	AUG-05	HOLIDAY INN-AIRPORT		(3.50)

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WORKPAPER FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
EXPENSES REMOVED FROM ACCOUNT 921

LINE NO.	GENERAL LEDGER PERIOD	PA EXPENDITURE COMMENT	INVOICE NUMBER	NET AMOUNT
493	FEB-05	HOLIDAY INNS		$ 345.51
494	MAR-05	HOLIDAY INNS		388.68
495	APR-05	HOLIDAY INNS		777.36
496	JUN-05	HOLIDAY INNS		539.85
497	JUL-05	HOLIDAY INNS		151.16
498	AUG-05	HOLIDAY INNS		194.34
499	OCT-05	HOLIDAY INNS		75.58
500	DEC-05	HOLIDAY INNS		194.34
501	JAN-05	HOLIDAY INNS EXPRESS		173.67
502	FEB-05	HOLIDAY INNS EXPRESS		139.54
503	APR-05	HOLIDAY INNS EXPRESS		147.33
504	MAY-05	HOLIDAY INNS EXPRESS		978.18
505	JUL-05	HOLIDAY INNS EXPRESS		710.93
506	AUG-05	HOLIDAY INNS EXPRESS		351.76
507	OCT-05	HOLIDAY INNS EXPRESS		388.45
508	DEC-05	HOLIDAY INNS EXPRESS		317.87
509	AUG-05	HOLIDAY INNS FLAGSTAFF		98.12
510	AUG-05	HOMETOWN BUFFE00103291		32.43
511	NOV-05	HOMETOWN BUFFE00103291		41.84
512	FEB-05	HOT WOK EXPRESS		8.30
513	NOV-05	HOTEL ST MICHEAL		22.12
514	SEP-05	HOTELS.COM - MC		259.00
515	APR-05	HOUSE OF BREAD		19.82
516	OCT-05	HOUSE OF BREAD		25.50
517	NOV-05	HOUSE OF BREAD		13.50
518	DEC-05	HOUSE OF BREAD		44.10
519	MAY-05	HUNAN WEST		24.93
520	JUL-05	HUNAN WEST		41.63
521	NOV-05	HUNAN WEST		6.90
522	OCT-05	ICUEE, THE DEMO EXPO		20.00
523	MAR-05	IHOP #1514 21815147		83.62
524	NOV-05	IHOP #1518 21815188		12.11
525	MAR-05	IHOP #1524 21815246		67.97
526	MAY-05	IHOP #1524 21815246		19.57
527	JUN-05	IHOP #1524 21815246		11.35
528	AUG-05	IHOP #1524 21815246		23.45
529	NOV-05	IHOP #1524 21815246		62.04
530	NOV-05	IHOP #3033		18.63
531	MAR-05	IHOP#1527 05415278		18.03
532	DEC-05	INCAHOOTS		162.19
533	APR-05	INDIAN PINE RESTAURANT		10.25
534	MAR-05	INTERNATIONAL HOUSE OF		24.74
535	SEP-05	IRON SKILLET #15		12.20
536	JUN-05	J BS RESTAURANT		137.85
537	OCT-05	J BS RESTAURANT		10.97
538	NOV-05	J BS RESTAURANT		44.73
539	JUL-05	JA STEAKHOUSE		27.22
540	MAR-05	JACK INTHE BOX05615Q43		5.83
541	FEB-05	JACK INTHE BOX06911Q43		19.24
542	MAR-05	JACK INTHE BOX06911Q43		6.88
543	JUN-05	JACK INTHE BOX06911Q43		6.67
544	JUL-05	JACK INTHE BOX06911Q43		19.24
545	JUN-05	JACKSONS GRILL		154.54
546	NOV-05	JACKSONS GRILL		30.07
547	NOV-05	JAVELINA CANTINA		36.91
548	MAY-05	JAVELINA CANTINA SED		100.33
549	JUN-05	JAVELINA CANTINA SED		14.55
550	JUL-05	JAVELINA CANTINA SED		21.00
551	AUG-05	JAVELINA CANTINA SED		49.22
552	DEC-05	JAVELINA CANTINA SED		29.68
553	OCT-05	JB'S REST #377		8.67
554	FEB-05	JB'S RESTAURANT 11		14.15
555	MAR-05	JB'S RESTAURANT 11		25.71
556	JUN-05	JB'S RESTAURANT 11		22.99
557	JUL-05	JB'S RESTAURANT 11		17.24
558	NOV-05	JB'S RESTAURANT 11		23.43
559	JAN-05	JD'S CAFE		6.77
560	JUN-05	JEROME BREWERY		12.21
561	JUL-05	JEROME PALACE		27.52
562	FEB-05	JOANN FABRIC #1831		8.29
563	APR-05	JOE'S CRAB SHACK-TEMPE		60.00
564	SEP-05	JOE'S CRAB SHACK-TEMPE		22.25
565	SEP-05	JOE'S CRAB-TEMPE		30.95
566	MAR-05	JOHNNY CARINO'S #1412		28.43
567	AUG-05	JOSHUA TREE FAMILY RES		41.63
568	JAN-05	JUICY'S RIVER CAFE		42.48
569	JAN-05	KACHINA DOWNTOWN		239.98
570	FEB-05	KACHINA DOWNTOWN		177.73
571	MAR-05	KACHINA DOWNTOWN		107.60

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WORKPAPER FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
EXPENSES REMOVED FROM ACCOUNT 921

LINE NO.	GENERAL LEDGER PERIOD	PA EXPENDITURE COMMENT	INVOICE NUMBER	NET AMOUNT
572	APR-05	KACHINA DOWNTOWN		$ 210.70
573	MAY-05	KACHINA DOWNTOWN		198.93
574	JUN-05	KACHINA DOWNTOWN		27.23
575	JUL-05	KACHINA DOWNTOWN		118.25
576	JUL-05	KACHINIA DOWNTOWN		41.34
577	AUG-05	KACHINIA DOWNTOWN		150.78
578	SEP-05	KACHINIA DOWNTOWN		94.79
579	OCT-05	KACHINIA DOWNTOWN		98.00
580	NOV-05	KACHINIA DOWNTOWN		38.59
581	DEC-05	KACHINIA DOWNTOWN		42.89
582	OCT-05	KENDALL'S FAMOUS B		23.25
583	MAR-05	KFC #6		18.25
584	JUL-05	KFC #6		6.05
585	AUG-05	KFC #6		6.38
586	NOV-05	KFC #6		7.28
587	OCT-05	KFC #7660002 76600Q30		5.57
588	NOV-05	KFC #7660002 76600Q30		5.24
589	MAY-05	KFC #G325005 87550Q30		5.08
590	FEB-05	KFC #J605011 22800Q30		8.69
591	MAR-05	KFC #J605011 22800Q30		30.82
592	APR-05	KFC #J605011 22800Q30		35.23
593	MAY-05	KFC #J605012 22800Q30		30.82
594	APR-05	KFC #K201001 46700Q30		10.80
595	JUN-05	KFC #K201001 46700Q30		5.80
596	JUL-05	KFC #K201001 46700Q30		7.30
597	FEB-05	KFC #K555001 38300Q30		4.75
598	FEB-05	KFC #L820-005 35000Q30		4.95
599	MAR-05	KFC #L820-005 35000Q30		9.92
600	APR-05	KFC #L820-005 35000Q30		12.63
601	DEC-05	KFC #L820-005 35000Q30		6.46
602	APR-05	KFC WINSLOW		4.15
603	OCT-05	KFC WINSLOW		5.23
604	NOV-05	KINGMAN DAILY MINER		103.60
605	SEP-05	KINGMAN-CHILI'00010462		21.09
606	NOV-05	KMART 00039248		42.13
607	NOV-05	KMART 00048801		5.42
608	NOV-05	KMART 00073130		33.88
609	FEB-05	KMART 00095281		53.92
610	JAN-05	KOKOPELLI INN AND HOPI		408.10
611	MAR-05	KRYSTAL S FINE DINING		25.80
612	MAR-05	LA CASITA CAFE		122.42
613	APR-05	LA CASITA CAFE		21.00
614	MAY-05	LA CASITA CAFE		16.00
615	JUN-05	LA CASITA CAFE		16.77
616	JUL-05	LA CASITA CAFE		19.00
617	SEP-05	LA CASITA CAFE		41.00
618	OCT-05	LA CASITA CAFE		24.08
619	DEC-05	LA CASITA CAFE		27.12
620	FEB-05	LA COCINA DE EVA		88.92
621	APR-05	LA COCINA DE EVA		27.64
622	MAR-05	LA FONDA		123.95
623	JUN-05	LA FONDA		15.49
624	AUG-05	LA FONDA		84.65
625	SEP-05	LA FONDA MEXICAN RESTA		20.86
626	OCT-05	LA PARILLA SUIZA #3		16.84
627	AUG-05	LA PARRILLA SUIZA #5		53.97
628	AUG-05	LA PINATA		14.13
629	AUG-05	LAKESIDE PRIMARY C		75.00
630	JAN-05	LAQUINTA_FLAGSTAFF PAA		317.20
631	FEB-05	LAS TRANKAS RESTAURANT		10.50
632	MAY-05	LAS TRANKAS RESTAURANT		24.40
633	NOV-05	LAS TRANKAS RESTAURANT		39.97
634	MAR-05	LAS VIGAS STEAK RANCH		81.85
635	APR-05	LAS VIGAS STEAK RANCH		64.68
636	MAY-05	LAS VIGAS STEAK RANCH		62.28
637	MAR-05	LATE FOR THE TRAIN		8.60
638	JUN-05	LATE FOR THE TRAIN		13.82
639	OCT-05	LATE FOR THE TRAIN		17.79
640	NOV-05	LATE FOR THE TRAIN		17.62
641	DEC-05	LATE FOR THE TRAIN		8.70
642	FEB-05	LICANO'S MEXICAN F		22.46
643	JUN-05	LIGHTNING RIDGE CAFE		12.97
644	FEB-05	LITTLE AMERICA FLAGSTA		100.71
645	MAR-05	LITTLE AMERICA FLAGSTA		22.71
646	APR-05	LITTLE AMERICA FLAGSTA		45.03
647	AUG-05	LITTLE AMERICA FLAGSTA		25.92
648	DEC-05	LITTLE AMERICA FLAGSTA		146.51
649	JUN-05	LITTLE CAESARS 3190		16.22
650	MAY-05	LK HAVASU CITY CHMBR		450.00
651	NOV-05	LO S RESTAURANT		8.36
652	OCT-05	LODGE ON ROUTE 66		68.94
653	DEC-05	LOMBARDI'S ITALIAN BAK		20.61
654	NOV-05	LOS PRIMOS BAR & GRILL		32.66

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WORKPAPER FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
EXPENSES REMOVED FROM ACCOUNT 921

LINE NO.	GENERAL LEDGER PERIOD	PA EXPENDITURE COMMENT	INVOICE NUMBER	NET AMOUNT
655	JAN-05	LOTUS GARDEN CHINESE R		$ 19.60
656	NOV-05	LOTUS GARDEN CHINESE R		30.55
657	JUN-05	LOVE S COUNTRY00002Q01		17.44
658	AUG-05	LOVE S COUNTRY00002Q01		14.49
659	JAN-05	LOVE S COUNTRY00004Q01		9.05
660	DEC-05	LOVES 265 F00002Q01		5.96
661	OCT-05	LU MANDARIN BUFFET		17.28
662	JAN-05	LU MANDARIN BUFFET LLC		14.96
663	NOV-05	LUS MANDARIN BUFFET		119.41
664	JUN-05	M & M DAIRY QUEEN		7.45
665	MAR-05	MACAYO PRESCOTT		28.88
666	APR-05	MACAYO PRESCOTT		136.69
667	JUN-05	MACAYO PRESCOTT		43.03
668	JUL-05	MACAYO PRESCOTT		69.21
669	OCT-05	MACAYO PRESCOTT		40.16
670	NOV-05	MACAYO PRESCOTT		14.20
671	SEP-05	MAIN STREET CATERING		33.00
672	MAR-05	MALONES BAKERY & D		113.05
673	SEP-05	MALONES BAKERY & D		109.74
674	MAY-05	MARGARITA CANTINA		32.46
675	DEC-05	MARIE CALLENDER'S #67		28.37
676	JUL-05	MARIPOSA HOTEL		267.12
677	AUG-05	MARIPOSA HOTEL		289.40
678	JAN-05	MARKETPLACE CAFE		23.74
679	SEP-05	MARKETPLACE CAFE		26.33
680	OCT-05	MARRIOTT DWTN LOUISVIL		667.08
681	DEC-05	MARRIOTT HOTELS UNIVER		234.00
682	MAY-05	MAVERIK CNTRY STRE		9.93
683	JUL-05	MAVERIK CTRY STRE #137		1.42
684	SEP-05	MAX AND THELMAS RESTAU		41.97
685	AUG-05	MCDONALD'S F12118 Q17		43.21
686	OCT-05	MCDONALD'S F17372 Q17		9.92
687	OCT-05	MCDONALD'S F18788 Q17		13.80
688	OCT-05	MCDONALD'S F2640 Q17		14.48
689	SEP-05	MICHAELS #9608		39.03
690	OCT-05	MICHAELS #9608		18.36
691	JAN-05	MICHAELS'S CHEESE STEA		15.02
692	DEC-05	MINERS DINER		32.24
693	OCT-05	MONSOON ON THE SQUARE		15.77
694	MAR-05	MR. C'S RESTAURANT		238.23
695	APR-05	MR. C'S RESTAURANT		100.51
696	MAY-05	MR. C'S RESTAURANT		78.79
697	SEP-05	MUDSHARK BREWING CO		40.59
698	MAR-05	MURPHYS		33.89
699	APR-05	MURPHYS		170.50
700	MAY-05	MURPHYS		88.65
701	JUN-05	MURPHY'S GRILL		339.13
702	JUL-05	MURPHY'S GRILL		283.08
703	AUG-05	MURPHY'S GRILL		113.28
704	SEP-05	MURPHY'S GRILL		76.72
705	OCT-05	MURPHY'S GRILL		94.03
706	NOV-05	MURPHY'S GRILL		100.48
707	DEC-05	MURPHY'S GRILL		193.35
708	JAN-05	MURPHYS GRILL COTTONWO		26.61
709	FEB-05	MURPHYS GRILL COTTONWO		242.14
710	MAR-05	MURPHYS GRILL COTTONWO		104.76
711	APR-05	MURPHYS GRILL COTTONWO		221.11
712	JUN-05	NATIVE NEW YORKER #12		136.00
713	JUL-05	NATIVE NEW YORKER #12		16.77
714	SEP-05	NATIVE NEW YORKER #12		17.32
715	OCT-05	NATIVE NEW YORKER #12		45.09
716	NOV-05	NATIVE NEW YORKER #12		60.34
717	DEC-05	NATIVE NEW YORKER #12		29.39
718	NOV-05	NAU TICKETING		400.00
719	APR-05	NAUTICAL INN CAPTAIN		50.49
720	APR-05	NILES RADIO		58.38
721	JUN-05	NILES RADIO		102.97
722	DEC-05	NILES RADIO		25.95
723	DEC-05	NIMARCOS PIZZA		77.75
724	FEB-05	ON THE BORD12700001271		49.36
725	JUN-05	OREGANO S PIZZA		22.59
726	JAN-05	OREGANOS		161.46
727	FEB-05	OREGANOS		88.14
728	MAR-05	OREGANOS		33.21
729	APR-05	OREGANOS		215.74
730	MAY-05	OREGANOS		121.67
731	JUN-05	OREGANOS		145.40
732	JUL-05	OREGANOS		173.13
733	AUG-05	OREGANOS		224.54
734	SEP-05	OREGANOS		181.08
735	OCT-05	OREGANOS		123.38
736	NOV-05	OREGANOS		34.64
737	DEC-05	OREGANOS		159.54

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WORKPAPER FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
EXPENSES REMOVED FROM ACCOUNT 921

LINE NO.	GENERAL LEDGER PERIOD	PA EXPENDITURE COMMENT	INVOICE NUMBER	NET AMOUNT
738	APR-05	OUR DAILY BREAD		$ 295.07
739	JUL-05	OUR DAILY BREAD		55.17
740	AUG-05	OUR DAILY BREAD		113.32
741	SEP-05	OUR DAILY BREAD		87.99
742	OCT-05	OUR DAILY BREAD		45.98
743	NOV-05	OUR DAILY BREAD		113.33
744	DEC-05	OUR DAILY BREAD		47.85
745	JAN-05	OUR DAILY BREAD DELI		24.39
746	FEB-05	OUR DAILY BREAD DELI		64.33
747	MAR-05	OUR DAILY BREAD DELI		195.90
748	MAR-05	OUTBACK #0312		37.57
749	JAN-05	OUTBACK #0317		57.95
750	FEB-05	OUTBACK #0317		27.29
751	MAY-05	OUTBACK #0317		182.36
752	OCT-05	OUTBACK #0317		31.29
753	NOV-05	OUTBACK #0317		181.86
754	APR-05	OUTBACK #0319		198.77
755	OCT-05	OUTBACK #0319		60.00
756	DEC-05	OUTBACK #0319		38.05
757	MAR-05	P.F. CHANG'S #8000		14.63
758	DEC-05	P.F. CHANG'S #8000		63.52
759	JAN-05	PANCHOS MC GILLICUDDYS		26.15
760	JUL-05	PANCHOS MC GILLICUDDYS		26.71
761	SEP-05	PANCHOS MC GILLICUDDYS		37.93
762	OCT-05	PANCHOS MC GILLICUDDYS		25.37
763	AUG-05	PAPA JOHN'S PIZZA		15.06
764	MAR-05	PAPPADEAUX SEAFOOD KIT		17.66
765	OCT-05	PAPPADEAUX SEAFOOD KIT		37.54
766	JAN-05	PARICUTIN		79.15
767	FEB-05	PATS PLACE		30.73
768	MAR-05	PATS PLACE		7.16
769	APR-05	PATS PLACE		185.24
770	JUN-05	PATS PLACE		189.64
771	AUG-05	PATS PLACE		65.35
772	SEP-05	PATS PLACE		40.00
773	NOV-05	PATS PLACE		63.71
774	DEC-05	PATS PLACE		29.80
775	JUN-05	PEI WEI ASIAN DINER-00		28.67
776	JAN-05	PETE S FAMILY RESTAURA		72.20
777	FEB-05	PETE S FAMILY RESTAURA		83.01
778	APR-05	PETE S FAMILY RESTAURA		38.07
779	MAY-05	PETE S FAMILY RESTAURA		95.83
780	AUG-05	PETE S FAMILY RESTAURA		13.86
781	JUL-05	PICACHO PEAK PLAZA		38.68
782	AUG-05	PICACHO PEAK PLAZA		8.94
783	FEB-05	PINE COUNTRY RESTA		47.30
784	MAR-05	PINE COUNTRY RESTA		9.55
785	APR-05	PINE COUNTRY RESTA		63.85
786	JUL-05	PINE COUNTRY RESTA		87.84
787	AUG-05	PINE COUNTRY RESTA		8.99
788	NOV-05	PINE COUNTRY RESTA		23.09
789	DEC-05	PINE COUNTRY RESTA		140.01
790	SEP-05	PINE COUNTRY RESTAURAN		30.09
791	OCT-05	PINE COUNTRY RESTAURAN		609.06
792	NOV-05	PINE COUNTRY RESTAURAN		8.77
793	MAR-05	PINNACLE PEAK		89.07
794	FEB-05	PIZZA FACTORY		8.26
795	APR-05	PIZZA FACTORY		9.53
796	JUL-05	PIZZA FACTORY		18.02
797	AUG-05	PIZZA FACTORY		10.30
798	SEP-05	PIZZA FACTORY		73.42
799	OCT-05	PIZZA FACTORY		406.89
800	NOV-05	PIZZA FACTORY		24.62
801	DEC-05	PIZZA FACTORY		88.47
802	NOV-05	PIZZA H006705 16800Q34		37.20
803	JAN-05	PIZZA H007980 17400Q34		25.74
804	NOV-05	PIZZA H010725 17500Q34		158.83
805	MAR-05	PIZZA HUT 55609Q34		16.94
806	JUN-05	PIZZA HUT 55609Q34		18.60
807	JUL-05	PIZZA HUT 55609Q34		54.25
808	FEB-05	PIZZA HUT #00742700Q34		17.54
809	APR-05	PIZZA HUT #00742700Q34		17.54
810	JUL-05	PIZZA HUT #00742700Q34		31.00
811	NOV-05	PIZZA HUT #00742700Q34		41.23
812	DEC-05	PIZZA HUT #00742700Q34		16.00
813	MAR-05	PIZZA HUT #00942700Q34		42.26
814	APR-05	PIZZA HUT #00942700Q34		(19.13)
815	SEP-05	PIZZA HUT #00942700Q34		20.00
816	DEC-05	PIZZA HUT #43 57400Q34		84.33
817	APR-05	PIZZA HUT #7 55700Q34		39.62
818	NOV-05	PIZZA HUT #7 55700Q34		17.15
819	FEB-05	PIZZA HUT OF C38400Q34		20.77
820	MAR-05	PIZZA HUT OF C38400Q34		23.50

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WORKPAPER FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
EXPENSES REMOVED FROM ACCOUNT 921

LINE NO.	GENERAL LEDGER PERIOD	PA EXPENDITURE COMMENT	INVOICE NUMBER	NET AMOUNT
821	JUN-05	PIZZA HUT OF TAYLOR		$ 19.13
822	AUG-05	PIZZA HUT OF TAYLOR		16.66
823	APR-05	PLACE M&R'S RESTAU		14.39
824	MAY-05	PLACE M&R'S RESTAU		120.68
825	JUN-05	PLACE M&R'S RESTAU		17.09
826	SEP-05	PLACE M&R'S RESTAU		18.75
827	OCT-05	PLACE M&R'S RESTAU		39.80
828	NOV-05	PLACE M&R'S RESTAU		16.98
829	DEC-05	PRESCOTT BREWING C		44.60
830	MAR-05	PRESCOTT BREWING COMPA		56.54
831	JUL-05	PRESCOTT BREWING COMPA		37.87
832	AUG-05	PRESCOTT BREWING COMPA		74.47
833	NOV-05	PRESCOTT BREWING COMPA		44.83
834	JAN-05	PRESCOTT CHAMBER OF CO		40.00
835	FEB-05	PRESCOTT CHAMBER OF CO		40.00
836	JUN-05	PRESCOTT COLLEGE		57.50
837	NOV-05	PRESCOTT CONVENTION CT		619.03
838	OCT-05	PRESCOTT MINING CO		108.20
839	APR-05	PROFLOWERS.COM		39.98
840	JAN-05	QUALITY INNS LAS CAMPA		152.54
841	APR-05	QUALITY INNS LAS CAMPA		132.64
842	JUN-05	QUALITY INNS LAS CAMPA		198.96
843	AUG-05	QUALITY INNS LAS CAMPA		297.08
844	JUN-05	QUIK MART #33		42.22
845	OCT-05	QUIZNO'S SUB #2515		35.68
846	NOV-05	QUIZNO'S SUB #2515		33.84
847	DEC-05	QUIZNO'S SUB #2515		27.66
848	MAR-05	QUIZNOS SUB #2777		5.43
849	MAY-05	QUIZNOS SUB #2777		13.13
850	APR-05	QUIZNOS SUB #5098 Q22		14.02
851	APR-05	R & R PIZZA EXPRES		108.42
852	SEP-05	RADIO SHACK 00134718		18.36
853	AUG-05	RADIOSHACK DEA01902659		67.82
854	JAN-05	RADISSON HOTELS-WOODLA		10.98
855	FEB-05	RADISSON HOTELS-WOODLA		97.74
856	MAR-05	RADISSON HOTELS-WOODLA		46.08
857	AUG-05	RADISSON HOTELS-WOODLA		135.63
858	SEP-05	RADISSON HOTELS-WOODLA		78.25
859	NOV-05	RADISSON HOTELS-WOODLA		74.38
860	APR-05	RAINFOREST-AZ REST.		27.83
861	JUL-05	RAMADA INN		84.92
862	DEC-05	RAMADA INN		86.59
863	FEB-05	RANDALL'S RESTAURANT		8.19
864	AUG-05	RANDALL'S RESTAURANT		34.80
865	SEP-05	RANDALL'S RESTAURANT		16.34
866	OCT-05	RBT REALTY/PERKINS RES		12.16
867	JUN-05	RDROBIN NO 394		32.85
868	MAR-05	RED LOBSTER US00003699		30.89
869	JUN-05	RED LOBSTER US00008458		56.65
870	JUL-05	RED LOBSTER US00008458		52.69
871	AUG-05	RED LOBSTER US00008458		69.28
872	SEP-05	RED LOBSTER US00008458		30.64
873	NOV-05	RED LOBSTER US00008458		79.84
874	DEC-05	RED LOBSTER US00008698		50.47
875	SEP-05	RED ROBIN		24.30
876	SEP-05	RED ROBIN 358		22.09
877	MAR-05	RED ROBIN NO 309		15.60
878	JUN-05	RED ROBIN NO 309		13.52
879	AUG-05	RED ROBIN NO 309		93.85
880	JAN-05	RED ROBIN NO 67		314.77
881	FEB-05	RED ROBIN NO 67		15.94
882	MAR-05	RED ROBIN NO 67		157.01
883	APR-05	RED ROBIN NO 67		210.37
884	MAY-05	RED ROBIN NO 67		81.64
885	JUL-05	RED ROBIN NO 67		14.11
886	AUG-05	RED ROBIN NO 67		51.37
887	SEP-05	RED ROBIN NO 67		27.97
888	NOV-05	RED ROBIN NO 67		64.73
889	JUN-05	RELIC'S RESTAURANT		75.48
890	AUG-05	RELIC'S RESTAURANT		98.30
891	DEC-05	RELIC'S RESTAURANT		18.04
892	JUL-05	RENTAL SERVICE CORP 41		36.93
893	MAR-05	RESIDENCE INNS-TUCSON		332.67
894	APR-05	RIO RICO RESORT RESTAU		401.93
895	MAR-05	ROCK SPRINGS CAFE		14.17
896	AUG-05	ROCK SPRINGS CAFE		27.28
897	SEP-05	ROCK SPRINGS CAFE		19.00
898	OCT-05	RODS STEAK HOUSE		27.14
899	JAN-05	ROMO S CAFE		30.46
900	APR-05	ROMO S CAFE		22.03
901	AUG-05	ROMO S CAFE		52.80
902	APR-05	ROSA'S CANTINA		64.17
903	SEP-05	ROSA'S CANTINA		69.45
904	FEB-05	ROSS STORES #441		35.63

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WORKPAPER FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
EXPENSES REMOVED FROM ACCOUNT 921

LINE NO.	GENERAL LEDGER PERIOD	PA EXPENDITURE COMMENT	INVOICE NUMBER	NET AMOUNT
905	MAR-05	ROYAL ROAD MARKET		$ 22.30
906	JUN-05	ROYAL ROAD MARKET		16.50
907	JUL-05	RUBIO'S AGUA FRIA #52		13.61
908	OCT-05	RUBIO'S BEARDSLEY #123		6.21
909	JAN-05	RUBY TUESDAY #4566		22.78
910	OCT-05	RUBY TUESDAY #4566		36.27
911	NOV-05	RUBY TUESDAY #4566		22.45
912	DEC-05	RUBY TUESDAY #4566		43.93
913	AUG-05	SAFARI BAR & GRILL INC		14.65
914	SEP-05	SAFARI BAR & GRILL INC		36.77
915	MAR-05	SAFEWAY STORE00002162		6.74
916	JUN-05	SAFEWAY STORE00002162		9.80
917	SEP-05	SAFEWAY STORE00002709		19.96
918	MAR-05	SAFEWAY STORE00012252		70.75
919	MAR-05	SAFEWAY STORE00012294		32.62
920	MAY-05	SAFEWAY STORE00012294		19.39
921	FEB-05	SAFEWAY STORE00016394		22.89
922	MAR-05	SAFEWAY STORE00016394		9.31
923	SEP-05	SAFEWAY STORE00016394		7.14
924	OCT-05	SAFEWAY STORE00016394		21.42
925	DEC-05	SAFEWAY STORE00016394		31.26
926	JAN-05	SAFEWAY STORE00017335		21.36
927	APR-05	SAFEWAY STORE00017335		67.48
928	JUN-05	SAFEWAY STORE00017335		18.33
929	JUL-05	SAFEWAY STORE00017335		46.45
930	AUG-05	SAFEWAY STORE00017335		60.87
931	DEC-05	SAFEWAY STORE00017335		44.20
932	MAY-05	SAFEWAY STORE00020172		10.78
933	FEB-05	SAFEWAY STORE00020289		54.08
934	MAR-05	SAFEWAY STORE00020289		112.38
935	APR-05	SAFEWAY STORE00020289		38.36
936	MAY-05	SAFEWAY STORE00020289		8.37
937	JUN-05	SAFEWAY STORE00020289		56.33
938	SEP-05	SAFEWAY STORE00020289		28.51
939	NOV-05	SAFEWAY STORE00020289		4.99
940	DEC-05	SAFEWAY STORE00020289		35.75
941	MAR-05	SAFEWAY STORE00020529		42.32
942	APR-05	SAFEWAY STORE00020529		20.09
943	JUN-05	SAFEWAY STORE00020529		51.75
944	JUL-05	SAFEWAY STORE00020529		14.78
945	AUG-05	SAFEWAY STORE00020529		12.47
946	APR-05	SAFEWAY STORE 00017475		9.56
947	MAY-05	SAFEWAY STORE 00017475		8.62
948	JUN-05	SAMURAI SAMS TERIYAKI		30.89
949	MAR-05	SCHLOTSKYS DELI		22.69
950	JUN-05	SCHLOTSKYS DELI		8.00
951	JUL-05	SCHLOTSKYS DELI		6.26
952	OCT-05	SCHLOTSKYS DELI		27.33
953	DEC-05	SCHLOTSKYS DELI		22.36
954	FEB-05	SCOTTYS BROASTED CHICK		46.04
955	MAR-05	SCOTTYS BROASTED CHICK		36.63
956	JUL-05	SCOTTYS BROASTED CHICK		20.57
957	SEP-05	SCOTTYS BROASTED CHICK		71.41
958	NOV-05	SCOTTYS BROASTED CHICK		12.19
959	DEC-05	SCOTTYS BROASTED CHICK		12.46
960	JAN-05	SCOUT'S GOURMET GR		20.37
961	JAN-05	SDI #F06-3582 Q63		6.27
962	JAN-05	SDI #F12-4351 Q63		6.92
963	FEB-05	SDI #F12-4351 Q63		8.42
964	JAN-05	SDI #F14-4427 Q63		21.92
965	FEB-05	SDI #F14-4427 Q63		10.37
966	MAR-05	SDI #F14-4427 Q63		12.34
967	FEB-05	SDI #N08-1139 Q63		18.82
968	MAR-05	SDI #N08-1139 Q63		16.78
969	MAR-05	SDI #N18-1263 Q63		9.05
970	JUL-05	SEARS DEALER 3238		495.00
971	FEB-05	SEARS ROEBUCK 2358		238.06
972	NOV-05	SEARS ROEBUCK 2358		75.68
973	APR-05	SEDONA RED ROCK NEWS		43.00
974	APR-05	SHAKEY'S PIZZA		9.90
975	DEC-05	SHERATON CHICAGO NORTH		285.60
976	DEC-05	SHOW LOW CHAMBER O		25.00
977	MAR-05	SHOW LOW FLOWER SHOPPE		60.05
978	OCT-05	SHOW LOW FLOWER SHOPPE		39.43
979	JAN-05	SIZZLER RESTRAUNT		36.17
980	JUN-05	SIZZLER RESTRAUNT		13.42
981	DEC-05	SLEEP INN		64.44
982	MAR-05	SMITHS FOOD #4190 SS6		9.98
983	AUG-05	SMITHS FOOD #4190 SS6		24.21
984	NOV-05	SONIC #1073		7.15
985	APR-05	SONIC #1077 Q63		6.37
986	DEC-05	SONIC #1139		11.28
987	MAY-05	SONIC #1139 Q63		18.49

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WORKPAPER FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
EXPENSES REMOVED FROM ACCOUNT 921

LINE NO.	GENERAL LEDGER PERIOD	PA EXPENDITURE COMMENT	INVOICE NUMBER	NET AMOUNT
988	JUN-05	SONIC #1145 Q63		$ 6.23
989	OCT-05	SONIC #1145 Q63		13.75
990	MAR-05	SONIC #1241 Q63		6.38
991	APR-05	SONIC #1263 Q63		7.97
992	APR-05	SONIC #3385 Q63		6.27
993	JUL-05	SONIC #3385 Q63		7.37
994	NOV-05	SONIC #3385 Q63		6.93
995	MAY-05	SONIC #3582 Q63		6.08
996	OCT-05	SONIC #4351 Q63		14.26
997	APR-05	SONIC #4427 Q63		12.88
998	MAY-05	SONIC #4427 Q63		13.08
999	JUN-05	SONIC #4427 Q63		16.81
1000	DEC-05	SONIC DRIVE IN #4833		5.24
1001	JAN-05	SONIC DRIVE IN #483Q63		5.25
1002	MAR-05	SONIC DRIVE IN #483Q63		9.96
1003	AUG-05	SONIC DRIVE IN #483Q63		5.25
1004	OCT-05	SONIC DRIVE IN #483Q63		7.28
1005	MAR-05	SOTO'S P/K OUTPOST		346.72
1006	APR-05	SOTO'S P/K OUTPOST		29.78
1007	MAY-05	SOTO'S P/K OUTPOST		37.94
1008	JUN-05	SOTO'S P/K OUTPOST		32.01
1009	OCT-05	SOTO'S P/K OUTPOST		111.18
1010	NOV-05	SOTO'S P/K OUTPOST		202.36
1011	JAN-05	SOUPER SALAD #88		13.53
1012	MAR-05	SOUPER SALAD #88		28.07
1013	APR-05	SOUPER SALAD #88		39.61
1014	JUN-05	SOUPER SALAD #88		14.53
1015	DEC-05	SPENCER GIFTS # 164		64.85
1016	APR-05	SPRINGHILL SUITES -PRE		120.93
1017	OCT-05	SPRINGHILL SUITES -PRE		208.41
1018	OCT-05	STARBUCKS USA 00058Q48		6.01
1019	JAN-05	STREETS OF NEW YORK #1		42.00
1020	FEB-05	STREETS OF NEW YORK #1		41.66
1021	MAR-05	STREETS OF NEW YORK #1		84.84
1022	AUG-05	STREETS OF NEW YORK #1		248.61
1023	SEP-05	STREETS OF NEW YORK #1		20.85
1024	NOV-05	STREETS OF NEW YORK #1		33.03
1025	MAR-05	SU CASA OF CLARKDALE		20.86
1026	APR-05	SU CASA OF CLARKDALE		53.24
1027	JUN-05	SU CASA OF CLARKDALE		79.17
1028	AUG-05	SU CASA OF CLARKDALE		27.24
1029	FEB-05	SUBWAY		5.10
1030	JUL-05	SUBWAY # 25887 Q16		5.72
1031	AUG-05	SUBWAY # 25887 Q16		6.58
1032	NOV-05	SUBWAY # 26252		8.91
1033	MAR-05	SUBWAY #15739 Q16		5.07
1034	APR-05	SUBWAY #15739 Q16		36.12
1035	JUL-05	SUBWAY 14220 Q16		5.99
1036	OCT-05	SUBWAY 14220 Q16		6.10
1037	NOV-05	SUBWAY 14220 Q16		6.10
1038	SEP-05	SUBWAY 17795		17.05
1039	JAN-05	SUBWAY 21530 Q16		5.83
1040	JAN-05	SUBWAY 2296 Q16		6.05
1041	FEB-05	SUBWAY 2296 Q16		6.05
1042	APR-05	SUBWAY 2296 Q16		5.94
1043	APR-05	SUBWAY 25137 Q16		5.07
1044	JAN-05	SUBWAY 27911 Q16		11.46
1045	FEB-05	SUBWAY 27912 Q16		5.83
1046	JAN-05	SUBWAY 6361 Q16		27.77
1047	MAR-05	SUBWAY 6361 Q16		5.49
1048	MAR-05	SUNWEST EXPRESS #280		8.44
1049	MAR-05	SUPER 8 MOTELS NOGALES		166.95
1050	MAR-05	SWEET & SUBS		24.41
1051	JUN-05	SWEET & SUBS		9.44
1052	JUL-05	SWEET & SUBS		14.27
1053	AUG-05	SWEET & SUBS		22.34
1054	NOV-05	SWEET & SUBS		111.91
1055	DEC-05	SWEET & SUBS		29.57
1056	OCT-05	SZECHUAN RESTAURANT		10.80
1057	NOV-05	SZECHUAN RESTAURANT		73.96
1058	MAR-05	T.G.I. FRIDAY'S #1141		11.33
1059	MAR-05	TACO BELL #9565 Q65		7.66
1060	APR-05	TACO DONS		104.10
1061	OCT-05	TACO DONS		104.01
1062	OCT-05	TACO HACIENDA		30.65
1063	AUG-05	TANIA 33		5.97
1064	JAN-05	TARGET 00009357		23.76
1065	MAR-05	TARGET 00009357		19.77
1066	JUL-05	TARGET 00009357		29.94
1067	DEC-05	TARGET 00009357		1,273.15
1068	SEP-05	TEMPE HOOTERS INC		130.43
1069	SEP-05	TEMPE MISSION PALM HTL		140.10
1070	SEP-05	TEMPE MISSION PALMS HO		2,749.10

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WORKPAPER FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
EXPENSES REMOVED FROM ACCOUNT 921

LINE NO.	GENERAL LEDGER PERIOD	PA EXPENDITURE COMMENT	INVOICE NUMBER	NET AMOUNT
1071	AUG-05	TEQUILA CHARLIE'S		$ 17.22
1072	FEB-05	TEQUILA CHARLIES LLC		21.20
1073	OCT-05	TERESA'S MOSAIC CAFE		27.00
1074	MAR-05	TERRIBLE HERBST #148		7.20
1075	AUG-05	TEXAS RDHSE HOLDINGS L		30.84
1076	OCT-05	TGI_FRIDAYS #0803		36.18
1077	FEB-05	THE CROWN RR CAFE-EAST		176.20
1078	MAR-05	THE CROWN RR CAFE-WEST		83.47
1079	JUL-05	THE CROWN RR CAFE-WEST		18.71
1080	DEC-05	THE CROWN RR CAFE-WEST		35.30
1081	NOV-05	THE FRESH TOMATO		23.43
1082	OCT-05	THE HOME DEPOT 0411		30.20
1083	DEC-05	THE HOME DEPOT 0411		43.18
1084	JAN-05	THE HOME DEPOT 482		37.08
1085	FEB-05	THE HOME DEPOT 482		108.10
1086	MAR-05	THE HOME DEPOT 482		165.14
1087	MAY-05	THE HOME DEPOT 482		164.24
1088	JUN-05	THE HOME DEPOT 482		21.28
1089	AUG-05	THE HOME DEPOT 482		49.50
1090	SEP-05	THE HOME DEPOT 482		46.71
1091	NOV-05	THE HOME DEPOT 482		33.27
1092	NOV-05	THE LONE SPUR CAFE		25.78
1093	MAY-05	THE OFFICE RESTAURANT		34.13
1094	OCT-05	THE OFFICE RESTAURANT		42.36
1095	FEB-05	THE OFFICE RESTAURNT&B		83.94
1096	AUG-05	THE OLD SPAGHETTI FACT		10.00
1097	APR-05	THE OLIVE GARD00010116		5.76
1098	JAN-05	THE OLIVE GARD00015131		76.12
1099	APR-05	THE OLIVE GARD00015131		73.11
1100	MAY-05	THE OLIVE GARD00015131		90.20
1101	JUN-05	THE OLIVE GARD00015131		34.96
1102	JUL-05	THE OLIVE GARD00015131		36.97
1103	AUG-05	THE OLIVE GARD00015131		73.84
1104	NOV-05	THE OLIVE GARD00015131		255.11
1105	DEC-05	THE OLIVE GARD00015131		50.88
1106	JUN-05	THE PLACE M&R'S RE		29.95
1107	AUG-05	THE PLACE M&R'S RE		15.77
1108	SEP-05	THE PLACE M&R'S RE		7.95
1109	AUG-05	THE SIZZLER		35.17
1110	SEP-05	THE SIZZLER		6.50
1111	DEC-05	THE SIZZLER		28.58
1112	DEC-05	THE TOWNE SCRIBE		3.25
1113	JUL-05	THE TURQUOISE ROOM		40.84
1114	JAN-05	THE WAFFLE IRON		16.29
1115	FEB-05	THE WAFFLE IRON		28.38
1116	NOV-05	THE WAFFLE IRON		16.03
1117	OCT-05	THUMB BUTTE ROOM		37.00
1118	MAY-05	TONYS SPUNKY STEER		24.41
1119	OCT-05	TORREON GOLF CLUB LLC		21.65
1120	DEC-05	TOTAL GRAND RENTAL STA		41.63
1121	MAR-05	TRAPPERS CAFE		92.80
1122	APR-05	TRAPPERS CAFE		63.02
1123	MAY-05	TRAPPERS CAFE		15.80
1124	JUN-05	TRAPPERS CAFE		14.95
1125	JUL-05	TRAPPERS CAFE		46.21
1126	AUG-05	TRAPPERS CAFE		68.59
1127	SEP-05	TRAPPERS CAFE		51.03
1128	DEC-05	TRAPPER'S CAFE		32.25
1129	MAR-05	TUCSON HOOTERS INC		77.46
1130	FEB-05	UGLY GREEN CAFE		6.50
1131	MAR-05	UGLY GREEN CAFE & LOUN		18.00
1132	APR-05	UGLY GREEN CAFE & LOUN		39.50
1133	MAY-05	UGLY GREEN CAFE & LOUN		41.00
1134	JUN-05	UGLY GREEN CAFE & LOUN		30.00
1135	JUN-05	U-HAUL-ARABIAN-CAMPE #		183.28
1136	JUN-05	U-HAUL-SILVER-SADDL #6		(91.64)
1137	MAR-05	UNCLE SAMS		22.62
1138	NOV-05	UNIQUE TRACKS		396.00
1139	AUG-05	VAGABOND HOTEL CIRCLE		140.28
1140	APR-05	VERDE LEA MARKET		12.06
1141	JUN-05	VERDE LEA MARKET		12.06
1142	JAN-05	VERDE VALLEY NEWSPAPER		93.00
1143	JAN-05	VILLA PIZZA #1203 Q93		11.35
1144	DEC-05	VILLA S FOOD MARKET		7.84
1145	OCT-05	VILLAGE-INN-REST #0394		11.24
1146	JAN-05	WAL MART		18.46
1147	AUG-05	WAL MART		44.62
1148	SEP-05	WAL MART		36.08
1149	OCT-05	WAL MART		9.60
1150	DEC-05	WAL MART		63.88
1151	SEP-05	WALDENBOOKS 01009422		28.06
1152	SEP-05	WALDOS BBQ		36.56

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WORKPAPER FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
EXPENSES REMOVED FROM ACCOUNT 921

LINE NO.	GENERAL LEDGER PERIOD	PA EXPENDITURE COMMENT	INVOICE NUMBER	NET AMOUNT
1153	JUN-05	WALGREEN 00052Q39		$ 12.95
1154	AUG-05	WALGREEN 00052Q39		2.58
1155	DEC-05	WALGREEN 00052Q39		21.60
1156	JAN-05	WALGREEN 00076232		12.01
1157	MAY-05	WAL-MART #1175		0.50
1158	JUN-05	WAL-MART #1175		37.78
1159	DEC-05	WAL-MART #1175		34.90
1160	JUN-05	WAL-MART #1230 SE2		38.33
1161	AUG-05	WAL-MART #1230 SE2		30.81
1162	OCT-05	WAL-MART #1230 SE2		54.57
1163	NOV-05	WAL-MART #1230 SE2		39.76
1164	DEC-05	WAL-MART #1230 SE2		41.36
1165	OCT-05	WAL-MART #1324 SE2		16.16
1166	NOV-05	WAL-MART #1324 SE2		167.08
1167	SEP-05	WAL-MART #1364		4.23
1168	JUL-05	WAL-MART #1417 SE2		251.09
1169	JUN-05	WAL-MART #2051 SE2		14.41
1170	JUL-05	WAL-MART #2051 SE2		18.44
1171	DEC-05	WAL-MART #5303 SE2		77.24
1172	FEB-05	WAL-MART STORES, INC		15.01
1173	JAN-05	WAL-MART STORES, INSE2		10.59
1174	FEB-05	WAL-MART STORES, INSE2		48.28
1175	MAR-05	WAL-MART STORES, INSE2		41.85
1176	APR-05	WAL-MART STORES, INSE2		61.63
1177	DEC-05	WARNERS NURSERY/LANDSC		59.39
1178	JAN-05	WAYSIDE CAFE		22.09
1179	JUL-05	WAYSIDE CAFE		22.09
1180	OCT-05	WAYSIDE CAFE		9.14
1181	NOV-05	WENDYS		9.11
1182	JAN-05	WENDY'S #0001 Q25		22.26
1183	APR-05	WENDYS #8809		5.18
1184	SEP-05	WENDYS NO 413 Q50		9.26
1185	JAN-05	WESTERN WAREHOUSE #260		77.83
1186	JAN-05	WESTSIDE LILO'S CA		12.64
1187	FEB-05	WESTSIDE LILO'S CA		23.67
1188	MAY-05	WESTSIDE LILO'S CA		149.10
1189	AUG-05	WESTSIDE LILO'S CA		15.18
1190	SEP-05	WESTSIDE LILO'S CA		27.42
1191	OCT-05	WESTSIDE LILO'S CA		10.58
1192	NOV-05	WESTSIDE LILO'S CA		11.57
1193	DEC-05	WESTSIDE LILO'S CA		30.52
1194	APR-05	WHATABURGER #227		5.76
1195	MAR-05	WHATABURGER #775		11.08
1196	NOV-05	WHATABURGER 227 Q26		6.67
1197	NOV-05	WHATABURGER 775 Q26		16.03
1198	APR-05	WHITE MTN PUBLISH		74.00
1199	AUG-05	WHITE MTN PURIFIED WAT		118.04
1200	SEP-05	WHITE MTN PURIFIED WAT		145.28
1201	OCT-05	WHITE MTN PURIFIED WAT		45.40
1202	NOV-05	WHITE MTN PURIFIED WAT		45.40
1203	OCT-05	WILDFLOWER BREAD COMPA		28.20
1204	MAR-05	WILLOW CREEK INN		18.71
1205	DEC-05	WILLOW CREEK INN		45.43
1206	AUG-05	WINGATE INN PHOENIX		88.54
1207	JAN-05	WM SUPERCENTER SE2		107.70
1208	MAR-05	WM SUPERCENTER SE2		134.54
1209	APR-05	WM SUPERCENTER SE2		99.67
1210	MAY-05	WM SUPERCENTER SE2		9.08
1211	JUN-05	WM SUPERCENTER SE2		154.66
1212	JUL-05	WM SUPERCENTER SE2		59.04
1213	AUG-05	WM SUPERCENTER SE2		104.40
1214	SEP-05	WM SUPERCENTER SE2		84.00
1215	OCT-05	WM SUPERCENTER SE2		47.52
1216	NOV-05	WM SUPERCENTER SE2		228.68
1217	DEC-05	WM SUPERCENTER SE2		314.80
1218	JAN-05	WOODLANDS PLAZA HOTEL		214.74
1219	FEB-05	WOODLANDS PLAZA HOTEL		143.16
1220	MAR-05	WOODLANDS PLAZA HOTEL		71.58
1221	APR-05	WOODLANDS PLAZA HOTEL		92.50
1222	AUG-05	WOODLANDS PLAZA HOTEL		156.06
1223	OCT-05	WOODLANDS PLAZA HOTEL		838.51
1224	NOV-05	WOODLANDS PLAZA HOTEL		880.94
1225	MAY-05	WOODY'S # 134		2.18
1226	AUG-05	WOODY'S #118		5.24
1227	APR-05	WOODY'S #128		10.34
1228	JUN-05	WOODY'S #128		35.12
1229	MAR-05	YAVAPAI CANTINA		42.00
1230	APR-05	YAVAPAI CANTINA		18.50
1231	NOV-05	YAVAPAI CANTINA		5.75
1232	SEP-05	YC'S MONGOLIAN BARBQ70		19.00
1233	AUG-05	YOSHIS #2		6.70

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WORKPAPER FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
EXPENSES REMOVED FROM ACCOUNT 921

LINE NO.	GENERAL LEDGER PERIOD	PA EXPENDITURE COMMENT	INVOICE NUMBER	NET AMOUNT
1234	JAN-05	ZEKE S EATIN PLACE		$ 146.36
1235	FEB-05	ZEKE S EATIN PLACE		75.30
1236	APR-05	ZEKE S EATIN PLACE		212.66
1237	JUN-05	ZEKE'S EATIN PLACE		273.34
1238	AUG-05	ZEKE'S EATIN PLACE		219.04
1239	NOV-05	ZEKE'S EATIN PLACE		36.78
1240	JAN-05	EXCHANGE CLUB	284	125.00
1241	MAY-05	EXCHANGE CLUB	320	125.00
1242	JUL-05	EXCHANGE CLUB	367	125.00
1243	NOV-05	FARMER BROTHERS COFFEE	02202167981 093005	65.37
1244	JAN-05	FARMER BROTHERS COFFEE	2493025	192.76
1245	JAN-05	FARMER BROTHERS COFFEE	2493347	168.84
1246	JAN-05	FARMER BROTHERS COFFEE	2493678	159.27
1247	APR-05	FARMER BROTHERS COFFEE	2494319	119.14
1248	APR-05	FARMER BROTHERS COFFEE	2494649	221.93
1249	AUG-05	FARMER BROTHERS COFFEE	2494971	167.05
1250	AUG-05	FARMER BROTHERS COFFEE	2495300	118.37
1251	AUG-05	FARMER BROTHERS COFFEE	2495633	162.46
1252	AUG-05	FARMER BROTHERS COFFEE	2495939	149.52
1253	AUG-05	FARMER BROTHERS COFFEE	2496243	60.43
1254	JAN-05	FLAGSTAFF CHAMBER OF COMMERCE	1014553	800.00
1255	AUG-05	FLAGSTAFF CHAMBER OF COMMERCE	1015606	828.00
1256	SEP-05	FLAGSTAFF CHAMBER OF COMMERCE	1016083	750.00
1257	NOV-05	FOG BAND	111705 50000	250.00
1258	AUG-05	KINGMAN CHAMBER OF COMMERCE	207515	386.00
1259	FEB-05	KINGMAN ROTARY CLUB	020805 15000	150.00
1260	JUN-05	KINGMAN ROTARY CLUB	061505 25000	250.00
1261	AUG-05	KINGMAN ROTARY CLUB	081805 20800	208.00
1262	JAN-05	NILES RADIO	230966	185.00
1263	FEB-05	NILES RADIO	231251	185.00
1264	MAR-05	NILES RADIO	231521	185.00
1265	APR-05	NILES RADIO	231796	185.00
1266	MAY-05	NILES RADIO	232126	185.00
1267	JUN-05	NILES RADIO	232380	185.00
1268	JUL-05	NILES RADIO	232761	185.00
1269	OCT-05	NILES RADIO	233127	185.00
1270	OCT-05	NILES RADIO	233664	185.00
1271	NOV-05	NILES RADIO	233873	555.00
1272	SUB-TOTAL			$ 106,442.55
AS PER COMPANY RESPONSE TO STAFF DATA REQUEST 5.58				
1273	APR-05	CENTER TIRE		$ 8.50
1274	MAY05	CITY OF SHOW LOW		225.00
1275	NOV-05	NAU TICKETING		400.00
1276	TOTAL			$ 107,076.05

UNS Gas Corporation
Docket No. G-04204A-06-0463
Test Year Ended December 31, 2005

Schedule WP RLM-11-923

WORKPAPER FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
EXPENSES REMOVED FROM ACCOUNT 923

LINE NO.	GENERAL LEDGER PERIOD	PA EXPENDITURE COMMENT	INVOICE NUMBER	NET AMOUNT
1	OCT-05	ANGELINAS ITALIAN CUIS		34.45
2	OCT-05	ARIZONA SHUTTLE		21.00
3	DEC-05	AS MECH ENG INTRNATL C		100.33
4	FEB-05	AVIS RENT-A-CAR 1		132.14
5	MAY-05	AVIS RENT-A-CAR 1		121.28
6	MAY-05	BAHAMA BREEZE 00030304		51.16
7	SEP-05	BATTISTA S HOLE IN THE		59.49
8	MAR-05	BEAVER STREET BREWERY		33.00
9	JUL-05	BEAVER STREET BREWERY		29.00
10	NOV-05	BEAVER STREET FAMILY P		75.00
11	MAY-05	BELLE FLEUR WINERY & R		24.77
12	FEB-05	BEST WESTERN HOTELS		69.11
13	FEB-05	BRANDING IRON STKHSE		31.00
14	FEB-05	BUDGET RENT-A-CAR		87.78
15	MAR-05	BUSTER S RESTAURANT		30.50
16	APR-05	BUSTER S RESTAURANT		26.82
17	MAY-05	BUSTER S RESTAURANT		204.98
18	JUN-05	BUSTER S RESTAURANT		43.01
19	OCT-05	BUSTER S RESTAURANT		24.34
20	MAY-05	CALIFORNIA CAFE BAR/GR		22.26
21	MAY-05	CAPIN CAR CARE CENTER		6.00
22	FEB-05	CIRCLE K 00166		20.01
23	MAR-05	CIRCLE K 00166		17.51
24	NOV-05	CIRCLE K 05923		47.61
25	NOV-05	CIRCLE K 08594		38.52
26	FEB-05	CIRCLE K 08772		18.83
27	JUN-05	CLAIM JUMPER #25		26.59
28	JUL-05	COCOS BAKERY RESTAURAN		8.90
29	SEP-05	COCOS BAKERY RESTAURAN		21.13
30	SEP-05	DAMBAR & STEAKHOUSE		23.76
31	MAY-05	DOUBLETREE HOTEL F&B		22.00
32	SEP-05	EMBASSY SUITES FLAGTIP		218.02
33	NOV-05	EMBASSY SUITES FLAGTIP		526.16
34	FEB-05	EXPEDIA*TRAVEL		113.61
35	MAY-05	GAS CITY 615		23.71
36	MAR-05	GOLDEN CORRAL 00007Q15		15.46
37	FEB-05	GOLDEN NUGGET HOTEL		29.62
38	FEB-05	GREAT STEAK AND POTATO		20.00
39	MAR-05	GREAT STEAK AND POTATO		17.90
40	OCT-05	GURLEY STREET GRILL		6.82
41	OCT-05	HASSAYAMPA RESTAURANT		17.59
42	DEC-05	HASSAYAMPA RESTAURANT		14.15
43	FEB-05	HMSHOST-LAS-AIRPT #005		29.00
44	NOV-05	HOLIDAY INN EXPRESSTIP		39.50
45	MAR-05	HOLIDAY INNS EXPRESS		34.58
46	AUG-05	HOTELS.COM - MC		24.50
47	NOV-05	HOUSE OF BREAD		20.65
48	DEC-05	HOUSE OF BREAD		22.02
49	JUL-05	IHOP #3033		7.08
50	JUL-05	JACKSONS GRILL		28.00
51	NOV-05	JACKSONS GRILL		124.18
52	MAY-05	JITTERS GOURMET COFFEE		11.73
53	JUN-05	JUNIPINE CAFE		6.30
54	FEB-05	KINGMAN DELI, THE		24.52
55	NOV-05	KINGMAN DELI, THE		900.00
56	MAY-05	LA VALENCIA HOTEL		47.77
57	FEB-05	LAQUINTA_FLAGSTAFF PAA		102.54
58	FEB-05	LAQUINTA_PHOENIX #0PAA		52.96
59	SEP-05	LAS VEGAS EMBASSY STIP		140.61
60	FEB-05	LICANO'S MEXICAN F		22.00
61	DEC-05	LITTLE AMERICA FLAGSTA		101.60
62	APR-05	LONDON BRIDGE RESORT		115.77
63	FEB-05	LUXOR HOTEL/CASINO		32.00
64	JAN-05	MAIN STREET CATERING		20.82
65	JUL-05	MAIN STREET CATERING		15.80
66	SEP-05	MAIN STREET CATERING		178.97
67	MAY-05	MARRIOTT HOTELS UNIVER		12.27
68	FEB-05	MARRIOTT HOTELS WEST L		263.05
69	FEB-05	MAVERIK CNTRY STRE		29.45
70	FEB-05	MURPHYS		61.66
71	JAN-05	OGDENS CLEANERS		20.00
72	FEB-05	OLD PUEBLO GRILLE		31.86
73	SEP-05	OPEN ROAD TOURES INC		125.00
74	JUN-05	OUR DAILY BREAD		177.60
75	SEP-05	OUR DAILY BREAD		26.62
76	FEB-05	OUR DAILY BREAD DELI		46.55
77	MAR-05	OUR DAILY BREAD DELI		114.80
78	DEC-05	PAYPAL *WIDESCANINC		100.00
79	AUG-05	PRESCOTT CONVENTION CT		388.91
80	DEC-05	PRESCOTT CONVENTION CT		42.59
81	NOV-05	PRESCOTT COURIER-ADVER		118.30
82	FEB-05	PRESCOTT RESORT & CONV		111.18
83	NOV-05	PRESCOTT TRUE VALUE HA		560.79
84	JUL-05	QUALITY INN		73.13
85	SEP-05	RADIO SHACK 00134718		107.85
86	MAR-05	RADISSON HOTELS-WOODLA		57.00
87	JUL-05	RADISSON HOTELS-WOODLA		29.00
88	NOV-05	RADISSON HOTELS-WOODLA		12.95

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WORKPAPER FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
EXPENSES REMOVED FROM ACCOUNT 923

LINE NO.	GENERAL LEDGER PERIOD	PA EXPENDITURE COMMENT	INVOICE NUMBER	NET AMOUNT
89	MAY-05	RED ROBIN NO 67		$ 64.73
90	OCT-05	RODS STEAK HOUSE		58.57
91	FEB-05	RULA BULA, TEMPE IRISH		35.30
92	FEB-05	SAFEWAY STORE00020289		10.25
93	JUL-05	SAFEWAY STORE00020289		8.75
94	SEP-05	SAFEWAY STORE00020289		11.53
95	FEB-05	SHUGRUE'S HILLSIDE GRI		41.59
96	JUL-05	SHUGRUES RESTAURANT		39.42
97	SEP-05	SHUGRUES RESTAURANT		135.76
98	APR-05	SKY HARBOR AIRPORT T4		63.00
99	FEB-05	SOUTHWES 5262738944536		109.20
100	FEB-05	SUBWAY # 12395 Q16		6.21
101	SEP-05	SUNSPOTS PRODUCTIONS I		356.50
102	DEC-05	SUNSPOTS PRODUCTIONS I		427.00
103	MAR-05	SUPERSHUTTLE BALT		31.00
104	MAR-05	TARGET 00009357		37.83
105	JUL-05	THE AGAVE INN		54.83
106	SEP-05	THE AGAVE INN		109.67
107	OCT-05	THE AGAVE INN		54.83
108	NOV-05	THE AGAVE INN		54.83
109	MAR-05	THE OLIVE GARD00015131		33.00
110	FEB-05	TUCSON AIRPORT TRMNL P		12.00
111	MAY-05	TUCSON AIRPORT TRMNL P		16.00
112	OCT-05	WESTIN KIERLAND RESTIP		136.17
113	JUL-05	WINDROCK AVIATION		332.00
114	FEB-05	WLI*RESERVATIONREWARDS		7.00
115	FEB-05	WOODLANDS PLAZA HOTEL		223.16
116	MAR-05	WOODLANDS PLAZA HOTEL		497.90
117	JUN-05	WOODLANDS PLAZA HOTEL		89.61
118	JUL-05	WOODLANDS PLAZA HOTEL		162.47
119	SEP-05	YAVAPAI BUS TOURS		235.00
120	APR-05	ENTERPRISE RENT A CAR	L67392 0305	666.78
121	AUG-05	ENTERPRISE RENT A CAR	JULY 2005	120.58
122	DEC-05	ENTERPRISE RENT A CAR	113005 1752985	202.77
123	JAN-05	ENTERPRISE RENT A CAR	D048904-271T	202.77
124	JUL-05	ENTERPRISE RENT A CAR	JUNE 2005	204.00
125	JUN-05	ENTERPRISE RENT A CAR	MAY 2005	196.11
126	MAR-05	ENTERPRISE RENT A CAR	DEC-04	202.77
127	MAR-05	ENTERPRISE RENT A CAR	FEB-05	269.19
128	MAR-05	ENTERPRISE RENT A CAR	JAN-05	795.33
129	NOV-05	ENTERPRISE RENT A CAR	103105 915873	312.63
130	OCT-05	ENTERPRISE RENT A CAR	SEPT 2005	148.11
131	SEP-05	ENTERPRISE RENT A CAR	AUGUST 2005	182.16
132	MAY-05	HOLIDAY INN	apr 06	314.56
133	DEC-05	NILES RADIO	234190	185.00
134	APR-05	PARKS AND RECREATION	041905 3000	30.00
135	APR-05	PARKS AND RECREATION	041905 5000	50.00
136	FEB-05	PETTY CASH	RPC39040NEVENHOVEN	9.00
137	MAR-05	SIMPLY DELICIOUS	82001 0205	102.50
138	TOTAL			$ 14,738.15

WORKPAPER FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
EXPENSES REMOVED FROM ACCOUNT 926

LINE NO.	GENERAL LEDGER PERIOD	PA EXPENDITURE COMMENT	NET AMOUNT	
1	OCTOBER 2005	LAKE HAVASU RETIREMENT LUNCHEON FOR BRENDA BARRANCO PAOD TO CASA SERRANO	$	100.00
2	DECEMBER 2005	VERDE VALLEY GAS EMPLOYEE APPRECIATION DINNER PAID TO SU CASA RESTAURANT		379.51
3	DECEMBER 2005	PRESCOTT GAS EMPLOYEE APPRECIATION DINNER PAID FOR RELATED DINNER EXPENSES		5,750.00
4	TOTAL		$	6,229.51

UNS Gas Corporation
Docket No. G-04204A-06-0463
Test Year Ended December 31, 2005

WORKPAPER FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
EXPENSES REMOVED FROM ACCOUNT 930

LINE NO.	GENERAL LEDGER PERIOD	PA EXPENDITURE COMMENT	INVOICE NUMBER	NET AMOUNT
1	FEB-05	050 WORLD MKT 00000505		$ 8.00
2	JAN-05	ALBERTSONS #967 S9H		19.97
3	MAR-05	ALFONSO S		7.00
4	JUL-05	ALFONSO S		9.32
5	OCT-05	ALFONSO S		5.68
6	APR-05	ALIBERTOS MEXICAN FOOD		8.94
7	SEP-05	AMERICA		335.00
8	FEB-05	AMERISUITES - FF		139.82
9	MAY-05	AMERISUITES - FF		59.46
10	OCT-05	AMERISUITES - FF		88.09
11	MAR-05	ARIZONA DAILY SUN-INTE		2.95
12	OCT-05	BARLEY BROTHERS BREWER		106.59
13	AUG-05	BARRIO		22.00
14	FEB-05	BASHA S 18 SYW		10.87
15	JUN-05	BASHAS 53 SYW		7.83
16	DEC-05	BASHAS 67 SYW		13.59
17	JUN-05	BEAVER STREET BREWERY		35.79
18	MAR-05	BEST WESTERN ADOBE INN		504.12
19	JUL-05	BEST WESTERN ADOBE INN		162.14
20	NOV-05	BEST WESTERN ADOBE INN		133.26
21	JUL-05	BISON WITCHES BAR & DE		32.17
22	NOV-05	BOJOS GRILL		14.00
23	NOV-05	BRUEGGERS BAGEL BAKERY		13.83
24	SEP-05	BUDGET RENT-A-CAR		113.08
25	JAN-05	BUSTER S RESTAURANT		121.82
26	JUN-05	BUSTER S RESTAURANT		30.12
27	SEP-05	BUSTER S RESTAURANT		24.21
28	NOV-05	BUSTER S RESTAURANT		158.70
29	DEC-05	BUSTER S RESTAURANT		68.20
30	FEB-05	CAFE ESPRESS		16.72
31	MAR-05	CAREER STYLES ETC		78.73
32	APR-05	CHILI'S GRI04900010496		49.64
33	FEB-05	CHILI'S GRI41600004168		11.87
34	JUN-05	CIRCLE K 01116		1.53
35	JUN-05	CIRCLE K 01846		1.61
36	JUN-05	CIRCLE K 06665		3.16
37	MAR-05	CITY PRESS		663.10
38	FEB-05	CLIFF CASTLE CASINO		145.00
39	SEP-05	COCOS BAKERY RESTAURAN		34.49
40	JUL-05	COMFORT INN		236.96
41	JUN-05	COMFORT INNS/SUITES TU		61.20
42	OCT-05	CRACKER BARREL #344		23.31
43	NOV-05	DAIRY QUEEN-18047 Q35		3.51
44	MAY-05	DAMBAR & STEAKHOUSE		104.93
45	OCT-05	DAMBAR & STEAKHOUSE		230.07
46	AUG-05	DENNY'S 00269134		14.11
47	JAN-05	DESERT DIAMOND CASINO		807.12
48	JUL-05	DOC HOLLIDAYS STEAK HO		23.98
49	FEB-05	DOLRTREE 2679 00026799		19.46
50	MAY-05	DOLRTREE 2679 00026799		12.98
51	JUN-05	EINSTEIN BROS #2081		5.59
52	MAR-05	EL FALCONE		31.02
53	NOV-05	EL FALCONE		11.34
54	APR-05	EL ZARAPE		63.90
55	AUG-05	ENOTECA PIZZARIA WINE		17.92
56	SEP-05	ENOTECA PIZZARIA WINE		13.92
57	NOV-05	ENTERPRISE RENT-A-CAR		41.78
58	FEB-05	FARR S SERVICE		36.50
59	MAY-05	FAZOLIS RESTAURANT NO		27.59
60	SEP-05	FAZOLIS RESTAURANT NO		18.12
61	NOV-05	FLAGSTAFF CHAMBER OF C		280.00
62	OCT-05	FLAGSTAFF TOYS FOR TOT		1,000.00
63	JUL-05	FLYING J COUNTRY MARKE		15.43
64	APR-05	GARRETT'S SUPERMARKS1B		13.16
65	NOV-05	GOLDEN CORRAL 29724Q15		14.21
66	MAR-05	HMSHOST-PHX-AIR #00		29.05
67	DEC-05	HOLIDAY INN TUCSON		263.39
68	JUN-05	HOLIDAY INN-AIRPORT		149.70
69	JUL-05	HOLIDAY INNS		101.31
70	AUG-05	HOLIDAY INNS		202.62
71	JUL-05	HOLIDAY INNS EXPRESS		120.75
72	NOV-05	HOLIDAY INNS EXPRESS		758.60
73	SEP-05	HON-DAH RESORT CASINO		96.00
74	APR-05	HOUSE OF BREAD		29.73
75	MAY-05	HOUSE OF BREAD		130.28
76	JUN-05	HOUSE OF BREAD		79.13
77	AUG-05	HOUSE OF BREAD		21.75
78	SEP-05	HOUSE OF BREAD		51.50
79	OCT-05	HOUSE OF BREAD		310.78
80	NOV-05	HOUSE OF BREAD		165.19
81	NOV-05	HOWARD JOHNSON EXPRESS		110.90
82	APR-05	IHOP #1524 21815246		26.69

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WORKPAPER FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
EXPENSES REMOVED FROM ACCOUNT 930

LINE NO.	GENERAL LEDGER PERIOD	PA EXPENDITURE COMMENT	INVOICE NUMBER	NET AMOUNT
83	JUL-05	JACK INTHE BOX07811Q43		$ 7.09
84	AUG-05	JACK INTHE BOX07811Q43		9.55
85	OCT-05	JACK POTS PORTABLES		195.00
86	MAY-05	JASON'S DELI		43.20
87	FEB-05	JAVELINA CANTINA		57.18
88	NOV-05	JAVELINA CANTINA SED		41.17
89	OCT-05	JOHN ASCUAGA'S NUGGET		374.47
90	JUN-05	KAREN SORENSEN ENT		1,193.34
91	NOV-05	KFC #K 201002 46710Q30		7.32
92	FEB-05	KINGMAN CHAMBER OF COM		200.00
93	MAR-05	KINGMAN CHAMBER OF COM		200.00
94	MAR-05	KIOWA DRIVE THRU MINI		2.94
95	OCT-05	KMART 00037077		20.18
96	APR-05	KMART 00039230		25.12
97	MAY-05	KMART 00095281		16.12
98	JUN-05	LA COCINA DE EVA		29.13
99	MAY-05	LA FONDA		98.29
100	FEB-05	LA SANDIA CAFE		9.86
101	JUL-05	LAQUINTA_FLAGSTAFF PAA		101.09
102	OCT-05	LAQUINTA_FLAGSTAFF PAA		181.88
103	NOV-05	LAQUINTA_FLAGSTAFF PAA		134.60
104	APR-05	LAS VIGAS STEAK RANCH		20.64
105	APR-05	LITTLE AMERICA FLAGSTA		5.68
106	JUL-05	LITTLE AMERICA FLAGSTA		37.87
107	SEP-05	LODGE ON ROUTE 66		68.94
108	OCT-05	LODGE ON ROUTE 66		206.82
109	OCT-05	LONDON BRIDGE RESORT		109.67
110	OCT-05	LOVE S COUNTRY00002Q01		10.46
111	APR-05	LU MANDARIN BUFFET		33.01
112	OCT-05	LU MANDARIN BUFFET		8.64
113	APR-05	MAIN STREET CATERING		93.13
114	MAY-05	MALONES BAKERY & D		31.32
115	JUL-05	MALONES BAKERY & D		29.62
116	NOV-05	MALONES BAKERY & D		13.77
117	DEC-05	MALONES BAKERY & D		24.23
118	OCT-05	MAMMA LUISA ITALIAN RE		189.01
119	JUN-05	MAVERIK CTRY STRE #137		1.42
120	JUN-05	MAVERIK CTRY STRE #288		48.70
121	SEP-05	MAVERIK CTRY STRE #288		17.25
122	JUL-05	MCDONALD'S F12211 Q17		10.93
123	DEC-05	MCDONALD'S F8259		14.68
124	MAR-05	MONTANA STEAK HOUSE		32.19
125	MAR-05	MUDSHARK BREWING CO		59.08
126	APR-05	MUDSHARK BREWING CO		40.59
127	MAY-05	N A U FOUNDATION		750.00
128	OCT-05	N AWLINS ON MONTEZUMA		600.00
129	NOV-05	N AWLINS ON MONTEZUMA		340.70
130	OCT-05	NAU MANAGEMENT DVLPMEN		620.00
131	MAR-05	NILES RADIO		20.54
132	APR-05	NILES RADIO		155.69
133	NOV-05	OAXACA RESTAURANTE		117.97
134	JUN-05	OLD PUEBLO GRILLE		37.14
135	NOV-05	OLD PUEBLO GRILLE		39.72
136	DEC-05	OLSEN'S GRAIN		27.03
137	AUG-05	OREGANOS		54.86
138	NOV-05	OREGANOS		40.12
139	JUN-05	OUR DAILY BREAD		392.64
140	JUL-05	OUR DAILY BREAD		343.30
141	SEP-05	OUR DAILY BREAD		476.56
142	OCT-05	OUR DAILY BREAD		333.11
143	NOV-05	OUR DAILY BREAD		138.83
144	DEC-05	OUR DAILY BREAD		625.36
145	FEB-05	OUR DAILY BREAD DELI		217.06
146	FEB-05	OUTBACK #0317		16.29
147	NOV-05	PAPA JOHN'S PIZZA #288		15.09
148	JAN-05	PETRO 15 TRUCKER STORE		38.08
149	OCT-05	PINE COUNTRY RESTAURAN		32.42
150	AUG-05	PINETOP-LAKESIDE C		475.00
151	JUL-05	PIZZA FACTORY		23.91
152	MAR-05	PIZZA HUT 21200Q34		16.13
153	JUL-05	PIZZA HUT #43 57400Q34		9.64
154	JUN-05	PIZZA HUT OF TAYLOR		20.35
155	OCT-05	RA@RENO TAHOE AIRPORT		18.72
156	FEB-05	RADISSON HOTELS-WOODLA		79.50
157	JAN-05	RAMADA EXPRESS HOTEL		27.25
158	OCT-05	RED LOBSTER US00008458		19.51
159	MAR-05	RED ROBIN NO 309		150.71
160	DEC-05	RENTS AND TENTS		41.25
161	MAR-05	RESIDENCE INNS-TUCSON		334.17
162	MAY-05	RINCON MARKET		155.16
163	APR-05	RIO RICO RESORT		33.34
164	APR-05	RIO RICO RESORT RESTAU		0.00
165	SEP-05	RODS STEAK HOUSE		22.70
166	JUL-05	ROSA'S CANTINA		20.00

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WORKPAPER FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
EXPENSES REMOVED FROM ACCOUNT 930

LINE NO.	GENERAL LEDGER PERIOD	PA EXPENDITURE COMMENT	INVOICE NUMBER	NET AMOUNT
167	NOV-05	RUBIO'S AGUA FRIA #52		$ 11.85
168	DEC-05	RUBIO'S AHWATUKEE #35		4.31
169	JUN-05	SAFEWAY STORE00016394		83.42
170	OCT-05	SAFEWAY STORE00016394		4.55
171	MAR-05	SAFEWAY STORE00017335		30.55
172	JUN-05	SAFEWAY STORE00017335		85.07
173	JUL-05	SAFEWAY STORE00017335		13.24
174	SEP-05	SAFEWAY STORE00017335		12.53
175	OCT-05	SAFEWAY STORE00017335		19.34
176	NOV-05	SAFEWAY STORE00018879		10.39
177	JAN-05	SAFEWAY STORE00020289		14.96
178	FEB-05	SAFEWAY STORE00020289		12.50
179	APR-05	SAFEWAY STORE00020289		64.96
180	JUN-05	SAFEWAY STORE00020289		48.07
181	JUL-05	SAFEWAY STORE00020289		37.64
182	SEP-05	SAFEWAY STORE00020289		17.98
183	OCT-05	SAFEWAY STORE00020289		138.45
184	NOV-05	SAFEWAY STORE00020289		30.20
185	DEC-05	SAFEWAY STORE00020289		26.85
186	OCT-05	SAFEWAY STORE00031898		23.71
187	MAY-05	SALSA BRAVA INC.-2		42.15
188	OCT-05	SEDONA-OAK CREEK CAN C		450.00
189	JUL-05	SHOW LOW CHAMBER O		435.00
190	OCT-05	SMITHS FOOD #4188 SS6		65.25
191	NOV-05	SMITHS FOOD #4188 SS6		10.63
192	APR-05	SONIC DRIVE IN #483Q63		13.95
193	APR-05	SPRING HILL PRESS,		1,000.00
194	NOV-05	SPRINGHILL SUITES -PRE		99.24
195	MAR-05	SUBWAY 14220 Q16		8.28
196	JUN-05	SUBWAY 25137 Q16		2.69
197	OCT-05	SUBWAY 30031		4.11
198	JAN-05	SWEET & SUBS		25.89
199	FEB-05	SWEET & SUBS		14.06
200	SEP-05	TEMPE MISSION PALMS HO		443.67
201	OCT-05	THE AGAVE INN		54.84
202	OCT-05	THE HOME DEPOT 403		203.02
203	SEP-05	THE SIZZLER		41.77
204	SEP-05	THE WEATHFORD HOTE		33.97
205	NOV-05	THE WEATHFORD HOTE		80.73
206	DEC-05	THE WEATHFORD HOTE		2,075.31
207	OCT-05	TOMAHAWK TRUCK STOP		28.48
208	FEB-05	TRAPPERS CAFE		30.30
209	JUN-05	TRAPPERS CAFE		20.54
210	DEC-05	VILLA PIZZA #1201		5.25
211	MAY-05	VZW*MU 000013822		32.38
212	FEB-05	WALGREEN 00052217		23.46
213	OCT-05	WALGREEN 00052Q39		71.75
214	DEC-05	WAL-MART #1175		71.00
215	MAY-05	WAL-MART #1230 SE2		29.97
216	JUN-05	WAL-MART #1230 SE2		28.82
217	JUL-05	WAL-MART #1417 SE2		8.06
218	OCT-05	WAL-MART #5329 SE2		13.79
219	JAN-05	WAL-MART STORES, INSE2		55.06
220	FEB-05	WAL-MART STORES, INSE2		16.65
221	APR-05	WEATHERFORD HOTEL & CA		167.47
222	SEP-05	WEATHERFORD HOTEL & CA		83.03
223	APR-05	WENDYS		4.29
224	APR-05	WENDYS #2663 Q25		2.30
225	NOV-05	WENDY'S #6710 Q25		10.87
226	JUL-05	WESTERN ENERGY INST		3,570.00
227	APR-05	WESTSIDE LILO'S CA		37.76
228	MAR-05	WILLIAMS GRAND CANYON		236.90
229	MAY-05	WILLIAMS-GRAND CANYON		180.00
230	DEC-05	WINDROCK AVIATION		1,246.15
231	FEB-05	WM SUPERCENTER SE2		40.99
232	AUG-05	WM SUPERCENTER SE2		10.45
233	SEP-05	WM SUPERCENTER SE2		23.99
234	OCT-05	WM SUPERCENTER SE2		14.04
235	NOV-05	WM SUPERCENTER SE2		9.53
236	DEC-05	WM SUPERCENTER SE2		23.98
237	FEB-05	WOODLANDS PLAZA HOTEL		71.58
238	OCT-05	WOODLANDS PLAZA HOTEL		143.16
239	NOV-05	WOODLANDS PLAZA HOTEL		357.90

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WORKPAPER FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
EXPENSES REMOVED FROM ACCOUNT 930

LINE NO.	GENERAL LEDGER PERIOD	PA EXPENDITURE COMMENT	INVOICE NUMBER	NET AMOUNT
240	SEP-05	CHINO VALLEY AREA CHAMBER OF COMMERCE	06-239	215.00
241	AUG-05	COCONINO HIGH SCHOOL ACTIVITIES	072805 20000	200.00
242	FEB-05	COZ CREATIVE COMMUNICATIONS LP	TEP0207-0193	25.00
243	JUL-05	COZ CREATIVE COMMUNICATIONS LP	TEP0708-0223	1,700.00
244	JUL-05	COZ CREATIVE COMMUNICATIONS LP	TEP0719-0230	600.00
245	MAY-05	DANCES WITH OPPORTUNITY LLC	A41405	3,661.25
246	JUL-05	DAVID SANDERS PHOTOGRAPHY	85000 071205	850.00
247	JAN-05	DAY NITE DESIGN	1685	146.25
248	JAN-05	DAY NITE DESIGN	1698	749.95
249	JAN-05	DAY NITE DESIGN	1712	376.20
250	JAN-05	DAY NITE DESIGN	1718	227.50
251	DEC-05	ENTERPRISE RENT A CAR	113005 1752985	17,529.85
252	APR-05	FLAGSTAFF CHAMBER OF COMMERCE	041305	100.00
253	MAY-05	FLAGSTAFF CHAMBER OF COMMERCE	1015283	1,200.00
254	JUN-05	GREATER FLAGSTAFF ECONOMIC COUNCIL	189	2,500.00
255	NOV-05	GREATER FLAGSTAFF ECONOMIC COUNCIL	305	350.00
256	JUN-05	IBA PUBLISHING INC	Fm-06-134	325.00
257	JUN-05	KAZM RADIO	5185	1,045.50
258	DEC-05	MAYER AREA CHAMBER OF COMMERCE	122705 7200	72.00
259	JAN-05	MINKUS ADVERTISING SPECIALTIES	045500	1,907.70
260	JAN-05	MINKUS ADVERTISING SPECIALTIES	045501	452.70
261	APR-05	MINKUS ADVERTISING SPECIALTIES	051157	1,075.49
262	APR-05	MINKUS ADVERTISING SPECIALTIES	051274	618.70
263	APR-05	MINKUS ADVERTISING SPECIALTIES	051304	484.20
264	APR-05	MINKUS ADVERTISING SPECIALTIES	051305	80.70

Contiuned On Page 5

WORKPAPER FOR RUCO ADJUSTMENT TO REMOVE UNECESSARY/INAPPROPRIATE EXPENSES
EXPENSES REMOVED FROM ACCOUNT 930

LINE NO.	GENERAL LEDGER PERIOD	PA EXPENDITURE COMMENT	INVOICE NUMBER	NET AMOUNT
265	APR-05	MINKUS ADVERTISING SPECIALTIES	051306	$ 161.40
266	JUL-05	MINKUS ADVERTISING SPECIALTIES	051849A	439.13
267	NOV-05	MINKUS ADVERTISING SPECIALTIES	055156	284.75
268	NOV-05	MINKUS ADVERTISING SPECIALTIES	055157	515.11
269	JAN-05	NILES RADIO	72492	68.25
270	JAN-05	NILES RADIO	230383	185.00
271	JAN-05	NILES RADIO	230496	140.00
272	JAN-05	NILES RADIO	230588	185.00
273	FEB-05	NILES RADIO	1110591	292.53
274	MAR-05	NILES RADIO	230264	243.92
275	MAR-05	NILES RADIO	1110591	292.53
276	APR-05	NILES RADIO	231795	185.00
277	MAY-05	NILES RADIO	232125	185.00
278	JUN-05	NILES RADIO	232379	185.00
279	JUL-05	NILES RADIO	232760	185.00
280	AUG-05	NILES RADIO	232855	364.92
281	AUG-05	NILES RADIO	233126	185.00
282	SEP-05	NILES RADIO	233405	185.00
283	OCT-05	NILES RADIO	233663	185.00
284	NOV-05	NILES RADIO	233942	185.00
285	DEC-05	NILES RADIO	234189	185.00
286	FEB-05	PRESCOTT CHAMBER OF COMMERCE	38600	386.00
287	JAN-05	PRESCOTT VALLEY CHAMBER OF COMMERCE	55000 011705	550.00
288	FEB-05	SELIGMAN CHAMBER OF COMMERCE	021605 4000	40.00
289	SEP-05	SHOW LOW GIRS SOCCER BOOSTER CLUB	090205 2500	25.00
290	JUN-05	SHOW LOW MAIN STREET	25000 062105	250.00
291	SEP-05	SHOW LOW MAIN STREET	090105 35000	350.00
292	OCT-05	SHOW LOW MAIN STREET	100405 2500	25.00
293	JAN-05	WHITE MOUNTAIN REGIONAL DEVELOPMENT CORP	415	1,100.00
294	TOTAL			$ 76,494.47

UNS Gas Corporation
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Test Year Ended December 31, 2005

OPERATING INCOME ADJUSTMENT NO. 7
PROPERTY TAX COMPUTATION

LINE NO.	DESCRIPTION	(A)	(B)
	Calculation Of The Company's Full Cash Value:		
1	Net Plant In Service (RLM-3, Column (H), Line 7)		$ 161,045,981
2	Licensed Transportation (Company Workpapers)	$ (3,224,086)	
3	Land Cost And Rights (Company Workpapers)	(414,955)	
4	Environmental Property (Company Workpapers)	(3,766,890)	
5	Land FCV Per ADOR (Company Workpapers)	697,806	
6	Material And Supplies (Company Workpapers)	2,039,798	
7	COMPANY'S FULL CASH VALUE (Sum Of Lines 1 Thru 6)		$ 156,377,654
	Calculation Of The Company's Tax Liability:		
8	Assessment Ratio (Per House Bill 2779)	24.0%	
9	Assessed Value (Line 7 X Line 8)	$ 37,530,637	
10	Average Tax Rate (Company Workpapers)	9.47%	
13	PROPERTY TAX Excluding Environmental Property (Line 9 X Line 10)		$ 3,555,915
14	Environmental Property (Line 4)	$ 3,766,890	
15	Statutory FCV Adjustment (Company Workpapers)	50%	
16	Environmental Property FVC (Line14 X Line 15)	$ 1,883,445	
17	Asessment Ratio Line 8)	24.0%	
18	Taxable Value (Line 16 X Line 17)	$ 452,027	
19	Average Tax Rate (Company Workpapers)	9.47%	
20	PROPERTY TAX On Environmental Property (Line 18 X Line 19)		$ 42,828
21	PROPERTY TAX On Leased Property (Company Workpapers)		
22	COMPANY PROPERTY TAX LIABILITY (Sum Of Lines 13, 20 & 21)		$ 3,598,743
23	Test Year Adjusted Property Tax Expense Per Company's Filing (Co. Workpapers Pg 2, L 2)	$ 3,908,052	
24	Decrease In Property Tax Expense (Line 22 - Line 23)	$ (309,309)	
25	RUCO ADJUSTMENT TO PROPERTY TAX EXPENSE (Line 24) (See RLM-7, Pages 1 & 2, Column (H))		$ (309,309)

UNS Gas Corporation
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Test Year Ended December 31, 2005

ADJUSTMENT TO REMOVE NON-RECURRING/ATYPICAL EXPENSES
EXPENSES REMOVED FROM ACCOUNT 921

LINE NO.	(A) GENERAL LEDGER PERIOD	(B) PA EXPENDITURE COMMENT	(C) NOTES	(D) NET AMOUNT
1	11/14/2005	HOLIDAY INNS EXPRESS	M.A.R.C. Training (Union Training)	$ 270.48
2	11/14/2005	HOLIDAY INNS EXPRESS	M.A.R.C. Training (Union Training)	197.58
3	11/14/2005	HOLIDAY INNS EXPRESS	M.A.R.C. Training (Union Training)	151.50
4	11/14/2005	HOLIDAY INNS EXPRESS	M.A.R.C. Training (Union Training)	151.50
5	11/14/2005	HOLIDAY INNS EXPRESS	M.A.R.C. Training (Union Training)	151.50
6	11/14/2005	HOLIDAY INNS EXPRESS	M.A.R.C. Training (Union Training)	108.68
7	11/14/2005	HOLIDAY INNS EXPRESS	M.A.R.C. Training (Union Training)	225.27
8	11/14/2005	HOLIDAY INNS EXPRESS	M.A.R.C. Training (Union Training)	296.37
9	11/14/2005	HOLIDAY INNS EXPRESS	M.A.R.C. Training (Union Training)	227.25
10	11/14/2005	HOLIDAY INNS EXPRESS	M.A.R.C. Training (Union Training)	303.00
11	11/14/2005	HOLIDAY INNS EXPRESS	M.A.R.C. Training (Union Training)	98.79
12	11/14/2005	HOLIDAY INNS EXPRESS	M.A.R.C. Training (Union Training)	98.79
13	11/14/2005	HOLIDAY INNS EXPRESS	M.A.R.C. Training (Union Training)	303.00
14	TOTAL		Sum Of Lines 1 Thru 13	$ 2,583.71
15	RUCO Adjustment (See RLM-7, Pages 3 & 4, Column (K))		Line 14	$ (2,584)

UNS Gas Corporation
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OPERATING INCOME ADJUSTMENT NO. 22
INCOME TAX EXPENSE

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	FEDERAL INCOME TAXES:		
1	Operating Income Before Taxes	Schedule RLM-6, Column (C), Line 10 + Line 8	$ 14,366,885
	LESS:		
2	Arizona State Tax	Line 11	(687,052)
3	Interest Expense	Note (A) Line 22	(4,506,788)
4	Federal Taxable Income	Sum Of Lines 1, 2 & 3	$ 9,173,045
5	Federal Tax Rate	Schedule RLM-2, Column (A), Line 9	34.00%
6	Federal Income Tax Expense	Line 4 X line 5	$ 3,118,835
	STATE INCOME TAXES:		
7	Operating Income Before Taxes	Line 1	$ 14,366,885
	LESS:		
8	Interest Expense	Note (A) Line 22	(4,506,788)
9	State Taxable Income	Line 7 + Line 8	$ 9,860,097
10	State Tax Rate	Tax Rate	6.9680%
11	State Income Tax Expense	Line 9 X Line 10	$ 687,052
	TOTAL INCOME TAX EXPENSE:		
12	Federal Income Tax Expense	Line 6	$ 3,118,835
13	State Income Tax Expense	Line 11	687,052
14	Total Income Tax Expense Per RUCO	Sum Of Lines 12 & 13	$ 3,805,887
15	Total Income Tax Expense Per Company Filing (Schedule C-1)		1,975,497
16	Difference	Line 14 - Line 15	$ 1,830,390
17	RUCO ADJUSTMENT TO INCOME TAX EXPENSE (See RLM 7, Page 6, Column (W))	Line 16	$ 1,830,390

NOTE (A):

LINE NO.	Interest Synchronization:	
18	Adjusted Rate Base (Schedule RLM-3, Column (H), Line 16)	$ 144,680,196
19	Weighted Cost Of Debt (Schedule RLM-16, Column (F), Line 1 + Line 2)	3.12%
20	Interest Expense (Line 20 X Line 21)	$ 4,506,788

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RATE DESIGN AND PROOF OF RUCO RECOMMENDED REQUIRED REVENUE

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
			RUCO ANNUALIZED/WEATHERIZED		PROPOSED MARGIN RATES		MARGIN AT PROPOSED RATES					
LINE NO.	DESCRIPTION	SCH. NO.	ADJUSTED BILL COUNT	SALES (THERMS)	BASIC SERVICE CHARGE	COM. CHARGE	BASIC SERVICE CHARGE	COMMODITY CHARGE	TOTAL MARGIN	FIXED ALLOCATION FACTORS	VARIABLE ALLOCATION FACTORS	RES/COM ALLOCATION FACTORS
	Residential Service	R-10										
1	Basic Service Charge per Month - Summer		973,181		$ 8.13		$ 7,908,119		$ 7,908,119	64.11%		
2	Basic Service Charge per Month - Winter		495,838		$ 8.13		$ 4,029,208		4,029,208	32.67%		
3	Commodity Charge All Therms		-	69,822,061		$ 0.28916		$ 20,189,803	20,189,803		97.17%	
4	Total Residential Service		1,469,020	69,822,061			$ 11,937,327	$ 20,189,803	$ 32,127,130			
	Residential Service Cares	R-12										
4	Basic Service Charge per Month - Summer		33,439		$ 8.13		$ 271,728		$ 271,728	2.20%		
5	Basic Service Charge per Month - Winter		15,476		$ 8.13		$ 125,758		125,758	1.02%		
6	Commodity Charge All Therms			2,036,847		$ 0.28916		$ 588,976	588,976		2.83%	
7	Total Residential Service Cares		48,915	2,036,847			$ 397,486	$ 588,976	$ 986,463			
8	SUB-TOTAL RESIDENTIAL		1,517,935	71,858,907			$ 12,334,813	$ 20,778,780	$ 33,113,593	100.00%	100.00%	70.00%
	Small Volume Commercial Service	C-20										
9	Basic Service Charge per Month		133,275		$ 33.58		$ 4,475,732		$ 4,475,732	84.67%		
10	Commodity Charge per Therm			29,392,577		$ 0.18147		$ 5,334,006	5,334,006		59.90%	
11	Total Small Volume Commercial Service		133,275	29,392,577			$ 4,475,732	$ 5,334,006	$ 9,809,738			
	Large Volume Commercial Service & Trans.	C-22										
12	Basic Service Charge per Month		225		$ 258.32		$ 58,061		$ 58,061	1.10%		
13	Commodity Charge per Therm			4,170,979		$ 0.11617		$ 484,555	484,555		5.44%	
14	Total Large Volume Commercial Service		225	4,170,979			$ 58,061	$ 484,555	$ 542,616			
	Small Volume Industrial Service	I-30										
15	Basic Service Charge		146		$ 33.58		$ 4,920		$ 4,920	0.09%		
16	Commodity Charge per Therm			474,830		$ 0.17065		$ 81,029	81,029		0.91%	
17	Total Small Volume Industrial Service		146	474,830			$ 4,920	$ 81,029	$ 85,949			
	Large Volume Industrial Service	I-32										
18	Basic Service Charge		238		$ 258.32		$ 61,558		$ 61,558	1.16%		
19	Commodity Charge per Therm			22,586,654		$ 0.06510		$ 1,470,481	1,470,481		16.51%	
20	Total Large Volume Industrial Service		238	22,586,654			$ 61,558	$ 1,470,481	$ 1,532,039			
	Small Volume Public Authority	PA-40										
21	Basic Service Charge per Month		12,795		$ 33.58		$ 429,693		$ 429,693	8.13%		
22	Commodity Charge per Therm			5,870,369		$ 0.17796		$ 1,044,703	1,044,703		11.73%	
23	Total Small Volume Public Authority		12,795	5,870,369			$ 429,693	$ 1,044,703	$ 1,474,395			
	Large Volume Public Authority	PA-42										
24	Basic Service Charge per Month		113		$ 258.32		$ 29,080		$ 29,080	0.55%		
25	Commodity Charge per Therm			5,906,070		$ 0.08012		$ 473,210	473,210		5.31%	
26	Total Larege Volume Public Authority		113	5,906,070			$ 29,080	$ 473,210	$ 502,289			
	Special Gas Light Service	PA-44										
27	Customer Charge Lighting Group A		866		$ 41.80		$ 36,215		$ 36,215	0.69%		
28	Customer Charge Lighting Group B		3,767		$ 50.15		$ 188,877		188,877	3.57%		
29	Total Special Gas Light Service		4,633				$ 225,093	$ -	$ 225,093			
	Irrigation Service	IR-60										
30	Basic Service Charge		66		$ 33.58		$ 2,212		$ 2,212	0.04%		
31	Commodity Charge per Therm			79,409		$ 0.21671		$ 17,209	17,209		0.19%	
32	Total Irrigation Service		66	79,409			$ 2,212	$ 17,209	$ 19,421	100.00% #	100.00%	30.00%
33											RES. TO TOTAL	RES. REVENUE
34	SUB-TOTAL COMMERCIAL		151,491	68,480,887			5,286,349	8,905,191	14,191,540		70.00%	$ 33,113,593
35												COM REVENUE
36	TOTAL TARIFF SALES		1,669,426	140,339,795			17,621,162	29,683,971	47,305,133		COM. TO TOTAL	$ 14,191,540
37											30.00%	RES FIX REV
38												$ 12,334,813
39								OTHER REVENUE	1,480,304			COM FIX REV
40								TOTAL REVENUE	48,785,437		FIXED TO TOTAL	$ 5,286,349
41											37.25%	RES VAR REV
42								RUCO PROPOSED REVENUE	$ 48,785,437			$ 20,778,780
43											VAR. TO TOTAL	COM VAR REV
44								DIFFERENCE	$ (0)		62.75%	$ 8,905,191

TYPICAL RESIDENTIAL BILL ANALYSIS

LINE NO.	DESCRIPTION	(A) PRESENT	(B) PRESENT	(C) COMPANY PROPOSED	(D) COMPANY PROPOSED	(E) RUCO PROPOSED	(F) RUCO PROPOSED
	REVENUE ALLOCATION						
1	RESIDENTIAL	$ 31,123,034	70.02%	$ 39,021,053	70.19%	$ 33,113,593	70.00%
2	OTHER	$ 13,323,588	29.98%	$ 16,573,116	29.81%	$ 14,191,540	30.00%
3	TOTAL	$ 44,446,622	100.00%	$ 55,594,169	100.00%	$ 47,305,133	100.00%
	ALLOCATION RATIOS						
4	FIX REVENUE	12,110,551	27.25%	$ 28,769,014	51.70%	$ 17,621,162	37.25%
5	VARIABLE REVENUE	32,336,071	72.75%	$ 26,879,714	48.30%	$ 29,683,971	62.75%
6	TOTAL	44,446,622	100.00%	$ 55,648,727	100.00%	$ 47,305,133	100.00%

LINE NO.	**RESIDENTIAL RATE DESIGN**	PRESENT	COMPANY PROPOSED		RUCO PROPOSED
	BASIC MONTHLY CHARGE				
7	SUMMER	$ 7.00	MONTHS 8	$ 20.00	$ 8.13
8	WINTER	$ 7.00	MONTHS 4	$ 11.00	$ 8.13
9	COMMODITY CHARGE	$ 0.3004		$ 0.18625	0.2892

LINE NO.	**RESIDENTIAL BILL COMPARISONS** GAS CHARGE AT MARGIN + PGA COSTS AT DIFFERENT LEVELS OF USAGE WITH PERCENTAGE INCREASE IN BILL	AVERAGE PROPOSED PGA RATES	% OF AVERAGE MONTH USAGE OF 46.59 Therms	PRESENT MONTHLY GAS COST	RUCO PROP'D MONTHLY GAS COST	RUCO PROP'D MONTHLY INCREASE	RUCO PROP'D MONTHLY % INCREASE
10		$ 0.6467	25.00%	$ 18.03	$ 19.03	$ 1.00	5.52%
11			50.00%	$ 29.06	$ 29.93	$ 0.86	2.97%
12			100.00%	$ 51.13	$ 51.73	$ 0.60	1.18%
13			150.00%	$ 73.19	$ 73.53	$ 0.34	0.47%
14			200.00%	$ 95.25	$ 95.33	$ 0.08	0.08%

UNS Gas Corporation
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COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED	(D) PERCENT	(E) COST RATE	(F) WEIGHTED COST RATE
1	Short-term Debt	N/A	$ -	$ -	0.00%	0.00%	0.00%
2	Long-term Debt	$ 98,859,000	$ -	$ 98,859,000	50.00%	6.23%	3.12%
3	Preferred Stock	N/A	$ -	$ -	0.00%	0.00%	0.00%
4	Common Equity	$ 98,859,000	$ -	$ 98,859,000	50.00%	9.64%	4.82%
5	TOTAL CAPITAL	$ 197,718,000	$ -	$ 197,718,000	100.00%		
6	WEIGHTED COST OF CAPITAL						7.94%

References:
Column (A): Company Schedule D-1
Column (B): Testimony, WAR
Column (C): Column (A) + Column (B)
Column (D): Column (C), Line Item / Total Capital (L5)
Column (E): Testimony, WAR
Column (F): Column (D) X Column (E)

EXHIBIT A

UNS Gas Corporation
Docket No. G-04204A-06-0463
Test Year Ended December 31, 2005

EXHIBIT A

American Gas Association
Expenditures Funded by Member Dues
For the Year Ended December 31, 2003

Group Number	Group Name	Net Expense		Adjusments	G&A Allocation (3)	Adjusted Net Expense	% of Dues
03	Public Affairs	5,466,314	1, 2	(2,086,787)	594,755	3,974,282	23.35%
03	Communications	-	2	2,135,112	543,776	2,678,888	15.74%
06, 16	Corporate Affairs and International	1,588,513		-	441,818	2,030,331	11.93%
05	General Counsel & Corp. Secretary	669,281	1	(36,677)	203,916	836,520	4.91%
09	Regulatory Affairs	1,126,488	1	984,182	339,860	2,450,530	14.40%
08	Marketing Development	160,846	1	-	101,958	262,804	1.54%
14	Operating & Engineering Services	2,727,138	1	(815,865)	1,121,540	3,032,813	17.82%
07	Policy & Analysis	1,373,570	1	419,920	543,776	2,337,266	13.73%
12	Industry Finance & Admin. Programs	655,825		-	152,937	808,762	4.75%
01,10,11	General & Administrative Expense	4,044,336		-	(4,044,336)	-	0.00%
	Grand Total	17,812,311		$ 599,885	$ -	$ 18,412,196	108.17%

Adjustments as a result of AGA/NARUC Oversight Committee Staff agreement.

1 Allocation of salaries and other expenses to benefiting group.
2 Breakout of communications portion of division expenses
3 G&A allocated on basis of average equivalent full-time employees during 2003.

EXHIBIT A

Calculation of Lobbying Expenses Pursuant to
Internal Revenue Code Section 162(e)

The American Gas Association incurred lobbying expenses, as defined under IRC Section 162, of 2.10% of total member dues during calendar year 2003.

IRC Section 162 Definition of Lobbying

(e) Denial of deduction for certain lobbying and political expenditures
- (1) In general no deduction shall be allowed under subsection (a) for any amount paid or incurred in connection with -
  - (A) influencing legislation,
  - (B) participation in, or intervention in, any political campaign on behalf of (or in opposition to) any candidate for public office,
  - (C) any attempt to influence the general public, or segments thereof, with respect to elections, legislative matters, or referendums, or
  - (D) any direct communication with a covered executive branch official in an attempt to influence the official actions or positions of such official.
- (2) Exception for local legislation - In the case of any legislation of any local council or similar governing body -
  - (A) paragraph (1)(A) shall not apply, and
  - (B) the deduction allowed by subsection (a) shall include all ordinary and necessary expenses (including, but not limited to, traveling expenses described in subsection (a)(2) and the cost of preparing testimony) paid or incurred during the taxable year in carrying on any trade or business -
    - (i) in direct connection with appearances before, submission of statements to, or sending communications to the committees, or individual members, of such council or body with respect to legislation or proposed legislation of direct interest to the taxpayer, or
    - (ii) in direct connection with communication of information between the taxpayer and an organization of which the taxpayer is a member with respect to any such legislation or proposed legislation which is of direct interest to the taxpayer and to such organization, and that portion of the dues so paid or incurred with respect to any organization of which the taxpayer is a member which is attributable to the expenses of the activities described in clauses (i) and (ii) carried on by such organization.
- (3) Application to dues of tax-exempt organizations - No deduction shall be allowed under subsection (a) for the portion of dues or other similar amounts paid by the taxpayer to an organization which is exempt from tax under this subtitle which the organization notifies the taxpayer under section 6033(e)(1)(A)(ii) is allocable to expenditures to which paragraph (1) applies.
- (4) Influencing legislation - For purposes of this subsection -
  - (A) In general The term "influencing legislation" means any attempt to influence any legislation through communication with any member or employee of a legislative body, or with any government official or employee who may participate in the formulation of legislation.
  - (B) Legislation - The term "legislation" has the meaning given such term by section 4911(e)(2).
- (5) Other special rules
  - (A) Exception for certain taxpayers - In the case of any taxpayer engaged in the trade or business of conducting activities described in paragraph (1), paragraph (1) shall not apply to expenditures of the taxpayer in conducting such activities directly on behalf of another person (but shall apply to payments by such other person to the taxpayer for conducting such activities).
  - (B) De minimis exception
    - (i) In general Paragraph (1) shall not apply to any in-house expenditures for any taxable year if such expenditures do not exceed $2,000. In determining whether a taxpayer exceeds the $2,000 limit under this clause, there shall not be taken into account overhead costs otherwise allocable to activities described in paragraphs (1)(A) and (D).
    - (ii) In-house expenditures for purposes of clause (i), the term "in-house expenditures" means expenditures described in paragraphs (1)(A) and (D) other than
      - (I) payments by the taxpayer to a person engaged in the trade or business of conducting activities described in paragraph (1) for the conduct of such activities on behalf of the taxpayer, or
      - (II) dues or other similar amounts paid or incurred by the taxpayer which are allocable to activities described in paragraph (1).
  - (C) Expenses incurred in connection with lobbying and political activities - Any amount paid or incurred for research for, or preparation, planning, or coordination of, any activity described in paragraph (1) shall be treated as paid or incurred in connection with such activity.
- (6) Covered executive branch official - For purposes of this subsection, the term "covered executive branch official" means -
  - (A) the President,
  - (B) the Vice President,
  - (C) any officer or employee of the White House Office of the Executive Office of the President, and the 2 most senior level officers of each of the other agencies in such Executive Office, and
  - (D) (i) any individual serving in a position in level I of the Executive Schedule under section 5312 of title 5, United States Code, (ii) any other individual designated by the President as having Cabinet level status, and (iii) any immediate deputy of an individual described in clause (i) or (ii).
- (7) Special rule for Indian tribal governments - For purposes of this subsection, an Indian tribal government shall be treated in the same manner as a local council or similar governing body.
- (8) Cross reference - For reporting requirements and alternative taxes related to this subsection, see section 6033(e).

Citation: IRC Sec. 6033(e)

UNS GAS, INC.

DOCKET NO. G-04204A-06-0463 et al.

SURREBUTTAL TESTIMONY

OF

RODNEY L. MOORE

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

APRIL 4, 2007

EXHIBIT
RUCO4
admitted

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INTRODUCTION

Q. Please state your name for the record.

A. My name is Rodney Lane Moore.

Q. Have you previously filed testimony regarding this docket?

A. Yes, I have. I filed direct testimony in this docket on February 9, 2007.

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony will address the Company's rebuttal comments pertaining to adjustments I sponsored in my direct testimony.

SUMMARY OF ADJUSTMENTS

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

A. My surrebuttal testimony will address the following RUCO proposed adjustments:

Rate Base:

Adjustment No. 1 – Pre-Acquisition Plant And Accumulated Depreciation

Adjustment No. 2 – Test-Year Accumulated Depreciation

Operating Income:

Adjustment No. 2 – Incentive Compensation

Adjustment No. 3 – Test-Year Depreciation Expense

Adjustment No. 4 – Postage Expense

Adjustment No. 5 – Customer Service Cost Allocation

Adjustment No. 6 – Unnecessary Expenses

Adjustment No. 7 – Property Tax Computation

Adjustment No. 8 – Rate Case Expense

Adjustment No. 10 – Non-Recurring/Atypical Expenses

Adjustment No. 11 - SERP

Adjustment No. 22 – Income Tax Calculation

To support the adjustments in my surrebuttal testimony, I have revised specific direct testimony Schedules and prepared Surrebuttal Schedules numbered SURR RLM-1, SURR RLM-2, SURR RLM-3, SURR RLM-6, SURR RLM-7, SURR RLM-9, and SURR RLM-14 through SURR RLM-17, which are filed concurrently in my surrebuttal testimony.

These Schedules quantify the adjustments recommended in RUCO's surrebuttal testimonies and consist of revisions to:

1. Allowance For Working Capital to reflect changes in the operating expenses associated with the surrebuttal adjustments;
2. Postage Expense to reflect computations based on the Company's rebuttal testimony;
3. Legal Expenses to reflect calculation error identified by the Company;
4. Income Tax Expense to reflect changes in the operating expenses associated with the surrebuttal adjustments;
5. Rate Design, Proof of Recommended Revenue and Typical Bill Analysis to reflect changes in the operating expenses associated with the surrebuttal adjustments; and

6. Cost of Capital to reflect current market conditions.

RATE BASE

<u>RUCO Rate Base Adjustment No. 1 – Remove Unsubstantiated Pre-Acquisition Gross Plant and Adjust Understated Accumulated Depreciation</u>

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to remove unsubstantiated pre-acquisition gross plant and adjust understated accumulated depreciation?

A. No. RUCO has empathy for the Company's dilemma to provide adequate documentation to substantiate all the perceived plant assets theoretically incorporated as an integral component of the acquisition price. Any of the remaining records from Citizens' are notoriously inadequate for a determination of the actual value of the pre-acquisition gross plant and accumulated depreciation. It is commonly accepted by those who have attempted (in past proceedings and in the instant case) to establish an accurate rate base for ratemaking purposes from Citizens' records that these records are inaccurate. Therefore, RUCO was supportive of the Company's predicament and accepted Citizens' gas assets identified by UNS. However, RUCO believes since the Company is requesting recognition of an adjusted rate base that UNS still has the burden of proof to provide reasonable documentation to substantiate the value of these adjustments to rate base. It is contrary to established rate making principles, detrimental to ratepayers, and normally not approved by the Commission to automatically assume that where there is a lack of adequate records to substantiate plant additions, the inclusion of these unsubstantiated plant assets are routinely accepted into rate base. RUCO believes it is disingenuous of the Company to request UNS's adjusted level of the prior test-year rate base receive ACC approval even though there is a lack of evidence all these plant assets exist.

Q. Does the fact UNS fulfilled the FERC accounting requirements associated with the acquisition of Citizens' assets change RUCO's position on this adjustment to remove unsubstantiated pre-acquisition gross plant and adjust understated accumulated depreciation?

A. No. The Company's "clean" audit simply represents the accurate recording of the value of the gross plant in service was $248,032,644 as of August 11, 2003 (UNS' acquisition date), which is the level of gross plant UNS believes it purchased from Citizens and also the same amount requested as a component of the rate base in the instant case. However, for rate making purposes the Commission stipulated in the Settlement Agreement of the prior rate case the value of the test-year gross plant in service was $219,383,559 as of December 31, 2001. The difference between the value of the Commission approved test-year gross plant in the prior rate case and the Company's requested amount in the instant case is $28,649,085. Both RUCO and the Company are in agreement with this value. Regardless of the FERC approval of the Company's appropriate recording of this plant balance, UNS was unable to provide any documentation for the existence of plant assets worth $3,133,264 of the $28,649,085 requested. Therefore, as clearly outlined in my direct testimony RUCO removed $3,133,264 in gross plant and correspondingly increased the level of accumulated depreciation by $3,857,413 for a total reduction in the rate base of $6,990,677.

<u>RUCO Rate Base Adjustment No. 2 – Reduce Test-Year Accumulated Depreciation</u>

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to the test-year accumulated depreciation?

A. No. The Company continues to maintain in its rebuttal testimony that the depreciation rates that were proposed in Docket No. G-1032A-02-0598 are Commission authorized depreciation rates.

Q. Did Decision No. 66028 authorize a change in depreciation rates for UNS Gas?

A. No. Please refer to RUCO witness Ms. Marylee Diaz Cortez surrebuttal testimony's discussion of Citizens Acquisition Adjustment in which RUCO clearly explains the Commission did not approve the depreciation rates proposed in Docket No. G-1032A-02-0598.

Accordingly, my proposed adjustment to the test-year accumulated depreciation is correct and appropriate.

OPERATING INCOME

Operating Income Adjustment No. 2 – Incentive Compensation

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment on incentive compensation?

A. No, for the same reasons as outlined in my direct testimony, the Company has failed to justify why the ratepayers should be burdened with the additional costs of an incentive program that provides no direct ratepayer benefit.

RUCO's reasons for denying the pass through to the ratepayers of the costs associated with the 2005 Special Recognition Award are:

1. Despite the considerable effort the Company takes in rebuttal to explain the ultimate benefits of its Performance Enhancement Plan ("PEP"), in reality Unisource Energy did not meet its 2005 financial performance goal and therefore the PEP program was not initiated in the test year;
2. RUCO is very reluctant to abandon the Historical Test-Year principle that avoids mismatches in the ratemaking elements. Therefore, RUCO dismisses the Company's proposal to average the 2005 Special Recognition Award and the 2004 PEP program;

3. The Company promotes the PEP program as a valuable management tool to promote additional cost savings and motivate individual employees and encourage groups of employees to work together to impact specific goals. However, over 60 percent of the workforce do not even participate in this program; and

4. The Company also touts the PEP program as an employee program that reduces costs, promotes safety, increases customer service and increases the financial soundness of the Company. However, even if these efforts had been successful enough in 2005 to trigger the PEP program, 60 percent of employees sufficiently motivated to impact the actualization of these corporate goals received no compensation from the PEP program or any other arbitrary special award.

If the Company is reasonably confident it can attain its financial performance goal, operational cost containment target and customer service objectives despite the fact that the incentive compensation program incents less than half the workforce, the necessity to embed such expenditures in rates is highly suspect.

Operating Income Adjustment No. 3 – Depreciation Expenses

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to test-year depreciation expenses?

A. No, the level of RUCO's recommended test-year depreciation expenses is directly related to RUCO's recommended value of test-year gross plant in service. RUCO's recommended value of test-year gross plant in service was discussed previously in Rate Base Adjustment No. 1.

Operating Income Adjustment No. 4 – Postage Expense

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to postage expenses?

A. Yes, after reviewing Company witness Mr. Dukes' rebuttal testimony, RUCO accepts the level of test-year book postage expense as $445,171, and has corrected its calculation to reflect this amount. However, RUCO maintains it strict adherence to the historical test-year principle and disagrees with the Company's proposed proforma adjustment, which averages the 2004 and 2005 postage expenses.

As shown on Schedule SURR-RLM-9, RUCO's revised calculation decreases adjusted test-year expenses by $51,851.

Operating Income Adjustment No. 5 – Customer Service Cost Allocations

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to the corporate allocated costs for the customer service call centers?

A. No. The Company takes considerable effort in rebuttal to explain the perceived improvements in customer service attributable to this 432 percent increase in the costs associated with the direct interaction with its customers. However in reality, there is compelling evidence that the customer-base has become very dissatisfied with the Company's transition to a consolidated call center. Therefore, RUCO maintains that with such an increase in the level of customer frustration related to Unisource Energy's decision to integrate similar job functions among its affiliates, the UNS ratepayers should not be burdened with this imprudent expenditure until such time as statistical information proves the costs provide a beneficial impact to UNS ratepayers.

The increased level of customer dissatisfaction directly related to the consolidation of the TEP call centers is clearly evident in complaints filed at the Commission's Consumer Services Section and through customer contacts with the Arizona Community Action Association ("ACAA") as stated in the direct testimony of the ACAA witness Ms. Miquelle Scheier.

Through discussion I discovered the Commission's Customer Services Section recorded an escalation in consumer complaints directly attributable to the consolidation of UNS customer services. Prior to consolidation, in 2004 the Commission received 24 "quality of customer service" complaints out of a total of 178 complaints filed against UNS, or 13 percent. In 2005, when the consolidation was initiated, "quality of customer service" complaints jumped to 65 out of a total of 263 complaints filed against UNS, or 25 percent.

Continuing in 2006, the level of "quality of customer service" complaints filed remains high: 68 out of a total of 273 complaints filed against UNS, or 25 percent.

As referenced in ACAA testimony, the Company issued a pamphlet to justify the consolidation of the call centers and the corresponding closing of branch offices under the pretense of the Company's need to realize cost savings. It is very difficult to rationalize the reduction in customer service levels by embedding nearly a million-dollars in rates under the guise of cost savings.

<u>Operating Income Adjustment No. 6 – Disallowance of Inappropriate and/or Unnecessary Expenses</u>

Q. Has the Company accepted your adjustment to miscellaneous expenses?

A. No. The Company takes considerable effort in rebuttal to establish a warm and fuzzy feeling to guarantee that all test-year operating expenditures identified by RUCO "are reviewed by immediate supervisors and numerous controls are in place to ensure they are valid charges" and/or "the expenses referred to were incurred while performing regulatory-mandated functions". However, in reality the Company completely ignores the substance of RUCO's adjustment. Aggregately, the Company inappropriately padded the historical test-year expenses with unnecessary purchases worth over $200,000.

RUCO maintains certain categories of expenses should not be the financial burden of the ratepayers. For example:

1. Liquor, Coffee, Water, Bagels, Donuts, Subs, etc.
2. Flowers, Gift Certificates, Photographs, etc.
3. Charitable/Community/Service Club Donations, etc.
4. Recognition Events, Sports Events, Club Memberships, etc.
5. Numerous purchases at Circle K, Walgreen, Wal-Mart, Basha's, Fry's, Safeway, etc.

Nevertheless, the Company continues to maintain these items are appropriately charged to ratepayers.

In consideration of the Company's request for "RUCO to set a realistic materiality" to this adjustment, RUCO still questions the Company's avoidance to address several major expenses identified in my direct testimony.

For instance, the Company fails to acknowledge and/or explain the reasonableness and necessity of:

1. $1,200.00 for two people to play in Flagstaff's 8th Annual Golf Tournament;
2. $5,750.00 for an employee appreciation dinner in Prescott;
3. $1,000.00 for Toys for Tots;
4. $3,058.00 to the Flagstaff Chamber of Commerce, and
5. $1,246 for a chartered air flight.

The Company makes no attempt to mitigate this adjustment except to have the entire amount disregarded because "UNS Gas has established practices, policies, procedures and internal controls in place to assure that expenses recorded in the identified FERC accounts are materially correct, prudent and properly classified". The Company has made no concession that maybe an errant invoice here or there slipped past its internal controls nor has it discussed a meaningful adjustment. The burden of proof is on the Company to substantiate the appropriateness of the journal entries identified. The Company's mere avowal that the expenditures are prudent and necessary to provide gas service is not sufficient to satisfy that burden.

Operating Income Adjustment No. 7 – Property Tax

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to test-year property tax expenses?

A. No, the level of RUCO's recommended test-year property tax expenses is directly related to RUCO's recommended value of test-year gross plant in service and the revised Arizona Department of Revenue's ("ADOR") assessment ratio. RUCO's recommended value of test-year gross plant in service was discussed previously in Rate Base Adjustment No. 1. The ADOR assessment ratio recommended by RUCO is the effective rate through December 31, 2007 of 24 percent. Since the assessment ratio will continue to decline by one-half percent each year until it reaches 20 percent on December 31, 2014 this is the appropriate ratio to reflect a fair and reasonable level of property tax expense based on the rate making elements authorized in this case.

Operating Income Adjustment No. 8 – Rate Case Expense

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to rate case expenses?

A. No. The Company is suggesting the rate case expenses may reach nearly a million dollars. UNS is now requesting to amortize rate case expenses of $900,000. This is an unreasonable level of rate case expense, given that the entire requested rate increase is $9.6 million. Nearly ten percent of the requested increase is attributable to rate case expense.

The Commission did consider the reasonableness of rate case expenses in a recent Arizona-American rate case by stating in Decision No. 67093, dated June 30, 2004 on page 20 starting on line 14:

> "In addition, we agree with RUCO that the Company chose the test year for the application, and we believe that ratepayers should not be made to bear the burden of the Company's choices to incur unreasonable increases in expenses."

It is RUCO's position that the Company's request to burden the ratepayers with $900,000 in rate case expense is unreasonable and therefore RUCO is not revising this adjustment.

Operating Income Adjustment No. 10 – Non-Recurring/Atypical Expenses

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to non-recurring/atypical expenses?

A. No, I am confused by the Company witness Mr. Smith's rebuttal testimony. Specifically, Mr. Smith's response or actual lack of response to this adjustment does not reflect information conveyed during a telephone conversion we had during the discovery process. Mr. Smith and I discussed line by line the general ledger details provided by the Company in response to RUCO's data request 4.01 designated as "Procard Details – Data Request RUCO 4.01", pages 1 through 4. During that conversation I expressly asked for clarification of the entries noted as "M.A.R.C. Training (Union Training)". Mr. Smith indicated this training was a one-time only instructional session to acquaint Company personnel with working in a unionized environment. Based on that conversation with Mr. Smith, I selectively excluded only expenses denoted "M.A.R.C. Training (Union Training)" from data provided. Therefore, I continue to recommend disallowance, as this is not a recurring or typical test-year expense and is not appropriate for inclusion as a rate case operating expense.

<u>Operating Income Adjustment No. 11 – Supplemental Executive Retirement Plan</u>

Q. After analyzing the Company's rebuttal testimony, is RUCO revising its adjustment to the Supplemental Executive Retirement Plan ("SERP")?

A. No, RUCO's position is unchanged – the ratepayers should not be responsible to pay the cost of supplemental benefits to a small select group of high-ranking officers of the Company. However, RUCO did allow the cost of Company's officers' Deferred Compensation Plan ("DCP") to be included in test-year expenses.

The ratepayers are already burdened with the cost of adequately compensating this small select group of high-ranking officers for their work and who are provided with a wide array of benefits including a medical plan, dental plan, vision coverage, employee life insurance, supplemental life insurance, dependent life insurance, accidental death and dismemberment, business travel accident insurance, personal accident insurance, short and long term disability, health and dependent care spending accounts, pension, 401(k), incentive pay, vacation pay, holiday pay and sick time. If the Company feels it is necessary to provide additional perks to a select group of employees it should do so at its own expense.

It seems disingenuous in the present climate of spiraling utility costs to request that the ratepayers be burdened with the cost of this elite retirement plan for a select group of employees who are already receiving lucrative salaries and benefits.

Operating Income Adjustment No. 22 – Income Tax Expense

Q. Please explain RUCO's adjustment to the income tax expense.

A. This adjustment reflects income tax expenses calculated on RUCO's surrebuttal recommended revenues and expenses.

RATE DESIGN AND PROOF OF RECOMMENDED REVENUE

Q. Have you revised your direct testimony Schedule to present proof of your revised surrebuttal recommended revenue?

A. Yes, I have. Proof that RUCO's direct testimony recommended rate designs would produce the revised surrebuttal recommended required revenue as illustrated, is presented on Schedule SURR RLM-15.

TYPICAL BILL ANALYSIS

Q. Have you revised your direct testimony Schedule to present a typical bill analysis based on your surrebuttal recommended revenue?

A. Yes, I have. A revised typical bill analysis for metered residential customers with various levels of usage is presented on Schedule SURR RLM-16.

COST OF CAPITAL

Q. Is RUCO revising its adjustments to the Company proposed cost of capital?

A. Yes, it is. As shown on Schedule SURR RLM-17, this revised adjustment increases RUCO's direct testimony weighted cost of capital by 28 basis points, which is still 58 basis points below the Company's requested weighted cost of capital. This revised adjustment is fully explained in the surrebuttal testimony of RUCO witness Mr. Rigsby.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

UNS Gas Corporation
Docket No. G-04204A-06-0463
Test Year Ended December 31, 2005

SURREBUTTAL
TABLE OF CONTENTS TO RUCO REVISED SCHEDULES

UNS Gas Corporation
Docket No. G-04204A-06-0463
Test Year Ended December 31, 2005

SURREBUTTAL
REVENUE REQUIREMENT

		(A)	(B)	(C)	(D)	(E)	(F)
		COMPANY AS FILED			RUCO REVISED SURREBUTTAL		
LINE NO.	DESCRIPTION	ORIGINAL COST	RCND	FAIR VALUE	ORIGINAL COST	RCND	FAIR VALUE
1	Adjusted Rate Base	$ 161,661,362	$ 220,694,068	$ 191,177,714	$ 144,646,160	$ 197,732,117	$ 171,189,139
2	Adjusted Operating Income (Loss)	$ 8,428,981	$ 8,428,981	$ 8,428,981	$ 10,219,499	$ 10,219,499	$ 10,219,499
3	Current Rate Of Return (Line 2 / Line 1)	5.21%	3.82%	4.41%	7.07%	5.17%	5.97%
4	Required Operating Income (Line 5 X Line 1)	$ 14,223,179	$ 14,223,179	$ 14,204,479	$ 11,889,914	$ 11,889,914	$ 11,889,914
5	Required Rate Of Return	8.80%	6.44%	7.43%	8.22%	6.01%	6.95%
6	Operating Income Deficiency (Line 4 - Line 2)	$ 5,794,198	$ 5,794,198	$ 5,775,498	$ 1,670,416		$ 1,670,416
7	Gross Revenue Conversion Factor (Schedule RLM-1, Page 3)	1.6649	1.6649	1.6649			1.6370
8	Increase In Gross Revenue Requirement (Line 7 X Line 6)	$ 9,646,901	$ 9,646,901	$ 9,615,767			$ 2,734,443
9	Adjusted Test Year Revenue			$ 47,169,528			$ 47,280,434
10	Proposed Annual Revenue Requirement (Line 8 + Line 9)			$ 56,785,295			$ 50,014,877
11	Required Percentage Increase In Revenue (Line 8 / Line 9)			20.39%			5.78%
12	Rate Of Return On Common Equity			11.39%			9.84%

References:
- Columns (A) Thru (C): Company Schedule A-1, C-1 And D-1
- Column (D): Schedules RLM-2, RLM-3, RLM-6 And RLM-17
- Column (E): Schedule RLM-2
- Column (F): Average Of Column (D) + Column (E)

UNS Gas Corporation
Docket No. G-04204A-06-0463
Test Year Ended December 31, 2005

SURREBUTTAL
FAIR VALUE RATE BASE - OCRB / RCND (50/50 SPLIT)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)
		COMPANY AS FILED			OCRB/RCND	RUCO REVISED SURREBUTTAL		
LINE NO.	DESCRIPTION	OCRB	RCND	FVRB	% DIFF.	OCRB	RCND	FVRB
1	Gross Utility Plant In Service	$ 279,169,694	$ 374,243,421	$ 326,706,558	134.06%	$ 268,847,200	$ 360,405,510	$ 314,626,355
2	Accumulated Depreciation	(72,006,708)	(97,114,865)	(84,560,787)	134.87%	(78,719,575)	(106,168,455)	(92,444,015)
3	Net Utility Plant In Service	$ 207,162,986	$ 277,128,556	$ 242,145,771		$ 190,127,625	$ 254,237,055	$ 222,182,340
4	Citizens Acquisition Discount	$ (30,709,738)	$ (41,822,562)	$ (36,266,150)	136.19%	$ (30,709,738)	$ (41,822,562)	$ (36,266,150)
5	Accumulated Amortization	1,876,981	2,560,308	2,218,645	136.41%	1,628,094	2,220,812	1,924,453
6	Net Citizens Acq. Disc.	$ (28,832,757)	$ (39,262,254)	$ (34,047,506)		$ (29,081,644)	$ (39,601,750)	$ (34,341,697)
7	Total Net Utility Plant	$ 178,330,229	$ 237,866,302	$ 208,098,266		$ 161,045,981	$ 214,635,305	$ 187,840,643
	Deductions:							
8	Cust. Advances For Const.	$ (7,283,595)	$ (7,786,962)	$ (7,535,279)	106.91%	$ (7,283,595)	$ (7,786,962)	$ (7,535,279)
9	Customer Deposits	(3,040,484)	(3,040,484)	(3,040,484)	100.00%	(3,040,484)	(3,040,484)	(3,040,484)
10	Acc. Deferred Income Taxes	(6,484,809)	(6,484,809)	(6,484,809)	100.00%	(6,484,809)	(6,484,809)	(6,484,809)
11	Total Deductions	$ (16,808,888)	$ (17,312,255)	$ (17,060,572)		$ (16,808,888)	$ (17,312,255)	$ (17,060,572)
12	Allowance - Working Capital	$ (1,045,146)	$ (1,045,146)	$ (1,045,146)	100.00%	$ 120,969	$ 120,969	$ 120,969
13	Regulatory Assets	$ 1,204,887	$ 1,204,887	$ 1,204,887	100.00%	$ 307,819	$ 307,819	$ 307,819
14	Regulatory Liability	$ (19,721)	$ (19,721)	$ (19,721)	100.00%	$ (19,721)	$ (19,721)	$ (19,721)
15	TOTAL TEST YEAR RATE BASE	$ 161,661,361	$ 220,694,067	$ 191,177,714		$ 144,646,160	$ 197,732,117	$ 171,189,139

References:
- Columns (A) (B) (C): Company Schedule B-1
- Column (D): Column (B) / Column (A)
- Column (E): Schedule RLM-3, Column (H)
- Column (F): Column (D) X Column (E)
- Column (G): Average Of Column (E) + Column (F)

UNS Gas Corporation
Docket No. G-04204A-06-0463
Test Year Ended December 31, 2005

SURREBUTTAL
SUMMARY OF ORIGINAL COST RATE BASE

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB	(B) RUCO ADJUSTMENT NO. 1	(C) RUCO ADJUSTMENT NO. 2	(D) RUCO ADJUSTMENT NO. 3	(E) RUCO ADJUSTMENT NO. 4	(F) RUCO ADJUSTMENT NO. 5	(G) RUCO ADJUSTMENT NO. 6	(H) RUCO ADJUSTED OCRB
1	Gross Utility Plant In Service	$ 279,169,694	$ (3,133,264)	$ -	$ -	$ (7,189,230)	$ -	$ -	$ 268,847,200
2	Accumulated Depreciation	(72,006,708)	(3,857,413)	(2,855,454)	-	-	-	-	(78,719,575)
3	Net Utility Plant In Service	$ 207,162,986	$ (6,990,677)	$ (2,855,454)	$ -	$ (7,189,230)	$ -	$ -	$ 190,127,625
4	Citizens Acquisition Discount	$ (30,709,738)	$ -	$ -	$ -	$ -	$ -	$ -	$ (30,709,738)
5	Accumulated Amortization	1,876,981	-	-	(248,887)	-	-	-	1,628,094
6	Net Citizens Acq. Disc.	$ (28,832,757)	$ -	$ -	$ (248,887)	$ -	$ -	$ -	$ (29,081,644)
7	Total Net Utility Plant	$ 178,330,229	$ (6,990,677)	$ (2,855,454)	$ (248,887)	$ (7,189,230)	$ -	$ -	$ 161,045,981
	Deductions:								
8	Cust. Advances For Const.	$ (7,283,595)	$ -	$ -	$ -	$ -	$ -	$ -	$ (7,283,595)
9	Customer Deposits	(3,040,484)	-	-	-	-	-	-	(3,040,484)
10	Acc. Deferred Income Taxes	(6,484,809)	-	-	-	-	-	-	(6,484,809)
11	Total Deductions	$ (16,808,888)	$ -	$ -	$ -	$ -	$ -	$ -	$ (16,808,888)
12	Allowance - Working Capital	$ (1,045,146)	$ -	$ -	$ -	$ -	$ -	$ 1,166,115	$ 120,969
13	Regulatory Assets	$ 1,204,887	$ -	$ -	$ -	$ -	$ (897,068)	$ -	$ 307,819
14	Regulatory Liability	$ (19,721)	$ -	$ -	$ -	$ -	$ -	$ -	$ (19,721)
15	TOTAL OCRB	$ 161,661,361	$ (6,990,677)	$ (2,855,454)	$ (248,887)	$ (7,189,230)	$ (897,068)	$ 1,166,115	$ 144,646,160

References:
Column (A): - Company Schedule B-2
Column (B): - Adjustment No. 1 · RUCO Adjustment To Pre-Acquisition Gross Plant And Accumulated Depreciation (See RLM-4, Page 3, Lines 38 & 39)
Column (C): - Adjustment No. 2 RUCO Adjustment To Test-Year Accumulated Depreciation (See RLM-4, Page 5, Line 40)
Column (D): - Adjustment No. 3 RUCO Adjustment To Restate Accumulated Amortization On Citizens Acquisition. (See MDC-1)
Column (E): - Adjustment No. 4 · RUCO Adjustment To Remove CWIP From Test-Year Rate Base (See Testimony, MDC And RLM-5, Line 39)
Column (F): - Adjustment No. 5 · RUCO Adjustment To The Geographical Information System (See Testimony, MDC)
Column (G): - Adjustment No. 6 Allowance For Working Capital (See MDC-2)
Column (H): - Sum Of Columns (A) Through (G)

UNS GAS CORPORATION
TEST YEAR ENDED DECEMBER 31, 2005
REVISED RATE BASE ADJUSTMENT # 6 - WORKING CAPITAL

SURREBUTTAL

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
1	MATERIALS & SUPPLIES PER UNS	$2,039,798	SCH. B-5, PG. 1
2	MATERIALS & SUPPLIES PER RUCO	2,039,798	SCH. B-5, PG. 1
3	ADJUSTMENT	0	LINE 2 - LINE 1
4	PREPAYMENTS PER UNS	195,942	SCH. B-5, PG. 1
5	PREPAYMENTS PER RUCO	195,942	SCH. B-5, PG. 1
6	ADJUSTMENT	0	LINE 5 - LINE 4
7	CASH WORKING CAPITAL PER UNS	(3,280,886)	SCH. B-5, PG. 2
8	CASH WORKING CAPITAL PER RUCO	(2,114,771)	SCHEDULE MDC-
9	ADJUSTMENT	1,166,115	LINE 8 - LINE 7
10	TOTAL ADJUSTMENT (See RLM-3, Column (G))	$1,166,115	SUM LINES 3, 6 & 9

UNS GAS CORPORATION
TEST YEAR ENDED DECEMBER 31, 2005
REVISED RATE BASE ADJUSTMENT # 6 - WORKING CAPITAL

DOCKET NO. G-004204A-06-0463
SCHEDULE SURR MDC-2

SURREBUTTAL
LEAD/LAG DAY SUMMARY

LINE NO.	DESCRIPTION	(A) COMPANY EXPENSES AS FILED	(B) RUCO ADJUSTM'TS	(C) RUCO EXPENSES AS ADJUSTED	(D) (LEAD)/LAG DAYS	(E) DOLLAR DAYS
	Operating Expenses:					
	Non-Cash Expenses					
1	Bad Debts Expense	$ 722,634	$ -	$ -	0	$ -
2	Depreciation	7,950,183	-	-	0	-
3	Amortization	(729,791)	-	-	0	-
4	Deferred Income Taxes	3,178,719	-	-	0	-
5	Total Non-Cash Expenses	$ 11,121,745	$ -	$ -		$ -
	Other Operating Expenses:					
6	Salaries & Wages (UNS Dir.Emp's)	$ 7,287,745	$ -	$ 7,287,745	24.50	$ 178,549,753
7	Incentive Pay (UNS Dir. Emp's)	257,895	(257,895)	-	267.00	-
8	Purchased Gas	78,101,248	-	78,101,248	30.97	2,418,795,651
9	Office Supplies and Expenses	1,365,974	(54,434)	1,311,540	20.72	27,175,105
10	Injuries and Damages	574,128	(34,234)	539,894	64.75	34,958,114
11	Pensions and Benefits	2,452,071	(93,075)	2,358,996	54.66	128,942,703
12	Support Services - TEP(Dir. Labor)	4,570,692	-	4,570,692	44.91	205,269,778
13	Property Taxes	4,103,376	(476,193)	3,627,183	213.00	772,590,038
14	Payroll Taxes	537,877	(20,853)	517,024	19.30	9,978,563
15	Current Income Taxes	(1,203,222)	5,690,904	4,487,682	41.42	185,879,804
16	Interest on Customer Deposits	170,459	-	170,459	182.50	31,108,848
17	Other Operations and Maintenance	7,501,807	(1,023,893)	6,477,914	53.10	343,977,225
18	Total Other Operating Expenses	$105,720,050	$ 3,730,327	$109,450,377		$ 4,337,225,581
19	Total Operating Expenses	$116,841,794	$ 3,730,327	$109,450,377		$ 4,337,225,581
	Other Cash Working Capital Elements:					
20	Interest on Long-Term Debt	$ 5,334,825	$ (561,502)	$ 4,773,323	91.62	$ 437,331,879
21	Revenue Taxes and Assessments	18,788,535	(6,822,129)	11,966,406	76.25	912,438,458
22	Total Other Cash Working Capital	$ 24,123,360	$ (7,383,631)	$ 16,739,729		$ 1,349,770,337
23	TOTAL			$126,190,106		$ 5,686,995,918

24	Expense Lag	Line 23, Col. (E) / (D)	45.07
25	Revenue Lag	Company Workpapers	38.95
26	Net Lag	Line 25 - Line 24	(6.12)
27	RUCO Adjusted Expenses	Col. (C), Line 23	$126,190,106
28	Cash Working Capital	Line 26 X Line27 / 365 Days	(2,114,771)
29	Company As Filed	Co. Schedule B-5, Page 1	(3,280,886)
30	ADJUSTMENT (See MDC-2, Pg 1, L 9)	Line 28 - Line 29	1,166,115

References:
Column (A): - Company Schedule B-5, Page 3
Column (B): RUCO Operating Income Adjustments (See Schedule RLM-7)
Column (C): Column (B) - (A)
Column (D): Company Schedule B-5, Page 3
Column (E): Column (C) X Column (D)

UNS Gas Corporation
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SURREBUTTAL
OPERATING INCOME

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO REVISED SURREBUTTAL TEST YEAR ADJ'TMENTS	(C) TEST YEAR AS ADJUSTED	(D) PROPOSED CHANGES	(E) AS RECOMMENDED
	Operating Revenues:					
1	Gas Retail Revenues	$ 45,689,224	$ 110,906	$ 45,800,130	$ 2,734,443	$ 48,534,573
2	Other Operating Revenue	1,480,304	-	1,480,304	-	1,480,304
3	TOTAL OPERATING REVENUES	$ 47,169,528	$ 110,906	$ 47,280,434	$ 2,734,443	$ 50,014,877
	Operating Expenses:					
4	Purchased Gas	$ 355,528	$ (54)	$ 355,474	$ -	$ 355,474
5	Other O & M Expense	24,459,038	(1,955,752)	22,503,286	-	22,503,286
6	Depreciation & Amortization	7,220,391	(646,479)	6,573,912	-	6,573,912
7	Taxes Other Than Income Taxes	4,730,093	(525,485)	4,204,608	-	4,204,608
8	Income Taxes	1,975,497	1,448,158	3,423,655	1,064,027	4,487,682
9	TOTAL OPERATING EXPENSES	$ 38,740,547	$ (1,679,612)	$ 37,060,935	$ 1,064,027	$ 38,124,962
10	OPERATING INCOME (LOSS)	$ 8,428,981		$ 10,219,499		$ 11,889,914

References:
Column (A): Company Schedule C-1
Column (B): Testimony, RLM And Schedule RLM-7, Pages 1 Thru 6
Column (C): Column (A) + Column (B)
Column (D): Testimony, RLM And Schedule RLM-1
Column (E): Column (C) + Column (D)

UNS Gas Corporation
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Test Year Ended December 31, 2005

SURREBUTTAL
SUMMARY OF OPERATING INCOME ADJUSTMENT
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJ. NO. 1 WORKERS COMP.	(C) ADJ. NO. 2 INCENTIVE COMP.	(D) ADJ. NO. 3 DEPRECIATION EXPENSE	(E) ADJ. NO. 4 POSTAGE EXPENSE	(F) ADJ. NO. 5 CUSTOMER SERVICE COSTS	(G) ADJ. NO. 6 UNNECESSARY EXPENSES	(H) ADJ. NO. 7 PROPERTY TAX
	Operating Revenue					**REVISED**			
1	Net Sales to Ultimate Customers	$ 42,950,315	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Transportation of Gas	2,738,909	-	-	-	-	-	-	-
3	**Gas Retail Revenue**	**$ 45,689,224**	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	Forfeited Discounts (Late Fees)	$ 398,966	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Miscellaneous Service Revenues	1,046,891	-	-	-	-	-	-	-
6	Other Gas Revenues	34,447	-	-	-	-	-	-	-
7	**Other Operating Revenue**	**$ 1,480,304**	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	**Total Operating Revenue**	**$ 47,169,528**	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Expense								
9	**Purchased Gas**	**$ 355,528**	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Transmision - Mains Expense	$ 11,280	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Transmision - Meas. and Reg. Station	(52,221)	-	-	-	-	-	-	-
12	Transmision - Maint. Compressor Stat. Equip.	19	-	-	-	-	-	-	-
13	Transmision - Oper. Super'n and Eng.	315,983	-	-	-	-	-	-	-
14	Distribution - Load Dispatching	162	-	-	-	-	-	-	-
15	Distribution - Mains and Services	1,337,349	-	(42,144)	-	-	-	(1,592)	-
16	Distribution - Meas. and Reg. Station - Gen.	244,463	-	-	-	-	-	-	-
17	Distribution - Meas. and Reg. Station - Ind.	150,536	-	-	-	-	-	-	-
18	Distribution - Meas. and Reg. Station - City	56,529	-	-	-	-	-	-	-
19	Distribution - Meter and House Regulator	1,349,114	-	(34,242)	-	-	-	-	-
20	Distribution - Customer Installations	539,082	-	-	-	-	-	-	-
21	Distribution - Other Expenses	1,090,666	-	-	-	-	-	(27,217)	-
22	Distribution - Rents	44,510	-	-	-	-	-	-	-
23	Distribution - Maint. Superv'n & Eng.	243,170	-	-	-	-	-	-	-
24	Distribution - Maintenance of Mains	1,084,194	-	(26,340)	-	-	-	-	-
25	Distribution - Maint. M & R Stat. Equip. - Gen.	25,623	-	-	-	-	-	-	-
26	Distribution - Maint. M & R Stat. Equip. - Ind.	2,072	-	-	-	-	-	-	-
27	Distribution - Maint. M & R Equip. - City Gate	850	-	-	-	-	-	-	-
28	Distribution - Maintenance of Services	465,066	-	-	-	-	-	-	-
29	Distribution - Maint. of Meters and Reg.	167,015	-	-	-	-	-	-	-
30	Distribution - Maintenance of Other Equip.	96,826	-	-	-	-	-	-	-
31	Customer Account - Supervision	74,309	-	-	-	-	-	-	-
32	Customer Account - Meter Reading	719,037	-	-	-	-	-	-	-
33	Customer Account - Records and Collection	5,462,173	-	(60,582)	-	(51,851)	(490,413)	-	-
34	Customer Account - Uncollectibles	722,634	-	-	-	-	-	-	-

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SURREBUTTAL
SUMMARY OF OPERATING INCOME ADJUSTMENT - CONT'D
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJ. NO. 1 WORKERS COMP.	(C) ADJ. NO. 2 INCENTIVE COMP.	(D) ADJ. NO. 3 DEPRECIATION EXPENSE	(E) ADJ. NO. 4 POSTAGE EXPENSE	(F) ADJ. NO. 5 CUSTOMER SERVICE COSTS	(G) ADJ. NO. 6 UNNECESSARY EXPENSES	(H) ADJ. NO. 7 PROPERTY TAX
	Continued								
35	Customer Account - Miscellaneous	$ 34,381	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36	Customer Account - Superv'n - Cust. Service	14,743	-	-	-	-	-	-	-
37	Customer Account - Assistance	(34,228)	-	-	-	-	-	-	-
38	Customer Account - Info and Instruct Advert.	65,794	-	-	-	-	-	-	-
39	Customer Account - Miscellaneous	22,602	-	-	-	-	-	-	-
40	Sales - Demonstrating and Selling	558	-	-	-	-	-	-	-
41	A & G - Salaries	1,529,696	-	(94,587)	-	-	(25,437)	-	-
42	A & G - Office Supplies and Expenses	1,365,974	-	-	-	-	(11,157)	(107,076)	-
43	A & G - Transferred - Credit	(152,817)	-	-	-	-	(133)	-	-
44	A & G - Outside Services Employed	2,696,531	-	-	-	-	(2,559)	(14,738)	-
45	A & G - Property Insurance	7,415	-	-	-	-	(1,329)	-	-
46	A & G - Injuries and Damages	574,128	(34,234)	-	-	-	(293)	-	-
47	A & G - Employee Pension and Benefits	2,452,071	-	-	-	-	(143,577)	(6,230)	-
48	A & G - Miscellaneous General Expenses	1,082,411	-	-	-	-	-	(76,494)	-
49	A & G - Rents	109,053	-	-	-	-	-	-	-
50	A & G - Maintenance of General Plant	169,826	-	-	-	-	-	-	-
51	A & G - Rate Case Expense	200,000	-	-	-	-	-	-	-
52	Interest On Customer Deposits	170,459	-	-	-	-	-	-	-
53	**Other Oper. and Maint. Expense**	$ 24,459,038	$ (34,234)	$ (257,895)	$ -	$ (51,851)	$ (674,898)	$ (233,347)	$ -
54	Dep. & Amort. - Citizens Acq. Discount	$ (729,791)	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55	Dep. & Amort. - Intangible Plant	929,602	-	-	(57,341)	-	-	-	-
56	Dep. & Amort. - Transmission Plant	285,187	-	-	(1,618)	-	-	-	-
57	Dep. & Amort. - Distribution Plant	5,631,142	-	-	(427,753)	-	-	-	-
58	Dep. & Amort. - General Plant	1,104,251	-	-	162,629	-	(23,373)	-	-
59	**Depreciation and Amortization**	$ 7,220,391	$ -	$ -	$ (324,083)	$ -	$ (23,373)	$ -	$ -
60	Property Tax	$ 4,103,375	$ -	$ -	$ -	$ -	$ (28,439)	$ -	$ (309,309)
61	Payroll Tax - FUTA, SUTA, FICA & Medicare	537,877	-	(20,853)	-	-	-	-	-
62	Medical and Dental	86,130	-	-	-	-	-	-	-
63	Other	2,711	-	-	-	-	-	-	-
64	**Taxes Other Than Income Taxes**	$ 4,730,093	$ -	$ (20,853)	$ -	$ -	$ (28,439)	$ -	$ (309,309)
65	**Income Taxes**	$ 1,975,497	$ -	$ -	$ -	$ -	$ -	$ -	$ -
66	**Total Operating Expense**	$ 38,740,547	$ (34,234)	$ (278,748)	$ (324,083)	$ (51,851)	$ (726,710)	$ (233,347)	$ (309,309)
67	**Operating Income**	$ 8,428,981	$ 34,234	$ 278,748	$ 324,083	$ 51,851	$ 726,710	$ 233,347	$ 309,309

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SURREBUTTAL
SUMMARY OF OPERATING INCOME ADJUSTMENT - CONT'D
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	DESCRIPTION	(I) ADJ. NO. 8 RATE CASE EXPENSE	(J) ADJ. NO. 9 AGA DUES	(K) ADJ. NO. 10 ATYPICAL EXPENSES	(L) ADJ. NO. 11 SERP	(M) ADJ. NO. 12 AMORTIZATION GIS O&M	(N) ADJ. NO. 13 FLEET FUEL EXPENSE	(O) ADJ. NO. 14 CUSTOMER ANNUALIZ'N	(P) ADJ. NO. 15 CUSTOMER WEATHERIZ'N
	Operating Revenue								
1	Net Sales to Ultimate Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ 110,006	$ 900
2	Transportation of Gas	-	-	-	-	-	-	-	-
3	**Gas Retail Revenue**	$ -	$ -	$ -	$ -	$ -	$ -	$ 110,006	$ 900
4	Forfeited Discounts (Late Fees)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Miscellaneous Service Revenues	-	-	-	-	-	-	-	-
6	Other Gas Revenues	-	-	-	-	-	-	-	-
7	**Other Operating Revenue**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	**Total Operating Revenue**	$ -	$ -	$ -	$ -	$ -	$ -	$ 110,006	$ 900
	Operating Expense								
9	**Purchased Gas**	$ -	$ -	$ -	$ -	$ -	$ (54)	$ -	$ -
10	Transmision - Mains Expense	$ -	$ -	$ -	$ -	$ -	$ (69)	$ -	$ -
11	Transmision - Meas. and Reg. Station	-	-	-	-	-	(1)	-	-
12	Transmision - Maint. Compressor Stat. Equip.	-	-	-	-	-	-	-	-
13	Transmision - Oper. Super'n and Eng.	-	-	-	-	-	(1,907)	-	-
14	Distribution - Load Dispatching	-	-	-	-	-	-	-	-
15	Distribution - Mains and Services	-	-	-	-	-	(5,801)	-	-
16	Distribution - Meas. and Reg. Station - Gen.	-	-	-	-	-	(1,095)	-	-
17	Distribution - Meas. and Reg. Station - Ind.	-	-	-	-	-	(834)	-	-
18	Distribution - Meas. and Reg. Station - City	-	-	-	-	-	(123)	-	-
19	Distribution - Meter and House Regulator	-	-	-	-	-	(6,218)	-	-
20	Distribution - Customer Installations	-	-	-	-	-	(2,502)	-	-
21	Distribution - Other Expenses	-	-	-	-	-	(1,956)	-	-
22	Distribution - Rents	-	-	-	-	-	-	-	-
23	Distribution - Maint. Superv'n & Eng.	-	-	-	-	-	(1,358)	-	-
24	Distribution - Maintenance of Mains	-	-	-	-	-	(3,330)	-	-
25	Distribution - Maint. M & R Stat. Equip. - Gen.	-	-	-	-	-	(19)	-	-
26	Distribution - Maint. M & R Stat. Equip. - Ind.	-	-	-	-	-	(1)	-	-
27	Distribution - Maint. M & R Equip. - City Gate	-	-	-	-	-	(1)	-	-
28	Distribution - Maintenance of Services	-	-	-	-	-	(2,229)	-	-
29	Distribution - Maint. of Meters and Reg.	-	-	-	-	-	(366)	-	-
30	Distribution - Maintenance of Other Equip.	-	-	-	-	-	(169)	-	-
31	Customer Account - Supervision	-	-	-	-	-	(415)	-	-
32	Customer Account - Meter Reading	-	-	-	-	-	(3,799)	-	-
33	Customer Account - Records and Collection	-	-	-	-	-	(7,985)	-	-
34	Customer Account - Uncollectibles	-	-	-	-	-	-	-	-

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SURREBUTTAL
SUMMARY OF OPERATING INCOME ADJUSTMENT - CONT'D
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	DESCRIPTION	(I) ADJ. NO. 8 RATE CASE EXPENSE	(J) ADJ. NO. 9 AGA DUES	(K) ADJ. NO. 10 ATYPICAL EXPENSES	(L) ADJ. NO. 11 SERP	(M) ADJ. NO. 12 AMORTIZATION GIS O&M	(N) ADJ. NO. 13 FLEET FUEL EXPENSE	(O) ADJ. NO. 14 CUSTOMER ANNUALIZ'N	(P) ADJ. NO. 15 CUSTOMER WEATHERIZ'N
	Continued								
35	Customer Account - Miscellaneous	$ -	$ -	$ -	$ -	$ -	$ (9)	$ -	$ -
36	Customer Account - Superv'n - Cust. Service	-	-	-	-	-	(66)	-	-
37	Customer Account - Assistance	-	-	-	-	-	(71)	-	-
38	Customer Account - Info and Instruct Advert.	-	-	-	-	-	(3)	-	-
39	Customer Account - Miscellaneous	-	-	-	-	-	-	-	-
40	Sales - Demonstrating and Selling	-	-	-	-	-	-	-	-
41	A & G - Salaries	-	-	-	-	-	-	-	-
42	A & G - Office Supplies and Expenses	-	-	(2,584)	-	-	(8,981)	-	-
43	A & G - Transferred - Credit	-	-	-	-	-	-	-	-
44	A & G - Outside Services Employed	-	-	-	-	-	-	-	-
45	A & G - Property Insurance	-	-	-	-	-	-	-	-
46	A & G - Injuries and Damages	-	-	-	-	-	(3)	-	-
47	A & G - Employee Pension and Benefits	-	-	-	(93,075)	-	-	-	-
48	A & G - Miscellaneous General Expenses	-	(1,523)	-	-	-	(65)	-	-
49	A & G - Rents	-	-	-	-	-	-	-	-
50	A & G - Maintenance of General Plant	-	-	-	-	-	(120)	-	-
51	A & G - Rate Case Expense	(116,333)	-	-	-	-	-	-	-
52	Interest On Customer Deposits	-	-	-	-	-	-	-	-
53	**Other Oper. and Maint. Expense**	$ (116,333)	$ (1,523)	$ (2,584)	$ (93,075)	$ -	$ (49,493)	$ -	$ -
54	Dep. & Amort. - Citizens Acq. Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55	Dep. & Amort. - Intangible Plant	-	-	-	-	-	-	-	-
56	Dep. & Amort. - Transmission Plant	-	-	-	-	(299,023)	-	-	-
57	Dep. & Amort. - Distribution Plant	-	-	-	-	-	-	-	-
58	Dep. & Amort. - General Plant	-	-	-	-	-	-	-	-
59	**Depreciation and Amortization**	$ -	$ -	$ -	$ -	$ (299,023)	$ -	$ -	$ -
60	Property Tax	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
61	Payroll Tax - FUTA, SUTA, FICA & Medicare	-	-	-	-	-	-	-	-
62	Medical and Dental	-	-	-	-	-	-	-	-
63	Other	-	-	-	-	-	-	-	-
64	**Taxes Other Than Income Taxes**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
65	**Income Taxes**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
66	**Total Operating Expense**	$ (116,333)	$ (1,523)	$ (2,584)	$ (93,075)	$ (299,023)	$ (49,547)	$ -	$ -
67	**Operating Income**	$ 116,333	$ 1,523	$ 2,584	$ 93,075	$ 299,023	$ 49,547	$ 110,006	$ 900

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SURREBUTTAL
SUMMARY OF OPERATING INCOME ADJUSTMENT - CONT'D
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	DESCRIPTION	(Q) ADJ. NO. 16 CORP. COST ALLOCATION	(R) ADJ. NO. 17 UNCOLTIBLES	(S) ADJ. NO. 18 CWIP PROP. TAXES	(T) ADJ. NO. 19 OUT OF PERIOD EXPENSES	(U) ADJ. NO. 20	(V) ADJ. NO. 21	(W) ADJ. NO. 22 INCOME TAX REVISED	(X) RUCO AS ADJUSTED
	Operating Revenue								
1	Net Sales to Ultimate Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 43,061,221
2	Transportation of Gas	-	-	-	-	-	-	-	2,738,909
3	**Gas Retail Revenue**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 45,800,130
4	Forfeited Discounts (Late Fees)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 398,966
5	Miscellaneous Service Revenues	-	-	-	-	-	-	-	1,046,891
6	Other Gas Revenues	-	-	-	-	-	-	-	34,447
7	**Other Operating Revenue**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,480,304
8	**Total Operating Revenue**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 47,280,434
9	**Purchased Gas**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 355,474
10	Transmision - Mains Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,211
11	Transmision - Meas. and Reg. Station	-	-	-	-	-	-	-	(52,222)
12	Transmision - Maint. Compressor Stat. Equip.	-	-	-	-	-	-	-	19
13	Transmision - Oper. Super'n and Eng.	-	-	-	-	-	-	-	314,076
14	Distribution - Load Dispatching	-	-	-	-	-	-	-	162
15	Distribution - Mains and Services	-	-	-	-	-	-	-	1,287,812
16	Distribution - Meas. and Reg. Station - Gen.	-	-	-	-	-	-	-	243,368
17	Distribution - Meas. and Reg. Station - Ind.	-	-	-	-	-	-	-	149,702
18	Distribution - Meas. and Reg. Station - City	-	-	-	-	-	-	-	56,406
19	Distribution - Meter and House Regulator	-	-	-	-	-	-	-	1,308,654
20	Distribution - Customer Installations	-	-	-	-	-	-	-	536,580
21	Distribution - Other Expenses	-	-	-	-	-	-	-	1,061,493
22	Distribution - Rents	-	-	-	-	-	-	-	44,510
23	Distribution - Maint. Superv'n & Eng.	-	-	-	-	-	-	-	241,812
24	Distribution - Maintenance of Mains	-	-	-	-	-	-	-	1,054,524
25	Distribution - Maint. M & R Stat. Equip. - Gen.	-	-	-	-	-	-	-	25,604
26	Distribution - Maint. M & R Stat. Equip. - Ind.	-	-	-	-	-	-	-	2,071
27	Distribution - Maint. M & R Equip. - City Gate	-	-	-	-	-	-	-	849
28	Distribution - Maintenance of Services	-	-	-	-	-	-	-	462,837
29	Distribution - Maint. of Meters and Reg.	-	-	-	-	-	-	-	166,649
30	Distribution - Maintenance of Other Equip.	-	-	-	-	-	-	-	96,657
31	Customer Account - Supervision	-	-	-	-	-	-	-	73,894
32	Customer Account - Meter Reading	-	-	-	-	-	-	-	715,238
33	Customer Account - Records and Collection	-	-	-	-	-	-	-	4,851,342
34	Customer Account - Uncollectibles	-	(95,583)	-	-	-	-	-	627,051

SURREBUTTAL
SUMMARY OF OPERATING INCOME ADJUSTMENT - CONT'D
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	DESCRIPTION	(Q) ADJ. NO. 16 CORP. COST ALLOCATION	(R) ADJ. NO. 17 UNCOL'TIBLES	(S) ADJ. NO. 18 CWIP PROP. TAXES	(T) ADJ. NO. 19 OUT OF PERIOD EXPENSES	(U) ADJ. NO. 20 LEGAL EXPENSE	(V) ADJ. NO. 21	(W) ADJ. NO. 22 INCOME TAX	(X) RUCO AS ADJUSTED
	Continued								
35	Customer Account - Miscellaneous	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 34,372
36	Customer Account - Superv'n - Cust. Service	-	-	-	-	-	-	-	14,677
37	Customer Account - Assistance	-	-	-	-	-	-	-	(34,299)
38	Customer Account - Info and Instruct Advert.	-	-	-	-	-	-	-	65,791
39	Customer Account - Miscellaneous	-	-	-	-	-	-	-	22,602
40	Sales - Demonstrating and Selling	-	-	-	-	-	-	-	558
41	A & G - Salaries	-	-	-	-	-	-	-	1,409,672
42	A & G - Office Supplies and Expenses	-	-	-	-	-	-	-	1,236,177
43	A & G - Transferred - Credit	-	-	-	-	-	-	-	(152,950)
44	A & G - Outside Services Employed	-	-	-	-	(311,051)	-	-	2,368,183
45	A & G - Property Insurance	-	-	-	-	-	-	-	6,086
46	A & G - Injuries and Damages	-	-	-	-	-	-	-	539,598
47	A & G - Employee Pension and Benefits	-	-	-	-	-	-	-	2,209,189
48	A & G - Miscellaneous General Expenses	(12,765)	-	-	(21,120)	-	-	-	970,444
49	A & G - Rents	-	-	-	-	-	-	-	109,053
50	A & G - Maintenance of General Plant	-	-	-	-	-	-	-	169,706
51	A & G - Rate Case Expense	-	-	-	-	-	-	-	83,667
52	Interest On Customer Deposits	-	-	-	-	-	-	-	170,459
53	**Other Oper. and Maint. Expense**	**$ (12,765)**	**$ (95,583)**	**$ -**	**$ (21,120)**	**$ (311,051)**	**$ -**	**$ -**	**$ 22,503,286**
54	Dep. & Amort. - Citizens Acq. Discount	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (729,791)
55	Dep. & Amort. - Intangible Plant	-	-	-	-	-	-	-	872,261
56	Dep. & Amort. - Transmission Plant	-	-	-	-	-	-	-	(15,454)
57	Dep. & Amort. - Distribution Plant	-	-	-	-	-	-	-	5,203,389
58	Dep. & Amort. - General Plant	-	-	-	-	-	-	-	1,243,507
59	**Depreciation and Amortization**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 6,573,912**
60	Property Tax	$ -	$ -	$ (166,884)	$ -	$ -	$ -	$ -	$ 3,598,743
61	Payroll Tax - FUTA, SUTA, FICA & Medicare	-	-	-	-	-	-	-	517,024
62	Medical and Dental	-	-	-	-	-	-	-	86,130
63	Other	-	-	-	-	-	-	-	2,711
64	**Taxes Other Than Income Taxes**	**$ -**	**$ -**	**$ (166,884)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 4,204,608**
65	**Income Taxes**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 1,448,158**	**$ 3,423,655**
66	**Total Operating Expense**	**$ (12,765)**	**$ (95,583)**	**$ (166,884)**	**$ (21,120)**	**$ (311,051)**	**$ -**	**$ 1,448,158**	**$ 37,060,935**
67	**Operating Income**	**$ 12,765**	**$ 95,583**	**$ 166,884**	**$ 21,120**	**$ 311,051**	**$ -**	**$ (1,448,158)**	**$ 10,219,499**

UNS Gas Corporation
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SURREBUTTAL
OPERATING INCOME ADJUSTMENT NO. 4
NORMALIZATION OF POSTAGE EXPENSES

LINE NO.	DESCRIPTION	REFERENCE		(A) POSTAGE
	Postage Associated With Customer Records and Collections			
1	Actual Test-Year Costs	Company Workpapers	$	426,102
2	Actual Number Of Test-Year Customer Bills	Company Schedule H-2		1,632,576
3	Cost Per Customer Bill	Line 1 / Line 2	$	0.2610
4	RUCO Annualized Number Of Test-Year Customer Bills	RLM-15, Column (C)		1,669,426
5	RUCO Adjusted Postage Costs For Annualized Customer Base	Line 3 X Line 4	$	435,720
	Postage Associated With Office Expenses			
6	Actual Test-Year Costs	Company Workpapers	$	19,070
7	Total RUCO Adjusted Test-Year Postage Costs	Line 5 + Line 6	$	454,790
8	Postage Increase			5.00%
9	RUCO Total Adjusted Postage Cost	Line 7 + 5.00% Increase	$	477,530
10	Company As Filed	Company Workpapers	$	529,380
11	Difference	Line 7 - Line 8	$	(51,851)
12	RUCO Adjustment (See RLM-7, Pages 1 & 2, Column (E))	Line 9	$	(51,851)

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SURREBUTTAL
OPERATING INCOME ADJUSTMENT NO. 22
INCOME TAX EXPENSE

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	FEDERAL INCOME TAXES:		
1	Operating Income Before Taxes	Schedule RLM-6, Column (C), Line 10 + Line 8	$ 13,643,154
	LESS:		
2	Arizona State Tax	Line 11	(618,050)
3	Interest Expense	Note (A) Line 22	(4,773,323)
4	Federal Taxable Income	Sum Of Lines 1, 2 & 3	$ 8,251,781
5	Federal Tax Rate	Schedule RLM-2, Column (A), Line 9	34.00%
6	Federal Income Tax Expense	Line 4 X line 5	$ 2,805,605
	STATE INCOME TAXES:		
7	Operating Income Before Taxes	Line 1	$ 13,643,154
	LESS:		
8	Interest Expense	Note (A) Line 22	(4,773,323)
9	State Taxable Income	Line 7 + Line 8	$ 8,869,831
10	State Tax Rate	Tax Rate	6.9680%
11	State Income Tax Expense	Line 9 X Line 10	$ 618,050
	TOTAL INCOME TAX EXPENSE:		
12	Federal Income Tax Expense	Line 6	$ 2,805,605
13	State Income Tax Expense	Line 11	618,050
14	Total Income Tax Expense Per RUCO	Sum Of Lines 12 & 13	$ 3,423,655
15	Total Income Tax Expense Per Company Filing (Schedule C-1)		1,975,497
16	Difference	Line 14 - Line 15	$ 1,448,158
17	RUCO ADJUSTMENT TO INCOME TAX EXPENSE (See RLM 7, Page 6, Column (W))	Line 16	$ 1,448,158

NOTE (A):
Interest Synchronization:

LINE NO.	DESCRIPTION	AMOUNT
18	Adjusted Rate Base (Schedule RLM-3, Column (H), Line 16)	$ 144,646,160
19	Weighted Cost Of Debt (Schedule RLM-16, Column (F), Line 1 + Line 2)	3.30%
20	Interest Expense (Line 20 X Line 21)	$ 4,773,323

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SURREBUTTAL
RATE DESIGN AND PROOF OF RUCO RECOMMENDED REQUIRED REVENUE

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
			RUCO ANNUALIZED/WEATHERIZED		PROPOSED MARGIN RATES		MARGIN AT PROPOSED RATES					
LINE NO.	DESCRIPTION	SCH. NO.	ADJUSTED BILL COUNT	SALES (THERMS)	BASIC SERVICE CHARGE	COM. CHARGE	BASIC SERVICE CHARGE	COMMODITY CHARGE	TOTAL MARGIN	FIXED ALLOCATION FACTORS	VARIABLE ALLOCATION FACTORS	RES/COM ALLOCATION FACTORS
	Residential Service	R-10										
1	Basic Service Charge per Month - Summer		973,181		$ 8.34		$ 8,113,648		$ 8,113,648	64.11%		
2	Basic Service Charge per Month - Winter		495,838		$ 8.34		$ 4,133,925		4,133,925	32.87%		
3	Commodity Charge All Therms		-	69,822,061		$ 0.29668		$ 20,714,528	20,714,528		97.17%	
4	Total Residential Service		1,469,020	69,822,061			$ 12,247,573	$ 20,714,528	$ 32,962,101			
	Residential Service Cares	R-12										
4	Basic Service Charge per Month - Summer		33,439		$ 8.34		$ 278,790		$ 278,790	2.20%		
5	Basic Service Charge per Month - Winter		15,476		$ 8.34		$ 129,027		129,027	1.02%		
6	Commodity Charge All Therms			2,036,847		$ 0.29668		$ 604,283	604,283		2.83%	
7	Total Residential Service Cares		48,915	2,036,847			$ 407,817	$ 604,283	$ 1,012,100			
8	SUB-TOTAL RESIDENTIAL		1,517,935	71,858,907			$ 12,655,390	$ 21,318,811	$ 33,974,201	100.00%	100.00%	70.00%
	Small Volume Commercial Service	C-20										
9	Basic Service Charge per Month		133,275		$ 34.46		$ 4,592,054		$ 4,592,054	84.67%		
10	Commodity Charge per Therm			29,392,577		$ 0.18619		$ 5,472,634	5,472,634		59.90%	
11	Total Small Volume Commercial Service		133,275	29,392,577			$ 4,592,054	$ 5,472,634	$ 10,064,689			
	Large Volume Commercial Service & Trans.	C-22										
12	Basic Service Charge per Month		225		$ 265.03		$ 59,570		$ 59,570	1.10%		
13	Commodity Charge per Therm			4,170,979		$ 0.11919		$ 497,148	497,148		5.44%	
14	Total Large Volume Commercial Service		225	4,170,979			$ 59,570	$ 497,148	$ 556,719			
	Small Volume Industrial Service	I-30										
15	Basic Service Charge		146		$ 34.46		$ 5,048		$ 5,048	0.09%		
16	Commodity Charge per Therm			474,830		$ 0.17508		$ 83,135	83,135		0.91%	
17	Total Small Volume Industrial Service		146	474,830			$ 5,048	$ 83,135	$ 88,182			
	Large Volume Industrial Service	I-32										
18	Basic Service Charge		238		$ 265.03		$ 63,158		$ 63,158	1.16%		
19	Commodity Charge per Therm			22,586,654		$ 0.06680		$ 1,508,698	1,508,698		16.51%	
20	Total Large Volume Industrial Service		238	22,586,654			$ 63,158	$ 1,508,698	$ 1,571,856			
	Small Volume Public Authority	PA-40										
21	Basic Service Charge per Month		12,795		$ 34.46		$ 440,860		$ 440,860	8.13%		
22	Commodity Charge per Therm			5,870,369		$ 0.18259		$ 1,071,854	1,071,854		11.73%	
23	Total Small Volume Public Authority		12,795	5,870,369			$ 440,860	$ 1,071,854	$ 1,512,714			
	Large Volume Public Authority	PA-42										
24	Basic Service Charge per Month		113		$ 265.03		$ 29,835		$ 29,835	0.55%		
25	Commodity Charge per Therm			5,906,070		$ 0.08220		$ 485,508	485,508		5.31%	
26	Total Larege Volume Public Authority		113	5,906,070			$ 29,835	$ 485,508	$ 515,344			
	Special Gas Light Service	PA-44										
27	Customer Charge Lighting Group A		866		$ 42.88		$ 37,157		$ 37,157	0.69%		
28	Customer Charge Lighting Group B		3,767		$ 51.45		$ 193,786		193,786	3.57%		
29	Total Special Gas Light Service		4,633				$ 230,943	$ -	$ 230,943			
	Irrigation Service	IR-60										
30	Basic Service Charge		66		$ 34.46		$ 2,269		$ 2,269	0.04%		
31	Commodity Charge per Therm			79,409		$ 0.22234		$ 17,656	17,656		0.19%	
32	Total Irrigation Service		66	79,409			$ 2,269	$ 17,656	$ 19,925	100.00% #	100.00%	30.00%
33											RES. TO TOTAL	RES. REVENUE
34	SUB-TOTAL COMMERCIAL		151,491	68,480,887			5,423,739	9,136,633	14,560,372		70.00%	$ 33,974,201
35												COM REVENUE
36	TOTAL TARIFF SALES		1,669,426	140,339,795			18,079,128	30,455,444	48,534,573		COM. TO TOTAL	$ 14,560,372
37											30.00%	RES FIX REV
38												$ 12,655,390
39								OTHER REVENUE	1,480,304			COM FIX REV
40								TOTAL REVENUE	50,014,877		FIXED TO TOTAL	$ 5,423,739
41											37.25%	RES VAR REV
42								RUCO PROPOSED REVENUE	$ 50,014,877			$ 21,318,811
43											VAR. TO TOTAL	COM VAR REV
44								DIFFERENCE	$ (0)		62.75%	$ 9,136,633

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SURREBUTTAL

TYPICAL RESIDENTIAL BILL ANALYSIS

LINE NO.	DESCRIPTION	(A)	(B)	(C)	(D)	(E)	(F)
		PRESENT		COMPANY AS FILED PROPOSED		RUCO REVISED SURREBUTTAL PROPOSED	
	REVENUE ALLOCATION						
1	RESIDENTIAL	$ 31,123,034	70.02%	$ 39,021,053	70.19%	$ 33,974,201	70.00%
2	OTHER	$ 13,323,588	29.98%	$ 16,573,116	29.81%	$ 14,560,372	30.00%
3	TOTAL	$ 44,446,622	100.00%	$ 55,594,169	100.00%	$ 48,534,573	100.00%
	ALLOCATION RATIOS						
4	FIX REVENUE	12,110,551	27.25%	$ 28,769,014	51.70%	$ 18,079,128	37.25%
5	VARIABLE REVENUE	32,336,071	72.75%	$ 26,879,714	48.30%	$ 30,455,444	62.75%
6	TOTAL	44,446,622	100.00%	$ 55,648,727	100.00%	$ 48,534,573	100.00%
	RESIDENTIAL RATE DESIGN	PRESENT		COMPANY PROPOSED		RUCO PROPOSED	
	BASIC MONTHLY CHARGE						
7	SUMMER	$ 7.00		MONTHS 8	$ 20.00	$ 8.34	
8	WINTER	$ 7.00		MONTHS 4	$ 11.00	$ 8.34	
9	COMMODITY CHARGE	$ 0.3004			$ 0.18625	0.2967	
	RESIDENTIAL BILL COMPARISONS						
	GAS CHARGE AT MARGIN + PGA COSTS AT DIFFERENT LEVELS OF USAGE WITH PERCENTAGE INCREASE IN BILL	AVERAGE PROPOSED PGA RATES	% OF AVERAGE MONTH USAGE OF 46.59 Therms	PRESENT MONTHLY GAS COST	RUCO PROP'D MONTHLY GAS COST	RUCO PROP'D MONTHLY INCREASE	RUCO PROP'D MONTHLY % INCREASE
10		$ 0.6467	25.00%	$ 18.03	$ 19.33	$ 1.29	7.18%
11			50.00%	$ 29.06	$ 30.31	$ 1.25	4.30%
12			100.00%	$ 51.13	$ 52.29	$ 1.16	2.28%
13			150.00%	$ 73.19	$ 74.27	$ 1.08	1.47%
14			200.00%	$ 95.25	$ 96.24	$ 0.99	1.04%

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SURREBUTTAL
COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED	(D) PERCENT	(E) COST RATE	(F) WEIGHTED COST RATE
1	Short-term Debt	N/A	$ -	$ -	0.00%	0.00%	0.00%
2	Long-term Debt	$ 98,859,000	$ -	$ 98,859,000	50.00%	6.60%	3.30%
3	Preferred Stock	N/A	$ -	$ -	0.00%	0.00%	0.00%
4	Common Equity	$ 98,859,000	$ -	$ 98,859,000	50.00%	9.84%	4.92%
5	TOTAL CAPITAL	$ 197,718,000	$ -	$ 197,718,000	100.00%		
6	WEIGHTED COST OF CAPITAL						8.22%

References:
- Column (A): Company Schedule D-1
- Column (B): Surrebuttal Testimony, WAR
- Column (C): Column (A) + Column (B)
- Column (D): Column (C), Line Item / Total Capital (L5)
- Column (E): Surrebuttal Testimony, WAR
- Column (F): Column (D) X Column (E)

UNS GAS, INC.

DOCKET NO. G-04204A-06-0463 et al.

DIRECT TESTIMONY

OF

MARYLEE DIAZ CORTEZ, CPA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

FEBRUARY 9, 2007

EXHIBIT
tabbies
RUCO 5
admitted

INTRODUCTION

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

A. My name is Marylee Diaz Cortez. I am a Certified Public Accountant. I am the Chief of Accounting and Rates for the Residential Utility Consumer Office (RUCO) located at 1110 W. Washington, Phoenix, Arizona 85007.

Q. Please state your educational background and qualifications in the utility regulation field.

A. Appendix I, which is attached to this testimony, describes my educational background and includes a list of the rate case and regulatory matters in which I have participated.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to discuss certain issues pertaining to operating income, rate base, and rate design and to present my recommendations on these issues. RUCO witness Rodney L. Moore also presents recommendations on these same ratemaking elements as well as sponsors RUCO's overall revenue requirement recommendation. RUCO witness William A. Rigsby presents recommendations regarding cost of capital.

Q. Please describe your work effort on this project.

A. I obtained and reviewed data and performed analytical procedures necessary to understand the Company's application as it relates to operating income, rate base, and the Company's overall revenue requirements. Procedures performed included the issuance of seven sets of data requests, review of other parties' data requests, conversations with Company personnel, and the review of prior ACC Decisions pertaining to this Company.

Q. Please identify the exhibits you are sponsoring.

A. I am sponsoring Schedules MDC-1 through MDC-7.

SUMMARY OF ISSUES

Q. Please summarize the issues and recommendations you address in your testimony.

A. I address the following issues in my testimony:

Rate Base

Citizens Acquisition Adjustment – This adjustment decreases rate base by $248,887 to restate the accumulated amortization of the acquisition adjustment to reflect the current Commission authorized depreciation rate. The Company has been amortizing the acquisition adjustment utilizing rates that never were approved by the Commission.

Construction Work in Progress - This adjustment decreases rate base by $7,189,230 to remove CWIP balances that are not used and useful in the provision of gas service.

Amortization of Geographic Information System (GIS) – This adjustment removes expenses associated with a GIS from rate base. The Company did not obtain an accounting order from the Commission allowing them to establish a regulatory asset for these expenses.

Working Capital – This adjustment increases working capital by $1,200,152 and is necessary to correct an error the Company has identified as well as to calculate the effect RUCO's recommended level of expense has on cash working capital.

Operating Income

Amortization of GIS Expenses – This adjustment decreases operating income by $299,023 in amortization expense related to a regulatory asset that was never established or approved by the Commission.

Fleet Fuel Expense – This adjustment increases operating income by $67,502 to correct certain errors the Company made in its calculation of normalized fleet fuel expense.

Customer Annualization – This adjustment increases test year revenues by $110,006 to restate the Company revenue annualization using the Commission-accepted methodology of utilizing the test year-end level of customers.

Corporate Cost Allocation – This adjustment increases operating income by $12,765 to remove additional non-recurring merger expenses that the Company failed to include in its adjustment.

Uncollectible Expense – This adjustment increases operating income by $95,583 to exclude the bad debt expense that the Company erroneously included related to Griffith Plant revenue and to reflect RUCO's recommended level of revenue.

CWIP Property Taxes – This adjustment increases operating income by $166,884 to remove the proforma property taxes the Company has computed as attributable to its CWIP balances.

Out-of-Period Expenses – This adjustment increases operating income by $21,120 to remove accounting fees related to periods prior to the test year.

Legal Expenses – This adjustment increases operating income by $311,051 to removes non-recurring legal expenses.

Other Issues

Changes to the PGA – This section discusses the Company's proposed changes to its PGA and sets forth RUCO's recommendations.

Rate Design – This section discusses the Company-proposed rate design modifications and the Company-proposed decoupling mechanism and sets forth RUCO's recommendations.

BACKGROUND

Q. Please provide some historical background for this case.

A. UniSource Energy acquired the electric and gas operations of Citizens' Utilities in 2003 pursuant to a settlement agreement[1]. The gas operations became known as UNS Gas, which is the subject of the instant case. UNS Gas' current rates and charges were authorized in the 2003 settlement agreement based on a 2001 test year.

RATE BASE

Rate Base Adjustment #3 – Citizens' Acquisition Adjustment

Q. Please discuss the Company's treatment of the negative acquisition adjustment it incurred when it acquired the gas properties of Citizens Utilities.

A. The required ratemaking treatment for the negative acquisition adjustment was part of the settlement agreement that was adopted in Decision No. 66028. The agreement required a permanent rate base credit of $30,700,000 for the Gas Company. The agreement also required the Company to allocate the $30.7 million reduction over its FERC plant accounts and to amortize these reductions using the depreciation rate applicable to each account.

[1] Decision No. 66028

Q. Is the Company's treatment of the Citizens' acquisition adjustment in compliance with the requirements of the settlement agreement?

A. No, not entirely. The Company has not utilized its authorized depreciation rates to amortize the acquisition adjustment. As discussed in the testimony of Mr. Moore, the Company has not been depreciating its assets with the Commission-authorized depreciation rates from Decision No. 58664. Likewise, it has used these same wrong depreciation rates to amortize the acquisition adjustment.

Q. Have you made an adjustment to correct this error?

A. Yes. As shown on Schedule MDC-1, I have recomputed the accumulated amortization of the negative acquisition adjustment using the Commission authorized rates. This adjustment decreases rate base by $248,887.

Rate Base Adjustment #4 – CWIP

Q. Is UNS Gas requesting the inclusion of its test year-end CWIP balance in rate base?

A. Yes. The Company claims that this extraordinary treatment of CWIP is warranted for it to maintain its financial integrity, to fund its rapid growth, to mitigate regulatory lag, to make up for its large negative acquisition adjustment, and to prolong the period between rate cases.

Q. Is this the accepted ratemaking treatment for CWIP?

A. No. Utility regulation routinely excludes CWIP from rate base because it does not meet the used and useful ratemaking standard, which requires that assets actually be in service and providing a benefit to ratepayers before their inclusion in rates. Utility accounting already allows the accrual of interest, in the form of an Allowance for Funds Used During Construction (AFUDC), on the CWIP balances. These interest accruals are ultimately recovered over the life of the asset once it enters service through depreciation expense. Thus, rate base treatment of CWIP does not change a utility's level of earnings, merely the timing of earnings recovery.

Q. Are you aware of any instances where utility commissions have made an exception to standard ratemaking treatment and included CWIP in rate base?

A. Yes, but only as result of extraordinary circumstances. During the 1970's and 1980's many utility commissions made an exception and allowed CWIP in rate base. In most cases the exception was made due to the drain on cash flow caused by construction of nuclear plants. Due to the large outlays of cash required to build a nuclear plant coupled with the very long lead time before such plants enter service, many utilities became unable to service their debt due to lack of cash flows. The inclusion of CWIP was considered an emergency measure as well as a temporary measure. It historically has not been a routine ratemaking mechanism.

Q. Do the reasons cited by the Company that warrant rate base treatment of CWIP meet the "extraordinary circumstance" standard just discussed?

A. No. First, the Company's argument that CWIP in rate base is necessary to maintain financial integrity is without merit. Other than in extraordinary circumstances this Commission has never allowed CWIP in rate base and Arizona utilities have not lost their financial integrity as a result. Likewise, the Company's growth argument is without merit as growth has a positive effect on the Company, generating more revenue and cash flow. Regulatory lag always has been a characteristic of rate of return regulation. It does not all of the sudden create a need to put CWIP in rate base. Regulatory lag is a two way street that works both for and against the Company. Types of regulatory lag that benefit the Company are plant retirements, accumulated depreciation, and expired amortizations. In all these instances the Company continues to earn a return on and recovery of assets that have already been recovered. Thus, the notion that we need to mitigate the regulatory lag that does not favor the Company, such as the Company suggests in its CWIP in rate base argument, yet continue to allow the effects of regulatory that do benefit the Company is clearly biased. The Company's argument that CWIP in rate base will lengthen the period between rate cases also has little merit. The Company currently has no CWIP in rate base and even so it has been five years since its last rate case in 2002. In fact no large Arizona utilities that I am aware of have CWIP in rate base, yet these utilities are not filing back-to-back rate cases. Further, in my experience the Commission has favored, rather than disapproved of, utilities coming in for regular rate reviews. Finally, the Company's argument that the large negative acquisition it agreed to when it acquired Citizens gas properties now justifies the inclusion of CWIP in rate base, is disingenuous at best.

Q. Why do you say this argument is disingenuous at best?

A. At the time of the settlement agreement, the Company touted the negative acquisition as an attractive feature of the agreement that would provide substantial benefits to ratepayers. Company witness, and then-UniSource Vice President Steven Glaser stated the following in his testimony in that proceeding:

> A further benefit of the settlement is that Citizens' gas customers will have use of approximately $30.7 million of facilities and Citizens' electric customers will have use of approximately $93.6 million of facilities that they will never have to pay for because UniSource has agreed not to seek recovery of the negative acquisition adjustments.[2]

It is hardly appropriate to now use the benefit of the negative acquisition adjustment as a reason to increase rates by including CWIP in rate base.

[2] Rebuttal Testimony of Steven Glaser, Docket No. E-01933A-02-0914, page 2.

Q. What adjustment are you recommending?

A. I have decreased rate base by $7,189,231 to remove the Company-requested CWIP balances.

Rate Base Adjustment #5 – GIS Deferral

Q. Please discuss the Company-proposed GIS Deferral adjustment.

A. The Company has expended $897,068 on a Global Information System (GIS) project. Under Generally Accepted Accounting Principles (GAAP) such expenditures are consider expenses, and in recognition of the GAAP requirements the Company expensed these costs on its income statement during the test year. However, for ratemaking purposes the Company has deferred these expenses and established a regulatory asset for which it seeks rate base and amortization treatment.

Q. Can a regulated utility establish a regulatory asset of its own volition?

A. No. Pursuant to GAAP accounting SFAS 71 only the regulator of a utility can establish a regulatory asset via the issuance of an accounting order that provides reasonable assurance that the created asset will be recovered.

Q. Has the UNS Gas' regulator established and approved a regulatory asset for the Company's GIS expenses?

A. No. The Company has neither sought nor received approval from the Commission for a regulatory asset related to GIS expenses.

Q. What adjustment are you recommending?

A. In the absence of a Commission-authorized accounting order, the Company is required to expense these expenditures on its income statement and cannot include them its it rate base to earn a return on. As shown on Schedule RLM-3 I have removed the $897,068 in GIS expenses from rate base. I am also recommending a companion adjustment related to the amortization of unapproved regulatory asset that is discussed in the operating income section of my testimony.

Rate Base Adjustment #6 – Working Capital

Q. Have you reviewed the Company's working capital calculations?

A. Yes. The Company's working capital request is comprised of a 13-month average balance for its prepayment and material and supplies accounts, and its cash working capital request is based on a lead/lag study.

Q. Do you agree with the Company's methodology?

A. Yes. Further, I have reviewed the Company's individual lag day calculations and find them to be reasonable. The only difference between the Company's calculation and RUCO's is the different level of expense recommendations and a correction of an error that the Company identified in its test year level of revenue taxes and assessments. These adjustments result in a net increase in cash working capital of $1,200,152, which is primarily attributable to the Company's revenue tax error.

OPERATING INCOME

Operating Adjustment #12 – GIS Expenditures

Q. Are you recommending an adjustment to remove amortization expense associated with the Company's GIS deferrals?

A. Yes. As discussed previously in the rate base section of my testimony, the Company has neither sought nor received approval for a GIS regulatory asset. Thus, it has no such asset for which it is entitled to amortize. As shown on Schedule RLM-7 I have therefore removed the Company-proposed $299,023 in amortization expense associated with the GIS expenditures.

Q. Did the Company complete the GIS project during the test year?

A. Yes. Thus, these expenditures are unique and will not recur on an annual basis.

Q. Hasn't the Company already recovered its GIS expenditures anyway?

A. Yes. During the test year the Company expensed the GIS expenditures on its income statement. In the test year the Company had net income of over $10.5 million, which means not only did the Company recover all its operating expenses (including the GIS expenditures) it also had money to spare. Amortizing these expenses over three years, as proposed by the Company, would result in a double recovery.

Operating Adjustment #13 – Fleet Fuel Expense

Q. Has the Company proposed an adjustment to its test year level of fuel expense for its fleet of vehicles?

A. Yes. The Company has proposed an adjustment to annualize its fuel expense to reflect the additional employees it has included in its payroll annualization adjustment.

Q. Do you agree with this adjustment in concept?

A. Yes. The Company's payroll annualization has the effect of increasing payroll expense to recognize payroll attributable to the year-end level of employees for the entire year. The Company's proposed fleet fuel adjustment recognizes the additional fuel expense attributable to these additional employees as well as annualizes the average cost of gasoline. Thus, conceptually the adjustment is necessary to match these two items of expense.

Q. Do you agree with the Company's calculation of the fleet fuel expense adjustment?

A. No. The Company's calculation was based on the average fuel prices during the first few months of 2006. However, gasoline prices in early 2006 were abnormally high, thus the Company's calculation inflates the annualized level of fuel expenses as a result. Further, the Company has understated the average miles per gallon (mpg) that its fleet gets. As shown on Schedule MDC-3, I have restated the mpg in the Company's calculation to reflect actual test year mpg and utilized the average price of gasoline over the entire test year. My adjustment results in an annualized level of fuel expense that is $67,502 less than the annualized level proposed by the Company.

Operating Adjustment #14 – Customer Annualization

Q. Have you reviewed the Company's customer annualization?

A. Yes. The Company performs a calculation that it purports annualizes the test year-end customers. The Company's revenue annualization methodology, which uses growth percentages instead of absolute bill counts, understates the revenue attributable to growth.

Q. What is the proper methodology for a customer annualization adjustment?

A. The Commission's accepted method is to compare the customer counts in each month of the test year to the December 31, 2005 test year-end level of customers, and then multiply the additional customers attributable to each month by the average revenue for each month, to quantify the additional revenue attributable to the additional customers. As shown on Schedule MDC-4, my calculations using this methodology result in an $110,006 increase in revenue attributable to customer growth.

Operating Adjustment #15 – Weather Normalization

Q. Have you reviewed the Company's weather normalization adjustment?

A. Yes. The results of the Company's weather normalization adjustment are reasonable and RUCO accepts this adjustment to increase test year therms based on warmer-than-normal weather. I am also proposing an additional adjustment of $900, which is the weather adjustment related to the additional customers I recognized in Operating Adjustment #14.

Operating Adjustment #16 – Corporate Cost Allocations

Q. Have you reviewed the Company's proposed Corporate Cost Allocation adjustment?

A. Yes. As part of this adjustment the Company has removed $130,471 in test year expenses related to the attempted merger with KKR. I agree with the Company that these test year expenses should be removed because they are non-recurring in nature. However, pursuant to my audit in this case I reviewed the Company's accounting records of its test year Corporate allocated expenses and identified a total of $149,094 in test year merger-related expenses. I have therefore decreased operating expenses by $12,765 ($149,094 - $130,471) to remove the additional test year merger-related expenses that the Company's adjustment does not recognize.

Operating Adjustment #17 – Bad Debts – Uncollectibles

Q. Has the Company proposed an adjustment to reflect the level of proforma bad debt expense attributable to its test year revenues?

A. Yes. The Company has computed its two-year average bad debt-to-revenue ratio and applied that ratio to its adjusted test year revenue.

Q. Do you agree with this adjustment?

A. Yes and no. Conceptually it is appropriate to normalize the bad debt ratio and to apply that to the test year adjusted revenues. However, the Company's calculation is erroneous in that it applies the normalized bad debt ratio to a level of revenue that is only partially adjusted.

Q. What do you mean only partially adjusted?

A. The Company's calculation begins with its actual test year revenue and adds to that its customer annualization adjustment revenue and its weather normalized adjustment revenue. From this amount the Company backs out revenue attributable to a prior period. However, the Company's test year adjusted revenue is comprised of more than these three adjustments.

Q. What other revenue adjustments has the Company failed to recognize in its bad debt calculation?

A. The Company's bad debt calculation fails to recognize the adjustments it has made to decrease revenue for the Griffith plant revenue and the Negotiated Sales Program (NSP) revenue. Since the Company has not recognized these revenues for ratemaking purposes it would be inappropriate to recognize bad debt expense associated with this revenue. As shown on Schedule MDC-5, I have recalculated a normalized level of bad debt expense based on RUCO's fully adjusted test year revenue. This adjustment corrects the Company's error.

Operating Adjustment #18 – CWIP Property Taxes

Q. Has the Company proposed an adjustment for property taxes related to its CWIP balances?

A. Yes. The Company proposes to increase test year expenses for both depreciation on its CWIP balances and property tax on its CWIP balances. I will not discuss the CWIP deprecation portion of this adjustment because it is addressed by Mr. Moore in his testimony. The property tax portion of this adjustment represents only the adjustment attributable to CWIP and the Company has proposed a separate property tax adjustment for its overall plant. This separate property tax adjustment, related to the overall plant, is also addressed in the testimony of Mr. Moore.

Q. Do you agree with the property tax portion of the Company's CWIP expense adjustment?

A. No. As discussed previously in the rate base section of my testimony, CWIP is not used and useful and as such historically has not been afforded rate base recognition. Likewise, the property tax attributable to CWIP balances should not be included in test year operating expense. My adjustment removes the Company's proforma CWIP property taxes of $166,884 from test year expenses.

Operating Adjustment #19 – Out-of-Period Expenses

Q. Has the Company made an adjustment to remove certain expenses from the test year that relate to other accounting periods?

A. Yes. The Company had made an adjustment to remove three specific expenses from the test year that relate to other accounting periods.

Q. Do you agree with this adjustment?

A. Yes. Rates should be set based only on costs in the test year and it is appropriate to remove any costs related to prior or subsequent periods. Pursuant to my rate case audit, however, I uncovered other out-of-period expenses that the Company has failed to remove.

Q. What adjustment are you recommending?

A. As shown on Schedule MDC-6, I have identified three Price Waterhouse invoices that are related to services performed at the end of 2004. These expenses relate to a period prior to the test year and accordingly must be removed from test year expenses. This adjustment decreases test year expenses by $21,120, which is the portion of these out-of-period expenses that was allocated to UNS Gas.

Operating Adjustment #20 – Legal Expenses

Q. As part of your rate case audit did you review the Company's test year legal expenses?

A. Yes. I reviewed the Company's test year legal expenses to ensure that only those legal expenses necessary and beneficial to ratepayers were included for rate recovery. I also sought to ensure that no non-recurring or extraordinary legal expense were included for rate recovery.

Q. Did you identify any legal expenses that met this criterion?

A. Yes. There were a number of extraordinary, non-recurring legal expenses present in the test year, all of which were incurred for the negotiation of a settlement with El Paso Gas.

Q. Why do you say the El Paso settlement negotiation costs are extraordinary and non-recurring?

A. These costs are extraordinary in that they represent the largest portion of total test year legal expense and non-recurring in that a settlement has now been reached in the El Paso Gas case that is pending FERC approval. Thus, on a going forward basis there will not be any legal fees associated with negotiating an El Paso Gas settlement.

Q. What adjustment are you recommending?

A. I have decreased test year operating expenses by $311,051 to remove the test year cost of negotiating the El Paso Gas settlement. These costs have already been recovered in the test year and will not be incurred on a going forward basis.

CHANGES IN THE PURCHASED GAS ADJUSTOR (PGA)

Q. Has the Company requested any changes to the characteristics of its PGA?

A. Yes. The Company is requesting the following changes to its PGA:

1) No gas costs included in base rates. All gas costs would be recovered through the PGA;

2) Elimination of the bandwidth or alternatively increased to $0.25 from $0.10 and then eliminated.

3) Interest earnings to be based on LIBOR plus 1.5%, except when the PGA balance exceeds two times the threshold and then the rate should be the Company's weighted cost of capital;

4) Change the threshold for requesting a surcredit for over-collected balances to $6,240,000;

5) Long-term debt used to finance PGA balances would not be reflected in the capital structure for purposes of ratemaking; and

6) Surcharges should eliminate PGA balances in a timely manner.

Q. Please discuss the first of the Company proposed changes.

A. The Company requests that all of its gas costs be recovered through the PGA. This compares with the status quo where a portion of the Company's gas costs is recovered through base rates and a portion from the PGA.

Q. Does RUCO support this proposed change?

A. Yes. RUCO supported this same change in the Southwest Gas rate case and the Commission adopted the change. RUCO believes having one tariff for the recovery of gas costs is more understandable to customers and better provides the necessary information to enable customers to better manage their gas bills.

Q. Please discuss the second of the Company-proposed changes.

A. This proposed change would eliminate the $0.10 annual band on the PGA adjustor. The Company argues that the purpose of the PGA is to allow UNS Gas to recover its gas costs in a reasonably timely manner. In light of recent significant increases in the cost of gas, the Company further argues that because of the small bandwidth the PGA mechanism is no longer capable of ensuring reasonably timely recovery of its gas costs. In support of this argument the Company cites the high level of unrecovered PGA balances that have accumulated in the PGA account over the past five years or so.

Q. Do you support elimination of the band?

A. No. However, RUCO does believe that escalating gas prices and Company's need to have timely recovery of its costs in order to remain financially healthy warrant an increase in the width of the band. RUCO recommends doubling the annual bandwidth to $0.20. This will have the effect of reducing what otherwise would have been the bank balance for 2007 by half. RUCO does not believe it is in the best interest of the Company, or its customers, to continue mounting up a large liability.

Q. Please discuss the third proposed change.

A. This proposed change is comprised of two elements. First, the Company proposes to change the interest rate applicable to the PGA bank balance from the three-month commercial financial paper rate to LIBOR plus 1.5%, which is the rate it pays on its line of credit. The Company argues that it should be entitled to be made whole for the cost of financing its PGA liability.

Q. Do you agree with this change?

A. Yes. RUCO believes the Company is entitled to be made whole for the cost of financing its unrecovered prudently incurred gas costs. Therefore, RUCO supports changing the interest on the PGA balance for UNS Gas to LIBOR plus 1.5%.

Q. Please discuss the second aspect of the proposed interest rate change.

A. The second element the Company proposes is authority to apply its authorized weighted cost of capital to its unrecovered PGA balance when that balance exceeds two times its threshold level of $6.24 million. The Company argues that when the PGA bank balance becomes that large it no longer represents a short-term investment, but rather a long-term investment and should be afforded the same level of return as the long-term assets in its rate base.

Q. Do you agree that the Commission should authorize this second aspect of the proposed interest rate change?

A. No. While in the past UNS Gas may have had to carry large bank balances over long periods of time, this is not what should be happening. Given RUCO's recommendation to double the bandwidth and its recommendation pursuant to the sixth proposed change (discussed below) UNS Gas will no longer be burdened with large carry-forward PGA balances and there will be no need for this proposed change. RUCO believes that timely recovery of prudently incurred fuel costs results in a healthy utility and protects ratepayers from a growing liability and high interest costs.

Q. Please discuss the fourth proposed change.

A. The Company proposes that the threshold level for requesting a surcredit for over-collected PGA balances be increased to $6.24 million so it is symmetrical with the under- collected balance threshold.

Q. Does RUCO agree with this proposed change?

A. Yes. RUCO believes it is fair and reasonable to treat the over-collected balances in the same manner as the under-collected balances.

Q. Please discuss the fifth proposed change.

A. The Company seeks commitment from the Commission that any debt it incurs solely to support under-collected PGA balances would not be recognized in the Company's capital structure for purposes of setting rates. The Company argues that since the PGA balances are not included in rate base the debt associated with such balances should not serve to lower its authorized rate of return.

Q. Do you agree that this is a commitment the Commission needs to make?

A. No. The Commission generally does not predetermine outside of a rate case the ratemaking treatment it will afford a company's assets, liabilities, revenues, and expenses. Further, based on RUCO's recommendation to increase the bandwidth and for timely recognition of mounting PGA liabilities, large balances should not accrue as they have in the past, reducing the likelihood of debt issuances for the sole purpose of financing under-collected PGA balances. Certainly, it would appear reasonable to exclude debt associated with non-rate based liabilities from the Company's capital structure, however, the appropriate time and place for such a request is in a rate case.

Q. Please discuss the sixth proposed change.

A. The Company requests that the Commission grant timely and adequate PGA surcharges so it can eliminate these balances over a reasonable time period.

Q. Does RUCO agree?

A. Yes. As discussed earlier, it is neither in the Company's nor ratepayers' best interest have a large mounting liability accruing. This jeopardizes the financial health of the utility and creates rate shock for ratepayers when the liability is eventually flowed into rates. Thus, RUCO supports addressing growing PGA balances in a timely and adequate manner.

RATE DESIGN

Q. Is UNS Gas proposing any material changes in its rate design?

A. Yes. The Company is proposing several material changes to its current rate design, which when taken in aggregate will create rate shock for some customers, result in perverted price signals, and stifle conservation.

Q. Please discuss the Company's proposed changes.

A. The rate design changes proposed by the Company are as follows:

1) Shift revenue recovery from the commodity charge to the fixed monthly charge;

2) Create a separate monthly charge for the winter months from the summer months. Winter rates would be effective for four months of the year and summer rates for eight months of the year. Summer monthly charges would be nearly double the winter monthly charges;

3) Create a decoupling mechanism called the Throughput Adjustment Mechanism (TAM) that would guarantee UNS Gas recovery of its authorized margin regardless of its therm sales.

Q. Please discuss the proposed shift in commodity revenues to the fixed monthly charge.

A. Currently the Company recovers approximately 26% of its revenue from the fixed monthly charge. The remainder is recovered through its commodity rates. The Company's proposed rate design would recover approximately 51% of its revenue from the fixed monthly charge. The Company argues that such a shift is necessary so that it can recover its authorized margin in spite of weather, conservation, and declining sales.

Q. What effect does such a drastic shift have on customer bills?

A. There are several ways customer bills will be affected by this drastic shift in revenue recovery. First the lowest users will receive the greatest percentage bill increase. The highest users will receive bill decreases. The price signal on all customer bills will be diluted since so much more of the bill will no longer driven by consumption. Such a drastic shift in price signals is undesirable and at odds with the clearly-expressed Commission intent to encourage conservation.

Q. Why does the Company-proposed rate design result in such perverse price signals?

A. The Company has shifted more revenue to its fixed charge than it is asking for as a rate increase in this rate case. Thus, to achieve a 51% recovery from the fixed monthly charge, the Company has had to *decrease* its commodity rate from the current $0.30 per therm to $0.18 per therm. As a result, higher users will see their bills decrease under this proposed design and low users will have the highest percentage increases in their bills. This is a very perverse price signal that would all but halt any incentive for conservation.

Q. Please discuss the second aspect of the Company-proposed rate design.

A. The Company is proposing a fixed charge for the winter months (December – March) of $11 and a fixed monthly charge of $20 for the summer months (April – November). This aspect of the Company-proposed rate design further exacerbates the perverse price signal that results from nearly doubling the percentage fixed revenue and decreasing the commodity charge, as just discussed. The higher summer fixed charges will further flatten any price signal possible from the Company's rate design by equalizing summer and winter bills. UNS Gas already offers a levelized billing program and RUCO believes the choice of whether a customer prefers a levelized bill should be left with the customer and UNS Gas should concentrate greater efforts to ensure that customers are aware of the availability and advantages of the levelized bill option.

Q. Please discuss the Company's proposed decoupling mechanism.

A. The Company claims that while its proposed rate structure would mitigate some of its perceived revenue recovery problems, the continued use of *any* volumetric charge creates uncertainty of revenue recovery. UNS Gas proposes to remove this uncertainty with what it calls a Throughput Adjustment Mechanism (TAM).

Q. How would the TAM work?

A. The TAM would true-up customer usage to match the billing determinants authorized in this rate case. In other words, customers would pay for a fixed amount of consumption regardless of how much they actually consumed. The Company claims it needs this mechanism to "mitigate" the risk of revenue recovery.

Q. Would this mechanism "mitigate" the risk of revenue recovery?

A. No. This mechanism would *entirely remove* any risk associated with revenue recovery, not just merely mitigate it. In combination with the proposed fixed charge shift, and the biased summer/winter rate proposal, it would also send a perverse price signal that tells customers they will pay the same whether they use large quantities of gas or no gas at all. It also would guarantee UNS Gas' revenue recovery.

Q. Is it appropriate for the regulator of a monopoly public service company to guarantee revenues?

A. No. Regulation is required to provide a public service company the opportunity to recover its revenue requirement. As a public utility UNS Gas already has an exclusive service territory and a captive customer base, which places the Company at low business risk. The rate of return that the Commission grants the Company is comprised of a risk element that compensates the Company for business and financial risk. If the regulator were to remove all risk to UNS Gas via the TAM, which RUCO does not recommend, it would need to lower the authorized rate of return to reflect the absence of any risk element.

Q. Has the Company's cost of capital witness made an adjustment to his recommended rate of return to recognize the lack of risk under a TAM?

A. No.

Q. What other arguments does the Company make regarding the TAM?

A. The Company argues that the TAM would minimize the impact of weather on customer bills, and characterizes that as a "benefit" of the TAM. Further, the Company argues that the TAM "will allow" the Company to implement, fund, and actively promote energy efficiency programs for its customers.

Q. Do you agree with these arguments?

A No. First, the effect of "minimizing the impact of weather on customers bills" is not necessarily a desirable feature for a gas rate design. Under such a rate design, customers would receive no price signal reflecting their consumption, therefore removing any incentive to conserve. Second, the Company does not need a TAM to "allow" it to promote energy efficiency programs. In fact, UNS Gas currently has some energy efficiency programs in effect and the Commission has been very supportive of utilities' efforts in this regard.

Q. Has the Commission rejected decoupling proposals in the past?

A. Yes. Southwest Gas, in its last rate case proposed a decoupling mechanism (the CMT) very similar to that being proposed in this case. In Decision No. 68487 the Commission denied the proposed decoupling mechanism and stated the following:

> Further, as RUCO points out, the likely effect of adopting the proposed CMT is that residential customers will 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. We are also concerned with the dramatic impact that could be experienced by customers faced with a surcharge for not using "enough" gas the prior year. The Company is requesting that customers provide a guaranteed method of recovering authorized revenues, thereby virtually eliminating the Company's attendant risk. Neither the law nor sound public policy requires such a result and we decline to adopt the Company's CMT in this case.

Thus, the Commission fully recognized the perverse incentives such a mechanism could have, and accordingly denied the request. RUCO recommends that the Commission take the same action here.

Q. Please summarize RUCO's position on the Company-proposed rate design.

A. The three salient features of the Company-proposed rate design when viewed independently are extreme and when reviewed in aggregate result in perverse price signals that will only serve to incent are the wrong behaviors. Customers that aggressively consume would be rewarded under the Company-proposed rate design and customers who conserve would be penalized. RUCO recommends the Commission reject the biased winter/summer rates, the doubling of the revenue allocated to the fix charge, and the TAM.

Q. Please discuss RUCO's proposed rate design.

A. RUCO's proposal is for a rate design that removes the perverse price signals inherent in the Company's proposal, while at the same time addresses some of the Company's fixed cost and risk of revenue recovery concerns. First, I have maintained the existing allocation of rate recovery between the customer classes. Thus, my proposed rate design does not shift rate recovery between customer classes. Second, the Company's existing rate design recovers 26% of it revenue from the fixed monthly charge. RUCO's proposed rate design increases this percentage to 36%, which addresses the Company's risk of recovery concerns without flattening out the rate so much that it discourages conservation. Third, I have applied the same fixed charge in both the winter and summer. This aspect of my rate design allows for a price signal from weather. Customers who do not want this price signal are still able to opt into UNS Gas' levelized billing plan. RUCO's proposed rate design leaves this choice with the individual customer as opposed to the Company's proposal which would levelize all bills, whether the customer wanted it or not. Finally, RUCO's proposed rate design will not result in customers having to pay for therms they did not use and adheres to the Commission's findings in Decision No. 68487 regarding the undesirability of the proposed decoupling mechanism. RUCO's recommended rates and charges are shown on Schedule RLM-15 and RLM-16 presents an average residential bill analysis at different usage levels.

RULES AND REGULATIONS OF SERVICE

Q. Is the Company proposing any changes to its rules and regulations of service?

A. Yes. The Company has proposed to several changes to its rules and regulations of service. RUCO takes issue with one of the proposed changes.

Q. Which proposed change does RUCO take issue with.

A. The Company proposes to shorten the period of time customers have to pay their gas bills before a late fee is assessed from 15 days to 10 days and to short the time customers have to pay a past due bill prior to notice of shut-off from 30 days to 15 days.

Q. Why does RUCO take issue with these proposed changes?

A. The proposed changes are unreasonable. The proposed payment due dates are so short that a UNS Gas customer on vacation could foreseeably come home and find their gas shut-off. Since gas is a vital service to many, a more flexible payment schedule should prevail. As a regulated utility UNS Gas already receives a working capital allowance to bridge differences between receipt of revenues and payment of expenses, and should not have to impose unreasonable payment terms on its customers. RUCO recommends the Commission deny the proposed changes in payment due dates.

Q. Does this conclude your direct testimony?
A. Yes.

APPENDIX I

APPENDIX I

Qualifications of Marylee Diaz Cortez

EDUCATION:	University of Michigan, Dearborn B.S.A., Accounting 1989
CERTIFICATION:	Certified Public Accountant - Michigan Certified Public Accountant - Arizona
EXPERIENCE:	Audit Manager Residential Utility Consumer Office Phoenix, Arizona 85007 July 1994 - Present

Responsibilities include the audit, review and analysis of public utility companies. Prepare written testimony, schedules, financial statements and spreadsheet models and analyses. Testify and stand cross-examination before Arizona Corporation Commission. Advise and work with outside consultants. Work with attorneys to achieve a coordination between technical issues and policy and legal concerns. Supervise, teach, provide guidance and review the work of subordinate accounting staff.

Senior Rate Analyst
Residential Utility Consumer Office
Phoenix, Arizona 85004
October 1992 - June 1994

Responsibilities included the audit, review and analysis of public utility companies. Prepare written testimony and exhibits. Testify and stand cross-examination before Arizona Corporation Commission. Extensive use of Lotus 123, spreadsheet modeling and financial statement analysis.

Auditor/Regulatory Analyst
Larkin & Associates - Certified Public Accountants
Livonia, Michigan
August 1989 - October 1992

Performed on-site audits and regulatory reviews of public utility companies including gas, electric, telephone, water and sewer throughout the continental United States. Prepared integrated proforma financial statements and rate models for some of the largest public utilities in the United States. Rate models consisted of anywhere from twenty to one hundred fully integrated schedules. Analyzed financial statements, accounting detail, and identified and developed rate case issues based on this analysis. Prepared written testimony, reports, and briefs. Worked closely with outside legal counsel to achieve coordination of technical accounting issues with policy, procedural and legal concerns. Provided technical assistance to legal counsel at hearings and depositions. Served in a teaching and supervisory capacity to junior members of the firm.

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.	Client
Potomac Electric Power Co.	Formal Case No. 889	Peoples Counsel of District of Columbia
Puget Sound Power & Light Co.	Cause No. U-89-2688-T	U.S. Department of Defense - Navy
Northwestern Bell-Minnesota	P-421/EI-89-860	Minnesota Department of Public Service
Florida Power & Light Co.	890319-EI	Florida Office of Public Counsel
Gulf Power Company	890324-EI	Florida Office of Public Counsel
Consumers Power Company	Case No. U-9372	Michigan Coalition Against Unfair Utility Practices
Equitable Gas Company	R-911966	Pennsylvania Public Utilities Commission
Gulf Power Company	891345-EI	Florida Office of Public Counsel

Jersey Central Power & Light	ER881109RJ	New Jersey Department of Public Advocate Division of Rate Counsel
Green Mountain Power Corp.	5428	Vermont Department of Public Service
Systems Energy Resources	ER89-678-000 & EL90-16-000	Mississippi Public Service Commission
El Paso Electric Company	9165	City of El Paso
Long Island Lighting Co.	90-E-1185	New York Consumer Protection Board
Pennsylvania Gas & Water Co.	R-911966	Pennsylvania Office of Consumer Advocate
Southern States Utilities	900329-WS	Florida Office of Public Counsel
Central Vermont Public Service Co.	5491	Vermont Department of Public Service
Detroit Edison Company	Case No. U-9499	City of Novi
Systems Energy Resources	FA-89-28-000	Mississippi Public Service Commission
Green Mountain Power Corp.	5532	Vermont Department of Public Service
United Cities Gas Company	176-717-U	Kansas Corporation Commission

General Development Utilities	911030-WS & 911067-WS	Florida Office of Public Counsel
Hawaiian Electric Company	6998	U.S. Department of Defense - Navy
Indiana Gas Company	Cause No. 39353	Indiana Office of Consumer Counselor
Pennsylvania American Water Co.	R-00922428	Pennsylvania Office of Consumer Advocate
Wheeling Power Co.	Case No. 90-243-E-42T	West Virginia Public Service Commission Consumer Advocate Division
Jersey Central Power & Light Co.	EM89110888	New Jersey Department of Public Advocate Division of Rate Counsel
Golden Shores Water Co.	U-1815-92-200	Residential Utility Consumer Office
Consolidated Water Utilities	E-1009-92-135	Residential Utility Consumer Office
Sulphur Springs Valley Electric Cooperative	U-1575-92-220	Residential Utility Consumer Office
North Mohave Valley Corporation	U-2259-92-318	Residential Utility Consumer Office
Graham County Electric Cooperative	U-1749-92-298	Residential Utility Consumer Office
Graham County Utilities	U-2527-92-303	Residential Utility Consumer Office

Consolidated Water Utilities	E-1009-93-110	Residential Utility Consumer Office
Litchfield Park Service Co.	U-1427-93-156 & U-1428-93-156	Residential Utility Consumer Office
Pima Utility Company	U-2199-93-221 & U-2199-93-222	Residential Utility Consumer Office
Arizona Public Service Co.	U-1345-94-306	Residential Utility Consumer Office
Paradise Valley Water	U-1303-94-182	Residential Utility Consumer Office
Paradise Valley Water	U-1303-94-310 & U-1303-94-401	Residential Utility Consumer Office
Pima Utility Company	U-2199-94-439	Residential Utility Consumer Office
SaddleBrooke Development Co.	U-2492-94-448	Residential Utility Consumer Office
Boulders Carefree Sewer Corp.	U-2361-95-007	Residential Utility Consumer Office
Rio Rico Utilities	U-2676-95-262	Residential Utility Consumer Office
Rancho Vistoso Water	U-2342-95-334	Residential Utility Consumer Office
Arizona Public Service Co.	U-1345-95-491	Residential Utility Consumer Office
Citizens Utilities Co.	E-1032-95-473	Residential Utility Consumer Office
Citizens Utilities Co.	E-1032-95-417 et al.	Residential Utility Consumer Office
Paradise Valley Water	U-1303-96-283 & U-1303-95-493	Residential Utility Consumer Office
Far West Water	U-2073-96-531	Residential Utility Consumer Office

Southwest Gas Corporation	U-1551-96-596	Residential Utility Consumer Office
Arizona Telephone Company	T-2063A-97-329	Residential Utility Consumer Office
Far West Water Rehearing	W-0273A-96-0531	Residential Utility Consumer Office
SaddleBrooke Utility Company	W-02849A-97-0383	Residential Utility Consumer Office
Vail Water Company	W-01651A-97-0539 & W-01651B-97-0676	Residential Utility Consumer Office
Black Mountain Gas Company Northern States Power Company	G-01970A-98-0017 G-03493A-98-0017	Residential Utility Consumer Office
Paradise Valley Water Company Mummy Mountain Water Company	W-01303A-98-0678 W-01342A-98-0678	Residential Utility Consumer Office
Bermuda Water Company	W-01812A-98-0390	Residential Utility Consumer Office
Bella Vista Water Company Nicksville Water Company	W-02465A-98-0458 W-01602A-98-0458	Residential Utility Consumer Office
Paradise Valley Water Company	W-01303A-98-0507	Residential Utility Consumer Office
Pima Utility Company	SW-02199A-98-0578	Residential Utility Consumer Office
Far West Water & Sewer Company	WS-03478A-99-0144 Interim Rates	Residential Utility Consumer Office
Vail Water Company	W-01651B-99-0355 Interim Rates	Residential Utility Consumer Office
Far West Water & Sewer Company	WS-03478A-99-0144	Residential Utility Consumer Office
Sun City Water and Sun City West	W-01656A-98-0577 & SW-02334A-98-0577	Residential Utility Consumer Office

Southwest Gas Corporation ONEOK, Inc.	G-01551A-99-0112 G-03713A-99-0112	Residential Utility Consumer Office
Table Top Telephone	T-02724A-99-0595	Residential Utility Consumer Office
U S West Communications Citizens Utilities Company	T-01051B-99-0737 T-01954B-99-0737	Residential Utility Consumer Office
Citizens Utilities Company	E-01032C-98-0474	Residential Utility Consumer Office
Southwest Gas Corporation	G-01551A-00-0309 & G-01551A-00-0127	Residential Utility Consumer Office
Southwestern Telephone Company	T-01072B-00-0379	Residential Utility Consumer Office
Arizona Water Company	W-01445A-00-0962	Residential Utility Consumer Office
Litchfield Park Service Company	W-01427A-01-0487 & SW-01428A-01-0487	Residential Utility Consumer Office
Bella Vista Water Co., Inc.	W-02465A-01-0776	Residential Utility Consumer Office
Generic Proceedings Concerning Electric Restructuring Issues	E-00000A-02-0051	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-02-0707	Residential Utility Consumer Office
Qwest Corporation	RT-00000F-02-0271	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-02-0403	Residential Utility Consumer Office
Citizens/UniSource	G-01032A-02-0598 E-01032C-00-0751 E-01933A-02-0914 E-01302C-02-0914 G-01302C-02-0914	Residential Utility Consumer Office

Arizona-American Water Company	WS-01303A-02-0867	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-03-0437	Residential Utility Consumer Office
UniSource	E-04230A-03-0933	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-04-0407	Residential Utility Consumer Office
Qwest Corporation	T-01051B-03-0454 & T-00000D-00-0672	Residential Utility Consumer Office
Tucson Electric Power Company	E-01933A-04-0408	Residential Utility Consumer Office
Arizona-American Water Company	W-1303A-05-0280	Residential Utility Consumer Office
Southwest Gas Corporation	G-01551A-04-0876	Residential Utility Consumer Office
Arizona-American Water Company	W-1303A-05-0405	Residential Utility Consumer Office
Arizona-American Water Company	W-1303A-05-0718	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-06-0009	Residential Utility Consumer Office
Black Mountain Sewer Corporation	SW-02361A-05-0657	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-05-0816	Residential Utility Consumer Office
Arizona-American Water Company	WS-1303A-06-0014	Residential Utility Consumer Office
Tucson Electric Power Company	E-01933A-05-0650	Residential Utility Consumer Office

SCHEDULES

MDC-1 THROUGH MDC-7

UNS GAS, INC.
TEST YEAR ENDED DECEMEMBER 31, 2005
RATE BASE ADJ #3 - ACCUMULATED AMORTIZATION
OF ACQUISITION ADJUSTMENT

DOCKET NO. G-04204A-06-0463
SCHEDULE MDC-1

FERC ACCT	FERC ACCOUNT DESCRIPTION	(A)	(B)	(C)
114 (302)	Franchises & Consents - Citizens Acquisition Discount	44,743	4.00%	4,178
114 (303)	Miscellaneous Intangible Plant - Citizens Acquisition Discount	44,346	4.00%	4,141
114 (365)	Land and Land Rights - Citizens Acquisition Discount	18,927		0
114 (366)	Structures & Improvements - Citizens Acquisition Discount	2,886		0
114 (367)	Mains - Citizens Acquisition Discount	1,968,939	2.57%	118,115
114 (369)	Measuring and Reg. Station Equipment - Citizens Acquisition Discount	520,801	3.32%	40,360
114 (371)	Other Equipment - Citizens Acquisition Discount	29,679		0
114 (374)	Land and Land Rights - Citizens Acquisition Discount	47,590		0
114 (375)	Structures & Improvements - Citizens Acquisition Discount	303	3.35%	24
114 (376)	Mains - Citizens Acquisition Discount	21,622,117	2.22%	1,120,442
114 (378)	Meas. and Reg. Station Equipment - General - Citizens Acquisition Discount	231,298	5.73%	30,936
114 (379)	Meas. and Reg. Station Equipment - City Gate - Citizens Acquisition Discount	293,957	5.52%	37,876
114 (380)	Services - Citizens Acquisition Discount	8,147,940	4.75%	903,399
114 (381)	Meters - Citizens Acquisition Discount	1,424,561	2.86%	95,101
114 (382)	Meter Installations - Citizens Acquisition Discount	913,884	2.86%	61,009
114 (383)	House Regulators - Citizens Acquisition Discount	219,269	3.77%	19,296
114 (384)	House Regulatory Installations - Citizens Acquisition Discount	100,939	3.77%	8,883
114 (385)	Industrial Meas. & Reg. Station Equipment - Citizens Acquisition Discount	130,614	3.82%	11,646
114 (387)	Other Equipment - Citizens Acquisition Discount	179,204	3.64%	15,226
114 (389)	Land and Rights - Citizens Acquisition Discount	60,370		0
114 (390)	Structures & Improvements - Citizens Acquisition Discount	150,945	3.10%	10,922
114 (391)	Office Furniture and Equipment - Citizens Acquisition Discount	790,019	4.82%	88,884
114 (392)	Transportation Equipment - Citizens Acquisition Discount	104,867		0
114 (393)	Stores Equipment - Citizens Acquisition Discount	21,810	2.27%	1,156
114 (394)	Tools, Shop and Garage Equipment - Citizens Acquisition Discount	283,074	5.76%	38,059
114 (395)	Laboratory Equipment - Citizens Acquisition Discount	96,782	5.76%	13,012
114 (396)	Power Operated Equipment - Citizens Acquisition Discount	6,761	24.60%	3,882
114 (397)	Communication Equipment - Citizens Acquisition Discount	188,597	4.93%	21,703
114 (398)	Miscellaneous Equipment - Citizens Acquisition Discount	36,333	5.43%	4,605
Total Accumulated Amortization				$2,652,853
Per Company				$2,403,966
Adjustment				$248,887

References
Col. (A): Company w/p
Col. (B): Authorized Depreciation Rates per Dec. # 58664
Col. (C): Col. (A) x Col. (B) x 2.3342 years

UNS GAS CORPORATION
TEST YEAR ENDED DECEMBER 31, 2005
RATE BASE ADJUSTMENT # 6 - WORKING CAPITAL

DOCKET NO. G-004204A-06-0463
SCHEDULE MDC-2

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
1	MATERIALS & SUPPLIES PER UNS	$2,039,798	SCH. B-5, PG. 1
2	MATERIALS & SUPPLIES PER RUCO	2,039,798	SCH. B-5, PG. 1
3	ADJUSTMENT	0	LINE 2 - LINE 1
4	PREPAYMENTS PER UNS	195,942	SCH. B-5, PG. 1
5	PREPAYMENTS PER RUCO	195,942	SCH. B-5, PG. 1
6	ADJUSTMENT	0	LINE 5 - LINE 4
7	CASH WORKING CAPITAL PER UNS	(3,280,886)	SCH. B-5, PG. 2
8	CASH WORKING CAPITAL PER RUCO	(2,080,734)	SCHEDULE MDC-
9	ADJUSTMENT	1,200,152	LINE 8 - LINE 7
10	TOTAL ADJUSTMENT (See RLM-3, Column (G))	$1,200,152	SUM LINES 3, 6 & 9

UNS GAS CORPORATION
TEST YEAR ENDED DECEMBER 31, 2005
RATE BASE ADJUSTMENT # 6 - WORKING CAPITAL

DOCKET NO. G-004204A-06-0463
SCHEDULE MDC-2
PAGE 2 OF 2

LEAD/LAG DAY SUMMARY

LINE NO.	DESCRIPTION		(A) COMPANY EXPENSES AS FILED	(B) RUCO ADJUSTM'TS	(C) RUCO EXPENSES AS ADJUSTED	(D) (LEAD)/LAG DAYS	(E) DOLLAR DAYS
	Operating Expenses:						
	Non-Cash Expenses						
1	Bad Debts Expense		$ 722,634	$ -	$ -	0	$ -
2	Depreciation		7,950,183	-	-	0	-
3	Amortization		(729,791)	-	-	0	-
4	Deferred Income Taxes		3,178,719	-	-	0	-
5	Total Non-Cash Expenses		$ 11,121,745	$ -	$ -		$ -
	Other Operating Expenses:						
6	Salaries & Wages (UNS Dir.Emp's)		$ 7,287,745	$ -	$ 7,287,745	24.50	$ 178,549,753
7	Incentive Pay (UNS Dir. Emp's)		257,895	(257,895)	-	267.00	-
8	Purchased Gas		78,101,248	-	78,101,248	30.97	2,418,795,651
9	Office Supplies and Expenses		1,365,974	(156,063)	1,209,911	20.72	25,069,354
10	Injuries and Damages		574,128	(34,234)	539,894	64.75	34,958,114
11	Pensions and Benefits		2,452,071	(93,075)	2,358,996	54.66	128,942,703
12	Support Services - TEP(Dir. Labor)		4,570,692	-	4,570,692	44.91	205,269,778
13	Property Taxes		4,103,376	(476,193)	3,627,183	213.00	772,590,038
14	Payroll Taxes		537,877	(20,853)	517,024	19.30	9,978,563
15	Current Income Taxes		(1,203,222)	5,594,736	4,391,514	41.42	181,896,507
16	Interest on Customer Deposits		170,459	-	170,459	182.50	31,108,848
17	Other Operations and Maintenance		7,501,807	(1,023,893)	6,477,914	53.10	343,977,225
18	Total Other Operating Expenses		$105,720,050	$ 3,532,530	$109,252,580		$ 4,331,136,533
19	Total Operating Expenses		$116,841,794	$ 3,532,530	$109,252,580		$ 4,331,136,533
	Other Cash Working Capital Elements:						
20	Interest on Long-Term Debt		$ 5,334,825	$ (828,037)	$ 4,506,788	91.62	$ 412,911,927
21	Revenue Taxes and Assessments		18,788,535	(6,822,129)	11,966,406	76.25	912,438,458
22	Total Other Cash Working Capital		$ 24,123,360	$ (7,650,166)	$ 16,473,194		$ 1,325,350,385
23	TOTAL				$125,725,774		$ 5,656,486,918
24	Expense Lag	Line 23, Col. (E) / (D)		44.99			
25	Revenue Lag	Company Workpapers		38.95			
26	Net Lag	Line 25 - Line 24		(6.04)			
27	RUCO Adjusted Expenses	Col. (C), Line 23		$125,725,774			
28	Cash Working Capital	Line 26 X Line27 / 365 Days		(2,080,734)			
29	Company As Filed	Co. Schedule B-5, Page 1		(3,280,886)			
30	ADJUSTMENT (See MDC-2, Pg 1, L 9)	Line 28 - Line 29		1,200,152			

References:
Column (A): - Company Schedule B-5, Page 3
Column (B): RUCO Operating Income Adjustments (See Schedule RLM-7)
Column (C): Column (B) - (A)
Column (D): Company Schedule B-5, Page 3
Column (E): Column (C) X Column (D)

UNS GAS, INC.
TEST YEAR ENDED DECEMBER 31, 2005
OPERATING ADJ #13 - FLEET FUEL EXPENSE

DOCKET NO. G-04204A-06-0463
SCHEDULE MDC-3

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
1	AVERAGE MILEAGE PER CONSTRUCTION FTE	$15,016	COMPANY W/P
2	2006 FTE'S	158	COMPANY W/P
3	2006 PROFORMA MILEAGE	2,372,528	LINE 1 x LINE 2
4	2005 MILES PER GALLON	10.28	T/Y MILES/T/Y GALLONS
5	PROFORMA GALLONS PURCHASED	230,746	LINE 4/LINE 4
6	COST PER GALLON 2005	2.43	COMPANY W/P
7	FUEL COSTS	560,714	LINE 5 x LINE 6
8	PRO CARD PURCHASES	37,491	COMPANY W/P
9	TOTAL PROFORMA FUEL EXPENSE	598,205	LINE 7 + LINE 8
10	PER COMPANY	665,707	COMPANY W/P
11	ADJUSTMENT	(67,502)	LINE 9 - LINE 10
12	O&M ALLOCATION FACTOR	73.4%	COMPANY W/P
13	O&M ADJUSTMENT	($49,547)	LINE 11 x LINE 12

UNS GAS, INC.
TEST YEAR ENDED DECEMBER 31, 2005
OPERATING ADJ #14 - REVENUE ANNUALIZATION

DOCKET NO. G-04204A-06-0463
SCHEDULE MDC-4
PAGE 1 OF 8

LINE NO.	DESCRIPTION	RUCO ANNUALIZED REVENUE	REFERENCE
1	RESIDENTIAL RATE 10	$620,694	SCH. MDC-4, PG. 2
2	RESIDENTIAL RATE 12	84,010	SCH. MDC-4, PG. 3
3	COMMERCIAL RATE 20	107,350	SCH. MDC-4, PG. 4
4	COMMERCIAL RATE 22	15,418	SCH. MDC-4, PG. 5
5	INDUSTRIAL RATE 30	(6,885)	SCH. MDC-4, PG. 6
6	PUBLIC AUTH. RATE 40	16,423	SCH. MDC-4, PG. 7
7	PUBLIC AUTH. RATE 42	(1,321)	SCH. MDC-4, PG. 8
8	TOTAL	835,688	SUM LINES 1 THROUGH 7
9	PER COMPANY	725,682	COMPANY W/P
10	ADJUSTMENT	$110,006	LINE 8 - LINE 9

UNS GAS, INC.
TEST YEAR ENDED DECEMBER 31, 2005
OPERATING ADJ #14 - REVENUE ANNUALIZATION

LINE NO.	DESCRIPTION	JAN	FEB	MARCH	APRIL	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC
	RESIDENTIAL RATE 10												
1	T/Y END CUSTOMERS	121,125	121,125	121,125	121,125	121,125	121,125	121,125	121,125	121,125	121,125	121,125	121,125
2	T/Y MONTHLY CUSTOMERS	117,503	117,602	118,507	118,170	118,064	118,566	118,318	118,974	119,000	119,735	120,289	121,125
3	INCREASE IN CUSTOMERS	3,622	3,523	2,618	2,955	3,061	2,559	2,807	2,151	2,125	1,390	836	0
4	MONTHLY MINIMUM CHRG.	7	7	7	7	7	7	7	7	7	7	7	7
5	REVENUE FROM MINIMUM	25,354	24,661	18,326	20,685	21,427	17,913	19,649	15,057	14,875	9,730	5,852	0
6	MARGIN RATE	0.3004	0.3004	0.3004	0.3004	0.3004	0.3004	0.3004	0.3004	0.3004	0.3004	0.3004	0.3004
7	THERMS PER CUSTOMER	107	89	78	65	38	21	15	13	15	18	33	75
8	REVENUE FROM MARGIN	$116,421	$94,190	$61,343	$57,699	$34,942	$16,143	$12,648	$8,400	$9,575	$7,516	$8,287	$0
9	TOTAL INCREASE IN REVENUE	620,694											
10	PER COMPANY	540,499											
11	ADJUSTMENT	$80,195											

UNS GAS, INC.
TEST YEAR ENDED DECEMBER 31, 2005
OPERATING ADJ #14 - REVENUE ANNUALIZATION

LINE NO.	DESCRIPTION	JAN	FEB	MARCH	APRIL	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC
	RESIDENTIAL RATE 12												
1	T/Y END CUSTOMERS	5,556	5,556	5,556	5,556	5,556	5,556	5,556	5,556	5,556	5,556	5,556	5,556
2	T/Y MONTHLY CUSTOMERS	4,798	4,905	5,045	5,161	5,295	5,358	5,407	5,443	5,377	5,341	5,484	5,556
3	INCREASE IN CUSTOMERS	758	651	511	395	261	198	149	113	179	215	72	0
4	MONTHLY MINIMUM CHRG.	7	7	7	7	7	7	7	7	7	7	7	7
5	REVENUE FROM MINIMUM	5,306	4,557	3,577	2,765	1,827	1,386	1,043	791	1,253	1,505	504	0
6	MARGIN RATE	0.3004	0.3004	0.3004	0.3004	0.3004	0.3004	0.3004	0.3004	0.3004	0.3004	0.3004	0.3004
7	THERMS PER CUSTOMER	92	76	66	55	32	18	14	12	14	16	29	66
8	REVENUE FROM MARGIN	$20,949	$14,863	$10,131	$6,526	$2,509	$1,071	$627	$407	$753	$1,033	$627	$0
9	TOTAL INCREASE IN REVENUE	84,010											
10	PER COMPANY	105,047											
11	ADJUSTMENT	$\boxed{(\$21,037)}$											

UNS GAS, INC.
TEST YEAR ENDED DECEMBER 31, 2005
OPERATING ADJ #14 - REVENUE ANNUALIZATION

LINE NO.	DESCRIPTION	JAN	FEB	MARCH	APRIL	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC
	COMMERCIAL RATE 20												
1	T/Y END CUSTOMERS	11,017	11,017	11,017	11,017	11,017	11,017	11,017	11,017	11,017	11,017	11,017	11,017
2	T/Y MONTHLY CUSTOMERS	10,877	10,891	10,974	10,960	10,902	10,816	10,772	10,730	10,701	10,728	10,821	11,017
3	INCREASE IN CUSTOMERS	140	126	43	57	115	201	245	287	316	289	196	0
4	MONTHLY MINIMUM CHRG.	11	11	11	11	11	11	11	11	11	11	11	11
5	REVENUE FROM MINIMUM	1,540	1,386	473	627	1,265	2,211	2,695	3,157	3,476	3,179	2,156	0
6	MARGIN RATE	0.2420	0.2420	0.2420	0.2420	0.2420	0.2420	0.2420	0.2420	0.2420	0.2420	0.2420	0.2420
7	THERMS PER CUSTOMER	404	340	301	269	183	140	124	114	121	134	179	318
8	REVENUE FROM MARGIN	$13,688	$10,367	$3,132	$3,711	$5,093	$6,810	$7,352	$7,918	$9,253	$9,372	$8,490	$0
9	TOTAL INCREASE IN REVENUE	107,350											
10	PER COMPANY	60,672											
11	ADJUSTMENT	$46,678											

UNS GAS, INC.
TEST YEAR ENDED DECEMBER 31, 2005
OPERATING ADJ #14 - REVENUE ANNUALIZATION

LINE NO.	DESCRIPTION	JAN	FEB	MARCH	APRIL	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC
	COMMERCIAL RATE 22												
1	T/Y END CUSTOMERS	11	11	11	11	11	11	11	11	11	11	11	11
2	T/Y MONTHLY CUSTOMERS	10	10	10	10	10	10	10	10	10	11	11	11
3	INCREASE IN CUSTOMERS	1	1	1	1	1	1	1	1	1	0	0	0
4	MONTHLY MINIMUM CHRG.	85	85	85	85	85	85	85	85	85	85	85	85
5	REVENUE FROM MINIMUM	85	85	85	85	85	85	85	85	85	0	0	0
6	MARGIN RATE	0.1551	0.1551	0.1551	0.1551	0.1551	0.1551	0.1551	0.1551	0.1551	0.1551	0.1551	0.1551
7	THERMS PER CUSTOMER	17,420	14,475	13,507	13,143	10,212	7,636	6,936	5,073	6,073	6,961	7,857	10,200
8	REVENUE FROM MARGIN	$2,702	$2,245	$2,095	$2,038	$1,584	$1,184	$1,076	$787	$942	$0	$0	$0
9	TOTAL INCREASE IN REVENUE	15,418											
10	PER COMPANY	11,350											
11	ADJUSTMENT	$4,068											

UNS GAS, INC.
TEST YEAR ENDED DECEMBER 31, 2005
OPERATING ADJ #14 - REVENUE ANNUALIZATION

LINE NO.	DESCRIPTION	JAN	FEB	MARCH	APRIL	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC
	INDUSTRIAL RATE 30												
1	T/Y END CUSTOMERS	12	12	12	12	12	12	12	12	12	12	12	12
2	T/Y MONTHLY CUSTOMERS	13	13	13	13	13	13	13	13	13	13	12	12
3	INCREASE IN CUSTOMERS	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	0	0
4	MONTHLY MINIMUM CHRG.	11	11	11	11	11	11	11	11	11	11	11	11
5	REVENUE FROM MINIMUM	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	(11)	0	0
6	MARGIN RATE	0.2122	0.2122	0.2122	0.2122	0.2122	0.2122	0.2122	0.2122	0.2122	0.2122	0.2122	0.2122
7	THERMS PER CUSTOMER	4,068	3,758	3,254	3,258	2,276	6,206	1,869	2,167	2,925	2,148	2,206	5,653
8	REVENUE FROM MARGIN	($863)	($797)	($690)	($691)	($483)	($1,317)	($397)	($460)	($621)	($456)	$0	$0
9	TOTAL INCREASE IN REVENUE	(6,885)											
10	PER COMPANY	0											
11	ADJUSTMENT	($6,885)											

UNS GAS, INC.
TEST YEAR ENDED DECEMBER 31, 2005
OPERATING ADJ #14 - REVENUE ANNUALIZATION

LINE NO.	DESCRIPTION	JAN	FEB	MARCH	APRIL	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC
	PUBLIC AUTH. RATE 40												
1	T/Y END CUSTOMERS	1,051	1,051	1,051	1,051	1,051	1,051	1,051	1,051	1,051	1,051	1,051	1,051
2	T/Y MONTHLY CUSTOMERS	1,027	1,033	1,039	1,044	1,044	1,043	1,041	1,046	1,042	1,039	1,050	1,051
3	INCREASE IN CUSTOMERS	24	18	12	7	7	8	10	5	9	12	1	0
4	MONTHLY MINIMUM CHRG.	11	11	11	11	11	11	11	11	11	11	11	11
5	REVENUE FROM MINIMUM	264	198	132	77	77	88	110	55	99	132	11	0
6	MARGIN RATE	0.2354	0.2354	0.2354	0.2354	0.2354	0.2354	0.2354	0.2354	0.2354	0.2354	0.2354	0.2354
7	THERMS PER CUSTOMER	1,109	896	759	633	333	161	98	101	109	150	316	761
8	REVENUE FROM MARGIN	$6,265	$3,797	$2,144	$1,043	$549	$303	$231	$119	$231	$424	$74	$0
9	TOTAL INCREASE IN REVENUE	16,423											
10	PER COMPANY	21,325											
11	ADJUSTMENT	($4,902)											

UNS GAS, INC.
TEST YEAR ENDED DECEMBER 31, 2005
OPERATING ADJ #14 - REVENUE ANNUALIZATION

LINE NO.	DESCRIPTION	JAN	FEB	MARCH	APRIL	MAY	JUNE	JULY	AUG	SEPT	OCT	NOV	DEC
	PUBLIC AUTH. RATE 42												
1	T/Y END CUSTOMERS	5	5	5	5	5	5	5	5	5	5	5	5
2	T/Y MONTHLY CUSTOMERS	6	6	6	6	6	6	6	6	6	6	5	5
3	INCREASE IN CUSTOMERS	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	0	0
4	MONTHLY MINIMUM CHRG.	85	85	85	85	85	85	85	85	85	85	85	85
5	REVENUE FROM MINIMUM	(85)	(85)	(85)	(85)	(85)	(85)	(85)	(85)	(85)	(85)	0	0
6	MARGIN RATE	0.1084	0.1084	0.1084	0.1084	0.1084	0.1084	0.1084	0.1084	0.1084	0.1084	0.1084	0.1084
7	THERMS PER CUSTOMER	1,109	896	759	633	333	161	98	101	109	150	316	761
8	REVENUE FROM MARGIN	($120)	($97)	($82)	($69)	($36)	($17)	($11)	($11)	($12)	($16)	$0	$0
9	TOTAL INCREASE IN REVENUE	(1,321)											
10	PER COMPANY	(13,212)											
11	ADJUSTMENT	$\boxed{\$11,891}$											

UNS GAS, INC.
TEST YEAR ENDED DECEMBER 31, 2005
OPERATING ADJ #17 - UNCOLLECTIBLES EXPENSE

DOCKET NO. G-04204A-06-0463
SCHEDULE MDC-5

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
1	RUCO T/Y ADJUSTED REVENUE	$47,280,434	SCHEDULE RLM-6
2	T/Y GAS REVENUES	75,545,465	SCHEDULE C-2, PAGE 1
3	TOTAL T/Y ADJUSTED REVENUES	122,825,899	LINE 1 + LINE 2
4	UNCOLLECTIBLES RATE	0.51052%	COMPANY W/P
5	UNCOLLECTIBLES EXPENSE	627,051	LINE 3 x LINE 4
6	UNCOLLECTIBLES PER COMPANY	722,634	COMPANY W/P
7	ADJUSTMENT	($95,583)	LINE 5 - LINE 6

UNS GAS, INC.
TEST YEAR ENDED DECEMBER 31, 2005
OPERATING ADJ #19 - OUT OF PERIOD EXPENSES

DOCKET NO. G-04204A-06-0463
SCHEDULE MDC-6

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
1	PRICE WATER HOUSE - NOV-DEC 2004	$172,607	RUCO DR 2.22, UNSG0463/00101
2	PRICE WATER HOUSE - NOV-DEC 2004	9,058	RUCO DR 2.22, UNSG0463/00108
3	PRICE WATER HOUSE DEC 1-DEC 31 2004	58,335	RUCO DR 2.22, UNSG0463/00098
4	TOTAL	240,000	SUM LINES 1 - 3
5	ALLOCATION FACTOR	8.80%	RUCO DR 7.3
6	ADJUSTMENT	$21,120	LINE 4 x LINE 5

UNS GAS, INC.
TEST YEAR ENDED DECEMBER 31, 2005
OPERATING ADJ #20 - LEGAL FEES

DOCKET NO. G-04204A-06-0463
SCHEDULE MDC-7

LINE NO.	DATE	DESCRIPTION	AMOUNT
1	5-May	FLEISCHMAN & WALSH LLP	$87,269
2	5-Aug	FLEISCHMAN & WALSH LLP	28,463
3	5-Sep	FLEISCHMAN & WALSH LLP	56,612
4	5-Oct	FLEISCHMAN & WALSH LLP	32,331
5	5-Nov	FLEISCHMAN & WALSH LLP	28,712
6	5-Dec	FLEISCHMAN & WALSH LLP	39,129
7	5-Dec	FLEISCHMAN & WALSH LLP	38,535
8		TOTAL	$311,051

UNS GAS, INC.

DOCKET NO. G-04204A-06-0463 et al.

SURREBUTTAL TESTIMONY

OF

MARYLEE DIAZ CORTEZ, CPA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

APRIL 4, 2007

EXHIBIT

RUCO 6

admitted

INTRODUCTION

Q. Please state your name for the record.

A. My name is Marylee Diaz Cortez.

Q. Have you previously filed testimony in this docket?

A. Yes. I filed direct testimony in this docket on February 9, 2007.

Q. What is the purpose of your surrebuttal testimony?

A. In my surrebuttal testimony I will respond to the positions and arguments set forth by various UNS Gas witnesses in their rebuttal testimony. I will show that certain arguments are without merit and demonstrate why such arguments should be rejected.

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

A. I will address the following issues in my surrebuttal testimony:

Rate Base

* Fair Value Rate Base
* Citizens Acquisition Adjustment
* CWIP
* GIS Deferral
* Working Capital

Operating Income

* Fleet Fuel Expense

* Customer Annualization
* Corporate Cost Allocations
* Bad Debts – Uncollectibles
* Out-of-Period Expenses
* Legal Expenses

Rate Design

Rules and Regulations of Service

RATE BASE

Fair Value Rate Base

Q. In its rebuttal testimony, has the Company proposed any significant revisions to its application as originally filed?

A. Yes. In its rebuttal testimony the Company has significantly altered its cost of capital recommendation, such that UNS Gas is requesting that its original cost rate of return of 8.80% now be applied to its fair value rate base, whereas in its original application this rate of return was applied to the original cost rate base. This is a significant alteration in the Company's request.

Q. Why did the Company change its position on this issue?

A. According to UNS Gas, it has altered its position based on an Arizona Court of Appeals decision regarding Chaparral City Water Company.

Q. Are you familiar with this decision?

A. Yes. While I am not a lawyer, I believe the decision the Company is referring to is a Memorandum Decision issued by the Court of Appeals in Arizona on February 13, 2007. (Chapparral City Water v. ACC, Docket No. 1 CA-CC 05-0002) (Court of Appeals, February 13, 2007). That decision, in part, addressed the issue of how the Commission had determined its fair value rate of return in that case, and ultimately remanded the issue to the Commission.

Q. Does that decision require that UNS Gas revise its rate request in the instant case?

A. No. The decision is a memorandum decision, which has no precedential effect on other cases. Further, the court recently granted an extension of the time for the Commission to seek review of the decision by the Arizona Supreme Court. Thus, the issue is, at best, prematurely raised, and more likely irrelevant given the decision's non-precedential status.

Q. Had the Company originally filed its application requesting that an original cost rate of return be applied to a fair value rate base, would RUCO's analysis and conclusions in its direct testimony have been different?

A. Certainly. RUCO's analysis of both the cost of capital as well as the Reconstruction Cost New Depreciated (RCND) rate base would have been entirely different, and most likely produced different conclusions.

Q. Is the untimeliness of this revision prejudicial to the parties?

A. Yes. The parties have had no opportunity to conduct discovery and analysis of this new request. In fact the Commission in its own rules recognizes that substantial revisions to a utility's application are prejudicial and provides the following relief under such circumstances:

> Upon motion by any party to the matter or on its own motion, the Commission or the Hearing Officer may determine the time periods prescribed by sub-section (B)(11)(d) should be extended or begin again due to:
> i. Any amendment to a filing which changes the amount sought by the utility or substantially alters the facts used as a basis for the requested in rates or charges; (R14-2-103 (B)(11)(e))

Q. Are you recommending an extension in this case as a result of this material change to the Company's request?

A. No. The Chaparral decision has not reached its final conclusion in the courts, and even if it had, it is not binding in other proceedings. An extension of time to undertake additional analysis would not be necessary to resolve the issue, as there is currently no change in the applicable legal requirements.

Citizens Acquisition Adjustment

Q. Please discuss the Company's rebuttal comments pertaining to your adjustment to the Citizens Acquisition Adjustment.

A. The Company continues to maintain in its rebuttal testimony that the depreciation rates that were proposed in Docket No. G-1032A-02-0598 have been authorized by the Commission.

Q. Did Decision No. 66028 authorize a change in depreciation rates for UNS Gas?

A. No. Furthermore, in its rebuttal testimony[1] the Company acknowledges that Decision No. 66028 makes no mention of a change in depreciation rates.

Q. Why then does the Company continue to maintain that Decision No. 66028 authorized a change in depreciation rates?

A. The Company argues that one element of the increase in revenues that was approved in Decision No. 66028 was depreciation expense based on the then Company-proposed depreciation rates and that the Commission's approval of that revenue level constitutes Commission approval of those depreciation rates.

[1] Rebuttal Testimony of Karen G. Kissinger, page 8, lines 1-2.

Q. Do you agree?

A. No. Decision No. 66028 was a result of a settlement agreement between Staff and the Company. The terms of that agreement are specifically stated in the agreement and in the resultant Commission order. Nowhere in the settlement agreement or the Commission's order is there any indication that the agreed upon revenue level is based on the depreciation that would result from the Company's then-proposed depreciation rates. Depreciation rates simply are not addressed in the terms of that agreement, and thus remain unchanged by Decision No. 66028. Accordingly, my proposed adjustment to the accumulated amortization of the Citizens Acquisition Adjustment is correct and appropriate.

Construction Work in Progress (CWIP)

Q. Please discuss the Company's rebuttal comments regarding CWIP.

A. The Company argues that CWIP in rate base is an accepted ratemaking concept that is routinely recognized in many states. The Company further expounds that, contrary to my testimony, CWIP inclusion in rate base does not require extraordinary circumstances.

Q. Please respond.

A. While CWIP in rate base may be accepted ratemaking treatment in some states, it is not accepted ratemaking in Arizona. In fact, Arizona has always required extraordinary circumstances before it even considered rate base treatment for CWIP. The Commission explicitly stated such in Decision No. 54247:

> Beginning in Decision No. 53909 (January 30, 1984) and again in Decision No. 54204, the Commission has recognized that the **extraordinary** inclusion of Palo Verde CWIP necessitates an equally extraordinary reward to ratepayers for their admittedly involuntary investment in Palo Verde carrying costs. [Decision No. 54247, dated November 28, 1984, page 5-6]

Q. What other arguments does the Company make on the CWIP issue?

A. The Company further argues that RUCO's exclusion of CWIP from rate base creates a mismatch because of some of those projects have CIAC balances associated with them, which are included in the test-year rate base.

Q. Please respond.

A. As just discussed, Arizona has historically excluded CWIP in rate base and historically included CIAC in rate base. Thus, under RUCO's recommendations, UNS Gas is being afforded the same rate base treatment for these two items that every other utility in Arizona is afforded.

Q. In fact, isn't it the Company's proposal to rate base CWIP that creates a mismatch?

A. Yes. Mismatches result from the Company's CWIP proposal because while it has included its investment in CWIP in rate base, it has failed to recognize the additional revenues those construction projects will generate.

Q. How do you know these CWIP projects will create additional revenue?

A. The Company provided RUCO with a workpaper that the identified FERC plant accounts where the $7.2 million in CWIP will eventually reside. Fully 86% of the $7.2 million in CWIP projects are for Mains, Services, and Meters. These projects will extend service to new customers and create additional revenue. Biased rates will result if the investment in these line extensions is recognized, but not the additional revenue the line extensions will generate.

Global Information System (GIS) Deferral

Q. Please discuss the Company's rebuttal comments pertaining to your GIS deferral adjustment.

A. The Company argues that even though it failed to obtain an accounting order allowing it to capitalize these expenses as a regulatory asset, it should be able to do so anyway.

Q. Do you agree?

A. No. The costs associated with the GIS are expenses, not assets, under Generally Accepted Accounting Principles (GAAP)[2] accounting.

[2] Statement of Financial Accounting Standards No. 71

Accordingly, the only way UNS Gas could have accounted for these expenses as assets was to have obtained approval of an accounting order from the Commission, which it did not.

Q. What other arguments does the Company set forth in its rebuttal testimony on this issue?

A. In response to my testimony that UNS Gas already recovered the GIS expenses during the test year because it generated over $10.5 million in operating income[3], the Company states it has not recovered these costs.

Q. If the Company's operating income exceeded its operating expenses how is it possible that the Company did not recover these costs?

A. That is a good question, and one the Company does not explain in its rebuttal testimony, other than to claim that by definition if it deferred these expenses it did not recover them.

Q. Please respond.

A. That is precisely the point. The Company did not obtain an accounting order from the Commission permitting deferral treatment of these expenses and accordingly did not defer these expenses. Rather, in accordance with GAAP, the Company expensed the GIS expenses during the test year. Since test-year revenues exceeded test-year expenses by

[3] In my direct testimony I said, "net income of over $10.5 million". This was inadvertent and should have read "operating income of over $10.5 million".

over $10.5 million the test-year costs associated with the GIS have in fact been recovered by UNS Gas.

Working Capital

Q. Please discuss the Company's rebuttal testimony regarding working capital.

A. The Company has provided no rebuttal testimony regarding working capital. Thus, it appears the only working capital issue in contention is the level of operating expenses to be used in the cash working capital lead/lag calculation. The Commission will ultimately determine the appropriate level of operating expenses in its decision in this docket.

OPERATING INCOME

Fleet Fuel Expense

Q. Has the Company provided any rebuttal comments to your recommended adjustment to Fleet Fuel Expense?

A. Very little. Other than to say the Company prefers the Staff witness' suggested adjustment over RUCO's recommended adjustment, the Company is silent on this issue. The Staff proposed adjustment normalizes the average cost of gasoline, as does RUCO's adjustment. The Staff adjustment, however, does not correct for error the Company made in calculating the average miles per gallon (mpg) its fleet realizes.

My adjustment corrects for Company's understatement of mpg and is necessary to reflect an appropriate level of fleet fuel expense.

Customer Annualization

Q. Please discuss the Company's rebuttal comments regarding your revenue annualization adjustment.

A. The Company argues that the "traditional" approach that myself and the Staff witness used to annualize the test-year revenue is inappropriate for UNS Gas given the seasonal characteristics of its customer base.

Q. Do you agree?

A. No. The test-year customer count data that the Company provided does not support the Company's argument regarding seasonality. The Company realizes the majority of its revenue from Residential Rate 10. I have prepared Surrebuttal Schedule MDC-1, which shows the percentage increase in customers on this rate schedule from month to month during the test year. As shown on this schedule, the customer base has incrementally increased in every month of the test year excepting April, May, and July. The decreases in those three months range between 9/100$^{\text{ths}}$ of a percent to 1/3$^{\text{rd}}$ of a percent. This is hardly the extreme seasonality that the Company portrays in its rebuttal testimony, or a reason to depart from the "traditional" or Commission-accepted methodology of revenue annualization.

Corporate Cost Allocations

Q. Please discuss the Company's rebuttal comments pertaining to your Corporate Cost Allocation adjustment.

A. The Company agrees with my recommended adjustment which removes additional non-recurring charges related to the recent merger attempt.

Bad Debts – Uncollectibles

Q. Please discuss the Company's rebuttal comments regarding your bad debt adjustment.

A. The Company argues that my bad debt recommendation is flawed because while I removed the Griffith Plant and NSP revenues from the calculation, I did not likewise remove these revenues from my calculation of the bad debt ratio.

Q. Do you agree?

A. Yes, both the numerator and the denominator of the bad debt ratio would have to be adjusted to remove the NSP and Griffith Plant. Because this issue only recently arose, I have not as yet obtained the information necessary to make a revised calculation that would adjust the numerator of the ratio for both 2004 and 2005 and that would adjust the denominator for 2004.

Out-of-Period Expenses

Q. Please discuss the Company's rebuttal comments pertaining to your Out-of-Period Expense adjustment.

A. The Company agrees that the test year contains a number of expenditures that relate to 2004 that should not have been included. However, the Company argues that likewise there were expenses recorded in 2006 that should have been recorded in 2005, and that these out-of-period expenses would outweigh the 2004 out-of-period expenses removed in my adjustment.

Q. Do you agree?

A. I can't know. My audit in this case was primarily of the 2005 test year. Thus, I am not familiar with the 2006 data to which the Company's rebuttal testimony refers. The Company has provided no accounting documentation to support its rebuttal claim regarding 2006 out-of-period expenses, and therefore I can neither agree nor disagree with its rebuttal arguments.

Legal Expenses

Q. Please address the Company's rebuttal arguments regarding your legal expense adjustment.

A. The Company argues that the FERC rate case settlement in the El Paso matter has continued, and while certain cases may not repeat each year, legal expenses for different cases are recurring. The Company suggests using a two-year average to normalize the test year.

Q. Do you agree with this argument?

A. No, not entirely. While the Company is correct that the identical legal issues may not necessarily arise every year, other legal issues will arise. What makes the legal adjustment recommended by RUCO and Staff appropriate is not just that the El Paso settlement legal expenses are non-recurring, but also these legal expenses are extraordinary in their magnitude.

Q. Please explain.

A. During the test year, the Company incurred 46 invoices for outside legal services. Of these 46 invoices, RUCO and Staff determined 7 of them to be related to the El Paso rate settlement and non-recurring. The average cost of these 7 non-recurring invoices was $44,436, whereas the average cost of the other 39 recurring invoices was $5,292. Thus, the El Paso legal expenses were much larger than the routine or recurring legal expenses.

Q. Are there any other reasons why your legal expenses adjustment is reasonable?

A. Yes. Despite the fact that the El Paso rate settlement is non-recurring, I have not disallowed all of the El Paso legal invoices, only those that exceed $20,000. Thus, the test year, even after my proposed adjustment, contains over $75,000 in legal expenses associated with the El Paso settlement.

RATE DESIGN

Q. Please discuss the Company's rebuttal comments regarding your proposed rate design.

A. The Company's rebuttal takes exception to my characterization of its proposed rate design as creating rate shock for certain customers, resulting in perverted price signals, and stifling conservation. The Company claims that because customers do not have to pay the cost of gas charge of approximately 60 cents per therm when they conserve, that under its proposed rate design there still remains a price signal to conserve.

Q. Do you agree with this latter claim?

A. Yes, and RUCO has not claimed otherwise. The point I make in my direct testimony is that the Company's proposed rate design shifts so much revenue from the commodity charge to the fixed charge that it results in a large increase in the fixed charge and a significant decrease in the commodity rate. The price signal this sends to customers is that low users will receive the highest percentage increase in their bill and the highest users will actually receive decreases in their bills. This phenomena of the Company's rate design is irrespective of gas cost savings that can be achieved through conservation. RUCO's proposed rate design also includes an increase in the fixed charge, but not to the degree that commodity rates need to be decreased significantly.

Q. Please address the Company's rebuttal comments regarding RUCO's position on the Throughput Adjustment Mechanism (TAM).

A. The Company claims that, contrary to my assertion in direct testimony, the TAM would not entirely remove any risk associated with revenue recovery. UNS Gas maintains that it would have risk associated with increased costs and with those customers not subject to the TAM.

Q. Please respond.

A. The Company has the ability to control and mitigate increasing costs, and thus, increasing costs do not pose a big risk to the Company. Furthermore, the Company has the ability to file for a rate increase at any time that it perceives its revenue to be insufficient to cover its costs. What the TAM does is remove virtually all of the risk that the Company is unable to control and/or mitigate, such as weather, conservation, and consumption.

Q. What other arguments does the Company set out regarding the TAM?

A. The Company argues that other states have adopted such mechanisms and that while the ACC rejected such a mechanism in the recent Southwest Gas rate case, it also encouraged the parties to seek rate design alternatives that will encourage conservation.

Q. Have the parties to the Southwest Gas case met to explore rate design alternatives that will encourage conservation as ordered in Decision No. 68487?

A. Yes. Southwest Gas, Commission Staff, SWEEP, and RUCO have met on several occasions to have such discussions. While no consensus has been reached the parties have acknowledged that Southwest Gas' ability to recover its margin rates is primarily related to weather as opposed to declining usage attributable to conservation. Thus, at least in Southwest Gas' case, a TAM would do little to encourage conservation, which was the Commission's motive for encouraging the parties to discuss rate design alternatives.

RULES AND REGULATIONS OF SERVICE

Q. Please address the Company's rebuttal comments regarding RUCO's position on shortening the length of time customers have to pay their gas bill.

A. The Company argues that the shortened period of time for when a bill becomes delinquent is entirely reasonable and that my observation that the Company already receives adequate compensation for its billing lag through its working capital allowance is "irrelevant".

Q. Please respond.

A. I would differ from the Company's opinion that the shortened bill due date is "reasonable." RUCO has had calls from UNS Gas customers regarding this issue and none of those customers believed the proposal was reasonable. Further, the Company's characterization of the fact that they are compensated for the billing lag via the working capital allowance as "irrelevant" is irresponsible at best. Ratepayers are required to reimburse the Company through the rates they pay for this billing lag, so I do not believe this fact is "irrelevant" to them. The Company is not harmed by the current billing terms, but customers perceive harm in the shortened billing terms. Thus, RUCO believes the public interest is not served by granting abbreviated billing terms.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

SURREBUTTAL SCHEDULES

MDC-1 AND MDC-2

UNS GAS, INC.
TEST YEAR ENDED DECEMBER 31, 2005
PERCENTAGE INCREASE IN RESIDENTIAL RATE 10 CUSTOMERS

DOCKET NO. G-04204A-06-0463
SURREBUTTAL SCH. MDC-1

LINE NO.	MONTH	# OF CUSTOMERS	% INCREASE
	JANUARY	117,503	
	FEBRUARY	117,602	0.08%
	MARCH	118,507	0.77%
	APRIL	118,170	-0.28%
	MAY	118,064	-0.09%
	JUNE	118,566	0.43%
	JULY	118,318	-0.21%
	AUGUST	118,974	0.55%
	SEPTEMBER	119,000	0.02%
	OCTOBER	119,735	0.62%
	NOVEMEBER	120,289	0.46%
	DECEMBER	121,125	0.69%

UNS Gas, Inc.
Legal Invoice Query
2005

DOCKET NO. G-04204A-06-0463
SURREBUTTAL SCHEDULE MDC-2

	GL Date	Account	Amount	Payee/Vendor Name	Subject Matter	Service Performed
1	JAN-05	52010	18.00	ROSHKA DEWULF & PATTEN PLC		
2	JAN-05	52010	200.00	MARY L BONILLA		
3	JAN-05	52010	307.13	LEWIS AND ROCA LLP		
4	JAN-05	52010	600.00	THELEN REID & PRIEST LLP		
5	JAN-05	52010	6,248.77	FLEISCHMAN & WALSH LLP		
6	JAN-05	52010	19,216.41	LEWIS AND ROCA LLP		
7	MAR-05	52010	89.34	LEWIS AND ROCA LLP		
8	MAR-05	52010	252.00	ROSHKA DEWULF & PATTEN PLC		
9	MAR-05	52010	386.00	ROSHKA DEWULF & PATTEN PLC		
10	MAR-05	52010	563.40	ROSHKA DEWULF & PATTEN PLC		
11	MAR-05	52010	19,887.55	FLEISCHMAN & WALSH LLP		
12	APR-05	52010	111.35	LEWIS AND ROCA LLP		
13	APR-05	52010	180.00	ROSHKA DEWULF & PATTEN PLC		
14	APR-05	52010	11,201.01	ROSHKA DEWULF & PATTEN PLC		
15	APR-05	52010	19,083.78	FLEISCHMAN & WALSH LLP		
16	APR-05	52010	19,482.02	FLEISCHMAN & WALSH LLP		
17	MAY-05	52010	87,268.56	FLEISCHMAN & WALSH LLP	Rate case settlement negotiations	El Paso Gas Allocation/Rate Case
18	JUN-05	52010	(720.00)	THELEN REID & PRIEST LLP		
19	JUN-05	52010	133.75	LEWIS AND ROCA LLP		
20	JUN-05	52010	2,490.20	ROSHKA DEWULF & PATTEN PLC		
21	JUN-05	52010	11,030.00	FLEISCHMAN & WALSH LLP		
22	JUN-05	52010	11,234.83	ROSHKA DEWULF & PATTEN PLC		
23	JUL-05	52010	3.75	THELEN REID & PRIEST LLP		
24	JUL-05	52010	216.00	ROSHKA DEWULF & PATTEN PLC		
25	JUL-05	52010	360.00	ROSHKA DEWULF & PATTEN PLC		
26	JUL-05	52010	14,299.22	FLEISCHMAN & WALSH LLP		
27	AUG-05	52010	28,463.40	FLEISCHMAN & WALSH LLP	Rate case settlement negotiations	El Paso Gas Allocation/Rate Case
28	SEP-05	52010	40.80	LEWIS AND ROCA LLP		
29	SEP-05	52010	56,611.88	FLEISCHMAN & WALSH LLP	Rate case settlement negotiations	El Paso Gas Allocation/Rate Case
30	OCT-05	52010	297.80	ROSHKA DEWULF & PATTEN PLC		
31	OCT-05	52010	313.61	LEWIS AND ROCA LLP		
32	OCT-05	52010	462.00	BOULEY SCHIESINGER & SCHIPPERS		
33	OCT-05	52010	1,928.24	ROSHKA DEWULF & PATTEN PLC		
34	OCT-05	52010	2,304.50	ROSHKA DEWULF & PATTEN PLC		
35	OCT-05	52010	3,411.86	ROSHKA DEWULF & PATTEN PLC		
36	OCT-05	52010	32,330.68	FLEISCHMAN & WALSH LLP	Rate case settlement negotiations	El Paso Gas Allocation/Rate Case
37	NOV-05	52010	396.00	ROSHKA DEWULF & PATTEN PLC		
38	NOV-05	52010	15,277.45	ROSHKA DEWULF & PATTEN PLC		
39	NOV-05	52010	28,712.29	FLEISCHMAN & WALSH LLP	Rate case settlement negotiations	El Paso Gas Allocation/Rate Case
40	DEC-05	52010	17,612.56	ROSHKA DEWULF & PATTEN PLC		
41	DEC-05	52010	39,128.51	FLEISCHMAN & WALSH LLP	Rate case settlement negotiations	El Paso Gas Allocation/Rate Case
42	DEC-05	52010	139.20	LEWIS AND ROCA LLP		
43	DEC-05	52010	228.00	BOULEY SCHIESINGER & SCHIPPERS		
44	DEC-05	52010	1,662.40	ROSHKA DEWULF & PATTEN PLC		
45	DEC-05	52010	25,452.58	ROSHKA DEWULF & PATTEN PLC	Professional Research and filing services	Prudency Audit/PGA Surcharge/Broderick Complaint
46	DEC-05	52010	38,534.74	FLEISCHMAN & WALSH LLP	Rate case settlement negotiations	El Paso Gas Allocation/Rate Case

Total Legal Expense	517,451.57
Total Non-recurring	311,051.00
Total Recurring	206,400.57
Average recurring expe	5,292.32
Average non-recurring	44,435.86

UNS GAS, INC.

DOCKET NO. G-04204A-06-0463 et al.

DIRECT TESTIMONY

OF

WILLIAM A. RIGSBY, CRRA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

FEBRUARY 9, 2007

EXHIBIT
RUCO 7
admitted

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 ("UNS" 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. UNS filed the Application with the ACC on July 13, 2006. The Company has chosen the fiscal year ended December 31, 2005 for the test year in this proceeding.

Q. Briefly describe UNS.

A. UNS 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.

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

A. I reviewed UNS' Application and performed a cost of capital analysis to determine a fair rate of return on the Company's invested capital. In

[1] NYSE ticker symbol UNS.

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

Q. Is this your first case involving UNS?

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 UNS entity was the result of that acquisition and the Company's present rates were established in that proceeding.

Q. Were you also responsible for conducting an analysis on the Company's proposed revenue level, rate base and rate design?

A. No. RUCO witnesses Marylee Diaz Cortez, CPA, and Rodney L. Moore handled those aspects of the Company's Application.

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 current economic climate that UNS is 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 UNS' 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 UNS, I am making the following recommendations:

Cost of Equity Capital – I am recommending a 9.64 percent cost of equity capital. This 9.64 percent figure is based on the results that I obtained in my cost of equity analysis, which employed both the DCF and CAPM methodologies.

Cost of Debt – I am recommending 6.23 percent cost of debt. This is based on my review of the costs associated with UNS' various debt instruments.

Capital Structure – I am recommending that the Company-proposed capital structure, which is comprised of 50 percent debt and 50 percent common equity, be adopted by the Commission.

Cost of Capital – Based on the results of my recommended capital structure, cost of common equity, and debt analyses, I am recommending a 7.93 percent cost of capital for UNS. This figure represents the weighted cost of my recommended cost of common equity and my recommended cost of debt.

Q. Why do you believe that your recommended 7.93 percent cost of capital is an appropriate rate of return for UNS to earn on its invested capital?

A. The 7.93 percent cost of capital figure that I have recommended 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 UNS, 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 UNS?

A. Based on the results of my DCF and CAPM analyses, which ranged from 8.74 percent to 11.36 percent for a sample of local distribution companies ("LDC"), I am recommending a 9.64 percent cost of equity capital for UNS. My recommended 9.64 percent 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 UNS' 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:

$$k = (D_1 \div P_0) + g$$

where: k = the required return (cost of equity, equity capitalization rate),

$D_1 \div P_0$ = 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 UNS' cost of equity capital. It is similar to one of the models used by the Company.

Q. In determining the rate of future dividend growth for UNS, 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 x 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.[2]

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%

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

Table I of Mr. Hill's illustration presents data for a five-year period on his hypothetical utility. In Year 1, the utility had a common equity or book value of $10.00 per share, an investor-expected equity return of ten percent, and a dividend payout ratio of sixty percent. This results in earnings per share of $1.00 ($10.00 book value x 10 percent equity return) and a dividend of $0.60 ($1.00 earnings/sh. x 0.60 payout ratio) during Year 1. Because forty percent (1 - 0.60 payout ratio) of the utility's earnings are retained as opposed to being paid out to investors, book value increases to $10.40 in Year 2 of Mr. Hill's illustration. Table I presents the results of this continuing scenario over the remaining five-year period.

The results displayed in Table I demonstrate that under "steady-state" (i.e. constant) conditions, book value, earnings and dividends all grow at the same constant rate. The table further illustrates that the dividend growth rate, as discussed earlier, is a function of (1) the internally generated funds or earnings that are retained by a company to become new equity, and (2) the return that an investor earns on that new equity. The DCF dividend growth rate, expressed as $g = b \times r$, 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[3] 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.[4] 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 rates for earnings and dividends, displayed in the last column, are 16.20 percent. If this rate were to be used in the DCF model, the utility's return on common equity would be

[3] [(Year 2 Earnings/Sh – Year 1 Earnings/Sh) ÷ Year 1 Earnings/Sh] = [($1.04 - $1.00) ÷ $1.00] = [$0.04 ÷ $1.00] = 4.00%

[4] [(1 – Payout Ratio) x Rate of Return] = [(1 - 0.60) x 15.00%] = 0.40 x 15.00% = 6.00%

expected to increase by fifty percent every five years, [(15 percent ÷ 10 percent) – 1]. This is clearly an unrealistic expectation.

Although it is not illustrated in Mr. Hill's hypothetical example, a change only in 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,[5] 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	=	$1 - [(BV) \div (MP)]$

[5] Gordon, M.J., The Cost of Capital to a Public Utility, East Lansing, MI: Michigan State University, 1974, pp. 30-33.

where: BV = book value per share of common stock, and
MP = the market price per share of common stock.

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 the most recent Southwest Gas Corporation rate case[6], 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 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 a natural gas proxy group consisting of ten LDC's that have similar operating characteristics to UNS.

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

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 UNS itself. Although shares of UNS' parent company, UniSource, are traded on the NYSE, there is no financial data available on dividends paid on *publicly held* shares of UNS. Consequently it was

[6] Decision No. 68487, Dated February 23, 2006 (Docket No. G-01551A-04-0876)

necessary to create a proxy by analyzing publicly traded water companies 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 UNS?

A. All of the LDC's in my sample are publicly traded on the NYSE and are followed by The Value Line Investment Survey's ("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. ("ATG"), 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 seven 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. ATG 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 companies that Dr. Grant included in his sample?

A. No. My sample includes ten of the eleven LDC's that Mr. Grant included in his sample. Mr. Grant's sample included Cascade Natural Gas Corporation, which presently serves customers in Oregon and Washington in the Pacific Northwest region of the U.S.

Q. Why did you exclude Cascade Natural Gas Corporation from your sample?

A. On July 8, 2006, MDU Resources Group, Inc. (NYSE symbol MDU) entered into a definitive merger agreement to acquire Cascade Natural Gas Corp. (NYSE symbol CGC). Because the value of CGC's stock is now being driven by MDU's acquisition offering price, it is no longer suitable for my sample. As a result of this, I excluded CGC from my sample.

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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 2001 to 2005. Schedule WAR-5 also includes Value Line's projected 2006, 2007 and 2009-11 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 ATG) 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 ATG's earned return on common equity by its earnings retention ratio for each year in the 2001 to 2005 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, ATG's sustainable internal growth rate ranged from 3.44% in 2001 to 6.53% in 2003. The company's growth rates experienced an up and down pattern during the observation period, which resulted in a 5.49% average over the 2001 to 2005 time frame. Value Line's analysts are forecasting further declines through 2007 before growth reaches a level of 4.76% during the 2009-11 period. Value Line believes that earnings and dividend growth projections will remain steady at 4.00% and 6.50% respectively. Value Line, however, has increased its book value growth projection upward from 6.00% to 6.50%. Based on these estimates I believe a 4.25% rate of internal sustainable growth is reasonable for ATG.

Q. Please continue with the external growth rate component portion of your analysis.

A. Schedule WAR-5 demonstrates that ATG's share growth averaged 8.97% over the observation period. However, Value Line expects future outstanding shares to increase slightly from 77.90 million in 2006 to 78.30 million by the end of 2011. Taking this data into consideration, I am estimating a 0.13 rate of share growth for ATG. My final dividend growth rate estimate for AWR is 4.31 percent (4.25 percent internal + 0.06 percent external) and is shown on Page 1 of Schedule WAR-4.

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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 5.28 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 5.28 percent estimate is 30 basis points higher than the consensus projections published by Zacks, and 49 basis points higher than Value Line's 4.79 percent projected estimates. As can also be seen on Schedule WAR-6, the 5.28 percent estimate that I have calculated is 52 basis points higher than the 4.76 percent average of the 5-year EPS means of 4.98 percent for Zacks, the 4.79 percent projection by Value Line (which is an average of EPS, DPS and BVPS) and the 4.61 percent five-year historical average of Value Line data (on EPS, DPS and BVPS). In fact, my 5.28 percent estimate is 83 basis points higher than the 4.45 percent Value Line 5-year compound history also displayed on Schedule WAR-6. This indicates that investors are expecting increased performance from natural gas distribution companies in the future. Based on the information presented in Schedule WAR-6, I would say that my 5.28 percent estimate, which exceeds both Zack's Value Line's projections, is a fair representation of the growth projections presented by securities analysts at this point in time.

Q. How did you calculate the dividend yields displayed in Schedule WAR-3?

A. I used the estimated annual dividends, for the next twelve-month period, that appeared in Value Line's December 15, 2006 Ratings and Reports natural gas (Distribution) 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 November 27, 2006 to January 19, 2007.

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 8.74 percent.

Capital Asset Pricing Model (CAPM) Method

Q. Please explain the theory behind the capital asset pricing model ("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[7], the Timken Professor Emeritus of Finance at Stanford University, who shared the 1990 Nobel Prize in Economics for

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

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.[8] 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. 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:

[8] 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.

$$k = r_f + [\,ß\,(r_m - r_f)\,]$$

where: k = cost of capital 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 security did you use for a risk-free rate of return in your CAPM analysis?

A. I used a six-week average on a 91-day Treasury Bill ("T-Bill") rate.[9] This resulted in a risk-free (r_f) rate of return of 5.05 percent.

Q. Why did you use the short-term T-Bill rate as opposed to the yield on an intermediate 5-year Treasury note or a long-term 30-year Treasury bond?

A. Because a 91-day T-Bill presents the lowest possible total risk to an investor. 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

[9] A six-week average was computed for the current rate using 91-day T-Bill quotes listed in Value Line's Selection and Opinion newsletter from December 22, 2006 to January 26, 2007.

slightly higher yields. Treasury yields are comprised of two separate components,[10] a true rate of interest (believed to be approximately 2.00 percent) and an inflationary expectation. When the true 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 testimony, this compensation translates into higher rates of returns to the investor. Since a 91-day T-Bill presents the lowest possible total risk to an investor, it more closely meets the definition of a risk-free rate of return and is the more appropriate instrument to use in a CAPM analysis.

...

[10] As a general rule of thumb, there are three components that make up a given interest rate or rate of return on a security: the true 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.

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 returns on the S&P 500 index from 1926 to 2005 as the proxy for the market rate of return (r_m). The information was obtained from Ibbotson Associates' <u>SBBI Yearbook</u>, which publishes historical data on stock returns, U.S. Treasury yields and rates of inflation. The risk premium (r_m - r_f) that results by using the geometric mean calculation for r_m is equal to 5.35 percent (10.40% - 5.05% = <u>5.35%</u>). The risk premium that results by using the arithmetic mean calculation for r_m is 7.25 percent (12.30% - 5.05% = <u>7.25%</u>).

Q. How did you select the beta coefficients that were used in your CAPM model?

A. The beta coefficients (ß), for the LDC's used in my proxy, were calculated by Value Line and were current as of December 15, 2006. 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 0.70 to 1.30 with an average beta of 0.87.

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 for r_m results in an average expected return of 9.70 percent. My calculation using an arithmetic mean results in an average expected return of 11.36 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	8.74%
CAPM	9.70% – 11.36%

Based on these results, my best estimate of an appropriate range for a cost of common equity for UNS is 8.74 percent to 11.36 percent. My final recommendation for UNS is 9.64 percent.

Q How did you arrive at your recommended 9.64 percent cost of common equity?

A. My recommended 9.64 percent cost of common equity 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 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 136 basis points higher than the 9.64 percent cost of equity capital that I am recommending.

Current Economic Environment

Q. Please explain why it is necessary to consider the current economic environment when performing a cost of equity capital analysis for a regulated utility.

A. Consideration of the economic environment is necessary because trends in interest rates, present and projected levels of inflation, and the overall state of the U.S. economy determine the rates of return that investors earn on their invested funds. Each of these factors represent potential risks that must be weighed when estimating the cost of equity capital for a regulated utility and are, most often, the same factors considered by individuals who are investing in non-regulated entities also.

Q. Please discuss your analysis of the current economic environment.

A. My analysis includes a brief review of the economic events that have occurred since 1990. Schedule WAR-8 displays various economic indicators and other data that I will refer to during this portion of my testimony.

In 1991, as measured by the most recently revised annual change in gross domestic product ("GDP"), the U.S. economy experienced a rate of growth of negative 0.20 percent. This decline in GDP marked the beginning of a mild recession that ended sometime before the end of the first half of 1992. Reacting to this situation, the Federal Reserve Board ("Federal Reserve" or "Fed"), then chaired by noted economist Alan Greenspan, lowered its benchmark federal funds rate[11] in an effort to further loosen monetary constraints - an action that resulted in lower interest rates.

During this same period, the nation's major money center banks followed the Federal Reserve's lead and began lowering their interest rates as well. By the end of the fourth quarter of 1993, the prime rate (the rate charged by banks to their best customers) had dropped to 6.00 percent from a 1990 level of 10.01 percent. In addition, the Federal Reserve's discount rate on loans to its member banks had fallen to 3.00 percent and short-term interest rates had declined to levels that had not been seen since 1972.

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

[11] 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.

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 the recession that the U.S. now appears to have recovered from from.

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 current 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 45 years.

Even though some signs of economic strength, that were mainly attributed to consumer spending, began to crop up during the latter part of 2002 and into 2003, Chairman Greenspan appeared to be concerned with sharp declines in capital spending in the business sector.

During the latter part of 2003, the FOMC went on record as saying that it intended to leave interest rates low "for a considerable period." After its two-day meeting that ended on January 28, 2004, the FOMC announced "that with inflation 'quite low' and plenty of excess capacity in the economy, policy-makers 'can be patient in removing its policy accommodation.[12]"

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.

[12] Wolk, Martin, "Fed leaves short-term rates unchanged," MSNBC, January 28, 2004.

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 its current 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 has been 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 existing federal funds rate of 5.25 percent, where it has stood since June 29, 2006.

...

Q. How have analysts viewed the Fed's actions over the last five years?

A. According to an article that appeared in the December 2, 2004 edition of The Wall Street Journal, the FOMC's decision to begin raising rates two years ago was viewed as a move to increase rates from emergency lows in order to avoid creating an inflation problem in the future as opposed to slowing down the strengthening economy.[13] In other words, the Fed was trying to head off inflation *before* it became a problem. During the period following the August 8, 2006 FOMC meeting, the Fed's decisions not to raise rates were viewed as a gamble that a slower U.S. economy would help to cap growing inflationary pressures.[14]

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 – 1995 time frame, in which a recession or a bear market were avoided rarely happen[15]. Since it began increasing the federal funds rate in June 2004, the Fed has assured investors that it would increase rates at a "measured" pace. Many analysts

[13] McKinnon, John D. and Greg IP, "Fed Raises Rates by a Quarter Point," The Wall Street Journal, September 22, 2004.

[14] Ip, Greg, "Fed Holds Interest Rates Steady As Slowdown Outweighs Inflation," The Wall Street Journal Online Edition, August 8, 2006.

[15] Browning, E.S, "Not Too Fast, Not Too Slow…," The Wall Street Journal Online Edition, August 21, 2006.

and economists interpreted this language to mean that former Chairman Greenspan would be cautious in increasing interest rates too quickly in order to avoid what is considered to be one of the Fed's few blunders during Greenspan's tenure – a series of increases in 1994 that caught the financial markets by surprise after a long period of low rates. The rapid rise in rates contributed to the bankruptcy of Orange County, California and the Mexican peso crisis[16]. According to Mr. Browning, the hope, at the time that his article was published, 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."

Q. Has the Fed's attempt to engineer a soft landing been successful to date?

A. It would appear so. Recent articles published in the mainstream financial press have been generally upbeat on the current economy. An example of this is an article written by Nell Henderson that appeared in the January 30, 2007 edition of The Washington Post. According to Ms. Henderson, "a year into [Fed Chairman] Bernanke's tenure, the [economic] picture has turned considerably brighter. Inflation is falling; unemployment is low; wages are rising; and the economy, despite continued problems in housing, is growing at a brisk clip."[17]

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[16] Associated Press (AP), "Fed begins debating interest rates" USA Today, June 29, 2004.
[17] Henderson, Nell, "Bullish on Bernanke" The Washington Post, January 30, 2007.

Q. Putting this all into perspective, how have the Fed's actions since 2001 affected benchmark rates?

A. Despite the increases by the FOMC, interest rates and yields on 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, with the exception of the federal discount rate (the rate charged to member banks), which has increased to 6.25 percent from 5.73 percent in 2000, the other key interest rates (i.e. the prime rate and the federal funds rate) are still below their year-end 2000 levels.

Q. What has been the trend in other leading interest rates over the last year?

A. As of January 26, 2007, all of the leading interest rates have moved up. The prime rate has increased from 7.25 percent a year ago to its current level of 8.25 percent. The benchmark federal funds rate, just discussed, has increased from 4.25 percent, in January 2006, to its current level of 5.25 percent (the result of the seventeen quarter point increases noted earlier). The yields on all maturities of U.S. Treasury instruments have increased over the past year. A previous trend, described by former Chairman Greenspan as a "conundrum"[18], in which long-term rates fell as short-term rates increased, thus creating the inverted yield curve that currently exists (Attachment B), appears to have ended. The 91-day T-bill

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

rate, used in my CAPM analysis, increased from 4.35 percent, in January 2006, to 5.10 percent as of January 26, 2007. The 1-Year Treasury Constant Maturity rate also increased from 4.42 percent over the past year to 5.06 percent. Again, for the most part, these current yields are 73 to 285 basis points lower than corresponding yields that existed during the early nineties (as can be seen on Schedule WAR-8).

Q. What is the current outlook for interest rates, inflation, and the economy?

A. Stability is the word that best sums up analyst's expectations for the majority of 2007 according to an article by Peter A. McKay that appeared in the January 29, 2007 issue of The Wall Street Journal[19]. Mr. McKay reported on Fed watchers that have revised their expectations for a spring rate cut and who now believe that the Fed will keep rates at their current levels through the end of 2007. As expected, the Fed continued to hold pat on interest rates during the FOMC meetings held on January 30 and 31, 2007, fulfilling the 98 percent expectancy by futures contracts that track the likelihood of a Fed move (as noted in the McKay article).

The recent views of Value Line analysts, who anticipate lower rates of inflation in the coming months, support the aforementioned outlook for stable rates. In their Economic and Stock Market Commentary that appeared in the February 2, 2007 edition of Value Line's Selection and Opinion publication, Value Line's analyst's stated the following:

[19] McKay, Peter A., "A Long Stretch of Steady Rates" The Wall Street Journal, January 29, 2007

> "Inflation is likely to start trending lower over the next few quarters, in part because the modest rate of GDP growth should cap the the increases in demand for labor and raw materials. Moreover, recent declines in oil prices will keep costs down for products that are oil-based and for companies that are heavy users of electricity."

Q. Please summarize how the economic data just presented relates to UNS.

A. If Federal Reserve Chairman Bernanke continues to keep inflation in check, and keep it contained within his preferred range of 1 to 2 percent[20], UNS could look forward to relatively stable and even possibly declining prices for goods and services, which in turn means that the Company can expect its present operating expenses to either remain stable or possibly decline in the coming years. Lower interest rates would also benefit UNS in regard to any short or long-term borrowing needs that the Company may have. Despite the recent slowdown in the housing market noted earlier, lower interest rates would further help to accelerate growth in new construction projects and home developments in the Company's service territories, and may result in new revenue streams to UNS.

Q. After weighing the economic information that you've just discussed, do you believe that the 9.64 percent cost of equity capital that you have estimated is reasonable for UNS?

A. I believe that my recommended 9.64 percent cost of equity will provide UNS with a reasonable rate of return on the Company's invested capital

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[20] Ip, Greg, "Fed Minutes Indicate Inflation Still a Worry for Some Officials, " The Wall Street Journal, February 22, 2006.

when economic data on interest rates (that are still low by historical standards), a rebound in growth in new housing construction (attributed to historically low interest rates), 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 UNS' testimony on the Company-proposed cost of debt?

A. Yes, I have reviewed the testimony prepared by Mr. Grant.

Q. Briefly explain how UNS calculated the Company-proposed 6.60 percent cost of debt.

A. The Company-proposed 6.60 percent cost of debt is comprised of $6,230,000 in annual interest on UNS' Series A and B bonds, $201,000 in amortized debt discount and expenses and losses attributed to reacquired debt, and $90,000 attributed to credit facility fees.

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 6.60 percent?

A. No. I believe that these costs should have been expensed as opposed to being included in the cost of debt. For this reason I am recommending that the Commission adopt the 6.23 percent cost attributed to the annual interest expense on the Company's Series A and B bonds as UNS' cost of debt.

CAPITAL STRUCTURE

Q. Have you reviewed UNS' testimony regarding the Company's proposed capital structure?

A. Yes, I have reviewed the direct testimony of Company witness Grant, who testified on UNS' proposed capital structure, cost of debt and cost of common equity.

Q. Please describe the Company's proposed capital structure.

A. The Company is proposing a hypothetical capital structure comprised of 50 percent debt and 50 percent common equity.

Q. What capital structure are you proposing for UNS?

A. I am also recommending a hypothetical capital structure comprised of 50 percent debt and 50 percent equity.

Q. Is UNS' actual capital structure in line with industry averages?

A. No. UNS' actual test year capital structure, comprised of approximately 55 percent debt and 45 percent common equity, is somewhat heavier in debt than the capital structures of the LDC's included in my cost of capital analysis (Schedule WAR-9). The capital structures for those utilities averaged approximately 48 percent for debt and 52 percent for equity (51.2 percent common equity + 0.8 percent preferred equity).

Q. In terms of risk, how does UNS' actual capital structure compare to the LDC's in your sample?

A. The LDC's in my sample would be considered as having a lower level of financial risk (i.e. the risk associated with debt repayment) because of their lower levels of debt. The additional financial risk due to debt leverage is embedded in the cost of equities derived for those companies through the DCF analysis. Thus, the cost of equity derived in my DCF analysis is applicable to companies that are not as leveraged and, theoretically speaking, not as risky than a utility with a level of debt similar to UNS'. In the case of a publicly traded company, such as those included in my proxy, a company with UNS' level of debt would be perceived as having a higher level of financial risk and would therefore also have a higher expected return on common equity.

Q. Have you made an adjustment to your cost of equity estimate based on this perception of higher financial risk?

A. No. Because I am recommending a capital structure that contains more equity than what the Company actually had during the test year, I have decided not to make an upward adjustment on my recommended 9.64 percent cost of common equity. The hypothetical capital structure of 50 percent debt and 50 percent common equity that I am recommending provides the Company with a weighted cost of capital of 7.93 percent, which is 18 basis points higher than the 7.75 percent that would result from the Company's actual test year capital structure of approximately 55 percent debt and 45 percent common equity.

WEIGHTED COST OF CAPITAL

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

A. The Company has proposed a weighted cost of capital of 8.80 percent. This composite figure is the result of a weighted average of UNS' proposed 6.60 percent cost of debt and 11.00 percent cost of common equity. The Company-proposed 8.80 percent weighted cost of capital is 87 basis points higher than the 7.93 percent weighted cost that I am recommending which is the weighted cost of my recommended 6.23 percent cost of debt and my recommended 9.64 percent cost of common equity.

COMMENTS ON UNS' COST OF EQUITY CAPITAL TESTIMONY

Q. What methods did Mr. Grant use to arrive at his cost of common equity for UNS?

A. Mr. Grant used a DCF methodology and a CAPM methodology to estimate UNS' cost of common equity.

Q. Can you provide a comparison of the results derived from Mr. Grant's models and yours?

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 eleven LDC's that I described earlier in my testimony, as opposed to the single-stage constant growth model that I relied on using all but one of the LDC's in Mr. Grant's proxy group. 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 is referring to is the 6.00 percent long-term projection of inflation-adjusted GDP, which is an inflation adjusted-projection of the growth rate of the entire U.S. economy as opposed to the regulated LDC's in his sample proxy. This is the long-term growth rate that he uses in the second step of his multi-stage DCF model. The use of such a growth estimate assumes that the long-term growth rate for the LDC's in his sample will be the same growth rate of all goods and services produced by labor and property in the U.S. A good argument can be made that regulated utilities' long-term growth rates may not actually mirror national GDP growth.

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 near-term and long-term growth rate projections that are specific to the LDC's included in my proxy.

...

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 10.50 percent and 9.10 percent are 172 to 36 basis points higher than the 8.74 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. A better comparison between his DCF estimates and mine is a 9.80 percent mean average of his estimates that excludes Cascade Natural Gas Corporation (whose price is now being driven by a merger with MDU Resources Group, Inc.). This comparison produces a 106 basis point difference between his estimate and mine.

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 (that excludes Cascade Natural Gas Corporation) would produce a mean average estimate of 8.21 percent or 53 basis points lower than my 8.74 percent 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 increased since Mr. Grant filed his direct testimony, thus producing lower 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
ATG	$39.04	$35.29	$3.75
ATO	$31.98	$26.47	$5.51
LG	$35.45	$33.86	$1.59
NJR	$49.52	$44.84	$4.68
GAS	$47.56	$39.71	$7.85
NWN	$41.59	$34.42	$7.17
PNY	$27.21	$24.28	$2.93
SJI	$33.08	$26.58	$6.50
SWX	$38.14	$26.58	$11.56
WGL	$32.56	$29.43	$3.13

The differences in our respective dividend yields are as follows:

...

	Rigsby	Grant	Difference
ATG	3.79%	4.28%	-0.49%
ATO	4.00%	4.85%	-0.85%
LG	4.01%	4.23%	-0.22%
NJR	2.91%	3.28%	-0.37%
GAS	3.91%	4.68%	-0.77%
NWN	3.41%	4.17%	-0.76%
PNY	3.53%	4.00%	-0.47%
SJI	2.72%	3.52%	-0.80%
SWX	2.15%	2.96%	-0.81%
WGL	4.15%	4.63%	-0.48%

When Mr. Grant's first year dividend estimates (i.e. the D_1 component of the DCF model) are divided by my more recent closing stock prices (i.e. the P_0 component of the DCF model) the resulting average dividend yield is 3.50 percent, which is only slightly higher than my 3.46 percent result exhibited in schedule WAR-3. The addition of a mean average of Mr. Grant's lower 5-year growth (i.e. g) estimate of 4.15 percent for his sample LDC's (again excluding Cascade Natural Gas Corporation) produces a single-stage estimate of 7.65 percent, which is 56 basis points lower than the 8.21 percent single-stage model figure that I noted earlier.

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 component estimates (with the exception of Cascade Natural Gas Corporation) 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 2005 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.

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 bond, which was 5.30 percent as of April 28, 2006.

Q. What is the current yield on a 20-year U.S. Treasury bond?

A. As of January 30, 2007 the yield on a 20-year U.S. Treasury bond had fallen to 5.07 percent.

Q. Did Mr. Grant use the same Value Line betas that you used in your CAPM analysis?

A. Yes. However Value Line's beta's for the LDC's in our proxies have increased since Mr. Grant filed his direct testimony. The mean average of the Value Line betas used by Mr. Grant (excluding Cascade Natural Gas Corporation) is 0.81 as opposed to my average beta of 0.87, which was current as of December 15, 2006.

Q. What is the difference between Mr. Grant's CAPM estimate and your CAPM estimate?

A. Mr. Grant's CAPM high and low estimates, derived from his arithmetic mean model, of 9.9 percent and 11.70 percent are 146 basis points lower to 34 basis points higher than the 11.36 percent cost of common equity derived from my arithmetic mean CAPM analysis which is a mean average of the ten LDC's in my proxy. Mr. Grant's CAPM high and low estimates of 9.9 percent and 11.70 percent are 20 to 200 basis points higher than the 9.70 percent cost of common equity derived from my geometric mean CAPM analysis. Again, as with the DCF model, a better comparison between his CAPM estimates and mine is an 11.02 percent mean average of his estimates that excludes Cascade Natural Gas Corporation. This comparison produces a difference of 132 basis points higher to 34 basis points lower than the results produced by my geometric and arithmetic mean CAPM models respectively.

Final Cost of Equity Estimate

Q. How did Mr. Grant arrive at his final estimate of 11.00 percent for UNS?

A. Mr. Grant's final 11.00 percent recommendation is based on his belief that UNS should be awarded a return on equity that is at the upper range of his estimates given a number of factors that include UNS' size, the level of customer growth the Company faces, historical test-year concept, the fact that many of the LDC's in his proxy have decoupling mechanisms, and the lower credit rating of UNS.

Q. Do you believe that UNS should be awarded a higher return on equity based on the factors cited by Mr. Grant?

A. No. The Commission in prior cases has rejected many of the factors cited by Mr. Grant. This includes such issues such as company size, customer growth, and the historic test year concept. In regard to the decoupling mechanism cited by Mr. Grant, it is interesting that he has not recognized the fact that the implementation of such a mechanism, which the Company has requested in this case, would certainly merit a lower return on common equity for UNS given the fact that it would remove the risk associated with operating income volatility.

...

Q. Does your silence on any of the issues, matters or findings addressed in the testimony of Mr. Grant or any other witness for UNS constitute your acceptance of their positions on such issues, matters or findings?

A. No, it does not.

Q. Does this conclude your testimony on UNS?

A. Yes, it does.

APPENDIX 1

Qualifications of William A. Rigsby, CRRA

EDUCATION:

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

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

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

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

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

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

EXPERIENCE:

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

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

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

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

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

Appendix 1

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

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

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

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

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

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

ATTACHMENT A

INDUSTRY TIMELINESS: 88 (of 97)

Natural Gas (Distribution) companies have entered their most profitable time of the year as the winter heating season is upon us. Utilities earn most of their profits during the December and March quarters. To reduce the volatility of earnings that may arise due to warmer-than-normal temperatures, many companies have applied for, and been granted, regulatory programs that not only protect against warmer weather, but also reduced gas consumption (discussed below). Some key features of owning gas utilities include their Safety ranks and better-than-average dividend yields, rather than price performance or appreciation potential.

Natural Gas Distribution

The distribution operations of gas utilities are regulated by state agencies, which set the allowed rates of return these companies are permitted to earn. They are considered natural monopolies since it is more cost-effective to build one pipeline system to serve a region, versus multiple distributors competing over the same location. As a result, utilities typically generate steady earnings that rise with population growth over time. In the event that profits fall below their allowed return-on-equity utilities can petition their state regulatory authority for rate relief, although there is a time lag before new rates are put in place, if approved.

New Rate Plans

Over the past year, there have been numerous gas distributors that have received decoupling mechanisms in various forms that protect against both warmer-than-normal temperatures and reduced consumption by customers due to conservation. This enables utilities to promote conservation and efficiency, while also protecting financial performance. The New Jersey Board of Public Utilities recently approved conservation incentive plans for both *New Jersey Resources* and *South Jersey Industries*. *WGL Holdings* has a revenue normalization clause in place to protect against these issues in its Maryland service territory. The company is seeking to implement a similar plan in its Virginia service territory and plans to file a rate case this upcoming spring to recover costs associated with the Prince George's County rehabilitation project. At *SEMCO Energy*, the company received a rate increase of $8.5 million based on a return on equity of 10.15%-11.15%. However this is below the $18.1 million increase on a return on common equity of 11.9% that had been requested. Management plans to file a rebuttal shortly. Lastly, *Southern Union* has filed for a $41.7 million rate increase in its Missouri service territory, and is seeking additional relief in its Massachusetts service area.

Nonutility Operations

Industry deregulation has allowed gas utilities to expand their businesses beyond their normal distribution operations. This includes retail energy marketing, energy trading, and oil and gas exploration and production. In fact, most companies in this industry have at least a small percentage of their profits derived from these activities, with many looking to expand their presence further. One benefit is that there is no cap on the allowed return on equity as compared to the regulated operations. However, some drawbacks include regulatory agencies being less inclined to approve rate increases, along with corporate boards possibly reducing the rate of dividend increases to use the funds for other growth investments.

South Jersey Industries, through its Marina Energy subsidiary, is poised for growth out to late decade. The company is in the second phase of its expansion at the Borgata Hotel Casino & Spa, which is scheduled to be completed next year. In addition, Marina remains one of the finalists to co-own and operate a thermal facility to provide all the energy needs for a Las Vegas casino project.

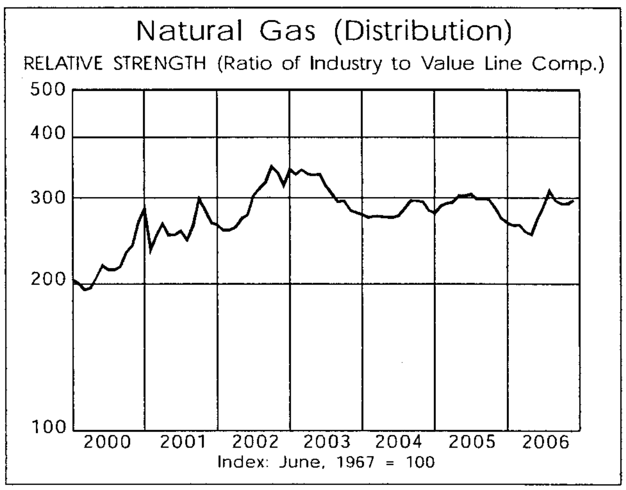
Investment Advice

This industry caters to risk-averse investors, who look for an above-average dividend yield when choosing a stock. It should be noted that as the percentage of earnings derived from nonregulated operations grows, risk increases. Therefore, it is worthwhile for investors to decide whether or not they are willing to take on the additional risk. Note, however, that especially high dividend yields for stocks in this sector can mean that growth opportunities are constrained.

Evan I. Blatter

Composite Statistics: Natural Gas (Distribution)

2002	2003	2004	2005	2006	2007		09-11
22947	29981	33220	41399	***44500***	***49000***	Revenues ($mill)	***58000***
1231.5	1395.3	1517.2	1788.8	***2000***	***2200***	Net Profit ($mill)	***2800***
35.3%	37.4%	35.7%	35.8%	***36.0%***	***36.0%***	Income Tax Rate	***36.0%***
5.4%	4.7%	4.6%	4.3%	***4.5%***	***4.5%***	Net Profit Margin	***4.8%***
57.8%	55.9%	53.2%	50.7%	***52.0%***	***52.0%***	Long-Term Debt Ratio	***52.0%***
41.4%	43.7%	45.7%	48.3%	***46.0%***	***46.0%***	Common Equity Ratio	***46.0%***
24907	28436	31268	33911	***35400***	***36750***	Total Capital ($mill)	***42000***
25590	31732	32053	35030	***37000***	***39000***	Net Plant ($mill)	***45000***
6.6%	6.4%	6.4%	6.9%	***7.0%***	***7.0%***	Return on Total Cap'l	***7.5%***
11.7%	11.1%	10.4%	10.7%	***11.0%***	***11.5%***	Return on Shr. Equity	***12.0%***
11.8%	11.2%	10.5%	10.8%	***11.0%***	***11.5%***	Return on Com Equity	***12.0%***
3.9%	4.1%	4.0%	4.4%	***5.0%***	***5.2%***	Retained to Com Eq	***5.5%***
68%	64%	63%	59%	***61%***	***60%***	All Div'ds to Net Prof	***60%***
14.8	14.1	15.6	16.2	*Bold figures are*	*Value Line estimates*	Avg Ann'l P/E Ratio	***13.0***
.81	.80	.82	.87			Relative P/E Ratio	***.85***
4.5%	4.5%	4.0%	3.6%			Avg Ann'l Div'd Yield	***4.6%***
281%	314%	308%	331%	***315%***	***330%***	Fixed Charge Coverage	***355%***



AGL RESOURCES NYSE-ATG

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD
39.50	14.8	(Trailing: 13.3 / Median: 14.0)	0.80	4.0%

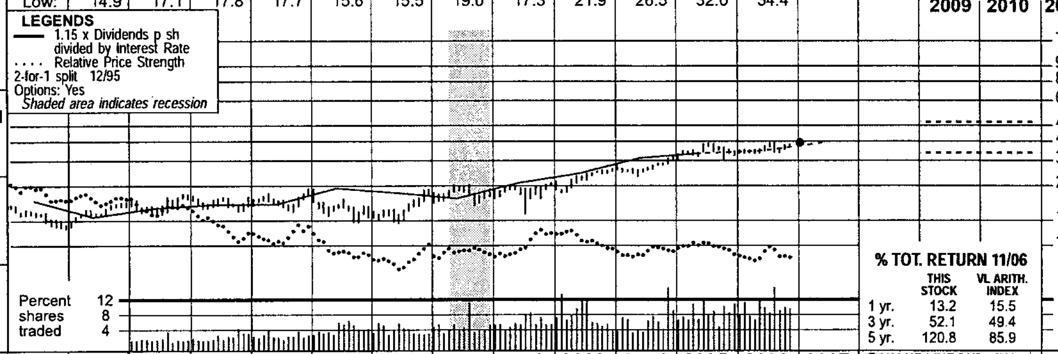
VALUE LINE

TIMELINESS 4 Lowered 8/11/06
SAFETY 2 New 7/27/90
TECHNICAL 2 Raised 12/1/06
BETA .95 (1.00 = Market)

High:	20.0	22.0	21.6	23.4	23.4	23.2	24.5	25.0	29.3	33.7	39.3	40.0	
Low:	14.9	17.1	17.8	17.7	15.6	15.5	19.0	17.3	21.9	26.5	32.0	34.4	

Target Price Range 2009 | 2010 | 2011

LEGENDS
— 1.15 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 12/95
Options: Yes
Shaded area indicates recession



2009-11 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+25%)	9%
Low	35	(-10%)	1%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	1	0	0	0	0	1	0
to Sell	0	0	1	0	0	0	0	2	0

Institutional Decisions

	4Q2005	1Q2006	2Q2006
to Buy	109	110	95
to Sell	88	83	102
Hld's(000)	49186	45106	49525

Percent shares traded 12 8 4

% TOT. RETURN 11/06

	THIS STOCK	VL ARITH. INDEX
1 yr.	13.2	15.5
3 yr.	52.1	49.4
5 yr.	120.8	85.9

1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	© VALUE LINE PUB., INC.	09-11
22.58	20.26	20.43	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	**35.55**	**36.10**	Revenues per sh A	**38.30**
2.04	2.07	2.31	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	**4.40**	**4.50**	"Cash Flow" per sh	**4.85**
1.01	1.04	1.13	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	**2.65**	**2.70**	Earnings per sh A B	**2.90**
.98	1.02	1.03	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	**1.50**	**1.58**	Div'ds Decl'd per sh C■	**1.75**
2.73	2.95	2.74	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	**3.20**	**3.10**	Cap'l Spending per sh	**2.25**
8.97	9.42	9.70	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	**20.40**	**21.50**	Book Value per sh D	**25.10**
44.32	47.57	48.69	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	**77.90**	**78.00**	Common Shs Outst'g E	**78.30**
14.2	15.3	15.5	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	*Bold figures are*	*Value Line estimates*	Avg Ann'l P/E Ratio	**15.0**
1.05	.98	.94	1.06	.99	.84	.86	.85	.72	1.22	.88	.75	.68	.71	.69	.76			Relative P/E Ratio	**1.00**
6.8%	6.4%	5.9%	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%			Avg Ann'l Div'd Yield	**4.0%**

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007		09-11
1220.2	1287.6	1338.6	1068.6	607.4	1049.3	868.9	983.7	1832.0	2718.0	**2770**	**2815**	Revenues ($mill) A	**3000**
75.6	76.6	80.6	52.1	71.1	82.3	103.0	132.4	153.0	193.0	**205**	**210**	Net Profit ($mill)	**230**
38.6%	37.9%	32.5%	33.1%	34.3%	40.7%	36.0%	35.9%	37.0%	37.7%	**38.0%**	**38.0%**	Income Tax Rate	**38.0%**
6.2%	5.9%	6.0%	4.9%	11.7%	7.8%	11.9%	13.5%	8.4%	7.1%	**7.5%**	**7.5%**	Net Profit Margin	**7.7%**
46.2%	48.7%	47.5%	45.3%	45.9%	61.3%	58.3%	50.3%	54.0%	51.9%	**51.0%**	**50.0%**	Long-Term Debt Ratio	**48.5%**
48.9%	45.9%	47.1%	49.2%	48.3%	38.7%	41.7%	49.7%	46.0%	48.1%	**49.0%**	**50.0%**	Common Equity Ratio	**51.5%**
1201.3	1356.4	1388.4	1345.8	1286.2	1736.3	1704.3	1901.4	3008.0	3114.0	**3225**	**3310**	Total Capital ($mill)	**3775**
1415.4	1496.6	1534.0	1598.9	1637.5	2058.9	2194.2	2352.4	3178.0	3271.0	**3350**	**3450**	Net Plant ($mill)	**3750**
8.0%	7.3%	7.6%	5.7%	7.4%	6.5%	8.1%	8.9%	6.3%	7.9%	**8.0%**	**8.0%**	Return on Total Cap'l	**7.5%**
11.7%	11.0%	11.1%	7.1%	10.2%	12.3%	14.5%	14.0%	11.0%	12.9%	**13.0%**	**12.5%**	Return on Shr. Equity	**12.0%**
12.1%	11.3%	12.3%	7.9%	11.5%	12.3%	14.5%	14.0%	11.0%	12.9%	**13.0%**	**12.5%**	Return on Com Equity	**12.0%**
3.8%	3.2%	4.4%	NMF	3.2%	4.2%	7.0%	6.6%	5.6%	6.2%	**5.5%**	**5.5%**	Retained to Com Eq	**5.0%**
71%	74%	64%	101%	72%	65%	52%	53%	49%	52%	**57%**	**58%**	All Div'ds to Net Prof	**59%**

CAPITAL STRUCTURE as of 9/30/06
Total Debt 2075.0 mill. **Due in 5 Yrs** $530.0 mill.
LT Debt $1634.0 mill. **LT Interest** $100.0 mill.

(Total interest coverage: 4.4x)
Leases, Uncapitalized Annual rentals $27.0 mill.

Pension Assets-12/05 $371.0 mill.
Oblig. $464.0 mill.
Pfd Stock None
Common Stock 77,696,090 shs.
as of 10/20/06

MARKET CAP: $3.1 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2004	2005	9/30/06
Cash Assets	49.0	30.0	14.0
Other	1408.0	2002.0	1498.0
Current Assets	1457.0	2032.0	1512.0
Accts Payable	207.0	264.0	540.0
Debt Due	334.0	522.0	441.0
Other	936.0	1153.0	335.0
Current Liab.	1477.0	1939.0	1316.0
Fix. Chg. Cov.	510%	442%	470%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '03-'05 to '09-'11
Revenues	1.0%	7.0%	7.5%
"Cash Flow"	5.0%	7.0%	5.0%
Earnings	6.5%	13.5%	4.0%
Dividends	1.5%	2.0%	6.5%
Book Value	5.5%	8.5%	6.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	352.5	186.6	166.3	278.3	983.7
2004	651.0	294.0	262.0	625.0	1832.0
2005	908.0	430.0	387.0	993.0	2718.0
2006	1047.0	436.0	434.0	**853**	**2770**
2007	**970**	**480**	**465**	**900**	**2815**

Cal-endar	EARNINGS PER SHARE A B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.98	.29	.27	.54	2.08
2004	1.00	.33	.31	.64	2.28
2005	1.14	.30	.19	.85	2.48
2006	1.41	.25	.46	**.53**	**2.65**
2007	**1.30**	**.37**	**.29**	**.74**	**2.70**

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.27	.27	.27	.27	1.08
2003	.27	.28	.28	.28	1.11
2004	.28	.29	.29	.29	1.15
2005	.31	.31	.31	.37	1.30
2006	.37	.37	.37	.37	

BUSINESS: AGL Resources, Inc. is a public utility holding company. Its distribution subsidiaries are Atlanta Gas Light, Chattanooga Gas, and Virginia Natural Gas. The utilities have more than 2.2 million customers in Georgia (primarily Atlanta), Virginia, and in southern Tennessee. Also engaged in nonregulated natural gas marketing and other, allied services. Also wholesales and retails propane. Nonregulated subsidiaries: Georgia Natural Gas Services markets natural gas at retail. Acq. Virginia Natural Gas, 10/00. Sold Utilipro, 3/01. Off./dir. own less than 1.0% of common; Goldman Sachs, 5.5%; JPMorgan, 5.9% (3/06 Proxy). Pres. & CEO: John W. Somerhalder II. Inc.: GA. Addr.: 10 Peachtree Place N.E., Atlanta, GA 30309. Tel.: 404-584-4000. Internet: www.aglresources.com.

AGL Resources is on track to register solid earnings gains in 2006. The company reported earnings of $0.46 a share in the third quarter, significantly ahead of the prior year. Most of the gains can be attributed to a strong performance at the company's Wholesale Services segment. The unit benefited from mark-to-market gains following the decline in NYMEX gas prices. This resulted in the recognition of $38 million in gains compared to the loss of $46 million last year when gas prices increased significantly. Since gas prices typically fluctuate over time, quarterly earnings should remain volatile at this unit.

The company is looking to reduce costs about 2%-3% at its distribution segment. Over the past few years, operating and maintenance costs per customer have decreased significantly thanks to numerous efficiency programs put in place. As another way to improve results, the company is looking to reduce customer attrition. Management believes it can achieve 0.8% growth this year and push the rate higher in the coming years.

No progress has been made on the Jefferson Island storage facility dispute since our last report. In August, the Louisiana Department of Natural Resources terminated the company's mineral lease. AGL Resources responded by filing suit in September against the state of Louisiana to maintain its lease and complete the project. Management is optimistic that a resolution can be reached, though the third cavern will likely not become operational until 2009 as a result of delays. In addition,

The company has signed an option to develop a salt dome in east Texas near the Gulf Coast. It has an estimated 12 billion cubic feet of working capacity. The location also provides the ability to connect to other pipelines in the area, along with potential LNG facilities that may come into the region. The first cavern, which would be about six bcf and similar in size to the Jefferson Island cavern, has the potential to be in operation by 2010.

Though untimely, this stock offers a good dividend yield. ATG shares offer only limited appreciation potential, but further expansion in nonregulated activities may well improve these prospects.

Evan I. Blatter *December 15, 2006*

(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). Next earnings report due late Jan.
(C) Dividends historically paid early March, June, Sept, and Dec. ■ Div'd reinvest. plan available.
(D) Includes intangibles. In 2005: $422 million, $5.43/share.
(E) In millions, adjusted for stock split.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	75

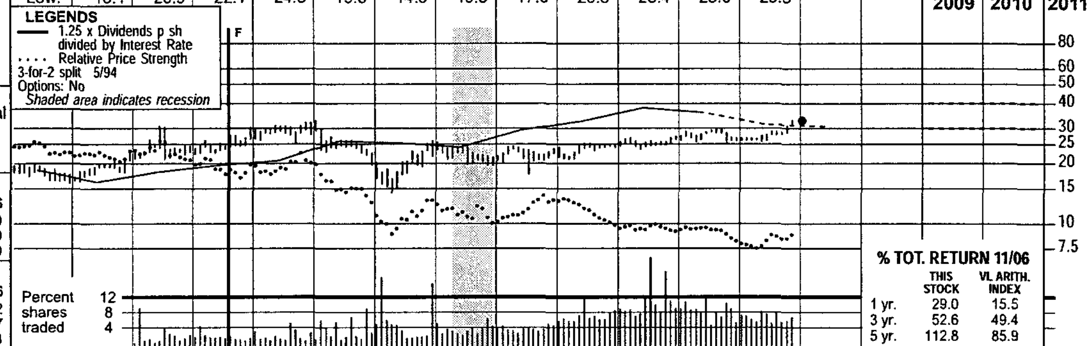
ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE 32.82 | P/E RATIO 14.1 (Trailing: 17.9 Median: 16.0) | RELATIVE P/E RATIO 0.77 | DIV'D YLD 3.9% | VALUE LINE

TIMELINESS 3 Raised 7/28/06
SAFETY 2 Raised 12/16/05
TECHNICAL 2 Raised 11/17/06
BETA .80 (1.00 = Market)

High:	23.0	31.0	30.5	32.3	33.0	26.3	25.8	24.5	25.5	27.6	30.0	33.1
Low:	16.1	20.9	22.1	24.8	19.6	14.3	19.5	17.6	20.8	23.4	25.0	25.5

Target Price Range 2009 | 2010 | 2011



2009-11 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+20%)	8%
Low	30	(-10%)	2%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	1	0	0	0
to Sell	0	0	0	1	0	1	0	0	0

Institutional Decisions

	4Q2005	1Q2006	2Q2006
to Buy	93	89	102
to Sell	91	84	67
Hld's(000)	43022	46004	46293

% TOT. RETURN 11/06

	THIS STOCK	VL ARITH. INDEX
1 yr.	29.0	15.5
3 yr.	52.6	49.4
5 yr.	112.8	85.9

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.

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	© VALUE LINE PUB., INC.	09-11
30.19	30.59	27.90	22.09	26.61	35.36	22.82	54.39	46.50	61.75	75.05	73.80	Revenues per sh A	100.00
2.80	2.85	3.38	2.62	3.01	3.03	3.39	3.23	2.91	3.90	4.25	4.30	"Cash Flow" per sh	4.85
1.51	1.34	1.84	.81	1.03	1.47	1.45	1.71	1.58	1.72	2.00	1.95	Earnings per sh A B	2.45
.96	1.01	1.06	1.10	1.14	1.16	1.18	1.20	1.22	1.24	1.26	1.28	Div'ds Decl'd per sh C■	1.35
4.84	4.13	4.44	3.53	2.36	2.77	3.17	3.10	3.03	4.14	5.20	5.15	Cap'l Spending per sh	7.10
10.75	11.04	12.21	12.09	12.28	14.31	13.75	16.66	18.05	19.90	20.10	20.20	Book Value per sh	22.95
16.02	29.64	30.40	31.25	31.95	40.79	41.68	51.48	62.80	80.54	82.00	84.00	Common Shs Outst'g D	100.00
15.1	17.9	15.4	33.0	18.9	15.6	15.2	13.4	15.9	16.1	13.5		Avg Ann'l P/E Ratio	14.0
.95	1.03	.80	1.88	1.23	.80	.83	.76	.84	.84	.72		Relative P/E Ratio	.95
4.2%	4.2%	3.7%	4.1%	5.9%	5.1%	5.4%	5.2%	4.9%	4.5%	4.7%		Avg Ann'l Div'd Yield	3.9%
483.7	906.8	848.2	690.2	850.2	1442.3	950.8	2799.9	2920.0	4973.3	6152.4	6200	Revenues ($mill) A	10000
23.9	39.2	55.3	25.0	32.2	56.1	59.7	79.5	86.2	135.8	162.3	165	Net Profit ($mill)	250
35.7%	37.5%	36.5%	35.0%	36.1%	37.3%	37.1%	37.1%	37.4%	37.7%	37.6%	37.5%	Income Tax Rate	38.0%
5.0%	4.3%	6.5%	3.6%	3.8%	3.9%	6.3%	2.8%	3.0%	2.7%	2.6%	2.7%	Net Profit Margin	2.5%
41.5%	48.1%	51.8%	50.0%	48.1%	54.3%	53.9%	50.2%	43.2%	57.7%	57.0%	57.0%	Long-Term Debt Ratio	55.0%
58.5%	51.9%	48.2%	50.0%	51.9%	45.7%	46.1%	49.8%	56.8%	42.3%	43.0%	43.0%	Common Equity Ratio	45.0%
294.6	630.2	769.7	755.1	755.7	1276.3	1243.7	1721.4	1994.8	3785.5	3830	3950	Total Capital ($mill)	5100
413.6	849.1	917.9	965.8	982.3	1335.4	1300.3	1516.0	1722.5	3374.4	3630	3900	Net Plant ($mill)	5000
10.6%	8.3%	9.0%	5.1%	6.5%	5.9%	6.8%	6.2%	5.8%	5.3%	6.0%	6.0%	Return on Total Cap'l	6.5%
13.9%	12.0%	14.9%	6.6%	8.2%	9.6%	10.4%	9.3%	7.6%	8.5%	10.0%	9.5%	Return on Shr. Equity	11.0%
13.9%	12.0%	14.9%	6.6%	8.2%	9.6%	10.4%	9.3%	7.6%	8.5%	10.0%	9.5%	Return on Com Equity	11.0%
5.1%	3.9%	6.3%	NMF	NMF	2.1%	1.9%	2.8%	1.7%	2.3%	3.5%	3.5%	Retained to Com Eq	5.0%
64%	67%	58%	NMF	112%	79%	82%	70%	77%	73%	64%	65%	All Div'ds to Net Prof	54%

CAPITAL STRUCTURE as of 6/30/06
Total Debt $2481.2 mill. **Due in 5 Yrs** $860.0 mill.
LT Debt $2180.8 mill. **LT Interest** $135.0 mill.
(LT interest earned: 2.7x; total interest coverage: 2.6x)
Leases, Uncapitalized Annual rentals $15.3 mill.
Pfd Stock None
Pension Assets-9/05 $355.9 mill. **Oblig.** $359.9 mill.
Common Stock 81,595,723 shs. as of 7/31/06
MARKET CAP: $2.7 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2004	2005	6/30/06
Cash Assets	201.9	40.1	26.8
Other	475.2	1224.3	1023.4
Current Assets	677.1	1264.4	1050.2
Accts Payable	185.3	461.3	306.8
Debt Due	5.9	148.1	300.4
Other	223.3	503.4	407.6
Current Liab.	414.5	1112.8	1014.8
Fix. Chg. Cov.	384%	395%	400%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '03-'05 to '09-'11
Revenues	6.0%	16.5%	10.5%
"Cash Flow"	3.5%	2.0%	6.5%
Earnings	4.0%	6.5%	6.5%
Dividends	3.0%	2.0%	2.0%
Book Value	6.5%	8.5%	4.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2003	680.4	1194.1	488.5	436.9	2799.9
2004	763.6	1117.5	546.1	492.8	2920.0
2005	1371.0	1687.8	909.9	1004.6	4973.3
2006	2283.8	2033.8	863.2	971.6	6152.4
2007	1550	1550	1550	1550	6200

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2003	.60	1.24	--	d.05	1.71
2004	.57	1.12	.09	d.11	1.58
2005	.79	1.11	.06	d.21	1.72
2006	.88	1.10	d.22	.25	2.00
2007	.85	1.15	.08	d.13	1.95

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.295	.295	.295	.30	1.19
2003	.30	.30	.30	.305	1.21
2004	.305	.305	.305	.31	1.23
2005	.31	.31	.31	.315	1.25
2006	.315	.315	.315	.32	

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to 3.2 million customers via seven regulated natural gas utility operations: Louisiana Division, Mid-States Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky Division. Combined 2005 gas volumes: 296 MMcf. Breakdown: 55%, residential; 31%, commercial; 10%, industrial; and 4% other. 2005 depreciation rate 3.7%. Has around 4,330 employees. Officers and directors own approximately 2.6% of common stock (12/05 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.

We believe that Atmos Energy's bottom line will be flat in fiscal 2007, which began on October 1st. This is attributable largely to the difficult comparison, reflecting a record performance from the non-utility marketing segment, which was able to capture highly favorable arbitrage spreads created by natural gas volatility. Note, too, that our figure for the fourth quarter of fiscal 2006 does not include an *$0.18-a-share charge for the impairment of* irrigation properties in the West Texas Division.

But the company ought to be aided by certain factors. Weather-normalized rates are now in effect for the Mid-Tex operation and Louisiana unit, presently accounting for almost 60% of the customer base, combined. Consequently, around 90% of the utility's margins are protected by these mechanisms, compared to about 33% previously. Also, this fiscal year's results should be absent the $0.10-a-share reduction from the impact of Hurricane Katrina.

Atmos is one of the more aggressively managed natural gas utilities in the *Value Line* universe, as it has completed a string of major acquisitions over the past 20 years (the last one being TXU Gas Company in 2004). The TXU purchase brought a substantial pipeline business into the fold. The company is now one of the largest operators in Texas, with room for expansion. Management will undoubtedly continue to implement its strategy of purchasing less-efficient utilities and shoring up their profitability through *expense-reduction initiatives, rate relief,* and aggressive marketing efforts.

These good-quality shares have exhibited strength since our last report in September, arising partly, we think, from the possibility that natural gas costs will decline this winter, in view of weather forecasts and supply levels.

Income-oriented accounts may be drawn to the dividend yield. And it seems that more increases in the payout are plausible. Earnings coverage should remain adequate.

But long-term total-return possibilities are limited, given the stock's price move. Also, the Timeliness rank is just 3 (Average).

Frederick L. Harris, III December 15, 2006

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. items: '97, d53¢; '99, d23¢; '00, 12¢; '03, d17¢; Q4 '06, d18¢. Next egs. rpt. due early Feb. (C) Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail. (D) In millions, adjusted for stock splits. (E) Qtrs may not add due to change in shrs outstanding. (F) ATO completed United Cities merger 7/97.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	30
Earnings Predictability	70

LACLEDE GROUP NYSE-LG

RECENT PRICE	36.70	P/E RATIO	15.2 (Trailing: 15.5; Median: 15.0)	RELATIVE P/E RATIO	0.83	DIV'D YLD	4.0%	VALUE LINE

TIMELINESS **4** Raised 9/8/06

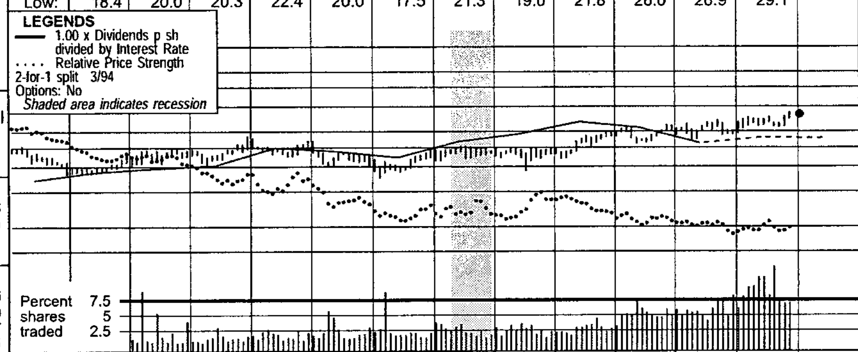
SAFETY **2** Raised 6/20/03

TECHNICAL **3** Lowered 9/15/06

BETA .90 (1.00 = Market)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
High:	23.1	24.9	28.6	27.9	27.0	24.8	25.5	25.0	30.0	32.5	34.3	37.5
Low:	18.4	20.0	20.3	22.4	20.0	17.5	21.3	19.0	21.8	26.0	26.9	29.1

Target Price Range 2009 | 2010 | 2011



2009-11 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+25%)	9%
Low	30	(-20%)	Nil

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	0	0	1	0	0	0	1
to Sell	0	1	0	0	1	0	0	0	1

Institutional Decisions

	4Q2005	1Q2006	2Q2006
to Buy	50	67	60
to Sell	37	30	47
Hld's(000)	8521	9470	10115

% TOT. RETURN 11/06

	THIS STOCK	VL ARITH. INDEX
1 yr.	27.7	15.5
3 yr.	43.3	49.4
5 yr.	97.3	85.9

1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	© VALUE LINE PUB., INC.	09-11
30.21	28.10	26.83	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	92.90	88.35	Revenues per sh	116.65
2.13	2.37	2.32	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	3.95	4.00	"Cash Flow" per sh	4.70
1.08	1.28	1.17	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	2.15	Earnings per sh A B	2.50
1.18	1.20	1.20	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	Div'ds Decl'd per sh C ■	1.55
1.87	2.46	2.87	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	2.95	3.05	Cap'l Spending per sh	4.35
11.75	11.83	11.79	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	20.65	Book Value per sh D	26.00
15.59	15.59	15.59	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	21.50	21.50	Common Shs Outst'g E	24.00
14.6	12.5	15.8	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		Avg Ann'l P/E Ratio	15.0
1.08	.80	.96	.80	1.08	1.04	.75	.72	.81	.90	.97	.74	1.09	.78	.83	.86	.73		Relative P/E Ratio	1.00
7.5%	7.5%	6.5%	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%		Avg Ann'l Div'd Yield	4.1%

CAPITAL STRUCTURE as of 6/30/06
Total Debt $518.8 mill. Due in 5 Yrs $175.0 mill.
LT Debt $395.4 mill. LT Interest $25.0 mill.
(Total interest coverage: 3.0x)

Leases, Uncapitalized Annual rentals $1.7 mill.
Pension Assets-9/05 $272.8 mill. Oblig. $327.2 mill.
Pfd Stock $.8 mill. Pfd Div'd $.05 mill.
Common Stock 21,357,009 shs. as of 7/28/06

MARKET CAP: $775 million (Small Cap)

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007		09-11
544.8	602.8	547.2	491.6	566.1	1002.1	755.2	1050.3	1250.3	1597.0	1997.5	1900	Revenues ($mill) A	2800
32.8	32.5	27.9	26.9	26.0	30.5	22.4	34.6	36.1	40.1	50.5	46.0	Net Profit ($mill)	60.0
35.9%	36.1%	35.6%	35.5%	35.2%	32.7%	35.4%	35.0%	34.8%	34.1%	32.5%	33.5%	Income Tax Rate	35.0%
6.0%	5.4%	5.1%	5.5%	4.6%	3.0%	3.0%	3.3%	2.9%	2.5%	2.5%	2.4%	Net Profit Margin	2.1%
42.5%	38.0%	40.9%	41.8%	45.2%	49.5%	47.5%	50.4%	51.6%	48.1%	49.5%	49.0%	Long-Term Debt Ratio	48.0%
57.1%	61.6%	58.6%	57.8%	54.5%	50.2%	52.3%	49.4%	48.3%	51.8%	50.5%	51.0%	Common Equity Ratio	52.0%
422.2	406.8	438.0	488.6	519.2	574.1	546.6	605.0	737.4	707.9	800	870	Total Capital ($mill)	1200
452.2	467.6	490.6	519.4	575.4	602.5	594.4	621.2	646.9	679.5	765	805	Net Plant ($mill)	1030
9.4%	9.7%	8.1%	7.1%	6.7%	6.9%	6.0%	7.4%	6.6%	7.7%	8.0%	7.0%	Return on Total Cap'l	6.5%
13.5%	12.9%	10.8%	9.5%	9.1%	10.5%	7.8%	11.5%	10.1%	10.9%	12.5%	10.5%	Return on Shr. Equity	9.5%
13.6%	12.9%	10.8%	9.5%	9.1%	10.5%	7.8%	11.6%	10.1%	10.9%	12.5%	10.5%	Return on Com Equity	9.5%
4.5%	3.9%	1.8%	1.0%	.2%	1.8%	NMF	3.1%	2.7%	3.1%	5.0%	3.5%	Retained to Com Eq	4.0%
67%	70%	83%	89%	98%	83%	113%	74%	73%	72%	60%	68%	All Div'ds to Net Prof	60%

CURRENT POSITION ($MILL.)

	2004	2005	6/30/06
Cash Assets	13.9	6.0	31.9
Other	323.7	418.1	319.1
Current Assets	337.6	424.1	351.0
Accts Payable	68.4	138.4	118.2
Debt Due	96.5	110.7	123.4
Other	97.7	116.5	62.9
Current Liab.	262.6	365.6	304.5
Fix. Chg. Cov.	279%	293%	290%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '03-'05 to '09-'11
Revenues	7.5%	17.0%	10.5%
"Cash Flow"	1.0%	1.5%	8.0%
Earnings	2.5%	4.5%	5.0%
Dividends	1.0%	.5%	2.5%
Book Value	3.0%	2.5%	7.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2003	280.1	422.2	186.6	161.4	1050.3
2004	332.6	475.0	245.1	197.6	1250.3
2005	442.5	576.5	311.3	266.7	1597.0
2006	689.2	708.8	330.5	269.0	1997.5
2007	475	475	475	475	1900

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2003	.80	1.14	.11	d.21	1.82
2004	.87	1.12	.19	d.28	1.82
2005	.79	1.06	.29	d.24	1.90
2006	1.23	1.05	.13	d.04	2.37
2007	1.15	1.05	.25	d.30	2.15

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.335	.335	.335	.335	1.34
2003	.335	.335	.335	.335	1.34
2004	.335	.34	.34	.34	1.36
2005	.34	.345	.345	.345	1.38
2006	.345	.355	.355	.355	

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 8 other counties. Has roughly 631,000 customers. Purchased SM&P for $43 million (1/02). Therms sold and transported in fiscal 2005: 1.12 mill. Revenue mix for regulated operations: residential, 60%; commercial and industrial, 23%; transportation, 2%; other, 15%. Has around 3,815 employees. Officers and directors own approximately 6.0% of common shares (1/06 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.lacledegas.com.

We don't expect Laclede Group's bottom line in fiscal 2007 (began October 1st) to reach last year's level. This can be attributed primarily to the tough comparison, reflecting an exceptional showing from Laclede Energy Resources (LER). Indeed, that division was aided by supply/demand imbalances resulting from the 2005 Gulf Coast hurricanes (one of the busiest storm seasons on record), plus a surge in volumes (due to higher interstate pipeline wholesale transactions). A repeat of that scenario seems unlikely anytime soon, though. Also, results for Laclede Gas Company, the core subsidiary, may continue to be dampened by rising operating costs and lackluster volumes within the service area (stemming from conservation efforts). But SM&P Utility Resources could begin to experience the benefits of initiatives directed toward the startup of new business in existing markets. The recent purchase of Reliant Services, which provides services that are similar to SM&P, ought to help performance here, too. Nonetheless, consolidated share net could decrease about 9%, to $2.15, in fiscal 2007. We think a bottom line rebound is plausible in fiscal 2008, partly assuming an easier comparison.

The company stands to post unspectacular earnings over the 3- to 5-year period. Customer increases for the natural gas unit have been sluggish because the service territory is mature. As such, internal growth here should remain moderate, at best. The non-regulated units hold promising prospects, although they have contributed a small portion to profits historically (with the exception of LER's performance in fiscal 2006). Major acquisitions could offset this, but it appears that management has no such plans in the works at this juncture. That said, annual share-net gains may only be in the mid-single-digit range out to 2009-2011.

These shares are trading at relatively high levels, coming off Laclede's excellent results in fiscal 2006. A record-breaking equity market has also helped matters.

But total-return possibilities are limited, given the stock's price movement and assuming continued modest hikes in the payout. Moreover, the Timeliness rank is 4 (Below Average).

Frederick L. Harris, III December 15, 2006

(A) Fiscal year ends Sept. 30th.
(B) Based on average shares outstanding thru. '97, then diluted. Excludes nonrecurring loss: Q2 '06, 7¢. Next earnings report due late Jan.
(C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available.
(D) Incl. deferred charges. In '05: $203.8 mill., $9.63/sh.
(E) In millions. Adjusted for stock split.
(F) Qtly. egs. may not sum due to change in shares outstanding.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	55
Earnings Predictability	65

NEW JERSEY RES. NYSE-NJR

RECENT PRICE	52.26	P/E RATIO	18.9 (Trailing: 18.7 Median: 15.0)	RELATIVE P/E RATIO	1.03	DIV'D YLD	2.9%	VALUE LINE

TIMELINESS **5** Lowered 12/15/06

SAFETY **1** Raised 9/15/06

TECHNICAL **3** Lowered 11/24/06

BETA .80 (1.00 = Market)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
High:	20.3	19.9	28.0	26.8	27.4	29.8	32.5	33.6	39.5	44.6	49.3	53.2
Low:	14.3	17.8	18.8	21.0	22.4	24.1	24.8	24.3	30.0	36.5	40.7	41.5

Target Price Range 2009 | 2010 | 2011

2009-11 PROJECTIONS

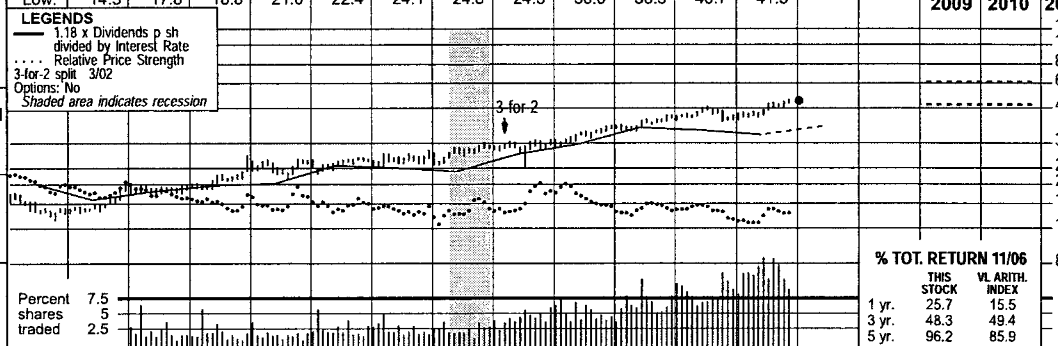
	Price	Gain	Ann'l Total Return
High	65	(+25%)	9%
Low	50	(-5%)	2%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	5	0	0	2	0	0	4	0
to Sell	0	4	0	0	2	0	0	4	0

Institutional Decisions

	4Q2005	1Q2006	2Q2006
to Buy	64	71	73
to Sell	60	52	60
Hld's(000)	13455	14778	16255



% TOT. RETURN 11/06

	THIS STOCK	VL ARITH. INDEX
1 yr.	25.7	15.5
3 yr.	48.3	49.4
5 yr.	96.2	85.9

1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	© VALUE LINE PUB., INC.	09-11
16.01	15.99	16.88	18.02	19.22	17.03	20.22	25.97	26.59	33.98	44.13	76.82	66.17	93.43	91.33	114.29	119.44	121.45	Revenues per sh A	129.80
1.54	1.58	1.95	2.14	2.31	2.13	2.22	2.45	2.60	2.79	2.99	3.18	3.21	3.58	3.75	3.92	4.10	4.20	"Cash Flow" per sh	4.75
.65	.55	1.09	1.15	1.26	1.29	1.37	1.48	1.55	1.66	1.79	1.95	2.09	2.38	2.55	2.65	2.80	2.90	Earnings per sh B	3.35
.96	1.00	1.01	1.01	1.01	1.01	1.03	1.07	1.09	1.12	1.15	1.17	1.20	1.24	1.30	1.36	1.44	1.52	Div'ds Decl'd per sh C■	1.70
4.37	2.91	1.99	2.31	2.10	1.77	1.78	1.72	1.60	1.81	1.85	1.66	1.53	1.71	2.17	1.92	1.92	1.95	Cap'l Spending per sh	2.10
8.85	8.57	9.44	9.81	9.64	9.70	10.10	10.38	10.88	11.35	12.43	13.20	13.06	15.38	16.87	15.90	22.50	23.60	Book Value per sh	27.85
20.28	20.95	24.43	25.23	25.95	26.69	27.13	26.82	26.72	26.61	26.39	26.66	27.67	27.23	27.74	27.55	27.63	28.00	Common Shs Outst'g D	28.50
24.0	22.3	12.4	15.1	13.0	11.7	13.6	13.5	15.3	15.2	14.7	14.2	14.7	14.0	15.3	16.8	16.1		Avg Ann'l P/E Ratio	17.0
1.78	1.42	.75	.89	.85	.78	.85	.78	.80	.87	.96	.73	.80	.80	.81	.89	.86		Relative P/E Ratio	1.15
6.2%	8.1%	7.5%	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%		Avg Ann'l Div'd Yield	3.0%

CAPITAL STRUCTURE as of 9/30/06
Total Debt $616.8 mill. Due in 5 Yrs $300.0 mill.
LT Debt $332.4 mill. LT Interest $25.0 mill.
Incl. $7.4 mill. capitalized leases.
(total interest coverage: 6.0x)
Pension Assets-9/06 $95.8 mill. Oblig. $103.7 mill.

Pfd Stock None

Common Stock 27,678,310 shs. as of 11/20/06
MARKET CAP: $1.5 billion (Mid Cap)

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007		09-11
548.5	696.5	710.3	904.3	1164.5	2048.4	1830.8	2544.4	2533.6	3148.3	3299.6	3400	Revenues ($mill) A	3700
38.7	41.5	43.3	44.9	47.9	52.3	56.8	65.4	71.6	74.4	78.5	82.0	Net Profit ($mill)	95.0
32.6%	33.3%	30.4%	36.2%	37.8%	38.0%	38.7%	39.4%	39.1%	39.1%	38.9%	39.0%	Income Tax Rate	40.0%
7.1%	6.0%	6.1%	5.0%	4.1%	2.6%	3.1%	2.6%	2.8%	2.4%	2.4%	2.4%	Net Profit Margin	2.5%
50.7%	49.3%	51.2%	48.7%	47.0%	50.1%	50.6%	38.1%	40.3%	42.0%	34.8%	34.0%	Long-Term Debt Ratio	32.5%
45.8%	47.1%	45.6%	51.2%	52.9%	49.9%	49.4%	61.9%	59.7%	58.0%	65.2%	66.0%	Common Equity Ratio	67.5%
598.2	590.6	638.2	590.4	620.1	706.2	732.4	676.8	783.8	755.3	954.0	1000	Total Capital ($mill)	1170
655.2	659.4	680.0	705.4	730.6	743.9	756.4	852.6	880.4	905.1	934.9	970	Net Plant ($mill)	1120
8.1%	8.6%	8.1%	9.0%	9.0%	8.5%	8.7%	10.7%	10.1%	11.2%	9.6%	9.5%	Return on Total Cap'l	9.5%
13.1%	13.9%	13.9%	14.8%	14.6%	14.8%	15.7%	15.6%	15.3%	17.0%	12.6%	12.5%	Return on Shr. Equity	12.0%
13.5%	14.3%	14.4%	14.8%	14.6%	14.9%	15.7%	15.6%	15.3%	17.0%	12.6%	12.5%	Return on Com Equity	12.0%
3.4%	4.0%	4.4%	5.0%	5.4%	6.1%	6.9%	7.7%	7.8%	8.5%	6.3%	6.0%	Retained to Com Eq	6.0%
76%	73%	71%	67%	63%	59%	56%	51%	49%	50%	50%	52%	All Div'ds to Net Prof	51%

CURRENT POSITION ($MILL.)

	2004	2005	9/30/06
Cash Assets	5.0	25.0	5.0
Other	681.0	927.8	960.5
Current Assets	686.0	952.8	965.5
Accts Payable	42.9	54.7	46.8
Debt Due	287.4	177.4	284.4
Other	357.4	744.2	566.0
Current Liab.	687.7	976.3	897.2
Fix. Chg. Cov.	826%	660%	571%

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '09-'11
Revenues	19.0%	16.0%	3.5%
"Cash Flow"	6.0%	5.5%	4.0%
Earnings	7.5%	8.0%	4.5%
Dividends	3.0%	3.5%	4.5%
Book Value	6.5%	8.5%	8.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2003	668.8	1152	369.7	353.1	2544.4
2004	643.0	1037	438.5	414.4	2533.6
2005	854.0	1065	544.3	684.9	3148.3
2006	1164	1064	536.1	534.5	3299.6
2007	1085	1150	610	555	3400

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2003	.85	1.50	.16	d.13	2.38
2004	.87	1.82	.06	d.20	2.55
2005	.91	1.84	.07	d.17	2.65
2006	1.23	2.14	d.14	d.43	2.80
2007	1.18	1.95	.07	d.30	2.90

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.30	.30	.30	.30	1.20
2003	.31	.31	.31	.31	1.24
2004	.325	.325	.325	.325	1.30
2005	.34	.34	.34	.34	1.36
2006	.36	.36	.36	.36	1.44

BUSINESS: New Jersey Resources Corp. is a holding company providing retail and Wholesale energy svcs. to customers in New Jersey, in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas has about 471,000 customers at 9/30/06 in Monmouth and Ocean Counties, and other N.J. Counties. Fiscal 2006 volume: 102.8 bill. cu. ft. (56% firm, 7% interruptible industrial and electric utility, 37% off-system and capacity release). N.J. Natural Energy subsid. provides unregulated retail and wholesale natural gas and related energy svcs. 2006 dep. rate: 2.7%. Has 766 employ. Off./dir. own about 3% of common (12/05 Proxy). Chrmn. and CEO: Laurence M. Downes. Inc.: N.J. Addr.: 1415 Wyckoff Road, Wall, NJ 07719. Tel.: 732-938-1000. Web: www.njliving.com.

We think New Jersey Resources' share earnings will advance only moderately in fiscal 2007 (year ends September 30th). Results at the company's main subsidiary, New Jersey Natural Gas (NJNG), should be helped by the approval of a conservation incentive plan (CIP) in October by the New Jersey Board of Public Utilities. The CIP is a three-year pilot program that protects against both warmer-than-normal temperatures and conservation by customers, unlike the previous weather normalization clause that only protected against warmer temperatures. This will enable NJNG to promote conservation and efficiency, while protecting its financial performance. Customer growth remains strong. The company added about 10,160 customers in 2006 (to a total of around 470,000), with almost 35% converting from other fuels, and we look for similar levels of growth this year.

The company's results were once again led by the Energy subsidiaries good performance. For the year, the division reported earnings of $28 million, more than 70% above the year-ago period. The strong performance helped offset results at NJNG, where earnings were hurt by reduced customer usage. The increase in earnings at the Energy unit was primarily due to favorable spreads on its storage asset positions. This can be attributable to the fact that the company's holding facilities become more valuable when prices change between areas and/or time periods. In addition, results from this segment are typically better during the winter months, since the fixed costs of these assets are spread throughout the entire year.

Though untimely, this good-quality stock generates consistent results. The board recently raised the quarterly dividend by 5.6%, to $0.38 a share. We look for further modest increases over the next few years. However, the yield is below that of its utility counterparts, partly owing to good customer growth prospects. The lower yield is also due to funds being used for nonutility investments. For 2007, these activities may comprise 25%–30% of total earnings. However, investors should be aware that these activities are more risky than regulated operations.

Evan I. Blatter *December 15, 2006*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Next earnings report due late Jan.
(C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available.
(D) In millions, adjusted for split.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	85
Earnings Predictability	100

NICOR, INC. NYSE-GAS

RECENT PRICE	49.59	P/E RATIO	18.1 (Trailing: 18.0 Median: 14.0)	RELATIVE P/E RATIO	0.98	DIV'D YLD	3.8%	VALUE LINE

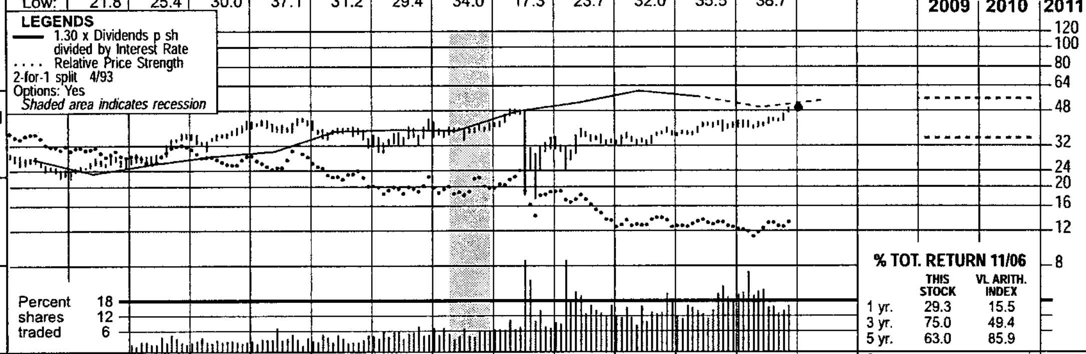
TIMELINESS 2 Raised 11/10/06
SAFETY 3 Lowered 6/17/05
TECHNICAL 2 Raised 11/3/06
BETA 1.30 (1.00 = Market)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
High:	28.5	37.1	42.9	44.4	42.9	43.9	42.4	49.0	39.3	39.7	43.0
Low:	21.8	25.4	30.0	37.1	31.2	29.4	34.0	17.3	23.7	32.0	35.5

High:	49.9
Low:	38.7

Target Price Range 2009 | 2010 | 2011

LEGENDS
— 1.30 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 4/93
Options: Yes
Shaded area indicates recession



2009-11 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+10%)	6%
Low	35	(-30%)	-4%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	1	0	0	1	0	0	1	1	3
Options	0	0	2	0	0	0	0	2	0
to Sell	0	0	2	0	0	0	0	0	0

Institutional Decisions

	4Q2005	1Q2006	2Q2006
to Buy	117	112	98
to Sell	97	94	110
Hld's(000)	30966	32581	32450

Percent shares traded 18 12 6

% TOT. RETURN 11/06

	THIS STOCK	VL ARITH. INDEX
1 yr.	29.3	15.5
3 yr.	75.0	49.4
5 yr.	63.0	85.9

1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	© VALUE LINE PUB., INC.	09-11
26.52	26.46	28.90	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	*71.90*	*72.30*	Revenues per sh	*71.25*
3.86	3.92	4.14	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	*5.95*	*6.10*	"Cash Flow" per sh	*6.15*
1.93	1.86	1.92	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	*2.70*	*2.72*	Earnings per sh A	*2.80*
1.06	1.12	1.18	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*	*1.90*	Div'ds Decl'd per sh B ■	*2.00*
3.00	3.65	3.12	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	*4.50*	*4.50*	Cap'l Spending per sh	*4.45*
11.67	12.28	12.76	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	*19.35*	*20.20*	Book Value per sh	*22.80*
57.93	57.30	55.77	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	*44.50*	*44.60*	Common Shs Outst'g C	*44.90*
10.7	11.5	11.6	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	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
.79	.73	.70	.83	.82	.88	.78	.82	.92	.83	.77	.66	.72	.90	.84	.91	*Value Line*		Relative P/E Ratio	*1.05*
5.1%	5.2%	5.3%	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%	*estimates*		Avg Ann'l Div'd Yield	*4.5%*

CAPITAL STRUCTURE as of 9/30/06
Total Debt $660.4 mill. Due in 5 Yrs $215.0 mill.
LT Debt $459.4 mill. LT Interest $20.0 mill.
(Total interest coverage: 4.0x)

Pension Assets-12/05 $424.0 mill. Oblig. $284.4 mill.

Pfd Stock $.6 mill. Pfd Div'd $2.2 mill.
(11,681 shares of 4.48% mandatorily redeemable preferred stock)
Common Stock 44,709,976 shares as of 10/27/06
MARKET CAP: $2.2 billion (Mid Cap)

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007		09-11
1850.7	1992.6	1465.1	1615.2	2298.1	2544.1	1897.4	2662.7	2739.7	3357.8	*3200*	*3225*	Revenues ($mill)	*3200*
121.2	124.3	111.1	121.9	136.4	136.3	128.0	93.1	98.1	101.1	*120*	*120*	Net Profit ($mill)	*125*
35.8%	35.0%	34.4%	34.7%	34.8%	33.5%	31.0%	35.2%	31.8%	28.3%	*27.0%*	*30.0%*	Income Tax Rate	*32.0%*
6.5%	6.2%	7.6%	7.5%	5.9%	5.4%	6.7%	3.5%	3.6%	3.0%	*3.8%*	*3.8%*	Net Profit Margin	*3.9%*
41.3%	42.3%	42.1%	35.5%	32.7%	37.8%	35.1%	39.6%	39.8%	37.4%	*34.0%*	*33.0%*	Long-Term Debt Ratio	*31.0%*
58.1%	57.2%	57.4%	64.0%	66.7%	61.7%	64.5%	60.3%	60.1%	62.5%	*66.0%*	*67.0%*	Common Equity Ratio	*69.0%*
1255.1	1300.6	1322.6	1230.1	1061.2	1180.1	1128.9	1251.5	1246.0	1297.7	*1310*	*1350*	Total Capital ($mill)	*1475*
1771.9	1735.8	1731.8	1735.2	1729.6	1768.6	1796.8	2484.2	2549.8	2659.1	*2760*	*2860*	Net Plant ($mill)	*3160*
11.1%	11.1%	9.9%	10.9%	13.7%	12.3%	12.2%	8.3%	8.8%	9.4%	*10.9%*	*10.6%*	Return on Total Cap'l	*10.0%*
16.4%	16.6%	14.5%	15.4%	19.1%	18.6%	17.5%	12.3%	13.1%	12.5%	*14.0%*	*13.5%*	Return on Shr. Equity	*12.0%*
16.6%	16.7%	14.6%	15.4%	19.2%	18.7%	17.5%	12.3%	13.1%	12.5%	*14.0%*	*13.0%*	Return on Com Equity	*12.0%*
7.6%	7.6%	5.4%	6.2%	8.5%	7.9%	6.5%	1.5%	2.1%	2.3%	*4.5%*	*4.0%*	Retained to Com Eq	*3.5%*
54%	55%	63%	60%	56%	58%	63%	88%	84%	81%	*68%*	*70%*	All Div'ds to Net Prof	*72%*

CURRENT POSITION ($MILL.)	2004	2005	9/30/06
Cash Assets	83.2	126.9	54.4
Other	937.7	1218.8	628.2
Current Assets	1020.9	1345.7	682.6
Accts Payable	502.9	658.2	519.4
Debt Due	490.2	636.0	201.0
Other	178.3	328.7	263.0
Current Liab.	1171.4	1622.9	983.4
Fix. Chg. Cov.	428%	367%	NMF

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '03-'05 to '09-'11
Revenues	8.0%	11.5%	1.0%
"Cash Flow"	4.0%	0.5%	1.0%
Earnings	1.0%	-3.5%	4.0%
Dividends	4.0%	3.5%	1.0%
Book Value	3.0%	1.5%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	1171.3	452.8	294.8	743.8	2662.7
2004	1115.7	429.5	299.9	894.6	2739.7
2005	1179.9	484.4	336.0	1357.5	3357.8
2006	1319.4	451.3	351.1	*1078.2*	*3200*
2007	*1250*	*500*	*350*	*1125*	*3225*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	1.11	.21	.01	.78	2.11
2004	.96	.44	d.26	1.08	2.22
2005	.98	.35	d.06	1.02	2.27
2006	.94	.41	.39	*.96*	*2.70*
2007	*1.02*	*.37*	*.28*	*1.05*	*2.72*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.46	.46	.46	.46	1.84
2003	.46	.465	.465	.465	1.86
2004	.465	.465	.465	.465	1.86
2005	.465	.465	.465	.465	1.86
2006	.465	.465	.465	.465	

BUSINESS: Nicor Inc. is a holding company with gas distribution as its primary business. Serves over 2.1 million customers in northern and western Illinois. 2005 gas delivered: 470.6 Bcf, incl. 219.4 Bcf from transportation. 2005 gas sales (251.2 bcf): residential, 80%; commercial, 18%; industrial, 2%. Principal supplying pipelines: Natural Gas Pipeline, Horizon Pipeline, and TGPC. Current operations include Tropical Shipping subsidiary and several energy related ventures. Divested inland barging, 7/86; contract drilling, 9/86; oil and gas E&P, 6/93. Has about 3,700 employees Off./dir. own about 2.8% of common stock. (3/06 proxy). Chairman and CEO: Russ Strobel. Inc.: Illinois Address: 1844 Ferry Road, Naperville, Illinois 60563. Telephone: 630-305-9500. Internet: www.nicor.com.

Nicor reported strong results for its September period. Indeed, the company registered a share-net gain of $0.39, which exceeded the popular consensus and topped last year's number at a loss of $0.06 a share. All operating segments produced solid results. However, volumes were particularly strong in the gas distribution segment.

As the unseasonably warm weather passes, the company will likely benefit from an increase in the usage of natural gas over the balance of the year. The industry suffered through a tough first half due to warm conditions, but now as we near 2007, gas deliveries are increasing. As gas consumption returns to normal levels, Nicor's bottom line should push forward, beginning in 2007.

Base rates will likely remain unchanged. Late in 2005, the Illinois Commerce Commission approved an increase in rates, which will likely continue to help the company's top and bottom lines in 2007. For the near term, Nicor seems to be content to move forward operating in the current conditions. Still, it has not fully utilized strategies that would protect its business through various mechanisms, which would help limit the variability of earnings. Thus, we anticipate similar volatility for these shares in the future.

Nicor's other business segments should continue to be solid. Particularly, the Tropical Shipping division has continued to generate high revenues, which ought to continue going into 2007, as demand for the service remains robust. The company's energy ventures ought to also add some consistent volume to Nicor's top line over the next year.

This issue is ranked to outperform the market in the year ahead. All told, the company has taken steps to improve its business across all of its segments and has benefited from the latest rate increase. However, much of this issue's long-term appreciation potential has been realized, as this stock is already trading within its Target Price Range.

These shares may be of interest to income-oriented investors. Although Nicor offers a yield that is slightly below the industry mean at 3.8%, it's still is above the *Value Line* average.

Richard Gallagher *December 15, 2006*

(A) Based on primary earnings thru. '96, then diluted. Excl. nonrecurring gains/(loss): '89, 7¢; '97, 6¢; '98, 11¢; '99, 5¢; '00, ($1.96); '01, 16¢; '03, (27¢); '04, (52¢); '05, 80¢; '06, (17¢). Excl. items from discontinued ops.: '93, 4¢; '96, 30¢. Quarterly earnings may not sum to total due to rounding. Next egs. report due early March. (B) Dividends historically paid early February, May, August, November. ■ Dividend reinvestment plan available. (C) In millions, adjusted for stock split.

Company's Financial Strength	A
Stock's Price Stability	55
Price Growth Persistence	35
Earnings Predictability	80

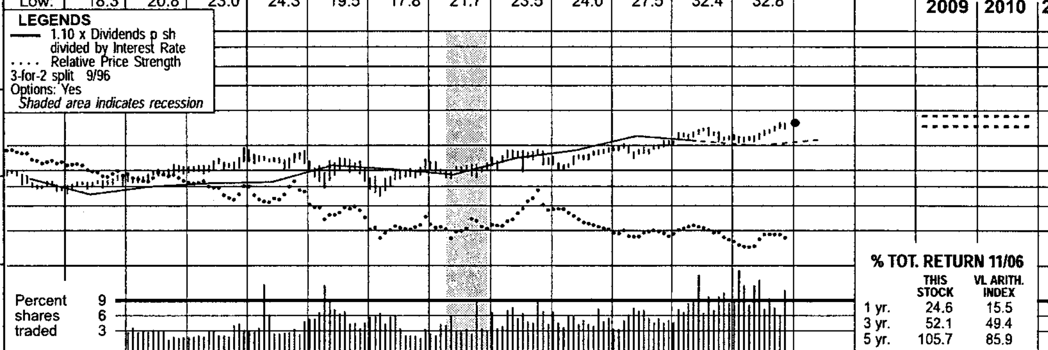
N.W. NAT'L GAS NYSE-NWN

RECENT PRICE **41.62** | P/E RATIO **17.9** (Trailing: 19.5 Median: 15.0) | RELATIVE P/E RATIO **0.97** | DIV'D YLD **3.4%** | VALUE LINE

TIMELINESS **4** Lowered 12/8/06
SAFETY **1** Raised 3/18/05
TECHNICAL **2** Raised 12/8/06
BETA .75 (1.00 = Market)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
High:	22.8	25.9	31.4	30.8	27.9	27.5	26.8	30.7	31.3	34.1	39.6	41.9
Low:	18.3	20.8	23.0	24.3	19.5	17.8	21.7	23.5	24.0	27.5	32.4	32.8

LEGENDS
— 1.10 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 9/96
Options: Yes
Shaded area indicates recession



Target Price Range
2009 | 2010 | 2011

2009-11 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+10%)	5%
Low	40	(-5%)	3%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	1	1	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	1
to Sell	0	0	0	0	1	0	0	0	1

Institutional Decisions

	4Q2005	1Q2006	2Q2006
to Buy	59	62	77
to Sell	54	59	59
Hld's(000)	12922	13095	14328

Percent shares traded 9 6 3

% TOT. RETURN 11/06

	THIS STOCK	VL ARITH. INDEX
1 yr.	24.6	15.5
3 yr.	52.1	49.4
5 yr.	105.7	85.9

1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	© VALUE LINE PUB., INC.	09-11
17.02	16.74	14.10	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	*36.35*	*36.85*	Revenues per sh	*51.80*
3.22	2.57	3.25	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	*4.65*	*4.75*	"Cash Flow" per sh	*5.10*
1.62	.67	.74	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	*2.25*	*2.40*	Earnings per sh A	*2.85*
1.10	1.13	1.15	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*	*1.43*	Div'ds Decl'd per sh B ■	*1.70*
3.85	3.58	3.73	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	*3.65*	*3.30*	Cap'l Spending per sh	*3.35*
12.61	12.23	12.41	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	*22.10*	*22.95*	Book Value per sh	*25.55*
17.41	17.68	19.46	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	*27.50*	*27.80*	Common Shs Outst'g C	*28.00*
10.2	28.1	27.0	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	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*15.0*
.76	1.79	1.64	.76	.85	.86	.73	.83	1.39	.83	.81	.66	.94	.90	.88	.91	*estimates*		Relative P/E Ratio	*1.00*
6.7%	5.9%	5.7%	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%			Avg Ann'l Div'd Yield	*4.0%*

CAPITAL STRUCTURE as of 9/30/06
Total Debt $624.8 mill. **Due in 5 Yrs** $251.7 mill.
LT Debt $492.0 mill. **LT Interest** $31.0 mill.

(Total interest coverage: 3.4x)

Pension Assets-12/05 $218.6 mill.
Oblig. $267.9 mill.
Pfd Stock None

Common Stock 27,504,896 shs.
as of 10/31/06
MARKET CAP $1.1 billion (Mid Cap)

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007		09-11
380.3	361.8	416.7	455.8	532.1	650.3	641.4	611.3	707.6	910.5	*1000*	*1025*	Revenues ($mill)	*1350*
46.8	43.1	27.3	44.9	47.8	50.2	43.8	46.0	50.6	58.1	*62.0*	*66.5*	Net Profit ($mill)	*80.0*
36.9%	32.9%	31.0%	35.4%	35.9%	35.4%	34.9%	33.7%	34.4%	36.0%	*36.0%*	*36.0%*	Income Tax Rate	*36.0%*
12.3%	11.9%	6.6%	9.9%	9.0%	7.7%	6.8%	7.5%	7.1%	6.4%	*6.2%*	*6.5%*	Net Profit Margin	*5.9%*
41.4%	46.0%	45.0%	46.0%	45.1%	43.0%	47.6%	49.7%	46.0%	47.0%	*47.0%*	*47.0%*	Long-Term Debt Ratio	*47%*
52.8%	49.0%	50.6%	49.9%	50.9%	53.2%	51.5%	50.3%	54.0%	53.0%	*53.0%*	*53.0%*	Common Equity Ratio	*53%*
657.4	748.0	815.6	861.5	887.8	880.5	937.3	1006.6	1052.5	1108.4	*1125*	*1175*	Total Capital ($mill)	*1350*
745.3	827.5	894.7	895.9	934.0	965.0	995.6	1205.9	1318.4	1373.4	*1425*	*1475*	Net Plant ($mill)	*1700*
8.9%	7.4%	5.0%	6.8%	6.7%	6.9%	5.9%	5.7%	5.9%	6.5%	*7.0%*	*7.0%*	Return on Total Cap'l	*7.0%*
12.1%	10.7%	6.1%	9.7%	9.8%	10.0%	8.9%	9.1%	8.9%	9.9%	*10.0%*	*10.5%*	Return on Shr. Equity	*10.5%*
12.7%	11.0%	6.0%	9.9%	10.0%	10.2%	8.5%	9.0%	8.9%	9.9%	*10.0%*	*10.5%*	Return on Com Equity	*10.5%*
5.0%	3.6%	NMF	2.8%	3.1%	3.5%	1.9%	2.6%	2.7%	3.7%	*3.7%*	*3.7%*	Retained to Com Eq	*3.8%*
63%	70%	118%	74%	70%	67%	79%	72%	69%	63%	*62%*	*59%*	All Div'ds to Net Prof	*60%*

CURRENT POSITION ($MILL.)	2004	2005	9/30/06
Cash Assets	5.2	7.1	5.7
Other	231.9	316.6	209.7
Current Assets	237.1	323.7	215.4
Accts Payable	102.5	135.3	64.5
Debt Due	117.5	134.7	132.8
Other	47.3	56.6	58.6
Current Liab.	267.3	326.6	255.9
Fx. Chg. Cov.	316%	340%	NMF

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '03-'05 to '09-'11
Revenues	4.5%	8.0%	*11.0%*
"Cash Flow"	1.5%	2.5%	*4.5%*
Earnings	1.5%	5.0%	*7.0%*
Dividends	1.0%	1.0%	*4.0%*
Book Value	4.0%	3.5%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	206.5	117.5	69.5	217.8	611.3
2004	254.5	109.7	81.4	262.0	707.6
2005	308.7	153.7	106.7	341.4	910.5
2006	390.4	171.0	114.9	*323.7*	*1000*
2007	*370*	*180*	*135*	*340*	*1025*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	1.01	.17	d.25	.83	1.76
2004	1.24	d.03	d.30	.95	1.86
2005	1.44	.04	d.31	.94	2.11
2006	1.48	.07	d.35	*1.05*	*2.25*
2007	*1.56*	*.06*	*d.33*	*1.11*	*2.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.315	.315	.315	.315	1.26
2003	.315	.315	.315	.325	1.27
2004	.325	.325	.325	.325	1.30
2005	.325	.325	.325	.345	1.32
2006	.345	.345	.345	.355	

BUSINESS: Northwest Natural Gas Co. distributes natural gas at retail to 90 communities, 624,000 customers, in Oregon (90% of custs.) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 2.4 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system to bring gas to market. Owns local underground storage. Rev. breakdown: residential, 53%; commercial, 27%; industrial, gas transportation, and other, 20%. Employs 1,305. Barclays owns 6.2% of shares; insiders, 1% (4/06 proxy). CEO: Mark S. Dodson. Inc.: OR. Address: 220 NW 2nd Ave., Portland, OR 97209. Tel.: 503-226-4211. Internet: www.nwnatural.com.

Northwest reported a seasonal loss in the third quarter. The increased loss was due largely to the effects of the company's weather adjustment clause, which cost about $0.02 in the September period, and to the fact that some industrial customers switched to lower rate schedules. Meanwhile, customer growth for the last 12 months was strong, at 3.4%.

We look for a solid earnings gain in the fourth quarter due in part to the absence of an unusual expense. In the final period of 2005, unusual litigation costs reduced earnings by $0.05 a share, which Northwest will not incur this year. Customer growth should add a few cents a share. Moreover, changes in the company's weather adjustment clause have moved the effective date back to October 1st, which give Northwest protection against warm weather in October and November for the first time. The first severance costs of the company's new operations streamlining plan will occur in the December period, but they should be offset by gains coming from sales of some non-core assets.

Continued customer growth and cost cutting will likely produce decent earnings growth in 2007. The pace of new single-home construction is likely to slow, but growth from new apartment houses in Portland will offset much of that. And conversions from oil will probably grow, if, as we believe likely, OPEC keeps the price of oil over $55 a barrel. Too, Northwest's program to pare costs to equal the top quartile of all gas utilities should begin to pay off next year.

Earnings growth at an above-industry pace looks likely out to 2009-2011. A zoning change east of Portland should lead to substantial growth in residential customers by the end of our time horizon. It is likely that the growing demand for natural gas will bring at least one new liquefied natural gas plant to Northwest's territory. Moreover, a new pipeline connection could boost gas supplies. Still,

These untimely, but top-quality, shares, have below-average total return potential. Earnings and dividends will probably grow faster than the industry averages, but the likelihood of higher interest rates limits capital appreciation potential.

Sigourney B. Romaine December 15, 2006

(A) Diluted earnings per share. Excludes nonrecurring gain: '98, $0.15; '00, $0.11. Next earnings report due early February.
(B) Dividends historically paid in mid-February, mid-May, mid-August, and mid-November.
■ Div'd reinvestment plan available.
(C) In millions, adjusted for stock split.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	75

PIEDMONT NAT'L. NYSE-PNY

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD
28.21	19.6 (Trailing: 21.9 Median: 17.0)	1.07	3.4%

VALUE LINE

TIMELINESS **4** Raised 12/23/05

SAFETY **2** New 7/27/90

TECHNICAL **3** Lowered 12/8/06

BETA .80 (1.00 = Market)

High:	12.4	12.9	18.2	18.1	18.3	19.7	19.0	19.0	22.0	24.3	25.8	28.3
Low:	9.1	10.3	11.0	13.9	14.3	11.8	14.6	13.7	16.6	19.2	21.3	23.2

Target Price Range 2009 | 2010 | 2011

2009-11 PROJECTIONS

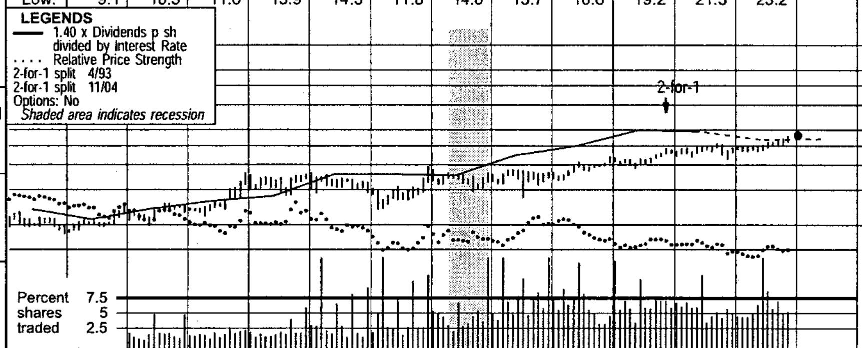
	Price	Gain	Ann'l Total Return
High	40	(+40%)	12%
Low	30	(+5%)	5%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	10	9	9	9	9	9	10	1	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	1	1	1	0	1	2	0	0

Institutional Decisions

	4Q2005	1Q2006	2Q2006
to Buy	76	66	85
to Sell	77	71	61
Hld's(000)	30419	31060	32936



% TOT. RETURN 11/06

	THIS STOCK	VL ARITH. INDEX
1 yr.	23.4	15.5
3 yr.	52.9	49.4
5 yr.	103.7	85.9

1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	© VALUE LINE PUB., INC.	09-11
9.42	8.32	8.91	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	*26.00*	*28.20*	Revenues per sh A	*33.10*
.97	.78	1.07	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	*2.50*	*2.65*	"Cash Flow" per sh	*3.20*
.61	.44	.70	.73	.68	.73	.84	.93	.98	.93	1.01	1.01	.95	1.11	1.27	1.32	*1.30*	*1.40*	Earnings per sh B	*1.75*
.42	.44	.46	.48	.51	.54	.57	.61	.64	.68	.72	.76	.80	.82	.85	.91	*.96*	*1.00*	Div'ds Decl'd per sh C■	*1.17*
1.62	1.37	1.41	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	*2.65*	*2.40*	Cap'l Spending per sh	*2.20*
4.58	4.83	5.13	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	*11.90*	*12.40*	Book Value per sh D	*13.85*
42.87	49.46	51.59	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	*75.00*	*74.50*	Common Shs Outst'g E	*72.50*
11.3	16.3	12.3	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	*Bold figures are*		Avg Ann'l P/E Ratio	*19.0*
.84	1.04	.75	.91	1.03	.92	.87	.78	.85	1.01	.93	.86	1.01	.95	.88	.95	*Value Line*		Relative P/E Ratio	*1.25*
6.0%	6.0%	5.3%	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%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 7/31/06
Total Debt $927.5 mill. Due in 5 Yrs $325.0 mill.
LT Debt $825.0 mill. LT Interest $40.0 mill.
(LT interest earned: 4.5x; total interest coverage: 4.5x)

Pension Assets-10/05 $199.2 mill. Oblig. $236.6 mill.

Pfd Stock None

Common Stock 75,327,139 shs. as of 9/1/06

MARKET CAP: $2.1 billion (Mid Cap)

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007		09-11
685.1	775.5	765.3	686.5	830.4	1107.9	832.0	1220.8	1529.7	1761.1	*1950*	*2100*	Revenues ($mill) A	*2400*
48.6	55.2	60.3	58.2	64.0	65.5	62.2	74.4	95.2	101.3	*100*	*105*	Net Profit ($mill)	*130*
38.9%	39.1%	39.2%	39.7%	34.7%	34.6%	33.1%	34.8%	35.1%	33.7%	*35.0%*	*36.0%*	Income Tax Rate	*36.0%*
7.1%	7.1%	7.9%	8.5%	7.7%	5.9%	7.5%	6.1%	6.2%	5.8%	*5.1%*	*5.1%*	Net Profit Margin	*5.3%*
50.3%	47.6%	44.7%	46.2%	46.1%	47.6%	43.9%	42.2%	43.6%	41.4%	*48.0%*	*47.0%*	Long-Term Debt Ratio	*45.0%*
49.7%	52.4%	55.3%	53.8%	53.9%	52.4%	56.1%	57.8%	56.4%	58.6%	*52.0%*	*53.0%*	Common Equity Ratio	*55.0%*
777.1	800.8	829.3	914.7	978.4	1069.4	1051.6	1090.2	1514.9	1509.2	*1715*	*1750*	Total Capital ($mill)	*1830*
862.0	941.7	990.6	1047.0	1072.0	1114.7	1158.5	1812.3	1849.8	1939.1	*2035*	*2170*	Net Plant ($mill)	*2400*
8.2%	8.9%	9.2%	8.1%	8.3%	7.9%	7.8%	8.6%	7.8%	8.2%	*7.0%*	*7.5%*	Return on Total Cap'l	*8.0%*
12.6%	13.1%	13.2%	11.8%	12.1%	11.7%	10.6%	11.8%	11.1%	11.5%	*11.0%*	*11.5%*	Return on Shr. Equity	*12.5%*
12.6%	13.1%	13.2%	11.8%	12.1%	11.7%	10.6%	11.8%	11.1%	11.5%	*11.0%*	*11.5%*	Return on Com Equity	*12.5%*
3.9%	4.6%	4.7%	3.3%	3.5%	3.0%	1.7%	3.1%	3.7%	3.6%	*3.0%*	*3.5%*	Retained to Com Eq	*4.5%*
69%	65%	65%	72%	71%	75%	83%	74%	66%	68%	*72%*	*70%*	All Div'ds to Net Prof	*67%*

CURRENT POSITION ($MILL.)	2004	2005	7/31/06
Cash Assets	5.7	7.1	8.5
Other	329.5	497.8	399.1
Current Assets	335.2	504.9	407.6
Accts Payable	99.6	182.8	64.9
Debt Due	109.5	193.5	102.5
Other	97.1	152.3	122.7
Current Liab.	306.2	528.6	290.1
Fix. Chg. Cov.	378%	400%	390%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '03-'05 to '09-'11
Revenues	7.5%	11.0%	8.5%
"Cash Flow"	7.0%	5.5%	6.0%
Earnings	5.5%	5.0%	6.0%
Dividends	5.5%	5.0%	5.5%
Book Value	6.5%	6.5%	3.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2003	493.5	407.8	140.1	179.4	1220.8
2004	618.8	482.4	214.7	213.8	1529.7
2005	680.6	508.0	232.9	339.6	1761.1
2006	921.4	483.2	237.9	*307.5*	*1950*
2007	*875*	*565*	*315*	*345*	*2100*

Fiscal Year Ends	EARNINGS PER SHARE A B F Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2003	.87	.47	d.15	d.08	1.11
2004	1.03	.54	d.11	d.21	1.27
2005	.93	.52	d.06	d.07	1.32
2006	.94	.57	d.16	*d.05*	*1.30*
2007	*.98*	*.57*	*d.06*	*d.09*	*1.40*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.193	.20	.20	.20	.79
2003	.20	.208	.208	.208	.82
2004	.208	.215	.215	.215	.85
2005	.215	.23	.23	.23	.91
2006	.23	.24	.24	.24	

BUSINESS: Piedmont Natural Gas Company is primarily a regulated natural gas distributor, serving over 990,000 customers in North Carolina, South Carolina, and Tennessee. 2005 revenue mix: residential (39%), commercial (24%), industrial (13%), other (24%). Principal suppliers: Transco and Tennessee Pipeline. Gas costs: 71.6% of revenues. '05 deprec. rate: 3.3%. Estimated plant age: 8.7 years. Non-regulated operations: sale of gas-powered heating equipment; natural gas brokering; propane sales. Has about 2,125 employees. Officers & directors own less than 1% of common stock (1/06 proxy). CEO & President: Thomas E. Skains. Inc.: NC. Addr.: 1915 Rexford Road, P.O. Box 33068 Charlotte, NC 28233. Telephone: 704-364-3120. Internet: www.piedmontng.com.

Fiscal 2006 (began November 1st) will likely be a better year for Piedmont Natural Gas. Last year's results were impacted by a number of factors. The company benefited from increased margins due to growth in its residential and commercial customer base, along with the impact of changes in rates at two of its jurisdictions. However, this was offset by decreased customer consumption due to conservation, which probably contributed to the expected year-over-year earnings decline. This year, we look for earnings to advance about 5%–10%, driven by customer growth that should remain above the industry average, along with increased margins owing to the rate stabilization act in South Carolina that will result in a $6.5 million increase in revenue. Also, the company's restructuring efforts from last year should contribute $7 million to $7.5 million in annual cost savings.

The company is expanding its presence in nonregulated activities. During the first nine months of fiscal 2006, these activities contributed almost $28 million to earnings, 14% above last year. This includes its operations through SouthStar Energy, Pine Needle LNG, Cardinal Pipeline Company, and Hardy Storage Company. In addition, we look for Piedmont to continue to pursue investments in storage or pipeline assets to broaden its earnings stream.

Piedmont is diversifying its natural gas supply portfolio. Currently, the majority of the company's supply is derived from the Gulf Coast region. To reduce risk in the event of a shutdown, Piedmont has a firm transportation contract pending with Midwestern Gas Transmission Company for 128,000 dekatherms per day of additional capacity that will provide it access to the Canadian and Rocky mountain gas suppliers via the Chicago hub. Also, it has an agreement with Hardy Storage Company for storage capacity in its West Virginia region, which is scheduled to be in service in April, 2007.

Though untimely, this equity provides a good dividend yield. Risk is also limited, thanks to the stock's Above-Average Safety rank. Looking ahead, total-return potential is above that of the average utility stock covered by *Value Line.*

Evan I. Blatter *December 15, 2006*

(A) Fiscal year ends October 31st.
(B) Diluted earnings. Excl. extraordinary item: '00, 8¢. Excl. nonrecurring charge: '97, 2¢. Next earnings report due early Feb.
(C) Dividends historically paid mid-January, April, July, October.
■ Div'd reinvest. plan available; 5% discount.
(D) Includes deferred charges. At 10/31/05: $4.0 million, 5¢/share.
(E) In millions, adjusted for stock splits.
(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	75
Earnings Predictability	80

SOUTH JERSEY INDS. NYSE-SJI

RECENT PRICE 33.89 | P/E RATIO 17.7 (Trailing: 20.3, Median: 14.0) | RELATIVE P/E RATIO 0.96 | DIV'D YLD 2.9% | VALUE LINE

TIMELINESS 4 Raised 10/6/06
SAFETY 2 Lowered 1/4/91
TECHNICAL 2 Raised 11/10/06
BETA .70 (1.00 = Market)

2009-11 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+5%)	4%
Low	25	(-25%)	-3%

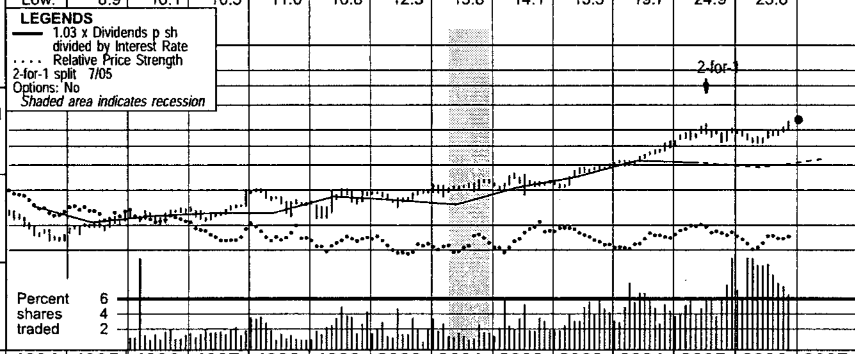
Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	3	0	0	0	0	0	0

Institutional Decisions

	4Q2005	1Q2006	2Q2006
to Buy	63	59	64
to Sell	49	52	46
Hld's(000)	14085	14260	15700

High:	11.8	12.3	15.3	15.4	15.4	15.1	17.0	18.3	20.3	26.5	32.4	34.0
Low:	8.9	10.1	10.5	11.0	10.8	12.3	13.8	14.1	15.3	19.7	24.9	25.6



Target Price Range
2009 | 2010 | 2011

% TOT. RETURN 11/06

	THIS STOCK	VL ARITH. INDEX
1 yr.	19.8	15.5
3 yr.	87.3	49.4
5 yr.	139.6	85.9

1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	© VALUE LINE PUB., INC.	09-11
14.40	15.10	16.67	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	*32.25*	*33.80*	Revenues per sh	*37.75*
1.34	1.37	1.56	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	*2.80*	*2.95*	"Cash Flow" per sh	*3.45*
.67	.64	.81	.78	.61	.83	.85	.86	.64	1.01	1.08	1.15	1.22	1.37	1.58	1.71	*1.85*	*1.95*	Earnings per sh A	*2.30*
.70	.71	.71	.72	.72	.72	.72	.72	.72	.72	.73	.74	.75	.78	.82	.86	*.92*	*.98*	Div'ds Decl'd per sh B ■	*1.15*
2.11	2.17	1.69	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	*3.60*	*3.70*	Cap'l Spending per sh	*4.05*
6.79	6.77	6.95	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	*14.25*	*15.05*	Book Value per sh C	*17.45*
18.06	18.48	19.00	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	*29.30*	*29.60*	Common Shs Outst'g D	*31.00*
13.6	14.5	13.2	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	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
1.01	.93	.80	.93	1.06	.82	.83	.80	1.10	.76	.85	.70	.74	.76	.74	.88	*Value Line*		Relative P/E Ratio	*.95*
7.7%	7.6%	6.6%	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%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 9/30/06
Total Debt $505.1 mill. **Due in 5 Yrs** $175.0 mill.
LT Debt $358.1 mill. **LT Interest** $20.0 mill.
(Total interest coverage: 4.8x)

Pension Assets-12/05 $108.5 mill. **Oblig.** $126.7 mill.

Pfd Stock none

Common Stock 29,279,288 common shs. as of 11/1/06

MARKET CAP: $1.0 billion (Mid Cap)

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007		09-11
355.5	348.6	450.2	392.5	515.9	837.3	505.1	696.8	819.1	921.0	*945*	*1000*	Revenues ($mill)	*1170*
18.5	18.4	13.8	22.0	24.7	26.8	29.4	34.6	43.0	48.6	*55.0*	*60.0*	Net Profit ($mill)	*70.0*
35.5%	36.8%	46.2%	42.8%	43.1%	42.2%	41.4%	40.6%	40.9%	41.5%	*40.5%*	*40.5%*	Income Tax Rate	*40.5%*
5.2%	5.3%	3.1%	5.6%	4.8%	3.2%	5.8%	5.0%	5.2%	5.3%	*5.7%*	*5.6%*	Net Profit Margin	*6.0%*
46.1%	54.6%	57.3%	53.8%	54.1%	57.0%	53.6%	50.8%	48.7%	44.9%	*46.0%*	*45.5%*	Long-Term Debt Ratio	*42.0%*
53.2%	35.8%	33.5%	37.0%	37.6%	35.9%	46.1%	49.0%	51.0%	55.1%	*54.0%*	*54.5%*	Common Equity Ratio	*58.0%*
324.8	387.1	401.1	405.9	443.5	516.2	512.5	608.4	675.0	710.3	*780*	*820*	Total Capital ($mill)	*935*
423.9	456.5	504.3	533.3	562.2	607.0	666.6	748.3	799.9	877.3	*940*	*1010*	Net Plant ($mill)	*1200*
7.9%	6.7%	5.3%	7.4%	7.4%	6.9%	7.6%	7.3%	7.9%	8.3%	*8.5%*	*8.0%*	Return on Total Cap'l	*8.5%*
10.5%	10.5%	8.1%	11.7%	12.1%	12.1%	12.4%	11.5%	12.4%	12.4%	*13.0%*	*12.5%*	Return on Shr. Equity	*13.0%*
10.6%	13.3%	10.3%	14.6%	14.8%	12.8%	12.5%	11.6%	12.5%	12.4%	*13.0%*	*12.5%*	Return on Com Equity	*13.0%*
1.6%	2.1%	NMF	4.2%	4.8%	3.5%	4.7%	5.0%	5.9%	6.2%	*6.5%*	*6.5%*	Retained to Com Eq	*6.0%*
85%	84%	112%	72%	67%	76%	62%	57%	52%	50%	*50%*	*51%*	All Div'ds to Net Prof	*53%*

CURRENT POSITION ($MILL.)	2004	2005	9/30/06
Cash Assets	10.6	4.9	5.0
Other	273.3	352.6	310.7
Current Assets	283.9	357.5	315.7
Accts Payable	118.8	179.0	52.3
Debt Due	97.6	149.7	177.9
Other	68.9	74.4	140.5
Current Liab.	285.3	403.1	370.7
Fix. Chg. Cov.	426%	486%	445%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '03-'05 to '09-'11
Revenues	5.5%	7.5%	4.5%
"Cash Flow"	4.5%	6.5%	6.5%
Earnings	8.0%	11.5%	7.0%
Dividends	1.5%	2.5%	6.0%
Book Value	5.5%	13.0%	6.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	279.9	106.2	90.1	220.6	696.8
2004	307.6	136.5	129.5	245.5	819.1
2005	328.6	154.0	157.0	281.4	921.0
2006	365.0	155.5	133.1	*291.4*	*945*
2007	*375*	*175*	*160*	*290*	*1000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.92	.08	d.07	.44	1.37
2004	.91	.15	.02	.50	1.58
2005	.96	.27	.09	.39	1.71
2006	.93	.25	.09	*.58*	*1.85*
2007	*.97*	*.28*	*.10*	*.60*	*1.95*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.185	.188	.188	.38	.94
2003	--	.193	.193	.395	.78
2004	--	.202	.202	.415	.82
2005	--	.213	.213	.438	.86
2006	--	.225	.225	.225	

BUSINESS: South Jersey Industries, Inc. is a holding company. Its subsidiary, South Jersey Gas Co., distributes natural gas to 322,424 customers in New Jersey's southern counties, which covers 2,500 square miles and includes Atlantic City. Gas revenue mix '05: residential, 45%; commercial, 23%; cogeneration and electric generation 4%; industrial, 23%. Non-utility operations include: South Jersey Energy, South Jersey Resource Group, Marina Energy, and South Jersey Energy Services Plus. Has 636 employees. Off./dir. cntrl. 1.5% of com. shares; Dimensional Fund Advisors, 7.9%; Barclays, 5.3% (3/06 proxy). Chrmn. & CEO: Edward Graham. Incorp.: NJ. Address: 1 South Jersey Plaza, Rte. 54, Folsom, NJ 08037. Tel.: 609-561-9000. Internet: www.sjindustries.com.

South Jersey Industries is on pace to close out 2006 on a strong note. We look for the company to report earnings of $0.58 a share in the fourth quarter, almost 50% above last year's figure. This can be attributed to a new Conservation Incentive Program (CIP) at South Jersey Gas, along with better performance from its nonutility operations (discussed below). The company continues to add customers at a nice rate, a trend that should continue in the coming years, driven by the strength of the local economy and steady demand for new housing in south New Jersey.

Earnings at South Jersey Gas, the company's main subsidiary, should become less volatile in the coming years. This is due to the approval in October of the CIP by the New Jersey Board of Public Utilities. It is a three-year pilot program that will allow the company to promote energy conservation, without earnings being impacted. The primary benefit of the program is that it protects SJG from margin variations related to both changes in weather and customer usage, versus just weather under the prior plan.

Nonutility business is positioned to grow over the 2009-2011 period. The company's Marina Energy subsidiary is in the second phase of its expansion of the Borgata Hotel Casino & Spa, which includes a 40-story hotel tower that is scheduled to be completed late next year. Marina is also pursuing a similar project with the Borgata in Las Vegas, and remains one of the finalists to co-own and operate a thermal facility to provide all the energy needs for this Las Vegas casino project. The winning bid is expected to be announced shortly, and if South Jersey gets the nod, the deal would be a meaningful contributor to earnings toward the latter part of the decade.

Good-quality South Jersey Industries shares have benefited from good news. Due to an improved outlook, the board now intends to raise the dividend payout about 6%-7% annually, up from 3%-6%. Even so, this untimely equity has risen about 15% since our last report, and is now trading at a lofty P/E ratio compared to historical levels. Looking ahead, total return potential is limited, despite the likelihood of dividend increases.

Evan I. Blatter *December 15, 2006*

(A) Based on avg. shs. Excl. nonrecur. gain: '01, $0.13. Excl gain (losses) from discont. ops.: '96, $1.14; '97, ($0.24); '98, ($0.26); '99, ($0.02); '00, ($0.04); '01, ($0.02); '02, ($0.04); '03, ($0.09); '05, ($0.02). Excl. gains due to acct'g change: '93, $0.04; '01, $0.14. Next egs. report due late January.
(B) Dividends paid early Apr., Jul., Oct, and late Dec. ■ Div. reinvest. plan avail. (2% disc.).
(C) Incl. regulatory assets ($121.5 mill.): at 12/31/05, $4.19 per shr.
(D) In millions, adjusted for split.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	95
Earnings Predictability	90

SOUTHWEST GAS NYSE-SWX

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD	
38.47	19.0 (Trailing: 22.1 Median: 20.0)	1.03	2.1%	VALUE LINE

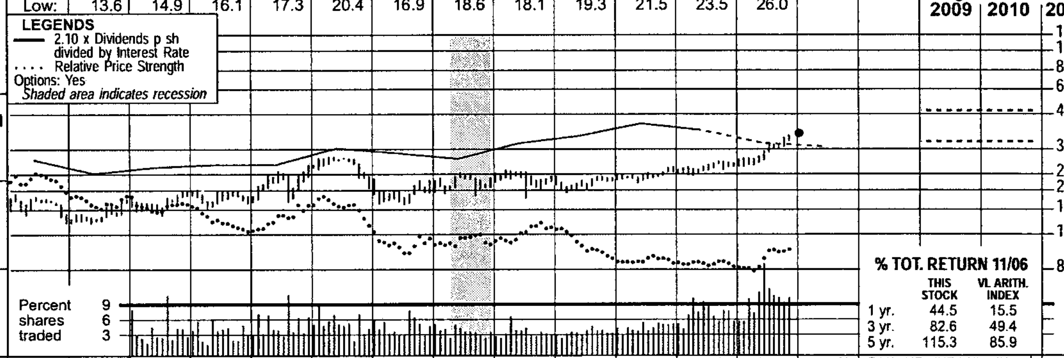
TIMELINESS 3 Raised 5/12/06

SAFETY 3 Lowered 1/4/91

TECHNICAL 2 Raised 9/29/06

BETA .85 (1.00 = Market)

													Target Price Range
High:	18.4	19.9	20.3	26.9	29.5	23.0	24.7	25.3	23.6	26.2	28.1	38.4	2009 | 2010 | 2011
Low:	13.6	14.9	16.1	17.3	20.4	16.9	18.6	18.1	19.3	21.5	23.5	26.0	



2009-11 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+30%)	8%
Low	35	(-10%)	Nil

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	3	0	0	0	1	0
Options	1	0	5	1	5	5	2	5	2
to Sell	1	0	5	1	6	6	2	5	2

Institutional Decisions

	4Q2005	1Q2006	2Q2006
to Buy	62	69	82
to Sell	53	53	46
Hld's(000)	25543	26476	29036

% TOT. RETURN 11/06

	THIS STOCK	VL ARITH. INDEX
1 yr.	44.5	15.5
3 yr.	82.6	49.4
5 yr.	115.3	85.9

1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	© VALUE LINE PUB., INC.	09-11
25.90	24.99	25.93	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	**47.15**	**47.90**	Revenues per sh A	**51.10**
3.96	1.53	3.34	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	**6.05**	**6.05**	"Cash Flow" per sh	**6.60**
1.81	d.76	.81	.63	1.22	.10	.25	.77	1.65	1.27	1.21	1.15	1.16	1.13	1.66	1.25	**1.95**	**2.00**	Earnings per sh A B	**2.35**
1.40	.88	.70	.74	.80	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	**.82**	**.82**	Div'ds Decl'd per sh C■	**.82**
5.06	3.76	5.02	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	**7.40**	**7.45**	Cap'l Spending per sh	**7.80**
17.63	15.88	15.99	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	**19.50**	**20.60**	Book Value per sh	**24.55**
20.04	20.60	20.60	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	**42.00**	**43.00**	Common Shs Outst'g D	**45.00**
8.7	--	16.6	26.5	14.0	NMF	NMF	24.1	13.2	21.1	16.0	19.0	19.9	19.2	14.3	20.6	*Bold figures are*		Avg Ann'l P/E Ratio	**18.0**
.65	--	1.01	1.57	.92	NMF	NMF	1.40	.69	1.20	1.04	.97	1.09	1.09	.76	1.10	*Value Line*		Relative P/E Ratio	**1.20**
8.9%	7.0%	5.2%	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%	*estimates*		Avg Ann'l Div'd Yield	**1.9%**

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007		09-11
644.1	732.0	917.3	936.9	1034.1	1396.7	1320.9	1231.0	1477.1	1714.3	**1980**	**2060**	Revenues ($mill) A	**2300**
6.6	20.8	47.5	39.3	38.3	37.2	38.6	38.5	58.9	48.1	**85.0**	**85.0**	Net Profit ($mill)	**105**
37.1%	29.2%	43.4%	35.5%	26.2%	34.5%	32.8%	30.5%	34.8%	29.7%	**34.0%**	**35.0%**	Income Tax Rate	**35.0%**
1.0%	2.8%	5.2%	4.2%	3.7%	2.7%	2.9%	3.1%	4.0%	2.8%	**4.2%**	**4.2%**	Net Profit Margin	**4.6%**
60.2%	63.6%	60.2%	60.3%	60.2%	56.2%	62.5%	66.0%	64.2%	63.8%	**61.3%**	**60.4%**	Long-Term Debt Ratio	**56.8%**
34.4%	31.5%	35.3%	35.5%	35.8%	39.6%	34.1%	34.0%	35.8%	36.2%	**38.7%**	**39.6%**	Common Equity Ratio	**43.2%**
1104.8	1224.7	1349.3	1424.7	1489.9	1417.6	1748.3	1851.6	1968.6	2076.0	**2120**	**2235**	Total Capital ($mill)	**2550**
1278.5	1360.3	1459.4	1581.1	1686.1	1825.6	1979.5	2175.7	2336.0	2489.1	**2600**	**2750**	Net Plant ($mill)	**3200**
2.8%	3.9%	5.8%	4.8%	4.6%	5.1%	4.3%	4.2%	5.0%	4.3%	**6.0%**	**5.5%**	Return on Total Cap'l	**6.0%**
1.5%	4.7%	8.9%	7.0%	6.5%	6.0%	5.9%	6.1%	8.3%	6.4%	**10.5%**	**9.5%**	Return on Shr. Equity	**9.5%**
1.7%	5.4%	10.0%	7.8%	7.2%	6.6%	6.5%	6.1%	8.3%	6.4%	**10.5%**	**9.5%**	Return on Com Equity	**9.5%**
NMF	NMF	5.0%	2.8%	2.4%	1.9%	1.9%	1.7%	4.3%	2.2%	**6.5%**	**5.5%**	Retained to Com Eq	**6.0%**
NMF	107%	50%	64%	67%	71%	70%	72%	49%	65%	**39%**	**41%**	All Div'ds to Net Prof	**35%**

CAPITAL STRUCTURE as of 9/30/06

Total Debt $1393.4 mill. Due in 5 Yrs $379.5 mill.
LT Debt $1366.1 mill. LT Interest $88.0 mill.
(Total interest coverage: 2.1x)

Pension Assets-12/05 $359.6 mill. Oblig. $511.0 mill.

Pfd Stock None

Common Stock 41,464,506 shs. as of 11/2/06

MARKET CAP: $1.6 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2004	2005	9/30/06
Cash Assets	13.6	29.6	31.6
Other	418.4	513.1	281.3
Current Assets	432.0	542.7	312.9
Accts Payable	165.9	259.5	102.4
Debt Due	129.8	107.2	27.3
Other	187.3	254.3	202.0
Current Liab.	483.0	621.0	331.7
Fix. Chg. Cov.	166%	167%	197%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '03-'05 to '09-'11
Revenues	4.5%	5.0%	3.5%
"Cash Flow"	4.0%	3.5%	3.5%
Earnings	7.5%	-0.5%	9.0%
Dividends	0.5%	--	Nil
Book Value	2.0%	3.0%	4.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	403.3	255.8	220.2	351.7	1231.0
2004	473.4	278.7	264.5	460.5	1477.1
2005	542.9	361.1	313.3	497.0	1714.3
2006	676.9	430.9	351.8	**520.4**	**1980**
2007	**690**	**450**	**370**	**550**	**2060**

Cal-endar	EARNINGS PER SHARE B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.76	d.12	d.51	1.00	1.13
2004	1.18	d.24	d.51	1.23	1.66
2005	.88	d.07	d.43	.87	1.25
2006	1.11	.02	d.26	**1.08**	**1.95**
2007	**1.15**	**.05**	**d.30**	**1.10**	**2.00**

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.205	.205	.205	.205	.82
2003	.205	.205	.205	.205	.82
2004	.205	.205	.205	.205	.82
2005	.205	.205	.205	.205	.82
2006	.205	.205	.205	.205	

BUSINESS: Southwest Gas Corporation is a regulated gas distributor serving approx. 1.7 million customers in sections of Arizona, Nevada, and California. '05 margin mix: resid. and small commercial, 86%; large commercial and industrial, 5%; transportation, 9%. Annual volume: 2.2 billion therms. Principal suppliers: El Paso Natural Gas Co. and Northwest Pipeline Corp. Acquired gas utility assets from Arizona Public Service in 1984. Sold PriMerit Bank (acq. in '86) in 7/96. Has about 4,940 employees. Officers & Directors own 2.3% of common stock (3/06 Proxy). Chairman: LeRoy Hanneman. Chief Executive Officer: Jeffrey W. Shaw. Incorporated: California. Address: 5241 Spring Mountain Rd., Las Vegas, Nevada 89193. Telephone: 702-876-7011. Internet: www.swgas.com.

Southwest Gas reported improving results in the third quarter. Revenues came in at $351.8 million, a 12% increase. The company reported a share-net loss of $0.26, compared to a loss of $0.43 in the prior year's period. Due to the seasonal nature of its operations (natural gas sales peak in the winter), losses during the second and third quarters are not uncommon. We find the recent period's improvement encouraging. Rate relief (primarily in Arizona) added roughly $10 million to operating income. Moderating operations and maintenance expenses also benefited the company. Growth in the customer base (discussed below) contributed, as well. For full-year 2006, we look for revenues and share earnings to advance by roughly 15% and 56%, respectively. We have increased our earnings-per-share estimate by a dime, to $1.95, as we expect strong performance during the fourth quarter.

During the past 12 months, the company built its customer base by over 4%. The pace of growth has been impressive in recent times. We expect this pattern to continue. However, as SWX continues to expand, it is likely to incur up-front costs and increased operating expenses. Improvements in technology may offset these costs, somewhat.

We are mildly optimistic about growth prospects for the coming years. We anticipate modest advances in both the top and bottom line figures from 2007 to the end of the decade, as demographic trends favor Arizona and Nevada. The net profit margin should improve, as well. But, in addition to customer growth, continued strength depends upon such variables as favorable weather temperatures and the company's ability to obtain sufficient rate relief. Its increased focus in this area is encouraging.

These shares are not a standout for the coming year. Moreover, appreciation potential is below average for the pull to late decade, as the shares are trading within our projected range. The dividend yield of 2.1% is lower than that of most utility stocks, and income-oriented accounts should note that the company has not increased its payout in roughly a decade. Investors could likely find better choices elsewhere.

Michael F. Napoli *December 15, 2006*

(A) Incl. income for PriMerit Bank on the equity basis through 1994.
(B) 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¢. Next egs. report due in March.
(C) Dividends historically paid early March, June, September, December.
■ Div'd reinvest. plan avail.
(D) In millions.

Company's Financial Strength	B
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	65

WGL HOLDINGS NYSE-WGL

RECENT PRICE	33.41	P/E RATIO	17.4 (Trailing: 19.0 Median: 15.0)	RELATIVE P/E RATIO	0.95	DIV'D YLD	4.1%	VALUE LINE

TIMELINESS	4 Raised 8/4/06
SAFETY	1 Raised 4/2/93
TECHNICAL	2 Raised 11/17/06
BETA .85 (1.00 = Market)	

High:	22.4	25.0	31.4	30.8	29.4	31.5	30.5	29.5	28.8	31.4	34.8	33.4
Low:	16.1	19.1	20.9	23.1	21.0	21.8	25.3	19.3	23.2	26.7	28.8	27.0

Target Price Range 2009 | 2010 | 2011

2009-11 PROJECTIONS

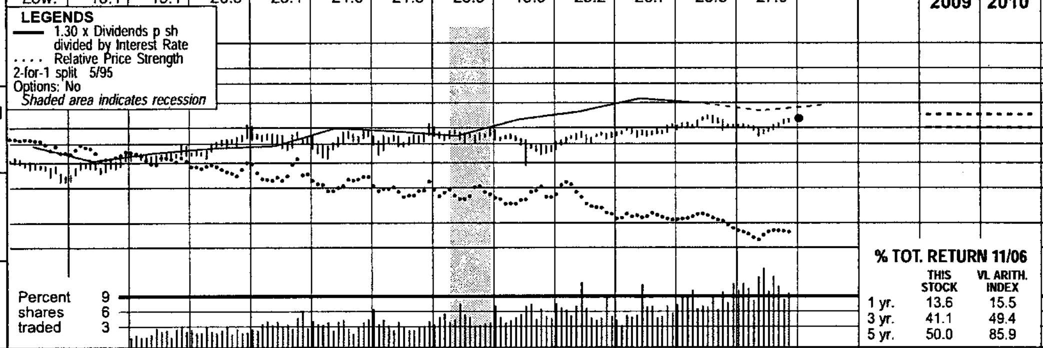
	Price	Gain	Ann'l Total Return
High	35	(+5%)	6%
Low	30	(-10%)	2%

Insider Decisions

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

Institutional Decisions

	4Q2005	1Q2006	2Q2006
to Buy	88	70	73
to Sell	67	77	78
Hld's(000)	27959	27311	29760



% TOT. RETURN 11/06

	THIS STOCK	VL ARITH. INDEX
1 yr.	13.6	15.5
3 yr.	41.1	49.4
5 yr.	50.0	85.9

1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	© VALUE LINE PUB., INC.	09-11
18.75	17.50	18.37	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	53.94	*55.10*	Revenues per sh A	*60.60*
2.17	2.04	2.17	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	3.68	*3.85*	"Cash Flow" per sh	*4.45*
1.26	1.14	1.27	1.31	1.42	1.45	1.85	1.85	1.54	1.47	1.79	1.88	1.14	2.30	1.98	2.11	1.90	*1.90*	Earnings per sh B	*2.35*
1.01	1.05	1.07	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	*1.38*	Div'ds Decl'd per sh C■	*1.48*
2.38	2.05	2.17	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	*3.40*	*3.30*	Cap'l Spending per sh	*3.95*
10.17	9.63	10.66	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	*18.25*	*18.90*	Book Value per sh D	*21.15*
39.23	39.89	40.62	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	48.88	*49.00*	Common Shs Outst'g E	*49.50*
11.7	12.8	13.6	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	15.8		Avg Ann'l P/E Ratio	*14.0*
.87	.82	.82	.92	.92	.85	.72	.73	.89	.99	.95	.75	1.26	.63	.75	.78	.85		Relative P/E Ratio	*.90*
6.9%	7.2%	6.2%	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%		Avg Ann'l Div'd Yield	*4.3%*
						969.8	1055.8	1040.6	972.1	1031.1	1446.5	1584.8	2064.2	2089.6	2186.3	2636.7	*2700*	Revenues ($mill) A	*3000*
						81.6	82.0	68.6	68.8	84.6	89.9	55.7	112.3	98.0	104.8	87.3	*95.0*	Net Profit ($mill)	*110*
						37.7%	36.9%	35.6%	36.0%	36.1%	39.6%	34.0%	38.0%	38.2%	37.4%	*40.0%*	*38.0%*	Income Tax Rate	*38.0%*
						8.4%	7.8%	6.6%	7.1%	8.2%	6.2%	3.5%	5.4%	4.7%	4.8%	3.3%	*3.4%*	Net Profit Margin	*3.8%*
						37.6%	41.1%	40.3%	41.5%	43.1%	41.7%	45.7%	43.8%	40.9%	39.5%	*38.0%*	*37.5%*	Long-Term Debt Ratio	*37.0%*
						59.4%	56.2%	57.1%	56.1%	54.8%	56.3%	52.4%	54.3%	57.2%	58.6%	*60.0%*	*60.5%*	Common Equity Ratio	*61.0%*
						941.1	1049.0	1064.8	1218.5	1299.2	1400.8	1462.5	1454.9	1443.6	1478.1	1496.4	*1570*	Total Capital ($mill)	*1760*
						1130.6	1217.1	1319.5	1402.7	1460.3	1519.7	1606.8	1874.9	1915.6	1969.7	2067.9	*2270*	Net Plant ($mill)	*2550*
						10.1%	9.3%	8.0%	7.1%	7.9%	7.9%	5.3%	9.1%	8.2%	8.5%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
						13.9%	13.3%	10.8%	9.7%	11.4%	11.0%	7.0%	13.7%	11.5%	11.7%	*9.0%*	*9.5%*	Return on Shr. Equity	*10.5%*
						14.4%	13.7%	11.1%	9.9%	11.7%	11.2%	7.2%	14.0%	11.7%	12.0%	*9.5%*	*10.0%*	Return on Com Equity	*11.0%*
						5.6%	5.1%	2.5%	1.8%	3.7%	3.8%	NMF	6.2%	4.1%	4.6%	*2.5%*	*2.5%*	Retained to Com Eq	*4.0%*
						62%	63%	78%	82%	69%	67%	112%	56%	65%	62%	*74%*	*74%*	All Div's to Net Prof	*65%*

CAPITAL STRUCTURE as of 9/30/06
Total Debt $814.5 mill. **Due in 5 Yrs** $520.0 mill.
LT Debt $576.1 mill. **LT Interest** $40.0 mill.
(LT interest earned: 4.6x; total interest coverage: 4.2x)
Pension Assets-9/05 $691.7 mill. **Oblig.** $691.2 mill.
Preferred Stock $28.2 mill. **Pfd Div'd** $1.3 mill.

Common Stock 48,878,000 shs.

MARKET CAP: $1.6 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2004	2005	9/30/06
Cash Assets	6.6	4.8	4.4
Other	426.3	476.2	556.9
Current Assets	432.9	481.0	561.3
Accts Payable	179.0	204.9	208.5
Debt Due	156.3	91.0	238.4
Other	77.6	115.5	113.9
Current Liab.	412.9	411.4	560.8
Fix. Chg. Cov.	449%	460%	450%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '03-'05 to '09-'11
Revenues	7.5%	14.5%	5.5%
"Cash Flow"	5.0%	6.5%	2.0%
Earnings	4.5%	6.0%	1.5%
Dividends	1.5%	1.5%	2.0%
Book Value	4.0%	3.0%	3.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2003	560.0	851.1	373.2	279.9	2064.2
2004	585.3	862.2	356.9	285.2	2089.6
2005	623.4	929.8	349.0	284.1	2186.3
2006	N/A	N/A	N/A	322.5	F2636.7
2007	*960*	*1010*	*380*	*350*	*2700*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2003	1.10	1.61	d.05	d.36	2.30
2004	.81	1.62	d.08	d.37	1.98
2005	.88	1.63	d.17	d.23	2.11
2006	.93	1.16	d.01	d.18	1.90
2007	*.91*	*1.29*	*d.10*	*d.20*	*1.90*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.315	.318	.318	.318	1.27
2002	.318	.32	.32	.32	1.28
2003	.32	.325	.325	.325	1.30
2004	.325	.333	.333	.333	1.32
2005	.333	.338	.338	.338	

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 (1,032,198 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 9.3% of common stock; Off./dir. less than 1% (1/06 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.

Fiscal 2006 (ended September 30th) was not the best of years for WGL Holdings. Results were impacted by a decline in natural gas deliveries due to customer conservation, along with higher operation and maintenance expenses, and results that were below last year's level at the company's nonutility segment. For 2007, we look for earnings to remain flat. This includes about $1.60 from the main utility segment, and $0.30 from nonutility operations. The company expects to add 20,000 new customers this year, slightly below previous years' additions. However, indicators point to a rebound in home construction in 2008.

Washington Gas Light aims to improve the consistency of its earnings through new rate designs. In 2006, the company was able to fully neutralize the effect of warmer-than-normal temperatures in the District of Columbia and Virginia. However, in Maryland the company is able to protect against both warmer weather and customer conservation through its revenue normalization adjustment plan. Due to the success of this plan, the company filed in September a similar rate case in Virginia, which also includes a performance-based rate plan that would put new rates in place by February if approved. The company also intends to file a rate case in the spring of 2007 to recover the costs associated with the Prince George's county rehabilitation program. We think the company is likely to receive most, if not all, of these costs.

The company is looking to improve its nonregulated operations. In September, WGL sold its interest in American Combustion Industries, which had been underperforming. This should permit management to focus on growth businesses. The company initiated a partnership with select heating, ventilating, and air conditioning contractors to increase market penetration through residential conversions. WGL expects the conversion rate, which is currently 7%, to increase to 14% for new residential businesses in 2007.

These shares are best suited for conservative investors. The dividend is well covered, and the yield is above its distribution counterparts. But investors should note the limited capital gains prospects.

Evan I. Blatter *December 15, 2006*

(A) Fiscal years end Sept. 30th.
(B) Based on diluted shares. Excludes nonrecurring losses: '01, (13¢); '02, (34¢); discontinued operations: '06, (14¢). Next earnings report due early Feb. (C) Dividends historically paid early February, May, August, and November. ■ Dividend reinvestment plan available.
(D) Includes deferred charges and intangibles. '05: $150.0 million, $3.08/sh.
(E) In millions, adjusted for stock split.
(F) Quarterly revenues will be adjusted following 10k release.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	70
Earnings Predictability	60

ATTACHMENT B

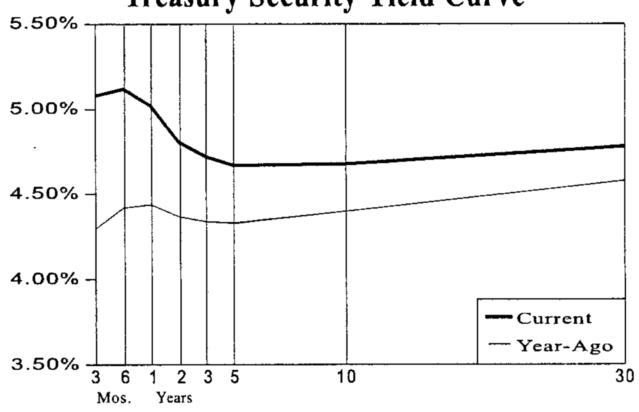
Selected Yields

TAXABLE

	Recent (1/10/07)	3 Months Ago (10/11/06)	Year Ago (1/12/06)
Market Rates			
Discount Rate	6.25	6.25	5.25
Federal Funds	5.25	5.25	4.25
Prime Rate	8.25	8.25	7.25
30-day CP (A1/P1)	5.24	5.24	4.34
3-month LIBOR	5.36	5.37	4.60
Bank CDs			
6-month	3.30	3.34	2.85
1-year	3.85	3.88	3.42
5-year	3.91	4.04	3.98
U.S. Treasury Securities			
3-month	5.08	5.01	4.30
6-month	5.12	5.09	4.42
1-year	5.02	5.00	4.44
5-year	4.67	4.74	4.33
10-year	4.68	4.78	4.40
10-year (inflation-protected)	2.42	2.47	2.02
30-year	4.78	4.91	4.58
30-year Zero	4.72	4.87	4.53

	Recent (1/10/07)	3 Months Ago (10/11/06)	Year Ago (1/12/06)
Mortgage-Backed Securities			
GNMA 6.5%	5.61	5.80	5.25
FHLMC 6.5% (Gold)	5.73	6.03	5.76
FNMA 6.5%	5.64	5.96	5.58
FNMA ARM	5.58	5.53	4.36
Corporate Bonds			
Financial (10-year) A	5.53	5.67	5.35
Industrial (25/30-year) A	5.74	5.83	5.61
Utility (25/30-year) A	5.76	5.95	5.62
Utility (25/30-year) Baa/BBB	6.06	6.30	5.99
Foreign Bonds (10-Year)			
Canada	4.08	4.13	4.03
Germany	4.02	3.81	3.28
Japan	1.76	1.74	1.45
United Kingdom	4.81	4.61	4.08
Preferred Stocks			
Utility A	7.17	7.19	7.09
Financial A	6.33	6.31	6.22
Financial Adjustable A	5.49	5.49	5.49

Treasury Security Yield Curve



TAX-EXEMPT

	Recent (1/10/07)	3 Months Ago (10/11/06)	Year Ago (1/12/06)
Bond Buyer Indexes			
20-Bond Index (GOs)	4.15	4.25	4.37
25-Bond Index (Revs)	4.50	4.77	5.11
General Obligation Bonds (GOs)			
1-year Aaa	3.50	3.45	3.20
1-year A	3.60	3.58	3.32
5-year Aaa	3.54	3.48	3.37
5-year A	3.82	3.77	3.65
10-year Aaa	3.72	3.79	3.75
10-year A	4.12	4.09	4.07
25/30-year Aaa	4.06	4.17	4.39
25/30-year A	4.38	4.44	4.66
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.41	4.45	4.42
Electric AA	4.39	4.46	4.56
Housing AA	4.50	4.50	4.75
Hospital AA	4.53	4.70	4.88
Toll Road Aaa	4.47	4.53	4.76

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	1/3/07	12/20/06	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	2103	1441	662	1756	1690	1694
Borrowed Reserves	191	210	-19	197	283	223
Net Free/Borrowed Reserves	1912	1231	681	1560	1407	1471

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	12/25/06	12/18/06	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1371.0	1343.3	27.7	3.2%	-0.5%	-0.4%
M2 (M1+savings+small time deposits)	7042.1	7011.3	30.8	9.1%	6.1%	5.4%

UNS GAS, INC.

DOCKET NO. G-04204A-06-0463

TABLE OF CONTENTS TO SCHEDULES WAR

UNS GAS, INC.
TEST YEAR ENDED DECEMBER 31, 2005
COST OF CAPITAL SUMMARY

DOCKET NO. G-04204A-06-0463
SCHEDULE WAR - 1

WEIGHTED 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	DEBT	$ 98,859	$ -	$ 98,859	50.00%	6.23%	3.12%
2	PREFERRED STOCK	-	-	-	0.00%	0.00%	0.00%
3	COMMON EQUITY	98,859	-	98,859	50.00%	9.64%	4.82%
4	TOTAL CAPITALIZATION	$ 197,718	$ -	$ 197,718	100.00%		
5	**WEIGHTED COST OF CAPITAL**						7.93%

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-1
COLUMN (B): TESTIMONY, WAR
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COLUMN (C) ÷ COLUMN (C), LINE 4
COLUMN (E): LINE 1 - SCHEDULE WAR-1, PAGE 2; LINE 3 - SCHEDULE WAR-1, PAGE 3
COLUMN (F): COLUMN (D) x COLUMN (E)

UNS GAS, INC.
TEST YEAR ENDED DECEMBER 31, 2005
COST OF CAPITAL SUMMARY

DOCKET NO. G-04204A-06-0463
SCHEDULE WAR - 1

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	6.230%	50.00%	3.115%
2	UNS GAS SERIES B BONDS	50,000	3,115	6.230%	50.00%	3.115%
3	TOTALS	$ 100,000	$ 6,230		100.00%	
4	**WEIGHTED COST OF DEBT**					6.23%

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)

UNS GAS, INC.
TEST YEAR ENDED DECEMBER 31, 2005
COST OF CAPITAL SUMMARY

COST OF COMMON EQUITY CALCULATION

LINE NO.			
1	**DCF METHODOLOGY**		
2	DCF - SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE	8.74%	SCHEDULE WAR-2, COLUMN (C), LINE 11
3	**CAPM METHODOLOGY**		
4	CAPM - GEOMETRIC MEAN ESTIMATE	9.70%	SCHEDULE WAR-7 PAGE 1, COLUMN (B), LINE 11
5	CAPM - ARITHMETIC MEAN ESTIMATE	11.36%	SCHEDULE WAR-7 PAGE 2, COLUMN (B), LINE 11
6	AVERAGE OF CAPM ESTIMATES	10.53%	(LINE 4 + LINE 5) ÷ 2
7	**AVERAGE**	9.64%	(LINE 2 + LINE 6) ÷ 2

UNS GAS, INC.
TEST YEAR ENDED DECEMBER 31, 2005
DCF COST OF EQUITY CAPITAL

DOCKET NO. G-04204A-06-0463
SCHEDULE WAR - 2

LINE NO.	STOCK SYMBOL	COMPANY	(A) DIVIDEND YIELD	+	(B) GROWTH RATE (g)	=	(C) DCF COST OF EQUITY CAPITAL
1	ATG	AGL RESOURCES, INC.	3.79%	+	4.31%	=	8.10%
2	ATO	ATMOS ENERGY CORPORATION	4.00%	+	5.39%	=	9.39%
3	LG	LACLEDE GROUP, INC.	4.01%	+	4.88%	=	8.89%
4	NJR	NEW JERSEY RESOURCES CORP.	2.91%	+	6.23%	=	9.14%
5	GAS	NICOR, INC.	3.91%	+	4.26%	=	8.17%
6	NWN	NORTHWEST NATURAL GAS CO.	3.41%	+	4.22%	=	7.63%
7	PNY	PIEDMONT NATURAL GAS COMPANY	3.53%	+	4.16%	=	7.69%
8	SJI	SOUTH JERSEY INDUSTIES, INC.	2.72%	+	7.08%	=	9.80%
9	SWX	SOUTHWEST GAS CORP.	2.15%	+	8.17%	=	10.32%
10	WGL	WGL HOLDINGS, INC.	4.15%	+	4.14%	=	8.29%
11	**NATURAL GAS LDC AVERAGE**						8.74%

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 DECEMBER 31, 2005
DIVIDEND YIELD CALCULATION

DOCKET NO. G-04204A-06-0463
SCHEDULE WAR - 3

LINE NO.	STOCK SYMBOL	COMPANY	(A) ESTIMATED DIVIDEND (PER SHARE)	÷	(B) AVERAGE STOCK PRICE (PER SHARE)	=	(C) DIVIDEND YIELD
1	ATG	AGL RESOURCES, INC.	$1.48	÷	$39.04	=	3.79%
2	ATO	ATMOS ENERGY CORPORATION	1.28	÷	31.98	=	4.00%
3	LG	LACLEDE GROUP, INC.	1.42	÷	35.45	=	4.01%
4	NJR	NEW JERSEY RESOURCES CORP.	1.44	÷	49.52	=	2.91%
5	GAS	NICOR, INC.	1.86	÷	47.56	=	3.91%
6	NWN	NORTHWEST NATURAL GAS CO.	1.42	÷	41.59	=	3.41%
7	PNY	PIEDMONT NATURAL GAS COMPANY	0.96	÷	27.21	=	3.53%
8	SJI	SOUTH JERSEY INDUSTIES, INC.	0.90	÷	33.08	=	2.72%
9	SWX	SOUTHWEST GAS CORP.	0.82	÷	38.14	=	2.15%
10	WGL	WGL HOLDINGS, INC.	1.35	÷	32.56	=	4.15%
11	**NATURAL GAS LDC AVERAGE**						3.46%

REFERENCES:
COLUMN (A): ESTIMATED 12 MONTH DIVIDEND REPORTED IN VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 12/15/2006.
COLUMN (B): EIGHT WEEK AVERAGE OF CLOSING PRICES FROM 11/27/2006 TO 01/19/2007 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 DECEMBER 31, 2005
DIVIDEND GROWTH RATE CALCULATION

LINE NO.	STOCK SYMBOL	COMPANY	(A) INTERNAL GROWTH (br)	+	(B) EXTERNAL GROWTH (sv)	=	(C) DIVIDEND GROWTH (g)
1	ATG	AGL RESOURCES, INC.	4.25%	+	0.06%	=	4.31%
2	ATO	ATMOS ENERGY CORPORATION	4.50%	+	0.89%	=	5.39%
3	LG	LACLEDE GROUP, INC.	4.00%	+	0.88%	=	4.88%
4	NJR	NEW JERSEY RESOURCES CORP.	5.75%	+	0.48%	=	6.23%
5	GAS	NICOR, INC.	3.75%	+	0.51%	=	4.26%
6	NWN	NORTHWEST NATURAL GAS CO.	4.00%	+	0.22%	=	4.22%
7	PNY	PIEDMONT NATURAL GAS COMPANY	4.00%	+	0.16%	=	4.16%
8	SJI	SOUTH JERSEY INDUSTIES, INC.	6.25%	+	0.83%	=	7.08%
9	SWX	SOUTHWEST GAS CORP.	6.50%	+	1.67%	=	8.17%
10	WGL	WGL HOLDINGS, INC.	4.00%	+	0.14%	=	4.14%
11	**NATURAL GAS LDC AVERAGE**						5.28%

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 DECEMBER 31, 2005
DIVIDEND GROWTH RATE CALCULATION

DOCKET NO. G-04204A-06-0463
SCHEDULE WAR - 4
PAGE 2 OF 2

LINE NO.	STOCK SYMBOL	COMPANY	(A) SHARE GROWTH	x	(B) { [((M ÷ B) + 1) ÷ 2] - 1 }	=	(C) EXTERNAL GROWTH (sv)
1	ATG	AGL RESOURCES, INC.	0.13%	x	{ [((1.91) + 1) ÷ 2] - 1 }	=	0.06%
2	ATO	ATMOS ENERGY CORPORATION	3.00%	x	{ [((1.59) + 1) ÷ 2] - 1 }	=	0.89%
3	LG	LACLEDE GROUP, INC.	2.00%	x	{ [((1.88) + 1) ÷ 2] - 1 }	=	0.88%
4	NJR	NEW JERSEY RESOURCES CORP.	0.80%	x	{ [((2.20) + 1) ÷ 2] - 1 }	=	0.48%
5	GAS	NICOR, INC.	0.70%	x	{ [((2.46) + 1) ÷ 2] - 1 }	=	0.51%
6	NWN	NORTHWEST NATURAL GAS CO.	0.50%	x	{ [((1.88) + 1) ÷ 2] - 1 }	=	0.22%
7	PNY	PIEDMONT NATURAL GAS COMPANY	0.25%	x	{ [((2.29) + 1) ÷ 2] - 1 }	=	0.16%
8	SJI	SOUTH JERSEY INDUSTIES, INC.	1.25%	x	{ [((2.32) + 1) ÷ 2] - 1 }	=	0.83%
9	SWX	SOUTHWEST GAS CORP.	3.50%	x	{ [((1.96) + 1) ÷ 2] - 1 }	=	1.67%
10	WGL	WGL HOLDINGS, INC.	0.35%	x	{ [((1.78) + 1) ÷ 2] - 1 }	=	0.14%
11	**NATURAL GAS LDC AVERAGE**						0.58%

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): VALUE LINE INVESTMENT SURVEY RATINGS & REPORTS DATED 12/15/2006
COLUMN (C): COLUMN (A) x COLUMN (B)

UNS GAS, INC.
TEST YEAR ENDED DECEMBER 31, 2005
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	ATG	AGL RESOURCES, INC.	2001	0.2800		12.30%		3.44%	12.19	55.10	
2			2002	0.4066		14.50%		5.90%	12.52	56.70	
3			2003	0.4663		14.00%		6.53%	14.66	64.50	
4			2004	0.4956		11.00%		5.45%	18.06	76.70	
5			2005	0.4758		12.90%		6.14%	19.29	77.70	
6			GROWTH 2001 - 2005					5.49%	8.50%		8.97%
7			2006	0.4340		13.00%		5.64%		77.90	0.26%
8			2007	0.4148		12.50%		5.19%		78.00	0.19%
9			2009-11	0.3966		12.00%		4.76%	6.50%	78.30	0.15%
10											
11	ATO	ATMOS ENERGY CORPORATION	2001	0.2109		9.60%		2.02%	14.31	40.79	
12			2002	0.1862		10.40%		1.94%	13.75	41.68	
13			2003	0.2982		9.30%		2.77%	16.66	51.48	
14			2004	0.2278		7.60%		1.73%	18.05	62.80	
15			2005	0.2791		8.50%		2.37%	19.90	80.54	
16			GROWTH 2001 - 2005					2.17%	8.50%		18.54%
17			2006	0.3700		10.00%		3.70%		82.00	1.81%
18			2007	0.3436		9.50%		3.26%		84.00	2.13%
19			2009-11	0.4490		11.00%		4.94%	4.00%	100.00	4.42%
20											
21	LG	LACLEDE GROUP, INC.	2001	0.1677		10.50%		1.76%	15.26	18.88	
22			2002	-0.1356		7.80%		NMF	15.07	18.96	
23			2003	0.2637		11.60%		3.06%	15.65	19.11	
24			2004	0.2582		10.10%		2.61%	16.96	20.98	
25			2005	0.2789		10.90%		3.04%	17.31	21.17	
26			GROWTH 2001 - 2005					2.62%	2.50%		2.90%
27			2006	0.4093		12.50%		5.12%		21.50	1.56%
28			2007	0.3256		10.50%		3.42%		21.50	0.78%
29			2009-11	0.3800		9.50%		3.61%	7.50%	24.00	2.54%
30											
31	NJR	NEW JERSEY RESOURCES CORP.	2001	0.4000		14.90%		5.96%	13.20	26.66	
32			2002	0.4258		15.70%		6.69%	13.06	27.67	
33			2003	0.4790		15.60%		7.47%	15.38	27.23	
34			2004	0.4902		15.30%		7.50%	16.87	27.74	
35			2005	0.4868		17.00%		8.28%	15.90	27.55	
36			GROWTH 2001 - 2005					7.18%	8.50%		0.82%
37			2006	0.4857		12.60%		6.12%		27.63	0.29%
38			2007	0.4759		12.50%		5.95%		28.00	0.81%
39			2009-11	0.4925		12.00%		5.91%	8.50%	28.50	0.68%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY RATINGS & REPORTS DATED 12/15/2006
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 & 26, SIMPLE AVERAGE GROWTH, 2001 - 2005

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

UNS GAS, INC.
TEST YEAR ENDED DECEMBER 31, 2005
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.	2001	0.4153		18.70%		7.77%	16.39	44.40	
2			2002	0.3611		17.50%		6.32%	16.55	44.01	
3			2003	0.1185		12.30%		1.46%	17.13	44.04	
4			2004	0.1622		13.10%		2.12%	16.99	44.10	
5			2005	0.1806		12.50%		2.26%	18.36	44.18	
6			GROWTH 2001 - 2005					3.98%	1.50%		-0.12%
7			2006	0.3111		14.00%		4.36%		44.50	0.72%
8			2007	0.3015		13.00%		3.92%		44.60	0.47%
9			2009-11	0.2857		12.00%		3.43%	4.50%	44.90	0.32%
10											
11	NWN	NORTHWEST NATURAL GAS CO.	2001	0.3351		10.20%		3.42%	18.56	25.23	
12			2002	0.2222		8.50%		1.89%	18.88	25.59	
13			2003	0.2784		9.00%		2.51%	19.52	25.94	
14			2004	0.3011		8.90%		2.68%	20.64	27.55	
15			2005	0.3744		9.90%		3.71%	21.28	27.58	
16			GROWTH 2001 - 2005					2.84%	3.50%		2.25%
17			2006	0.3822		10.00%		3.82%		27.50	-0.29%
18			2007	0.4042		10.50%		4.24%		27.80	0.40%
19			2009-11	0.4035		10.50%		4.24%	3.50%	28.00	0.30%
20											
21	PNY	PIEDMONT NATURAL GAS COMPANY	2001	0.2475		11.70%		2.90%	8.63	64.93	
22			2002	0.1579		10.60%		1.67%	8.91	66.18	
23			2003	0.2613		11.80%		3.08%	9.36	67.31	
24			2004	0.3307		11.10%		3.67%	11.15	76.67	
25			2005	0.3106		11.50%		3.57%	11.53	76.70	
26			GROWTH 2001 - 2005					2.98%	6.50%		4.25%
27			2006	0.2615		11.00%		2.88%		75.00	-2.22%
28			2007	0.2857		11.50%		3.29%		74.50	-1.44%
29			2009-11	0.3314		12.50%		4.14%	3.00%	72.50	-1.12%
30											
31	SJI	SOUTH JERSEY INDUSTIES, INC.	2001	0.3565		12.80%		4.56%	7.81	23.72	
32			2002	0.3852		12.50%		4.82%	9.67	24.41	
33			2003	0.4307		11.60%		5.00%	11.26	26.46	
34			2004	0.4810		12.50%		6.01%	12.41	27.76	
35			2005	0.4971		12.40%		6.16%	13.50	28.98	
36			GROWTH 2001 - 2005					5.31%	13.00%		5.13%
37			2006	0.5027		13.00%		6.54%		29.30	1.10%
38			2007	0.4974		12.50%		6.22%		29.60	1.06%
39			2009-11	0.5000		13.00%		6.50%	6.00%	31.00	1.36%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY RATINGS & REPORTS DATED 12/15/2006
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 & 26, SIMPLE AVERAGE GROWTH, 2001 - 2005

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

UNS GAS, INC.
TEST YEAR ENDED DECEMBER 31, 2005
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.	2001	0.2870		6.60%		1.89%	17.27	32.49	
2			2002	0.2931		6.50%		1.91%	17.91	33.29	
3			2003	0.2743		6.10%		1.67%	18.42	34.23	
4			2004	0.5060		8.30%		4.20%	19.18	36.79	
5			2005	0.3440		6.40%		2.20%	19.10	39.33	
6			GROWTH 2001 - 2005					2.37%	3.00%		4.89%
7			2006	0.5795		10.50%		6.08%		42.00	6.79%
8			2007	0.5900		9.50%		5.61%		43.00	4.56%
9			2009-11	0.6511		9.50%		6.19%	4.50%	45.00	2.73%
10											
11	WGL	WGL HOLDINGS, INC.	2001	0.3298		11.20%		3.69%	16.24	48.54	
12			2002	-0.1140		11.20%		NMF	15.78	48.56	
13			2003	0.4435		14.00%		6.21%	16.25	48.63	
14			2004	0.3434		11.70%		4.02%	16.95	48.67	
15			2005	0.3744		12.00%		4.49%	17.80	48.65	
16			GROWTH 2001 - 2005					4.60%	3.00%		0.06%
17			2006	0.2895		9.50%		2.75%		48.88	0.47%
18			2007	0.2737		10.00%		2.74%		49.00	0.36%
19			2009-11	0.3702		11.00%		4.07%	3.50%	49.50	0.35%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY RATINGS & REPORTS DATED 12/15/2006
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 & 26, SIMPLE AVERAGE GROWTH, 2001 - 2005

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

UNS GAS, INC.
TEST YEAR ENDED DECEMBER 31, 2005
GROWTH RATE COMPARISON

DOCKET NO. G-04204A-06-0463
SCHEDULE WAR - 6

LINE NO.	STOCK SYMBOL	(A) (br) + (sv)	(B) ZACKS EPS	(C) VALUE LINE PROJECTED EPS	(C) DPS	(C) BVPS	(D) VALUE LINE HISTORIC EPS	(D) DPS	(D) BVPS	(E) VALUE LINE & ZACKS AVGS.	(F) 5 - YEAR COMPOUND HISTORY EPS	(F) DPS	(F) BVPS
1	ATG	4.31%	4.60%	4.00%	6.50%	6.50%	13.50%	2.00%	8.50%	6.51%	13.39%	4.74%	12.16%
2	ATO	5.39%	5.50%	6.50%	2.00%	4.00%	6.50%	2.00%	8.50%	5.00%	4.00%	1.68%	8.59%
3	LG	4.88%	-	5.00%	2.50%	7.50%	4.50%	0.50%	2.50%	3.75%	4.23%	0.56%	3.20%
4	NJR	6.23%	6.00%	4.50%	4.50%	8.50%	8.00%	3.50%	8.50%	6.21%	7.97%	3.83%	4.76%
5	GAS	4.26%	2.50%	4.00%	1.00%	4.50%	-3.50%	3.50%	1.50%	1.93%	-6.81%	1.39%	2.88%
6	NWN	4.22%	5.30%	7.00%	4.00%	3.50%	5.00%	1.00%	3.50%	4.19%	2.93%	1.37%	3.48%
7	PNY	4.16%	5.60%	6.00%	5.50%	3.00%	5.00%	5.00%	6.50%	5.23%	6.92%	4.61%	7.51%
8	SJI	7.08%	6.00%	7.00%	6.00%	6.00%	11.50%	2.50%	13.00%	7.43%	10.43%	3.83%	14.66%
9	SWX	8.17%	6.00%	9.00%	NIL	4.50%	-0.50%	-	3.00%	4.40%	2.11%	0.00%	2.55%
10	WGL	4.14%	3.30%	1.50%	2.00%	3.50%	6.00%	1.50%	3.00%	2.97%	2.93%	1.17%	2.32%
11				5.45%	3.78%	5.15%	5.60%	2.39%	5.85%		4.81%	2.32%	6.21%
12	AVERAGES	5.28%	4.98%		4.79%			4.61%		4.76%		4.45%	

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 12/15/2006
COLUMN (D): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 12/15/2006
COLUMN (E): SIMPLE AVERAGE OF COLUMNS (B) THRU (D) LINES 1, 3, 5 AND 7
COLUMN (F): 5-YEAR ANNUAL GROWTH RATE CALCULATED WITH DATA COMPILED FROM VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 12/15/2006

BASED ON A GEOMETRIC MEAN:

LINE NO.	STOCK SYMBOL	k	=	r_f	+ [	(A) ß	x (	r_m	-	r_f)]	=	(B) EXPECTED RETURN
1	ATG	k	=	5.05%	+ [	0.95	x (	10.40%		5.05%)]	=	10.13%
2	ATO	k	=	5.05%	+ [	0.80	x (	10.40%		5.05%)]	=	9.33%
3	LG	k	=	5.05%	+ [	0.90	x (	10.40%		5.05%)]	=	9.86%
4	NJR	k	=	5.05%	+ [	0.80	x (	10.40%		5.05%)]	=	9.33%
5	GAS	k	=	5.05%	+ [	1.30	x (	10.40%		5.05%)]	=	12.01%
6	NWN	k	=	5.05%	+ [	0.75	x (	10.40%		5.05%)]	=	9.06%
7	PNY	k	=	5.05%	+ [	0.80	x (	10.40%		5.05%)]	=	9.33%
8	SJI	k	=	5.05%	+ [	0.70	x (	10.40%		5.05%)]	=	8.79%
9	SWX	k	=	5.05%	+ [	0.85	x (	10.40%		5.05%)]	=	9.60%
10	WGL	k	=	5.05%	+ [	0.85	x (	10.40%		5.05%)]	=	9.60%
11	**AVERAGE**					0.87						9.70%

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$k = r_f + [\ ß\ (r_m - r_f)\ ]$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) A 6-WEEK AVERAGE OF THE 91-DAY T-BILL RATES THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 12/22/2006 THROUGH 01/26/2007 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE MARKET RATE PROXY USED WAS THE ARITHMETIC MEAN FOR S&P 500 RETURNS OVER THE 1926 - 2005 PERIOD. THE DATA WAS OBTAINED FROM IBBOTSON ASSOCIATES' STOCKS, BONDS, BILLS AND INFLATION: 2005 YEARBOOK.

UNS GAS, INC.
TEST YEAR ENDED DECEMBER 31, 2005
CAPM COST OF EQUITY CAPITAL

BASED ON AN ARITHMETIC MEAN:

LINE NO.	STOCK SYMBOL	k	=	r_f	+ [	(A) ß	x (	r_m	-	r_f)]	=	(B) EXPECTED RETURN
1	ATG	k	=	5.05%	+ [	0.95	x (	12.30%		5.05%)]	=	11.94%
2	ATO	k	=	5.05%	+ [	0.80	x (	12.30%		5.05%)]	=	10.85%
3	LG	k	=	5.05%	+ [	0.90	x (	12.30%		5.05%)]	=	11.57%
4	NJR	k	=	5.05%	+ [	0.80	x (	12.30%		5.05%)]	=	10.85%
5	GAS	k	=	5.05%	+ [	1.30	x (	12.30%		5.05%)]	=	14.48%
6	NWN	k	=	5.05%	+ [	0.75	x (	12.30%		5.05%)]	=	10.49%
7	PNY	k	=	5.05%	+ [	0.80	x (	12.30%		5.05%)]	=	10.85%
8	SJI	k	=	5.05%	+ [	0.70	x (	12.30%		5.05%)]	=	10.12%
9	SWX	k	=	5.05%	+ [	0.85	x (	12.30%		5.05%)]	=	11.21%
10	WGL	k	=	5.05%	+ [	0.85	x (	12.30%		5.05%)]	=	11.21%
11	**AVERAGE**					0.87						11.36%

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$k = r_f + [ß (r_m - r_f)]$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) A 6-WEEK AVERAGE OF THE 91-DAY T-BILL RATES THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 12/22/2006 THROUGH 01/26/2007 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE MARKET RATE PROXY USED WAS THE ARITHMETIC MEAN FOR S&P 500 RETURNS OVER THE 1926 - 2005 PERIOD. THE DATA WAS OBTAINED FROM IBBOTSON ASSOCIATES' STOCKS, BONDS, BILLS AND INFLATION: 2005 YEARBOOK.

UNS GAS, INC.
TEST YEAR ENDED DECEMBER 31, 2005
ECONOMIC INDICATORS - 1990 TO PRESENT

DOCKET NO. G-04204A-06-0463
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	5.40%	1.90%	10.01%	6.98%	8.10%	7.49%	7.49%	9.86%	10.06%
2	1991	4.21%	-0.20%	8.46%	5.45%	5.69%	5.38%	5.38%	9.36%	9.55%
3	1992	3.01%	3.30%	6.25%	3.25%	3.52%	3.43%	3.43%	8.69%	8.86%
4	1993	2.99%	2.70%	6.00%	3.00%	3.02%	3.00%	3.00%	7.59%	7.91%
5	1994	2.56%	4.00%	7.14%	3.60%	4.20%	4.25%	4.25%	8.31%	8.63%
6	1995	2.83%	2.50%	8.83%	5.21%	5.84%	5.49%	5.49%	7.89%	8.29%
7	1996	2.95%	3.70%	8.27%	5.02%	5.30%	5.01%	5.01%	7.75%	8.17%
8	1997	1.70%	4.50%	8.44%	5.00%	5.46%	5.06%	5.06%	7.60%	8.12%
9	1998	1.60%	4.20%	8.35%	4.92%	5.35%	4.78%	4.78%	7.04%	7.27%
10	1999	2.70%	4.50%	7.99%	4.62%	4.97%	4.64%	4.64%	7.62%	7.88%
11	2000	3.40%	3.70%	9.23%	5.73%	6.24%	5.82%	5.82%	8.24%	8.36%
12	2001	1.60%	0.80%	6.92%	3.41%	3.88%	3.38%	5.95%	7.59%	8.02%
13	2002	2.40%	1.60%	4.67%	1.17%	1.66%	1.60%	5.38%	7.41%	7.98%
14	2003	1.90%	2.50%	4.12%	2.03%	1.13%	1.01%	4.92%	6.18%	6.64%
15	2004	3.30%	3.90%	4.34%	2.35%	1.35%	1.37%	5.03%	5.77%	6.20%
16	2005	3.40%	3.20%	6.16%	4.16%	3.16%	3.17%	4.57%	5.38%	5.78%
17	2006	2.50%	3.40%	7.97%	5.97%	4.97%	4.83%	4.88%	5.94%	6.30%
18	CURRENT	2.50%	3.50% (a)	8.25%	6.25%	5.25%	5.10%	5.10%	5.86%	6.14%

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 (F): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 01/26/2007
COLUMN (G) THROUGH (I): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 01/26/2007
COLUMN (H) THROUGH (J): 1990 - 2000, MOODY'S PUBLIC UTILITY REPORTS
COLUMN (H) THROUGH (I): 2001, MERGENT 2002 PUBLIC UTILITY MANUAL
COLUMN (H) THROUGH (I): 2003 MERGENT NEWS REPORTS

NOTES
(a) FOURTH QUARTER 2006

UNS GAS, INC.
TEST YEAR ENDED DECEMBER 31, 2005
CAPITAL STRUCTURES OF SAMPLE COMPANIES

DOCKET NO. G-04204A-06-0463
SCHEDULE WAR - 9

LINE NO.		ATG	PCT.	ATO	PCT.	LG	PCT.	NJR	PCT.	GAS	PCT.
1	DEBT	$ 1,615.0	51.9%	$ 1,602.4	42.3%	$ 340.5	48.1%	$ 317.2	42.0%	$ 1,071.8	56.9%
2											
3	PREFERRED STOCK	0.0	0.0%	0.0	0.0%	0.9	0.1%	0.0	0.0%	0.6	0.0%
4											
5	COMMON EQUITY	1,499.0	48.1%	2,183.1	57.7%	366.5	51.8%	438.1	58.0%	811.3	43.1%
6											
7	TOTALS	$ 3,114.0	100%	$ 3,785.5	100%	$ 707.9	100%	$ 755.3	100%	$ 1,883.7	100%
8											
9											
10		NWN	PCT.	PNY	PCT.	SJI	PCT.	SWX	PCT.	WGL	PCT.
11											
12	DEBT	$ 521.5	47.0%	$ 625.0	41.4%	$ 328.9	48.7%	$ 1,224.9	59.0%	$ 584.2	38.8%
13											
14	PREFERRED STOCK	0.0	0.0%	0.0	0.0%	1.6	0.2%	100.0	4.8%	28.2	1.9%
15											
16	COMMON EQUITY	586.9	53.0%	884.2	58.6%	344.4	51.0%	751.1	36.2%	894.0	59.3%
17											
18	TOTALS	$ 1,108.4	100%	$ 1,509.2	100%	$ 674.9	100%	$ 2,076.0	100%	$1,506.4	100%
19											
20											
21		NATURAL GAS LDC									
22		AVERAGE	PCT.								
23											
24	DEBT	$ 823.1	48.1%								
25											
26	PREFERRED STOCK	13.1	0.8%								
27											
28	COMMON EQUITY	875.9	51.2%								
29											
30	TOTALS	$ 1,712.1	100%								

REFERENCE:
MOST RECENT SEC 10-K FILINGS OR ANNUAL REPORTS

UNS GAS, INC.

DOCKET NO. G-04204A-06-0463 et al.

SURREBUTTAL TESTIMONY

OF

WILLIAM A. RIGSBY, CRRA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

APRIL 4, 2007

EXHIBIT
tabbies
RUCO 8
admitted

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 state the purpose of your surrebuttal testimony.

A. The purpose of my testimony is to respond to UNS Gas Inc.'s ("UNS" or "Company") 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 in northern Arizona and Santa Cruz County in southern Arizona.

Q. Have you filed any prior testimony in this case on behalf of RUCO?

A. Yes, on February 9, 2007, I filed direct testimony with the Arizona Corporation Commission ("ACC" or "Commission"). My direct testimony addressed the cost of capital issues that were raised in UNS' application requesting a permanent rate increase ("Application") based on a test year ended December 31, 2005.

...

Q. How is your surrebuttal testimony organized?

A. My surrebuttal testimony contains four parts: the introduction that I have just presented; a summary of UNS' rebuttal testimony; a section on the cost of debt; and a section on the cost of equity capital. My testimony is supported by a set of revised surrebuttal schedules labeled WAR-1 through WAR-9, which can be found at the end of this document.

Q. Have you made any revisions to your original cost of capital recommendation?

A. Yes. As I will explain in my testimony, I have made upward revisions to both my recommended costs of debt and equity. I am now recommending a cost of debt of 6.60 percent and a cost of common equity of 9.84 percent. These changes can be viewed on pages 1 and 2 of my Surrebuttal Schedule WAR-1.

SUMMARY OF UNS GAS, INC.'S REBUTTAL TESTIMONY

Q. Have you reviewed UNS' rebuttal testimony?

A. Yes. I have reviewed the rebuttal testimony, filed on March 16, 2007, of Company witness Kentton C. Grant.

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 as a result of the estimate that I obtained from my DCF analysis and explains why he believes that my growth estimates are unrealistic. Although Mr. Grant is in agreement with my recommendation to adopt the Company-proposed capital structure comprised of 50 percent equity and 50 percent debt, he disagrees with the 6.23 percent cost of debt that I originally recommended in my direct testimony.

COST OF DEBT

Q. Why have you revised your recommended cost of debt of 6.23 percent?

A. My decision to revise my recommended cost of debt was based on information that was provided to me by UNS in response to a RUCO data request that was sent to the Company after I filed my direct testimony in February[1], and a review of specific Federal Energy Regulatory Account ("FERC") balances that UNS included in the Company's Application. As a result, I have decided to adopt the 6.60 percent cost of debt that Mr. Grant proposed originally.

Q. Briefly summarize the current positions of the parties to the case regarding capital structure, cost of debt, cost of equity and weighted cost of capital.

A. Both RUCO and UNS are in agreement with the Company-proposed hypothetical capital structure comprised of 50.0 percent debt and 50.0 percent equity. Mr. David C. Parcell, ACC Staff's cost of capital witness,

[1] RUCO's Eighth set of Data Requests sent on March 1, 2007.

is recommending that the Commission adopt the Company's actual test year capital structure, which was comprised of 44.67 percent equity and 55.33 percent debt. To date, all of the parties to the case are in agreement on the cost of debt now that I have revised my recommendation to 6.60 percent. In regard to the cost of equity, the parties to the case are presently recommending the following estimates:

UNS	11.00%
ACC Staff	10.00%
RUCO	9.84%

Mr. Parcell's 10.00 percent cost of common equity recommendation is the mid-point of the upper end of his DCF range of 9.50 percent to 10.50 percent. The weighted costs of capital being recommended by the parties to the case are as follows:

UNS	8.80%
ACC Staff	8.12%
RUCO	8.22%

As can be seen above, there is presently a 58 basis point difference between the Company-proposed 8.80 percent weighted cost of capital and RUCO's recommended weighted cost of capital of 8.22 percent. RUCO and ACC Staff's recommended costs of capital fall within 10 basis points of each other.

COST OF EQUITY CAPITAL

Q. Has there been any recent activity in regard to interest rates?

A. Yes. On March 21, 2007, the Federal Reserve decided not to increase or decrease the federal funds rate for the sixth straight time and left it unchanged at 5.25 percent.[2] The short-term 91-day T-Bill rate has fallen to 5.03 as of March 21, 2007, and is 31 basis points higher than the benchmark long-term 30-year T-Bond yield of 4.72 percent (Attachment A).

Q. Please explain why you revised your recommended cost of common equity from 9.64 percent to 9.84 percent?

A. My revised cost of common equity is the result of updated Value Line and Zacks Investment Research projections (Attachments B and C respectively) and updated closing stock price information on the natural gas (distribution Industry) that is used in my DCF model. I also updated the 91-day T-Bill yields and betas that were used in my CAPM model.

...

[2] Blackstone, Brian and Campion Walsh, "Fed Holds Rates Steady, Softens Tightening Bias" The Wall Street Journal, March 21, 2007

Q. Please describe the updated Value Line projections that you used in your DCF model.

A. During the week ending March 16, 2007, Value Line published its quarterly update on the natural gas distribution industry with revised projections on earnings, dividends and book values. Because this is information that cannot be ignored in this proceeding, I decided to use it and revise the cost of equity recommendation that I made in my direct testimony. The updated Value Line projections can be viewed in my surrebuttal schedules.

Q. Please address Mr. Grant's criticism that the growth rates used in your DCF model are problematic from the standpoint of market expectations.

A. Mr. Grant presents two arguments in regard to the growth rates used in my DCF model. His first argument states that investors expect a convergence of individual growth rates towards the industry average growth rate and that my growth rate estimates fail to take this into account. Mr. Grant's second argument states that my growth estimates are not in line with long-term inflation-adjusted estimates of U.S. gross domestic product ("GDP") which is the long-term growth component used in the multi-stage DCF model that he has relied on for his cost of equity estimation. Both arguments presented by Mr. Grant are groundless and should be given no weight.

Q. Please explain why Mr. Grant's first argument regarding your growth rate estimates should not be afforded any weight.

A. Mr. Grant's first argument assumes that investors place their funds in an individual LDC's stock because they expect the individual LDC's growth rates to converge with the long-term average of the natural gas distribution industry. In other words, if you've seen one LDC stock, you've seen them all because you are investing in an industry as opposed to an individual utility. If his argument were true, then investors would be investing in the natural gas industry as a whole (i.e. through an investment vehicle such as a mutual fund) as opposed to investing in an individual LDC. His argument totally ignores the premise that rational investors place their funds in individual stocks because they feel comfortable with the dividend yields and the growth potentials offered by the individual LDC that they are investing in. I believe that rational investors also weigh other factors such as superior management, corporate culture and philosophy, and past records of performance when making their investment decisions. If you subscribe to Mr. Grant's argument, then it would not make any difference which LDC you made an investment in since they will all eventually provide the same returns in growth. This begs the question as to why there is so much investor information available on individual companies or why the managements of publicly traded firms tout their ability to provide returns that will exceed industry averages.

Q. Please address Mr. Grant's second argument regarding your growth rate estimates.

A. Mr. Grant's second argument assumes that my growth rates are unrealistic because they do not take into consideration the long-term inflation-adjusted estimates of U.S. GDP, which is the long-term growth component used in his multi-stage DCF model. If you subscribe to his argument then you have to believe that every individual LDC included in Mr. Grant's sample is going to have inflation-adjusted growth that mirrors the GDP of the entire U.S. economy into perpetuity. This in itself is a rather broad and unrealistic expectation. Professional analysts often have enough trouble making accurate projections of the near-term (i.e. one-year) earnings of the companies that they follow. It would be unrealistic to believe that projections that extend into perpetuity would be more accurate than the near-term projections. The growth estimates used in my DCF model are a balance of known historical 5-year growth figures and projected growth estimates over the next five-year period (i.e. 2007 through 2012). I believe that this is a reasonable horizon for future growth estimates, given the fact that utilities typically apply for rate relief within a three to five-year time frame.

...

Q. Are there any other reasons why you believe that Mr. Grant's second argument on your growth rate estimates is flawed?

A. Yes. It is interesting to note that in the multi-stage DCF model adopted by the FERC, more emphasis is given to short-term growth expectations as opposed to inflation-adjusted estimates of future U.S. GDP growth. This can be seen in the following excerpt from the FERC's Cost-of-Service Rates Manual (Attachment D):

> "**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."

As stated in the excerpt above, the FERC multi-stage DCF model weighs short-term estimates, similar to the ones used in my single stage DCF model, by a factor of two-thirds based on the fact that they are more predictable and deserve more weight than long-term estimates such as the inflation-adjusted estimates of future U.S. GDP growth used in the multi-stage DCF model that Mr. Grant has relied on.

Q. Have the comments made by Mr. Grant on page 5, lines 5 through 18 of his rebuttal testimony caused you to change the views that you expressed in your direct testimony?

A. No. As I stated in my direct testimony, the Commission has consistently rejected issues such as company size, customer growth, and the historic test year concept as reasons for making upward adjustments to estimated costs of common equity. Nowhere in his rebuttal testimony is Mr. Grant willing to concede that the implementation of a decoupling mechanism would merit a lower return on common equity for UNS given the fact that it would remove all of the risk associated with operating income volatility. Mr. Grant clearly wants the best of all worlds for UNS: a guaranteed return on investment and a high cost of common equity that reflects a riskier operating environment.

Q. Please discuss on Mr. Grant's comments regarding your grasp of the additional risk resulting from high customer growth and regulatory lag.

A. With all due respect to Mr. Grant, I believe that my grasp of the additional risk resulting from high customer growth and regulatory lag is much better than what he believes. I can say with confidence that high customer growth has been business as usual and a fact of life for utilities operating in the Arizona jurisdiction for the last fifty years. If a utility's management can't deal with that fact of life then they should consider getting into another business. The issue of high customer growth in UNS' service territory certainly never deterred the Company's parent, UniSource Energy Corporation ("UniSource"), from acquiring the natural gas and electric assets from Citizens Communications Company ("Citizens") in the first place. One cannot believe that the management of UniSource, which is based in Tucson, was blind to the fact that they were acquiring assets located in one of the fastest growing states in the U.S. High growth in Arizona is one of UniSource's biggest selling points to potential investors. UniSource even presents high growth in a positive light in the Chairman's Letter to Shareholders that appears in UniSource's 2005 Annual Report (Attachment E). Obviously the investment community does not view UniSource's high growth service territories in a negative light given the fact that shares of UniSource have increased from $25.25, at the time the ACC rejected an acquisition attempt by a limited liability partnership (which included the well heeled Wall Street investment firm of Kolberg Kravis Roberts & Co.), to a current price of $37.75 as of March 28, 2007.

In regard to regulatory lag, unless the utility is operating under an agreement that provides for a rate freeze, it is the utility that decides when to apply for rate relief and generally utilities apply for rate relief at times when it is an advantage to them. Once again, UniSource's management was well aware of the regulatory environment that they would be operating in when they acquired the natural gas and electric assets from Citizens in 2003. For the reasons stated above I believe that Mr. Grant's arguments regarding additional risk resulting from high customer growth and regulatory lag should be given no weight in this proceeding.

Q. Did Mr. Grant take issue with your use of a geometric mean to calculate the historical return on the market that is used in the equity risk premium component of your CAPM model?

A. Not directly. However he does take issue with Mr. Parcell's use of the geometric mean and for this reason I believe that it is important that I defend the use of the geometric mean in this proceeding.

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 Ibbotson Associates, 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 2005 observation period used in my CAPM analysis.

Q. Can you provide an example to illustrate the differences between the two averages?

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:

$$(\text{ year 1 return} + \text{year 2 return }) \div \text{number of periods} =$$
$$(20.0\% + -20.0\%) \div 2 =$$
$$(0.0\%) \div 2 = \underline{0.0\%}$$

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, <u>Valuation: Measuring and Managing the Value of Companies</u>, 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 Ibbotson'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 Ibbotson 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 Ibbotson historical return series in that it only measures the returns of successful firms, that is, those firms that are listed on stock exchanges. The Ibbotson 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 Ibbotson historical averages. After conducting their analysis, CKM conclude that 4.00 percent to 5.50 percent is a reasonable forward looking market risk premium. Adding the current 5-year Treasury yield of 4.43 percent to these two estimates indicate a cost of equity of 8.43 percent to 9.93 percent. Given 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 revised 9.84 percent cost of common equity estimate falls within this range.

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 UNS?

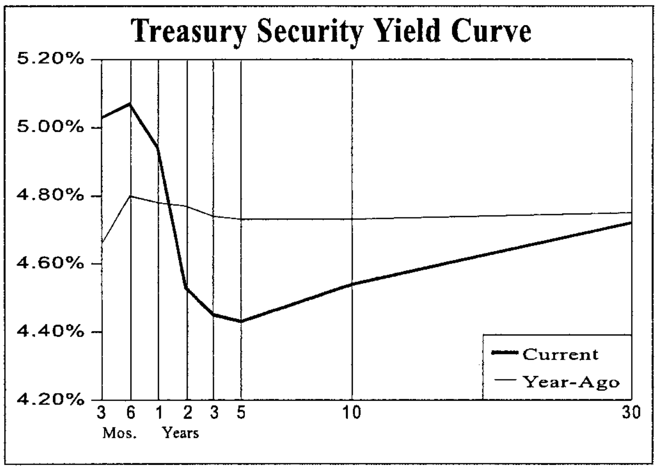
A. Yes, it does.

ATTACHMENT A

Selected Yields

	Recent (3/21/07)	3 Months Ago (12/20/06)	Year Ago (3/23/06)
TAXABLE			
Market Rates			
Discount Rate	6.25	6.25	5.50
Federal Funds	5.25	5.25	4.50
Prime Rate	8.25	8.25	7.50
30-day CP (A1/P1)	5.24	5.25	4.73
3-month LIBOR	5.35	5.37	4.96
Bank CDs			
6-month	3.26	3.30	2.97
1-year	3.87	3.84	3.57
5-year	3.92	3.91	3.96
U.S. Treasury Securities			
3-month	5.03	4.96	4.66
6-month	5.07	5.06	4.80
1-year	4.94	4.96	4.78
5-year	4.43	4.56	4.73
10-year	4.54	4.60	4.73
10-year (inflation-protected)	2.12	2.31	2.23
30-year	4.72	4.73	4.75
30-year Zero	4.68	4.67	4.61

	Recent (3/21/07)	3 Months Ago (12/20/06)	Year Ago (3/23/06)
Mortgage-Backed Securities			
GNMA 6.5%	5.53	5.53	5.53
FHLMC 6.5% (Gold)	5.60	5.68	5.93
FNMA 6.5%	5.50	5.61	5.85
FNMA ARM	5.60	5.55	4.53
Corporate Bonds			
Financial (10-year) A	5.40	5.45	5.66
Industrial (25/30-year) A	5.68	5.69	5.84
Utility (25/30-year) A	5.86	5.75	5.86
Utility (25/30-year) Baa/BBB	6.01	6.02	6.17
Foreign Bonds (10-Year)			
Canada	4.08	4.03	4.21
Germany	3.93	3.86	3.68
Japan	1.57	1.62	1.72
United Kingdom	4.83	4.71	4.34
Preferred Stocks			
Utility A	7.22	7.13	7.18
Financial A	6.31	6.34	6.28
Financial Adjustable A	5.47	5.47	N/A



	Recent (3/21/07)	3 Months Ago (12/20/06)	Year Ago (3/23/06)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.13	4.12	4.43
25-Bond Index (Revs)	4.38	4.52	5.08
General Obligation Bonds (GOs)			
1-year Aaa	3.54	3.48	3.43
1-year A	3.64	3.58	3.55
5-year Aaa	3.51	3.48	3.55
5-year A	3.80	3.77	3.83
10-year Aaa	3.65	3.69	3.93
10-year A	3.95	4.10	4.25
25/30-year Aaa	4.00	4.03	4.38
25/30-year A	4.30	4.35	4.65
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.33	4.47	4.39
Electric AA	4.30	4.38	4.45
Housing AA	4.55	4.50	4.65
Hospital AA	4.57	4.52	4.74
Toll Road Aaa	4.40	4.36	4.63

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	3/14/07	2/28/07	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1586	1772	-186	1577	1661	1663
Borrowed Reserves	43	30	13	133	196	227
Net Free/Borrowed Reserves	1543	1742	-199	1444	1465	1436

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	3/5/07	2/26/07	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1379.2	1347.6	31.6	0.3%	0.2%	0.4%
M2 (M1+savings+small time deposits)	7127.5	7144.3	-16.8	7.9%	7.5%	5.5%

ATTACHMENT B

The Natural Gas (Distribution) Industry's Timeliness rank remains about where it was in December, though it has gained a few places in the last year. In 2006, the industry outperformed the Standard & Poor's 500 index, returning about 20%, including dividends, though the group's stock prices have generally moved little since our last report. Still, the estimated dividend yield for most of the issues is below last year's, since dividend increases have not kept pace with the stock price gains of 2006.

Natural gas distribution stocks usually offer dividends that are substantially above the *Value Line Investment Survey* median, currently 1.7%, but they also, as a group, have below-average capital appreciation potential. Indeed, some of the stocks are currently trading within their 2010-2012 target price ranges, leaving dividends as the only source of forecast investment return. That's because we believe that interest rates will likely be higher in the out years than at present, when the long-term Treasury bond rate has been below 5% for some time.

Regulated Earnings and Regulation.

Most of the gas distribution companies derive over 85% of their earnings from local natural gas distribution. Like their larger cousins, the electric power distribution companies, gas distribution companies are allowed by their state-based public service commissions to earn a limited return on equity, generally in the 10%-12% range. In a few cases, regulators allow gas utilities to earn performance-based rates of return on equity of up to 15% and to share profits above that level with rate payers, provided the utility keeps rate growth at less than the general level of inflation. Other recent regulatory innovations include weather-adjusted rate mechanisms, which help the utility when weather is warmer than average and its customers when it's colder. Some states have gone a step further and have rules that "decouple" the utilities' revenues from gas usage to a certain extent in order not to discourage conservation. All told, the regulatory climate is better for the industry than ten years ago. That leaves volume as a main driver of earnings growth, and here, the group has wide variation. With natural gas consumption increasing about 1.5% a year, regulated earnings growth will likely be in the mid-single digits. The companies that appear to have

INDUSTRY TIMELINESS: 81 (of 96)

better prospects, such as *Northwest Natural Gas,* tend to have dividend yields that are lower than stocks facing slower growth, such as *Laclede.*

Nonregulated Activities

In an effort to boost earnings, most gas distribution companies also have small, unregulated businesses. These tend to include heating, ventilation and air conditioning services (HVAC), gas marketing, and gas storage for off-system customers. The group also invests in gas pipelines, the returns of which are regulated by the FERC, rather than the states. As demand for gas grows, the U.S. will need to import substantially more gas in liquid form, and liquefied natural gas (LNG) plants could offer some of the companies investment opportunities, as well as the chance to raise earnings by moving more gas through their pipelines.

Earnings and Dividend Growth Prospects

So far, customers seem to have handled recent high gas prices fairly well. Bad debt costs are up, but regulators are making allowances for that in some states, and gas price inflation will probably be less over the next two years than over the last two. Enlightened state regulation, combined with cost savings from measures like automated meter reading, will probably permit earnings to rise at a modest pace; dividends should follow suit.

Wheeling and Dealing

In the 1990s, many publicly held natural gas distributors were acquired, considerably reducing the variety of investment choices available. At present, three of the companies in our group are in the process of being acquired. While we don't encourage investors to bet on a company's being taken over, the possibility remains and could boost investment returns.

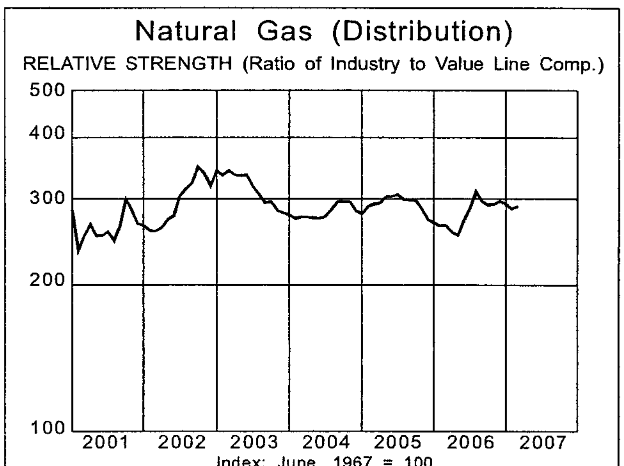
Investment Considerations

The Natural Gas (Distribution) Industry offers above-average dividends and, in some cases, some capital appreciation. Investors seeking relatively safe income can find prospects here, but dividend growth will likely be slow. Moreover, the industry is in fashion now; a change of investor sentiment unrelated to the industry's prospects or higher long-term interest rates could drive stock prices down.

Sigourney B. Romaine, CFA

Composite Statistics: Natural Gas (Distribution)

2003	2004	2005	2006	2007	2008		10-12
29981	33220	41399	*43500*	*44500*	*46500*	Revenues ($mill)	*58000*
1395.3	1517.2	1788.8	*1950*	*2050*	*2150*	Net Profit ($mill)	*2800*
37.4%	35.7%	35.8%	*36.0%*	*36.0%*	*36.0%*	Income Tax Rate	*36.0%*
4.7%	4.6%	4.3%	*4.5%*	*4.6%*	*4.6%*	Net Profit Margin	*4.8%*
55.9%	53.2%	50.7%	*51.0%*	*51.0%*	*51.0%*	Long-Term Debt Ratio	*52.0%*
43.7%	45.7%	48.3%	*48.0%*	*48.0%*	*48.0%*	Common Equity Ratio	*46.0%*
28436	31268	33911	*35400*	*36750*	*38000*	Total Capital ($mill)	*42000*
31732	32053	35030	*37000*	*39000*	*41000*	Net Plant ($mill)	*45000*
6.4%	6.4%	6.9%	*7.0%*	*7.0%*	*7.0%*	Return on Total Cap'l	*7.5%*
11.1%	10.4%	10.7%	*11.0%*	*11.5%*	*11.5%*	Return on Shr. Equity	*12.0%*
11.2%	10.5%	10.8%	*11.0%*	*11.5%*	*11.5%*	Return on Com Equity	*12.0%*
4.1%	4.0%	4.4%	*5.0%*	*5.2%*	*5.3%*	Retained to Com Eq	*5.5%*
64%	63%	59%	*61%*	*60%*	*60%*	All Div'ds to Net Prof	*60%*
14.1	15.6	16.2	*16.5*	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*13.0*
.80	.82	.87	*.90*			Relative P/E Ratio	*.85*
4.5%	4.0%	3.6%	*3.5%*			Avg Ann'l Div'd Yield	*4.6%*
314%	308%	331%	*325%*	*325%*	*325%*	Fixed Charge Coverage	*325%*



AGL RESOURCES NYSE-ATG

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
40.03	14.6	(Trailing: 14.7) (Median: 14.0)	0.81	4.1%	VALUE LINE

TIMELINESS 4 Lowered 8/11/06

SAFETY 2 New 7/27/90

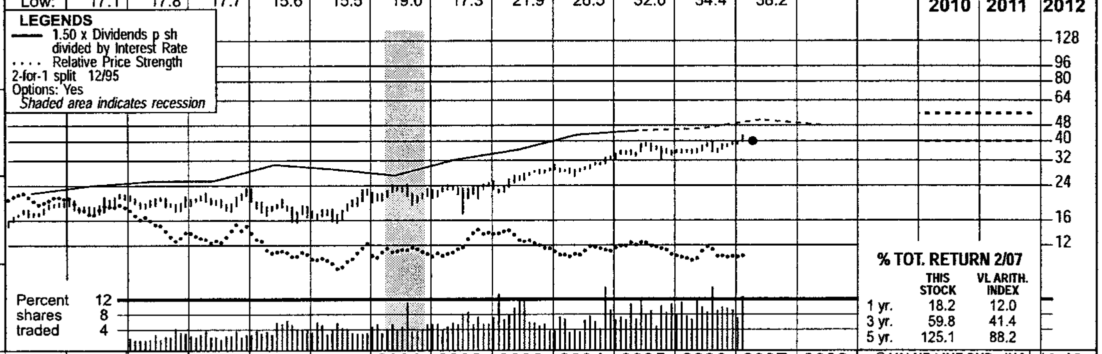
TECHNICAL 3 Raised 2/23/07

BETA .95 (1.00 = Market)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
High:	22.0	21.6	23.4	23.4	23.2	24.5	25.0	29.3	33.7	39.3	40.1	42.9
Low:	17.1	17.8	17.7	15.6	15.5	19.0	17.3	21.9	26.5	32.0	34.4	38.2

Target Price Range

2010	2011	2012



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+35%)	11%
Low	40	(Nil)	4%

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	1	0	0	3	6
to Sell	0	0	0	0	2	0	0	4	1

Institutional Decisions

	2Q2006	3Q2006	4Q2006
to Buy	95	113	121
to Sell	102	78	89
Hld's(000)	49525	50305	49321

% TOT. RETURN 2/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	18.2	12.0
3 yr.	59.8	41.4
5 yr.	125.1	88.2

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
20.26	20.43	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	33.75	*34.95*	*35.45*	Revenues per sh A	*38.75*
2.07	2.31	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	4.62	*4.85*	*5.05*	"Cash Flow" per sh	*5.55*
1.04	1.13	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	*2.80*	*2.90*	Earnings per sh A B	*3.10*
1.02	1.03	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*	*1.64*	Div'ds Decl'd per sh C■	*1.80*
2.95	2.74	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	3.25	*3.35*	*3.30*	Cap'l Spending per sh	*3.45*
9.42	9.70	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	20.69	*20.95*	*21.00*	Book Value per sh D	*22.50*
47.57	48.69	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	77.75	*78.00*	*79.00*	Common Shs Outst'g E	*80.00*
15.3	15.5	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	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.98	.94	1.06	.99	.84	.86	.85	.72	1.22	.88	.75	.68	.71	.69	.76	.72	*Value Line*		Relative P/E Ratio	*1.00*
6.4%	5.9%	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%	*estimates*		Avg Ann'l Div'd Yield	*3.9%*

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008		10-12
1287.6	1338.6	1068.6	607.4	1049.3	868.9	983.7	1832.0	2718.0	2624	*2725*	*2800*	Revenues ($mill) A	*3100*
76.6	80.6	52.1	71.1	82.3	103.0	132.4	153.0	193.0	212.2	*220*	*230*	Net Profit ($mill)	*250*
37.9%	32.5%	33.1%	34.3%	40.7%	36.0%	35.9%	37.0%	37.7%	37.8%	*38.0%*	*38.0%*	Income Tax Rate	*38.0%*
5.9%	6.0%	4.9%	11.7%	7.8%	11.9%	13.5%	8.4%	7.1%	8.1%	*8.0%*	*8.2%*	Net Profit Margin	*8.0%*
48.7%	47.5%	45.3%	45.9%	61.3%	58.3%	50.3%	54.0%	51.9%	50.2%	*50.0%*	*49.8%*	Long-Term Debt Ratio	*49.2%*
45.9%	47.1%	49.2%	48.3%	38.7%	41.7%	49.7%	46.0%	48.1%	49.8%	*50.0%*	*50.2%*	Common Equity Ratio	*50.8%*
1356.4	1388.4	1345.8	1286.2	1736.3	1704.3	1901.4	3008.0	3114.0	3231.0	*3270*	*3310*	Total Capital ($mill)	*3540*
1496.6	1534.0	1598.9	1637.5	2058.9	2194.2	2352.4	3178.0	3271.0	3436.0	*3550*	*3700*	Net Plant ($mill)	*4000*
7.3%	7.6%	5.7%	7.4%	6.5%	8.1%	8.9%	6.3%	7.9%	8.0%	*8.0%*	*8.5%*	Return on Total Cap'l	*8.5%*
11.0%	11.1%	7.1%	10.2%	12.3%	14.5%	14.0%	11.0%	12.9%	13.0%	*13.5%*	*14.0%*	Return on Shr. Equity	*14.0%*
11.3%	12.3%	7.9%	11.5%	12.3%	14.5%	14.0%	11.0%	12.9%	13.0%	*13.5%*	*14.0%*	Return on Com Equity	*14.0%*
3.2%	4.4%	NMF	3.2%	4.2%	7.0%	6.6%	5.6%	6.2%	6.5%	*5.5%*	*6.0%*	Retained to Com Eq	*6.0%*
74%	64%	101%	72%	65%	52%	53%	49%	52%	52%	*58%*	*56%*	All Div'ds to Net Prof	*58%*

CAPITAL STRUCTURE as of 12/31/06
Total Debt $2161.0 mill. Due in 5 Yrs $854.0 mill.
LT Debt $1622.0 mill. LT Interest $130.0 mill.

(Total interest coverage: 5.0x)
Leases, Uncapitalized Annual rentals $32.0 mill.

Pension Assets-12/06 $375.0 mill.
Oblig. $454.0 mill.

Pfd Stock None
Common Stock 77,752,515 shs.
as of 1/31/07

MARKET CAP: $3.1 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2004	2005	12/31/06
Cash Assets	49.0	30.0	20.0
Other	1408.0	2002.0	1802.0
Current Assets	1457.0	2032.0	1822.0
Accts Payable	207.0	264.0	213.0
Debt Due	334.0	522.0	539.0
Other	936.0	1153.0	875.0
Current Liab.	1477.0	1939.0	1627.0
Fix. Chg. Cov.	510%	442%	397%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	1.0%	7.0%	4.0%
"Cash Flow"	5.0%	7.0%	5.5%
Earnings	6.5%	13.5%	3.5%
Dividends	1.5%	2.0%	5.5%
Book Value	5.5%	8.5%	2.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	651	294	262	625	1832
2005	908	430	387	993	2718
2006	1044	436	434	707	2621
2007	*975*	*480*	*455*	*815*	*2725*
2008	*1000*	*500*	*470*	*830*	*2800*

Cal-endar	EARNINGS PER SHARE A B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	1.00	.33	.31	.64	2.28
2005	1.14	.30	.19	.85	2.48
2006	1.41	.25	.46	.60	2.72
2007	*1.35*	*.35*	*.45*	*.65*	*2.80*
2008	*1.40*	*.35*	*.45*	*.70*	*2.90*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.27	.28	.28	.28	1.11
2004	.28	.29	.29	.29	1.15
2005	.31	.31	.31	.37	1.30
2006	.37	.37	.37	.37	1.48
2007	.41				

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 (primarily Atlanta), Virginia, and in southern Tennessee. Also engaged in nonregulated natural gas marketing and other, allied services. Also wholesales and retails propane. Nonregulated subsidiaries: Georgia Natural Gas Services markets natural gas at retail. Acq. Virginia Natural Gas, 10/00. Sold Utilipro, 3/01. Off./dir. own less than 1.0% of common; Goldman Sachs, 5.5%; JPMorgan, 5.9% (3/06 Proxy). Pres. & CEO: John W. Somerhalder II. Inc.: GA. Addr.: 10 Peachtree Place N.E., Atlanta, GA 30309. Tel.: 404-584-4000. Internet: www.aglresources.com.

AGL Resources reported solid performance for 2006. Revenues declined slightly from the record top-line performance achieved in 2005, as a result of reduced customer usage due to warmer weather. Despite this, share earnings advanced by about 10%. This resulted from a lower cost of gas, which decreased by almost 9%. The Wholesale Services business also augmented AGL's bottom line, as operating earnings for this segment increased by 84%. For 2007, we anticipate a modest advance in revenues and share earnings, assuming normal weather patterns. Moderate growth should continue to the end of the decade.

The first phase of the company's rate case in Tennessee has been resolved. In December, the company received approval from the Tennessee Regulatory Authority for its joint settlement with the other parties in the case, resulting in a rate increase of $2.7 million, effective January 1, 2007. The second phase of this case will entail a review of the company's conservation and decoupling mechanisms. A final ruling on this matter is expected by the end of the third quarter.

AGL Resources has announced plans to build a natural gas storage facility in Beaumont, Texas. This initiative will require an investment of $180 million and provide 12 billion cubic feet of capacity upon completion of the first phase. Construction should commence next year, with the facility becoming operational in 2010.

The board of directors recently approved a dividend increase. The quarterly payout is now $0.41. This represents a very healthy 10.8% rise over the previous level. This pattern is encouraging, although the payout may rise at a slower pace going forward, given AGL's declining cash balance.

This stock is ranked to lag the broader market for the coming six to 12 months. However, this issue may appeal to income investors, considering the healthy dividend yield. Also, this good-quality stock scores high marks for Safety and Price Stability. Nevertheless, at the current quotation, appreciation potential is below average for the pull to late decade, as the shares currently trade within our Target Price Range.

Michael F. Napoli *March 16, 2007*

(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). Next earnings report due in May.
(C) Dividends historically paid early March, June, Sept, and Dec. ■ Div'd reinvest. plan available.
(D) Includes intangibles. In 2006: $420 million, $5.40/share.
(E) In millions, adjusted for stock split.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	70
Earnings Predictability	75

ATMOS ENERGY CORP. NYSE-ATO

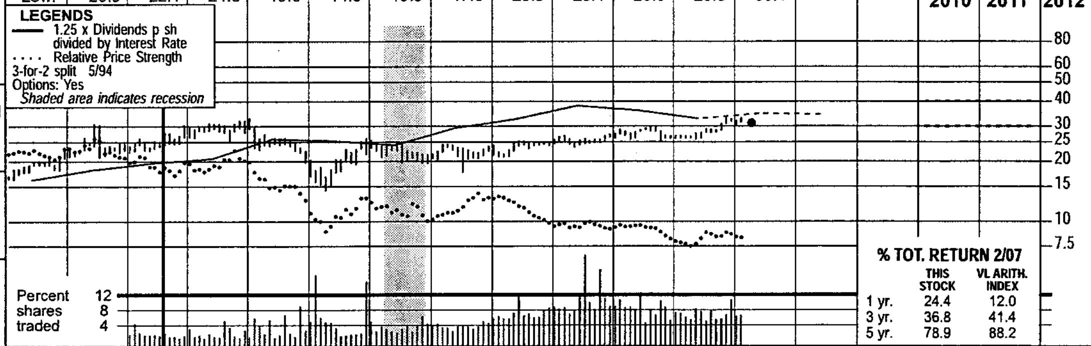
RECENT PRICE **31.23** | P/E RATIO **15.6** (Trailing: 14.9; Median: 16.0) | RELATIVE P/E RATIO **0.86** | DIV'D YLD **4.1%** | **VALUE LINE**

TIMELINESS **3** Raised 7/28/06
SAFETY **2** Raised 12/16/05
TECHNICAL **3** Lowered 1/12/07
BETA .80 (1.00 = Market)

High:	31.0	30.5	32.3	33.0	26.3	25.8	24.5	25.5	27.6	30.0	33.1	33.1	
Low:	20.9	22.1	24.8	19.6	14.3	19.5	17.6	20.8	23.4	25.0	25.5	30.4	

Target Price Range 2010 | 2011 | 2012

LEGENDS
— 1.25 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 5/94
Options: Yes
Shaded area indicates recession



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+30%)	10%
Low	30	(-5%)	4%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	1	0	0
Options	0	0	1	0	0	0	0	0	0
to Sell	1	0	1	0	0	0	0	0	0

Institutional Decisions

	2Q2006	3Q2006	4Q2006
to Buy	102	90	115
to Sell	67	88	84
Hld's(000)	46293	48572	53926

Percent shares traded 12 8 4

% TOT. RETURN 2/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	24.4	12.0
3 yr.	36.8	41.4
5 yr.	78.9	88.2

Atmos Energy's history dates back to 1906 in the Texas Panhandle. Over the years, through various mergers, it became part of Pioneer Corporation, and, in 1981, Pioneer named its gas distribution division Energas. In 1983, Pioneer organized Energas as a separate subsidiary and distributed the outstanding shares of Energas to Pioneer shareholders. Energas changed its name to Atmos in 1988. Atmos acquired Trans Louisiana Gas in 1986, Western Kentucky Gas Utility in 1987, Greeley Gas in 1993, United Cities Gas in 1997, and others.

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
30.59	27.90	22.09	26.61	35.36	22.82	54.39	46.50	61.75	75.27	58.75	60.10	Revenues per sh A	72.90
2.85	3.38	2.62	3.01	3.03	3.39	3.23	2.91	3.90	4.26	4.15	4.25	"Cash Flow" per sh	4.65
1.34	1.84	.81	1.03	1.47	1.45	1.71	1.58	1.72	2.00	2.00	2.10	Earnings per sh A B	2.50
1.01	1.06	1.10	1.14	1.16	1.18	1.20	1.22	1.24	1.26	1.28	1.30	Div'ds Decl'd per sh C■	1.35
4.13	4.44	3.53	2.36	2.77	3.17	3.10	3.03	4.14	5.20	5.00	5.30	Cap'l Spending per sh	6.60
11.04	12.21	12.09	12.28	14.31	13.75	16.66	18.05	19.90	20.16	22.45	21.75	Book Value per sh	25.20
29.64	30.40	31.25	31.95	40.79	41.68	51.48	62.80	80.54	81.74	89.50	92.50	Common Shs Outst'g D	107.00
17.9	15.4	33.0	18.9	15.6	15.2	13.4	15.9	16.1	13.5	Bold figures are		Avg Ann'l P/E Ratio	14.0
1.03	.80	1.88	1.23	.80	.83	.76	.84	.86	.73	Value Line		Relative P/E Ratio	.95
4.2%	3.7%	4.1%	5.9%	5.1%	5.4%	5.2%	4.9%	4.5%	4.7%	estimates		Avg Ann'l Div'd Yield	3.9%
906.8	848.2	690.2	850.2	1442.3	950.8	2799.9	2920.0	4973.3	6152.4	5260	5560	Revenues ($mill) A	7800
39.2	55.3	25.0	32.2	56.1	59.7	79.5	86.2	135.8	162.3	180	195	Net Profit ($mill)	270
37.5%	36.5%	35.0%	36.1%	37.3%	37.1%	37.1%	37.4%	37.7%	37.6%	38.0%	38.0%	Income Tax Rate	39.0%
4.3%	6.5%	3.6%	3.8%	3.9%	6.3%	2.8%	3.0%	2.7%	2.6%	3.4%	3.5%	Net Profit Margin	3.5%
48.1%	51.8%	50.0%	48.1%	54.3%	53.9%	50.2%	43.2%	57.7%	57.0%	49.0%	50.0%	Long-Term Debt Ratio	51.0%
51.9%	48.2%	50.0%	51.9%	45.7%	46.1%	49.8%	56.8%	42.3%	43.0%	51.0%	50.0%	Common Equity Ratio	49.0%
630.2	769.7	755.1	755.7	1276.3	1243.7	1721.4	1994.8	3785.5	3828.5	3940	4020	Total Capital ($mill)	5500
849.1	917.9	965.8	982.3	1335.4	1300.3	1516.0	1722.5	3374.4	3629.2	3900	4200	Net Plant ($mill)	5300
8.3%	9.0%	5.1%	6.5%	5.9%	6.8%	6.2%	5.8%	5.3%	6.1%	6.0%	6.5%	Return on Total Cap'l	6.5%
12.0%	14.9%	6.6%	8.2%	9.6%	10.4%	9.3%	7.6%	8.5%	9.9%	9.0%	9.5%	Return on Shr. Equity	10.0%
12.0%	14.9%	6.6%	8.2%	9.6%	10.4%	9.3%	7.6%	8.5%	9.9%	9.0%	9.5%	Return on Com Equity	10.0%
3.9%	6.3%	NMF	NMF	2.1%	1.9%	2.8%	1.7%	2.3%	3.6%	3.5%	3.5%	Retained to Com Eq	4.5%
67%	58%	NMF	112%	79%	82%	70%	77%	73%	63%	64%	62%	All Div'ds to Net Prof	54%

CAPITAL STRUCTURE as of 12/31/06
Total Debt $2336.4 mill. **Due in 5 Yrs** $1450.0 mill.
LT Debt $1878.7 mill. **LT Interest** $135.0 mill.
(LT interest earned: 2.9x; total interest coverage: 2.8x)
Leases, Uncapitalized Annual rentals $16.0 mill.
Pfd Stock None
Pension Assets-9/06 $362.7 mill.
Oblig. $326.5 mill.
Common Stock 88,577,022 shs.
as of 1/31/07
MARKET CAP: $2.8 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2005	2006	12/31/06
Cash Assets	40.1	75.8	94.4
Other	1224.3	1041.7	1481.2
Current Assets	1264.4	1117.5	1575.6
Accts Payable	461.3	345.1	762.5
Debt Due	148.1	385.6	457.7
Other	503.4	388.5	407.3
Current Liab.	1112.8	1119.2	1627.5
Fix. Chg. Cov.	395%	408%	420%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	7.5%	17.0%	2.5%
"Cash Flow"	4.0%	5.0%	3.5%
Earnings	3.5%	10.0%	5.0%
Dividends	3.0%	2.0%	1.5%
Book Value	6.5%	8.5%	4.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2004	763.6	1117.5	546.1	492.8	2920.0
2005	1371.0	1687.8	909.9	1004.6	4973.3
2006	2283.8	2033.8	863.2	971.6	6152.4
2007	1602.6	1800	900	957.4	5260
2008	1390	1390	1390	1390	5560

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2004	.57	1.12	.09	d.11	1.58
2005	.79	1.11	.06	d.21	1.72
2006	.88	1.10	d.22	.25	2.00
2007	.97	1.15	d.03	d.09	2.00
2008	.95	1.15	.08	d.08	2.10

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.30	.30	.30	.305	1.21
2004	.305	.305	.305	.31	1.23
2005	.31	.31	.31	.315	1.25
2006	.315	.315	.315	.32	1.27
2007	.32				

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 2006 gas volumes: 272 MMcf. Breakdown: 53%, residential; 32%, commercial; 10%, industrial; and 5% other. 2006 depreciation rate 3.6%. Has around 4,600 employees. Officers and directors own approximately 1.9% of common stock (12/06 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 got off to a good start in fiscal 2007 (ends September 30th), driven by its non-utility businesses. Profits for the core natural gas marketing segment were boosted by higher unrealized storage mark-to-market gains, and underlying business trends were solid, as well. The pipeline operation reaped the benefits of the North Side Loop and other projects completed last year, plus rate adjustments arising from filings under the Gas Reliability Infrastructure Program (authorizing companies to earn a rate of return on their incremental annual capital investments).

But full-year earnings per share could be flat. The utility unit may be weighed down a bit by increased operating expenses, reflecting costs from a higher employee headcount. (Weather-normalization mechanisms applicable to around 90% of the customer base ought to help here, though.) Moreover, the fourth-quarter comparison ought to be quite difficult, given that our fiscal 2006 figure excludes an $0.18-a-share charge for the impairment of irrigation properties in the West Texas Division. Lastly, the recent public offering of 6.3 million common shares is estimated to dilute share net by around a nickel. (The $192 million in net proceeds from that transaction were used to reduce short-term debt.) Atmos is gradually strengthening its capital structure following the issuance of debt to finance the acquisition of TXU's gas business.

The company is awaiting the results of several rate cases. The largest one seeks $60 million in additional annual revenues in Texas, which would affect some 1.5 million customers. There is also a filing in Kentucky for a $10.4 million annual revenue increase (175,000 customers) and Missouri for $3.4 million in additional annual revenues (60,000 customers). Note that our presentation will account for the aforementioned amounts if the measures are approved.

These good-quality shares offer a decent yield, a well-covered payout, and moderate dividend growth. But performance wise, they are already trading within our 3- to 5-year Target Price Range, and are ranked only 3 (Average) for Timeliness.

Frederick L. Harris, III *March 16, 2007*

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. items: '97, d53¢; '99, d23¢; '00, 12¢; '03, d17¢; '06, d18¢. 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, adjusted for stock splits. (E) Qtrs may not add due to change in shrs outstanding. (F) ATO completed United Cities merger 7/97.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	35
Earnings Predictability	70

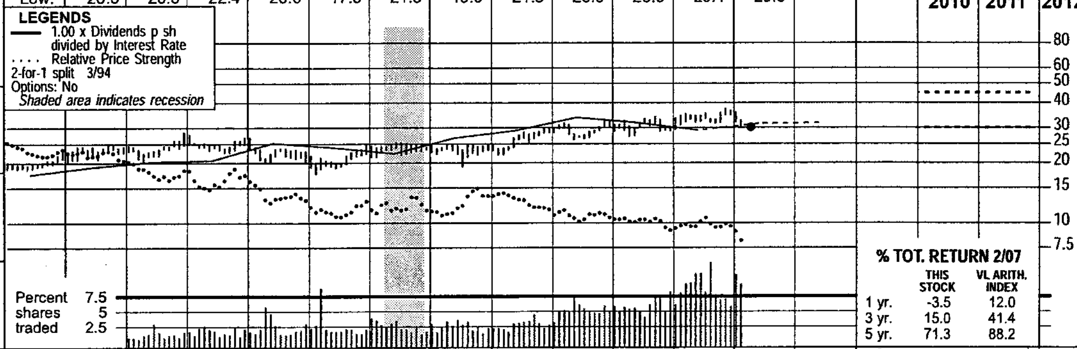
LACLEDE GROUP NYSE-LG

RECENT PRICE	30.18	P/E RATIO	15.9 (Trailing: 14.9; Median: 15.0)	RELATIVE P/E RATIO	0.88	DIV'D YLD	4.9%	VALUE LINE

TIMELINESS 5 Lowered 1/19/07
SAFETY 2 Raised 6/20/03
TECHNICAL 3 Raised 2/23/07
BETA .85 (1.00 = Market)

High:	24.9	28.6	27.9	27.0	24.8	25.5	25.0	30.0	32.5	34.3	37.5	36.0
Low:	20.0	20.3	22.4	20.0	17.5	21.3	19.0	21.8	26.0	26.9	29.1	29.6

Target Price Range 2010 | 2011 | 2012



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+50%)	14%
Low	30	(Nil)	5%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	1	0
Options	0	1	0	0	0	1	0	4	1
to Sell	0	1	0	0	0	1	0	4	1

Institutional Decisions

	2Q2006	3Q2006	4Q2006
to Buy	60	54	64
to Sell	47	52	38
Hld's(000)	10115	9986	10381

% TOT. RETURN 2/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	-3.5	12.0
3 yr.	15.0	41.4
5 yr.	71.3	88.2

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
28.10	26.83	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	**82.80**	**84.55**	Revenues per sh	**110.00**
2.37	2.32	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	**3.60**	**3.95**	"Cash Flow" per sh	**5.00**
1.28	1.17	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	**1.90**	**2.00**	Earnings per sh A B	**2.35**
1.20	1.20	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**	Div'ds Decl'd per sh C■	**1.60**
2.46	2.87	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	**2.95**	**3.05**	Cap'l Spending per sh	**3.80**
11.83	11.79	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	**20.70**	**20.90**	Book Value per sh D	**24.50**
15.59	15.59	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	**21.50**	**22.00**	Common Shs Outst'g E	**25.00**
12.5	15.8	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	*Bold figures are*	*Value Line estimates*	Avg Ann'l P/E Ratio	**16.0**
.80	.96	.80	1.08	1.04	.75	.72	.81	.90	.97	.74	1.09	.78	.83	.86	.73			Relative P/E Ratio	**1.05**
7.5%	6.5%	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%			Avg Ann'l Div'd Yield	**4.3%%**

CAPITAL STRUCTURE as of 12/31/06
Total Debt $652.8 mill. **Due in 5 Yrs** $275.0 mill.
LT Debt $355.5 mill. **LT Interest** $20.0 mill.
(Total interest coverage: 3.1x)

Leases, Uncapitalized Annual rentals $.9 mill.
Pension Assets-9/06 $246.1 mill. **Oblig.** $282.1 mill.
Pfd Stock $.8 mill. **Pfd Div'd** $.05 mill.
Common Stock 21,566,851 shs. as of 1/26/07

MARKET CAP: $650 million (Small Cap)

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
602.8	547.2	491.6	566.1	1002.1	755.2	1050.3	1250.3	1597.0	1997.6	**1780**	**1860**	Revenues ($mill) A	**2750**
32.5	27.9	26.9	26.0	30.5	22.4	34.6	36.1	40.1	50.5	**41.0**	**44.0**	Net Profit ($mill)	**60.0**
36.1%	35.6%	35.5%	35.2%	32.7%	35.4%	35.0%	34.8%	34.1%	32.5%	**35.5%**	**35.5%**	Income Tax Rate	**35.5%**
5.4%	5.1%	5.5%	4.6%	3.0%	3.0%	3.3%	2.9%	2.5%	2.5%	**2.3%**	**2.4%**	Net Profit Margin	**2.2%**
38.0%	40.9%	41.8%	45.2%	49.5%	47.5%	50.4%	51.6%	48.1%	49.5%	**47.0%**	**48.0%**	Long-Term Debt Ratio	**49.0%**
61.6%	58.6%	57.8%	54.5%	50.2%	52.3%	49.4%	48.3%	51.8%	50.4%	**53.0%**	**52.0%**	Common Equity Ratio	**51.0%**
406.8	438.0	488.6	519.2	574.1	546.6	605.0	737.4	707.9	798.9	**840**	**885**	Total Capital ($mill)	**1200**
467.6	490.6	519.4	575.4	602.5	594.4	621.2	646.9	679.5	763.8	**815**	**865**	Net Plant ($mill)	**1150**
9.7%	8.1%	7.1%	6.7%	6.9%	6.0%	7.4%	6.6%	7.6%	8.4%	**6.5%**	**6.5%**	Return on Total Cap'l	**6.5%**
12.9%	10.8%	9.5%	9.1%	10.5%	7.8%	11.5%	10.1%	10.9%	12.5%	**9.0%**	**9.5%**	Return on Shr. Equity	**10.0%**
12.9%	10.8%	9.5%	9.1%	10.5%	7.8%	11.6%	10.1%	10.9%	12.5%	**9.0%**	**9.5%**	Return on Com Equity	**10.0%**
3.9%	1.8%	1.0%	.2%	1.8%	NMF	3.1%	2.7%	3.1%	5.1%	**2.0%**	**2.5%**	Retained to Com Eq	**3.5%**
70%	83%	89%	98%	83%	113%	74%	73%	72%	59%	**76%**	**75%**	All Div'ds to Net Prof	**67%**

CURRENT POSITION ($MILL.)	2005	2006	12/31/06
Cash Assets	6.0	50.8	51.9
Other	418.1	409.0	522.3
Current Assets	424.1	459.8	574.2
Accts Payable	138.4	103.3	150.0
Debt Due	110.7	207.5	297.3
Other	116.5	120.1	115.0
Current Liab.	365.6	430.9	562.3
Fix. Chg. Cov.	293%	285%	290%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	10.0%	16.0%	5.5%
"Cash Flow"	1.0%	3.0%	7.0%
Earnings	3.0%	6.5%	2.0%
Dividends	1.0%	.5%	2.5%
Book Value	3.0%	3.5%	5.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.)A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2004	332.6	475.0	245.1	197.6	1250.3
2005	442.5	576.5	311.3	266.7	1597.0
2006	689.2	708.8	330.6	269.0	1997.6
2007	539.6	**650**	**340**	**250.4**	**1780**
2008	**465**	**465**	**465**	**465**	**1860**

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2004	.87	1.12	.19	d.28	1.82
2005	.79	1.06	.29	d.24	1.90
2006	1.23	1.05	.13	d.04	2.37
2007	.89	**.99**	**.15**	**d.13**	**1.90**
2008	**1.03**	**1.07**	**.20**	**d.30**	**2.00**

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.335	.335	.335	.335	1.34
2004	.335	.34	.34	.34	1.36
2005	.34	.345	.345	.345	1.38
2006	.345	.355	.355	.355	1.41
2007	.365				

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 631,000 customers. Purchased SM&P for approximately $43 million (1/02). Therms sold and transported in fiscal 2006: 1.02 mill. Revenue mix for regulated operations: residential, 60%; commercial and industrial, 25%; transportation, 1%; other, 14%. Has around 3,880 employees. Officers and directors own approximately 7.0% of common shares (1/07 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.lacledegas.com.

Laclede Group's share earnings took a dive in the first quarter of fiscal 2007, which ends September 30th. But we were not surprised because of the difficult comparison. For one thing, the performance of Laclede Energy Resources was not as strong as the prior-year period, when margins were substantially higher as the result of supply/demand imbalances arising from the 2005 Gulf Coast hurricanes (one of the busiest storm seasons on record). Furthermore, Laclede Gas Company, accounting for the biggest portion of revenues, suffered from heightened operation and maintenance expenses and decreased income from entities outside the service territory. Lastly, SM&P Utility Resources posted a loss primarily because of costs incurred from expansionary initiatives, although its longer-term performance should benefit nicely. At this point in time, it appears the company's bottom line may plummet roughly 20%, to $1.90 a share, in fiscal 2007. Share net may perk up a bit next year, assuming that the comparison will be easier.

The company's prospects for the coming three to five years look unexceptional. Annual growth in the customer base for the natural gas distribution unit has been sluggish for some time. That's because the market in eastern Missouri is in a mature phase. As such, any substantial gains will have to be derived from the unregulated businesses or from major acquisitions, scenarios we don't see happening anytime soon. Consequently, annual earnings-per-share increases may only be in the mid-single-digit range out to 2010-2012.

Income-oriented accounts should find the dividend yield of interest. (Note that the quarterly distribution just rose by 3%.) Future hikes in the payout will likely continue to be moderate, given that the regulated subsidiary operates in a slow-growth environment.

These shares have lost some ground in recent months, attributable largely, it seems, to the company's substantially lower results in the first quarter. The diminished price and earnings momentum has caused the Timeliness rank to be 5 (Lowest). Total-return potential over the 3- to 5-year horizon is limited, as well.

Frederick L. Harris, III *March 16, 2007*

(A) Fiscal year ends Sept. 30th.
(B) Based on average shares outstanding thru. '97, then diluted. Excludes nonrecurring loss: '06, 7¢. 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 '06: $256.8 mill., $12.02/sh.
(E) In millions. Adjusted for stock split.
(F) Qtly. egs. may not sum due to change in shares outstanding.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	65

NEW JERSEY RES. NYSE-NJR

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
49.49	17.1	(Trailing: 18.0 Median: 15.0)	0.94	3.1%	VALUE LINE

High:	19.9	28.0	26.8	27.4	29.8	32.5	33.6	39.5	44.6	49.3	53.2	51.1		
Low:	17.8	18.8	21.0	22.4	24.1	24.8	24.3	30.0	36.5	40.7	41.5	46.3		

Target Price Range 2010 | 2011 | 2012

TIMELINESS **5** Lowered 12/15/06
SAFETY **1** Raised 9/15/06
TECHNICAL **4** Lowered 3/2/07
BETA .80 (1.00 = Market)

2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(Nil)	4%
Low	40	(-20%)	-1%

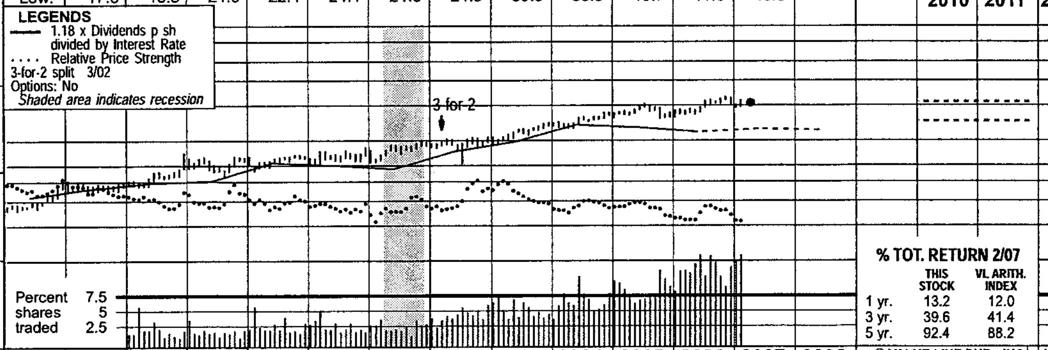
Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	2	0	0	4	0	0	1	1
to Sell	0	2	0	0	4	0	0	1	1

Institutional Decisions

	2Q2006	3Q2006	4Q2006
to Buy	73	61	68
to Sell	60	69	69
Hld's(000)	16255	16616	15657

LEGENDS
— 1.18 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 3/02
Options: No
Shaded area indicates recession



% TOT. RETURN 2/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	13.2	12.0
3 yr.	39.6	41.4
5 yr.	92.4	88.2

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
15.99	16.88	18.02	19.22	17.03	20.22	25.97	26.59	33.98	44.13	76.82	66.17	93.43	91.33	114.29	119.44	*121.45*	*123.00*	Revenues per sh A	*128.50*
1.58	1.95	2.14	2.31	2.13	2.22	2.45	2.60	2.79	2.99	3.18	3.21	3.58	3.75	3.92	4.10	*4.25*	*4.30*	"Cash Flow" per sh	*4.70*
.55	1.09	1.15	1.26	1.29	1.37	1.48	1.55	1.66	1.79	1.95	2.09	2.38	2.55	2.65	2.80	*2.90*	*3.00*	Earnings per sh B	*3.15*
1.00	1.01	1.01	1.01	1.01	1.03	1.07	1.09	1.12	1.15	1.17	1.20	1.24	1.30	1.36	1.44	*1.52*	*1.56*	Div'ds Decl'd per sh C■	*1.68*
2.91	1.99	2.31	2.10	1.77	1.78	1.72	1.60	1.81	1.85	1.66	1.53	1.71	2.17	1.92	1.92	*2.50*	*2.10*	Cap'l Spending per sh	*2.05*
8.57	9.44	9.81	9.64	9.70	10.10	10.38	10.88	11.35	12.43	13.20	13.06	15.38	16.87	15.90	22.50	*24.10*	*25.65*	Book Value per sh D	*0.50*
20.95	24.43	25.23	25.95	26.69	27.13	26.82	26.72	26.61	26.39	26.66	27.67	27.23	27.74	27.55	27.63	*28.00*	*28.50*	Common Shs Outst'g E	*29.50*
22.3	12.4	15.1	13.0	11.7	13.6	13.5	15.3	15.2	14.7	14.2	14.7	14.0	15.3	16.8	16.1	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*14.0*
1.42	.75	.89	.85	.78	.85	.78	.80	.87	.96	.73	.80	.80	.81	.89	.86	*estimates*		Relative P/E Ratio	*.95*
8.1%	7.5%	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%			Avg Ann'l Div'd Yield	*4.5%*

CAPITAL STRUCTURE as of 12/31/06
Total Debt $626.4 mill. Due in 5 Yrs $300.0 mill.
LT Debt $336.7 mill. LT Interest $25.0 mill.
Incl. $7.4 mill. capitalized leases.
(LT interest earned: 6.0x; total interest coverage: 6.0x)
Pension Assets-9/06 $95.8 mill. Oblig. $103.7 mill.
Pfd Stock None
Common Stock 27,833,620 shs. as of 2/6/07
MARKET CAP: $1.4 billion (Mid Cap)

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008		10-12
696.5	710.3	904.3	1164.5	2048.4	1830.8	2544.4	2533.6	3148.3	3299.6	*3400*	*3500*	Revenues ($mill) A	*3800*
41.5	43.3	44.9	47.9	52.3	56.8	65.4	71.6	74.4	78.5	*84.0*	*87.0*	Net Profit ($mill)	*100*
33.3%	30.4%	36.2%	37.8%	38.0%	38.7%	39.4%	39.1%	39.1%	38.9%	*39.0%*	*39.0%*	Income Tax Rate	*40.0%*
6.0%	6.1%	5.0%	4.1%	2.6%	3.1%	2.6%	2.8%	2.4%	2.4%	*2.5%*	*2.5%*	Net Profit Margin	*2.5%*
49.3%	51.2%	48.7%	47.0%	50.1%	50.6%	38.1%	40.3%	42.0%	34.8%	*34.5%*	*33.5%*	Long-Term Debt Ratio	*31.5%*
47.1%	45.6%	51.2%	52.9%	49.9%	49.4%	61.9%	59.7%	58.0%	65.2%	*65.5%*	*66.5%*	Common Equity Ratio	*68.5%*
590.6	638.2	590.4	620.1	706.2	732.4	676.8	783.8	755.3	954.0	*1025*	*1095*	Total Capital ($mill)	*1310*
659.4	680.0	705.4	730.6	743.9	756.4	852.6	880.4	905.1	934.9	*940*	*970*	Net Plant ($mill)	*1100*
8.6%	8.1%	9.0%	9.0%	8.5%	8.7%	10.7%	10.1%	11.2%	9.6%	*9.5%*	*9.5%*	Return on Total Cap'l	*9.0%*
13.9%	13.9%	14.8%	14.6%	14.8%	15.7%	15.6%	15.3%	17.0%	12.6%	*12.5%*	*12.0%*	Return on Shr. Equity	*11.0%*
14.3%	14.4%	14.8%	14.6%	14.9%	15.7%	15.6%	15.3%	17.0%	12.6%	*12.5%*	*12.0%*	Return on Com Equity	*11.0%*
4.0%	4.4%	5.0%	5.4%	6.1%	6.9%	7.7%	7.8%	8.5%	6.3%	*6.5%*	*6.0%*	Retained to Com Eq	*6.0%*
73%	71%	67%	63%	59%	56%	51%	49%	50%	50%	*49%*	*50%*	All Div'ds to Net Prof	*50%*

CURRENT POSITION ($MILL.)	2004	2005	12/31/06
Cash Assets	5.0	25.0	10.1
Other	681.0	927.8	1078.8
Current Assets	686.0	952.8	1088.9
Accts Payable	42.9	54.7	45.5
Debt Due	287.4	177.4	289.7
Other	357.4	744.2	687.8
Current Liab.	687.7	976.3	1023.0
Fix. Chg. Cov.	826%	660%	450%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	19.0%	16.0%	*2.5%*
"Cash Flow"	6.0%	5.5%	*3.0%*
Earnings	7.5%	8.0%	*2.5%*
Dividends	3.0%	3.5%	*3.0%*
Book Value	6.5%	8.5%	*8.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2004	643.0	1037	438.5	414.4	2533.6
2005	854.0	1065	544.3	684.9	3148.3
2006	1164	1064	536.1	534.5	3299.6
2007	741.5	*1285*	*688*	*685.5*	*3400*
2008	*1195*	*1090*	*585*	*630*	*3500*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2004	.87	1.82	.06	d.20	2.55
2005	.91	1.84	.07	d.17	2.65
2006	1.23	2.14	d.14	d.43	2.80
2007	1.01	*2.20*	*d.05*	*d.26*	*2.90*
2008	*1.26*	*2.03*	*d.04*	*d.25*	*3.00*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.31	.31	.31	.31	1.24
2004	.325	.325	.325	.325	1.30
2005	.34	.34	.34	.34	1.36
2006	.36	.36	.36	.36	1.44
2007	.38				

BUSINESS: New Jersey Resources Corp. is a holding company providing retail and Wholesale energy svcs. to customers in New Jersey, in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas has about 471,000 customers at 9/30/06 in Monmouth and Ocean Counties, and other N.J. Counties. Fiscal 2006 volume: 102.8 bill. cu. ft. (56% firm, 7% interruptible industrial and electric utility, 37% off-system and capacity release). N.J. Natural Energy subsid. provides unregulated retail and wholesale natural gas and related energy svcs. 2006 dep. rate: 2.7%. Has 766 empls. Off./dir. own about 2% of common (12/06 Proxy). Chrmn. and CEO: Laurence M. Downes. Inc.: N.J. Addr.: 1415 Wyckoff Road, Wall, NJ 07719. Tel.: 732-938-1480. Web: www.njliving.com.

New Jersey Resources began fiscal 2007 (ends September 30th) on a weak note. First-quarter profits increased 7% in the natural-gas-distribution segment (NJNG), but dropped 50% in the energy-services unit (NJRES) and dropped 40% in the retail business. Revenues declined in all three segments due to lower customer usage at NJNG and lower sales at NJRES, which was the result of lower natural gas prices and higher pipeline transportation costs due to infrastructure damage from regional hurricanes.

Even so, we look for a modest increase for share earnings, both this year and next. NJNG added about 10,000 new customers per year in 2005 and 2006 through new housing agreements and customer conversions from other fuels. We anticipate this annual new customer growth rate trend will continue. According to the company, the customer growth rate should increase natural gas sales volume by 1.5 billion cubic feet annually over the next two years and add $40 million in new utility revenues per year. Natural gas is being used in 95% of new construction due to its efficiency and reliability.

In late 2006, the Conservation Incentive Program (CIP) went into effect. NJNG's earnings and cash flows will be affected by this tariff. The CIP decouples the link between customer usage and the utility's profits. This feature will allow customers to conserve energy while addressing the company's utility profit margin variations due to weather and customer usage.

The wholesale energy services provider is on track to leverage its transportation and storage capacity to manage sales to its energy company customers. The portfolio maintains physical asset contracts across the North American continent and its varied weather areas. The portfolio's value increases when there are natural gas price differences in these different regions. In maintaining and trading this portfolio, we think that NJRES's customers will receive better pricing on these commodities.

We think this company will be able to register steady growth. Even so, the stock is untimely and is trading at the top of our 3- to 5- year price target.

Enzo DiCostanzo *March 16, 2007*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. 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 2006: $323.0 million, $11.70/share.
(E) In millions, adjusted for split.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	85
Earnings Predictability	95

NICOR, INC. NYSE-GAS

RECENT PRICE	45.33	P/E RATIO	15.4 (Trailing: 15.0 Median: 14.0)	RELATIVE P/E RATIO	0.85	DIV'D YLD	4.1%	VALUE LINE

TIMELINESS 3 Lowered 12/29/06

SAFETY 3 Lowered 6/17/05

TECHNICAL 4 Lowered 3/9/07

BETA 1.30 (1.00 = Market)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
High:	37.1	42.9	44.4	42.9	43.9	42.4	49.0	39.3	39.7	43.0	49.9	48.3
Low:	25.4	30.0	37.1	31.2	29.4	34.0	17.3	23.7	32.0	35.5	38.7	44.5

Target Price Range 2010 | 2011 | 2012

2010-12 PROJECTIONS

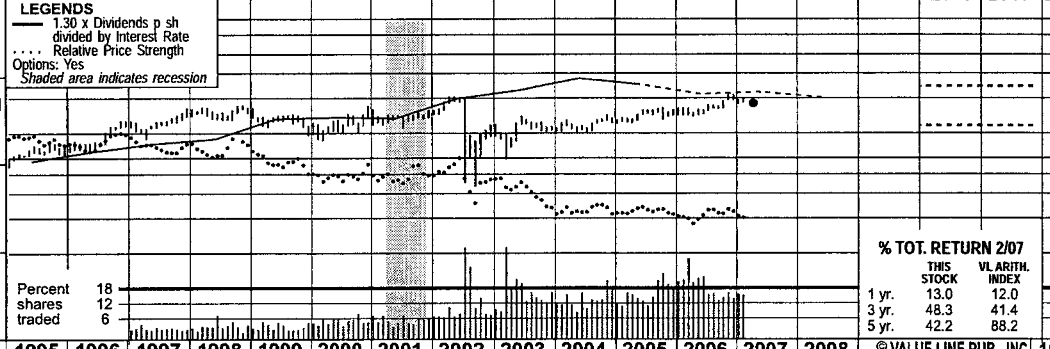
	Price	Gain	Ann'l Total Return
High	55	(+20%)	9%
Low	35	(-25%)	-1%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	1	0	0	1	1	3	0	1	0
Options	0	0	0	0	2	0	0	2	0
to Sell	0	0	0	0	0	0	0	2	0

Institutional Decisions

	2Q2006	3Q2006	4Q2006
to Buy	98	83	124
to Sell	110	118	80
Hld's(000)	32450	32534	32939



% TOT. RETURN 2/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	13.0	12.0
3 yr.	48.3	41.4
5 yr.	42.2	88.2

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
26.46	28.90	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	66.20	**63.90**	**64.90**	Revenues per sh	**71.00**
3.92	4.14	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	6.85	**6.05**	**6.20**	"Cash Flow" per sh	**6.20**
1.86	1.92	1.97	2.07	1.96	2.42	2.55	2.31	2.57	2.94	3.01	2.88	2.11	2.22	2.29	3.03	**2.70**	**2.75**	Earnings per sh A	**2.90**
1.12	1.18	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	**1.90**	**1.90**	Div'ds Decl'd per sh B ■	**2.00**
3.65	3.12	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	**4.50**	**4.50**	**4.45**	Cap'l Spending per sh	**4.45**
12.28	12.76	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	**19.35**	**20.50**	**21.45**	Book Value per sh	**24.10**
57.30	55.77	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	44.70	**44.60**	**44.70**	Common Shs Outst'g C	**45.00**
11.5	11.6	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	13.3	***Bold figures are***	***Value Line***	Avg Ann'l P/E Ratio	**16.0**
.73	.70	.83	.82	.88	.78	.82	.92	.83	.77	.66	.72	.90	.84	.92	.73	***estimates***		Relative P/E Ratio	**1.05**
5.2%	5.3%	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%	4.7%			Avg Ann'l Div'd Yield	**4.5%**

CAPITAL STRUCTURE as of 12/31/06
Total Debt $848.1 mill. **Due in 5 Yrs** $215.0 mill.
LT Debt $498.1 mill. **LT Interest** $20.0 mill.
(Total interest coverage: 4.0x)

Pension Assets-12/06 $432.3 mill. **Oblig.** $271.3 mill.

Pfd Stock $.6 mill. **Pfd Div'd** $2.2 mill.
(11,681 shares of 4.48% mandatorily redeemable preferred stock)
Common Stock 44,911,933 shares
as of 2/16/07
MARKET CAP: $2.0 billion (Mid Cap)

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008		10-12
1992.6	1465.1	1615.2	2298.1	2544.1	1897.4	2662.7	2739.7	3257.8	2960.0	**2850**	**2900**	Revenues ($mill)	**3200**
124.3	111.1	121.9	136.4	136.3	128.0	93.1	98.1	101.1	128.3	**120**	**122**	Net Profit ($mill)	**150**
35.0%	34.4%	34.7%	34.8%	33.5%	31.0%	35.2%	31.8%	28.3%	**27.0%**	**30.0%**	**31.0%**	Income Tax Rate	**33.0%**
6.2%	7.6%	7.5%	5.9%	5.4%	6.7%	3.5%	3.6%	3.0%	4.3%	**4.2%**	**4.2%**	Net Profit Margin	**4.0%**
42.3%	42.1%	35.5%	32.7%	37.8%	35.1%	39.6%	39.8%	37.4%	**34.0%**	**33.0%**	**32.0%**	Long-Term Debt Ratio	**29.0%**
57.2%	57.4%	64.0%	66.7%	61.7%	64.5%	60.3%	60.1%	62.5%	**66.0%**	**67.0%**	**68.0%**	Common Equity Ratio	**71.0%**
1300.6	1322.6	1230.1	1061.2	1180.1	1128.9	1251.5	1246.0	1297.7	**1310**	**1365**	**1400**	Total Capital ($mill)	**1550**
1735.8	1731.8	1735.2	1729.6	1768.6	1796.8	2484.2	2549.8	2659.1	**2760**	**2850**	**2950**	Net Plant ($mill)	**3250**
11.1%	9.9%	10.9%	13.7%	12.3%	12.2%	8.3%	8.8%	9.4%	**10.9%**	**10.5%**	**10.5%**	Return on Total Cap'l	**10.0%**
16.6%	14.5%	15.4%	19.1%	18.6%	17.5%	12.3%	13.1%	12.5%	**14.0%**	**13.0%**	**13.0%**	Return on Shr. Equity	**12.0%**
16.7%	14.6%	15.4%	19.2%	18.7%	17.5%	12.3%	13.1%	12.5%	**14.0%**	**13.0%**	**13.0%**	Return on Com Equity	**12.0%**
7.6%	5.4%	6.2%	8.5%	7.9%	6.5%	1.5%	2.1%	2.3%	**4.5%**	**4.0%**	**4.0%**	Retained to Com Eq	**3.5%**
55%	63%	60%	56%	58%	63%	88%	84%	81%	68%	**71%**	**69%**	All Div'ds to Net Prof	**69%**

CURRENT POSITION ($MILL.)	2004	2005	12/31/06
Cash Assets	83.2	126.9	67.6
Other	937.7	1218.8	843.1
Current Assets	1020.9	1345.7	910.7
Accts Payable	502.9	658.2	564.5
Debt Due	490.2	636.0	350.0
Other	178.3	328.7	227.9
Current Liab.	1171.4	1622.9	1142.4
Fix. Chg. Cov.	428%	367%	NMF

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '03-'05 to '10-'12
Revenues	8.0%	11.5%	*1.0%*
"Cash Flow"	4.0%	0.5%	*1.0%*
Earnings	1.0%	-3.5%	*4.0%*
Dividends	4.0%	3.5%	*1.0%*
Book Value	3.0%	1.5%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	1115.7	429.5	299.9	894.6	2739.7
2005	1179.9	484.4	236.0	1357.5	3257.8
2006	1319.4	451.3	351.1	838.2	2960.0
2007	***1200***	***400***	***250***	***1000***	***2850***
2008	***1100***	***450***	***300***	***1050***	***2900***

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.96	.44	d.26	1.08	2.22
2005	.98	.35	d.06	1.02	2.29
2006	.94	.41	.39	1.29	3.03
2007	***1.00***	***.37***	***.28***	***1.05***	***2.70***
2008	***1.02***	***.35***	***.30***	***1.08***	***2.75***

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.46	.465	.465	.465	1.86
2004	.465	.465	.465	.465	1.86
2005	.465	.465	.465	.465	1.86
2006	.465	.465	.465	.465	1.86
2007	.465				

BUSINESS: Nicor Inc. is a holding company with gas distribution as its primary business. Serves over 2.1 million customers in northern and western Illinois. 2006 gas delivered: 438.7 Bcf, incl. 206.0 Bcf from transportation. 2006 gas sales (232.7 bcf): residential, 80%; commercial, 18%; industrial, 2%. Principal supplying pipelines: Natural Gas Pipeline, Horizon Pipeline, and TGPC. Current operations include Tropical Shipping subsidiary and several energy related ventures. Divested inland barging, 7/86; contract drilling, 9/86; oil and gas E&P, 6/93. Has about 3,900 employees Off./dir. own about 2.8% of common stock. (3/06 proxy). Chairman and CEO: Russ Strobel. Inc.: Illinois Address: 1844 Ferry Road, Naperville, Illinois 60563. Telephone: 630-305-9500. Internet: www.nicor.com.

Nicor finished 2006 with a strong performance on its bottom line. Despite unseasonably warm weather, the company reported about a 32% year-over-year increase in share net in 2006. The improvement was helped by a turnaround in wholesale natural gas marketing. Nicor's weather-related utility bill management program particularly had a strong finish, which also provided a boost to earnings. However, revenues were dragged down by a subpar performance in the gas distribution business, which was attributed to the warm winter.

The recent growth will likely slow for the remainder of 2007. Our current estimates call for sales and earnings to drop about 4% and 12%, respectively. Results are due to moderate as Nicor has derived much of the benefit from its moves, while the cost-cutting initiative will probably no longer fuel share-net gains.

Base rates will likely remain unchanged in the near term. The company does not have any rate cases currently awaiting approval by the Illinois Commerce Commission. Moreover, Nicor seems to have adjusted to conditions with rates at current levels for the near term.

We have introduced our 2008 estimates. We believe the company will begin to rebound from the potential slowdown in 2007 with slight increases in 2008. Therefore, we are estimating roughly 2% growth in both revenues and earnings for next year.

Nicor offers a healthy dividend yield. The company currently offers a yield of 4.1%, which is above the industry average. Additionally, Nicor has paid a dividend for 212 consecutive quarters, which exhibits its commitment to the payout.

This issue is an average selection for the coming six- to 12 months. Moreover, these shares are currently trading within our 3- to 5-year Target Price Range, which limits the appeal of this stock for long-term investors. Nicor also has some exposure to the volatile natural gas commodity markets, which have the potential to weigh on the company's results in the coming years. All told, investors may want to look elsewhere until these shares develop more-attractive prospects.

Richard Gallagher *March 16, 2007*

(A) Based on primary earnings thru. '96, then diluted. Excl. nonrecurring gains/(loss): '89, 7¢; '97, 6¢; '98, 11¢; '99, 5¢; '00, ($1.96); '01, 16¢; '03, (27¢); '04, (52¢); '05, 80¢; '06, (17¢). Excl. items from discontinued ops.: '93, 4¢; '96, 30¢. Quarterly earnings may not sum to total due to rounding. Next egs. report due early May. (B) Dividends historically paid early February, May, August, November. ■ Dividend reinvestment plan available. (C) In millions.

Company's Financial Strength	A
Stock's Price Stability	50
Price Growth Persistence	40
Earnings Predictability	80

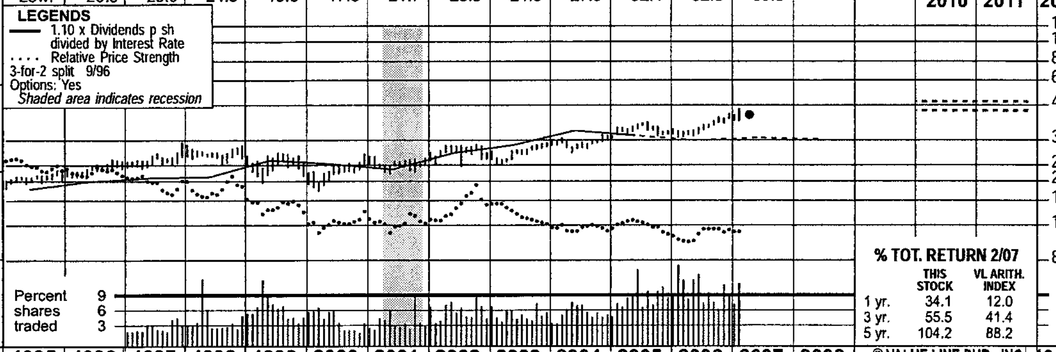
N.W. NAT'L GAS NYSE-NWN

RECENT PRICE **43.00** | P/E RATIO **18.1** (Trailing: 18.8; Median: 15.0) | RELATIVE P/E RATIO **1.00** | DIV'D YLD **3.4%** | **VALUE LINE**

TIMELINESS **3** Raised 2/23/07
SAFETY **1** Raised 3/18/05
TECHNICAL **3** Lowered 1/12/07
BETA .75 (1.00 = Market)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
High:	25.9	31.4	30.8	27.9	27.5	26.8	30.7	31.3	34.1	39.6	43.7	46.3
Low:	20.8	23.0	24.3	19.5	17.8	21.7	23.5	24.0	27.5	32.4	32.8	39.8

Target Price Range 2010 | 2011 | 2012



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+15%)	7%
Low	45	(+5%)	5%

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	1	2
to Sell	0	1	0	0	0	1	0	1	2

Institutional Decisions

	2Q2006	3Q2006	4Q2006
to Buy	77	66	75
to Sell	59	54	60
Hld's(000)	14328	14332	14381

% TOT. RETURN 2/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	34.1	12.0
3 yr.	55.5	41.4
5 yr.	104.2	88.2

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
16.74	14.10	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	37.11	*36.35*	*38.30*	Revenues per sh	*44.85*
2.57	3.25	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	4.65	*4.80*	*5.15*	"Cash Flow" per sh	*5.95*
.67	.74	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	2.29	*2.40*	*2.55*	Earnings per sh A	*2.95*
1.13	1.15	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*	*1.50*	Div'ds Decl'd per sh B ■	*1.80*
3.58	3.73	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	3.55	*3.85*	*3.85*	Cap'l Spending per sh	*3.85*
12.23	12.41	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	21.96	*22.70*	*23.65*	Book Value per sh	*25.85*
17.68	19.46	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	27.28	*27.50*	*27.50*	Common Shs Outst'g C	*29.00*
28.1	27.0	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	16.3	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
1.79	1.64	.76	.85	.86	.73	.83	1.39	.83	.81	.66	.94	.90	.88	.91	.89	*Value Line*		Relative P/E Ratio	*1.05*
5.9%	5.7%	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%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*
						361.8	416.7	455.8	532.1	650.3	641.4	611.3	707.6	910.5	1013.2	*1000*	*1050*	Revenues ($mill)	*1300*
						43.1	27.3	44.9	47.8	50.2	43.8	46.0	50.6	58.1	63.4	*66.0*	*70.0*	Net Profit ($mill)	*86.0*
						32.9%	31.0%	35.4%	35.9%	35.4%	34.9%	33.7%	34.4%	36.0%	36.3%	*36.5%*	*36.5%*	Income Tax Rate	*36.5%*
						11.9%	6.6%	9.9%	9.0%	7.7%	6.8%	7.5%	7.1%	6.4%	6.3%	*6.6%*	*6.7%*	Net Profit Margin	*6.6%*
						46.0%	45.0%	46.0%	45.1%	43.0%	47.6%	49.7%	46.0%	47.0%	46.4%	*47.0%*	*47.0%*	Long-Term Debt Ratio	*48.0%*
						49.0%	50.6%	49.9%	50.9%	53.2%	51.5%	50.3%	54.0%	53.0%	53.6%	*53.0%*	*53.0%*	Common Equity Ratio	*52.0%*
						748.0	815.6	861.5	887.8	880.5	937.3	1006.6	1052.5	1108.4	1116.5	*1150*	*1175*	Total Capital ($mill)	*1350*
						827.5	894.7	895.9	934.0	965.0	995.6	1205.9	1318.4	1373.4	1425.1	*1475*	*1525*	Net Plant ($mill)	*1600*
						7.4%	5.0%	6.8%	6.7%	6.9%	5.9%	5.7%	5.9%	6.5%	7.5%	*7.0%*	*7.0%*	Return on Total Cap'l	*7.0%*
						10.7%	6.1%	9.7%	9.8%	10.0%	8.9%	9.1%	8.9%	9.9%	10.6%	*10.5%*	*11.0%*	Return on Shr. Equity	*12.0%*
						11.0%	6.0%	9.9%	10.0%	10.2%	8.5%	9.0%	8.9%	9.9%	10.6%	*10.5%*	*11.0%*	Return on Com Equity	*12.0%*
						3.6%	NMF	2.8%	3.1%	3.5%	1.9%	2.6%	2.7%	3.7%	4.2%	*4.0%*	*4.5%*	Retained to Com Eq	*5.0%*
						70%	118%	74%	70%	67%	79%	72%	69%	63%	61%	*60%*	*59%*	All Div'ds to Net Prof	*60%*

CAPITAL STRUCTURE as of 12/31/06
Total Debt $646.6 mill. **Due in 5 Yrs** $251.7 mill.
LT Debt $517.0 mill. **LT Interest** $31.0 mill.

(Total interest coverage: 3.4x)

Pension Assets-12/05 $236 mill.
Oblig. $269 mill.
Pfd Stock None

Common Stock 27,256,341 shs.
as of 2/23/07
MARKET CAP $1.2 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2004	2005	12/31/06
Cash Assets	5.2	7.1	5.8
Other	231.9	316.6	303.0
Current Assets	237.1	323.7	308.8
Accts Payable	102.5	135.3	113.6
Debt Due	117.5	134.7	129.6
Other	47.3	56.6	98.3
Current Liab.	267.3	326.6	341.5
Fx. Chg. Cov.	316%	340%	349%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '03-'05 to '10-'12
Revenues	4.5%	8.0%	*11.0%*
"Cash Flow"	1.5%	2.5%	*4.5%*
Earnings	1.5%	5.0%	*7.0%*
Dividends	1.0%	1.0%	*4.0%*
Book Value	4.0%	3.5%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	254.5	109.7	81.4	262.0	707.6
2005	308.7	153.7	106.7	341.4	910.5
2006	390.4	171.0	114.9	336.9	1013.2
2007	*380*	*170*	*110*	*340*	*1000*
2008	*390*	*180*	*120*	*360*	*1050*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	1.24	d.03	d.30	.95	1.86
2005	1.44	.04	d.31	.94	2.11
2006	1.48	.07	d.35	1.09	2.29
2007	*1.56*	*.06*	*d.33*	*1.11*	*2.40*
2008	*1.64*	*.07*	*d.33*	*1.17*	*2.55*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.315	.315	.315	.325	1.27
2004	.325	.325	.325	.325	1.30
2005	.325	.325	.325	.345	1.32
2006	.345	.345	.345	.355	1.39
2007	.355				

BUSINESS: Northwest Natural Gas Co. distributes natural gas at retail to 90 communities, 636,000 customers, in Oregon (90% of custs.) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 2.4 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system to bring gas to market. Owns local underground storage. Rev. breakdown: residential, 55%; commercial, 28%; industrial, gas transportation, and other, 17%. Employs 1,200. Barclays owns 6.2% of shares; insiders, 1% (4/06 proxy). CEO: Mark S. Dodson. Inc.: OR. Address: 220 NW 2nd Ave., Portland, OR 97209. Tel.: 503-226-4211. Internet: www.nwnatural.com.

Northwest posted solid earnings growth in the last quarter of 2006 . . . The prior-year period suffered from about $0.06 a share in unusual litigation expenses. Still, fourth-quarter earnings rose around 9%, excluding the prior-year period charge. Northwest's customer count continued to grow at a 3% clip, about twice the industry average. Operation and maintenance costs declined 1%, after severance costs, as the company's work reorganization plan started to take effect. In 2006, the company earned $2.22 a share, before severance costs and mark-to-market accounting for derivatives ($2.29 a share overall).

. . . and the momentum will likely continue through at least 2008. For 20 years, Northwest has logged about twice the average industry customer growth, and we see no reason why that won't continue for the foreseeable future. Natural gas came to the Portland area rather late, in the 1950s, giving Northwest ample conversion opportunities. And the company has over a 90% share of new residential heating. We anticipate further gains on the cost side, too, as Northwest completes its work reorganization. This plan entails outsourcing most new construction and some administrative work, and standardizing and centralizing some functions. The company also plans to set up a new salesforce for the conversion market.

Suburban growth and other projects should keep earnings growing at a better-than average industry pace. Over the next 10 years, the Portland metro government will move its urban growth boundary out to the southeast of the city, opening a large new territory for natural gas service. Planners forecast that some towns in this area will grow by over 500% by 2015 with new, higher-density zoning. A new interstate pipeline project could also put to work over $100 million of capital, at a good, FERC-regulated rate of return, and NWN will probably benefit from the construction of at least one new liquefied natural gas terminal in its area.

These neutrally ranked, top-quality shares have below average total-return potential. Earnings and dividends will likely grow faster than industry averages, but the current yield is modest.

Sigourney B. Romaine *March 16, 2007*

(A) Diluted earnings per share. Excludes nonrecurring gain: '98, $0.15; '00, $0.11. Next earnings report due early May.
(B) Dividends historically paid in mid-February, mid-May, mid-August, and mid-November.
■ Div'd reinvestment plan available.
(C) In millions, adjusted for stock split.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	80

PIEDMONT NAT'L. GAS NYSE-PNY

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
25.14	18.0	(Trailing: 19.8 / Median: 17.0)	0.99	4.0%	VALUE LINE

TIMELINESS **4** Raised 12/23/05
SAFETY **2** New 7/27/90
TECHNICAL **3** Raised 3/16/07
BETA .80 (1.00 = Market)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
High:	12.9	18.2	18.1	18.3	19.7	19.0	19.0	22.0	24.3	25.8	28.4	27.3
Low:	10.3	11.0	13.9	14.3	11.8	14.6	13.7	16.6	19.2	21.3	23.2	24.4

Target Price Range 2010 | 2011 | 2012

2010-12 PROJECTIONS

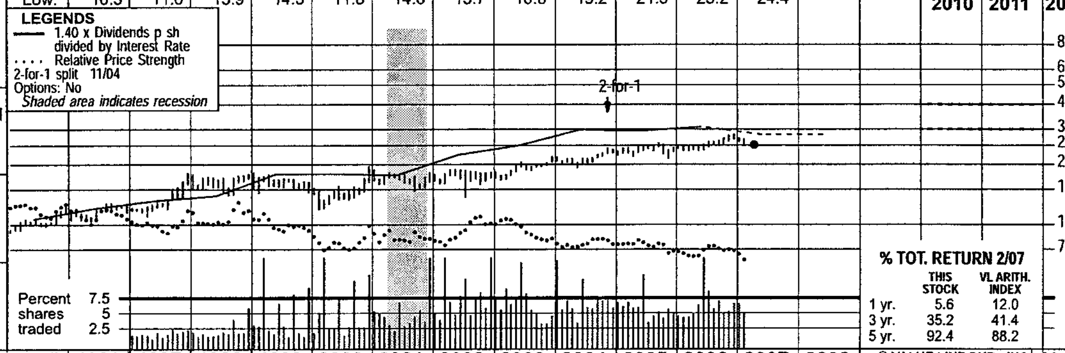
	Price	Gain	Ann'l Total Return
High	40	(+60%)	15%
Low	30	(+20%)	8%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	9	9	9	10	1	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	1	0	1	2	0	0	0	0	1

Institutional Decisions

	2Q2006	3Q2006	4Q2006
to Buy	85	68	79
to Sell	61	69	70
Hld's(000)	32936	33570	33589



% TOT. RETURN 2/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	5.6	12.0
3 yr.	35.2	41.4
5 yr.	92.4	88.2

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC. 10-12
Revenues per sh A	8.32	8.91	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	*27.10*	*28.75*	*33.50*
"Cash Flow" per sh	.78	1.07	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	2.50	*2.60*	*2.70*	*3.00*
Earnings per sh B	.44	.70	.73	.68	.73	.84	.93	.98	.93	1.01	1.01	.95	1.11	1.27	1.32	1.27	*1.40*	*1.45*	*1.55*
Div'ds Decl'd per sh C■	.44	.46	.48	.51	.54	.57	.61	.64	.68	.72	.76	.80	.82	.85	.91	.95	*.99*	*1.03*	*1.15*
Cap'l Spending per sh	1.37	1.41	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	*2.65*	*2.75*	*2.90*
Book Value per sh D	4.83	5.13	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	*12.00*	*12.40*	*13.40*
Common Shs Outst'g E	49.46	51.59	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	*73.80*	*73.00*	*71.80*
Avg Ann'l P/E Ratio	16.3	12.3	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	19.4	*Bold figures are*	*Value Line*	*22.0*
Relative P/E Ratio	1.04	.75	.91	1.03	.92	.87	.78	.85	1.01	.93	.86	1.01	.95	.88	.95	1.02	*estimates*		*1.30*
Avg Ann'l Div'd Yield	6.0%	5.3%	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%			*3.5%*
Revenues ($mill) A							775.5	765.3	686.5	830.4	1107.9	832.0	1220.8	1529.7	1761.1	1924.7	*2000*	*2100*	*2400*
Net Profit ($mill)							55.2	60.3	58.2	64.0	65.5	62.2	74.4	95.2	101.3	96.7	*105*	*105*	*110*
Income Tax Rate							39.1%	39.2%	39.7%	34.7%	34.6%	33.1%	34.8%	35.1%	33.7%	35.0%	*35.0%*	*36.0%*	*36.0%*
Net Profit Margin							7.1%	7.9%	8.5%	7.7%	5.9%	7.5%	6.1%	6.2%	5.8%	5.0%	*5.2%*	*5.1%*	*5.0%*
Long-Term Debt Ratio							47.6%	44.7%	46.2%	46.1%	47.6%	43.9%	42.2%	43.6%	41.4%	48.3%	*49.0%*	*50.0%*	*49.0%*
Common Equity Ratio							52.4%	55.3%	53.8%	53.9%	52.4%	56.1%	57.8%	56.4%	58.6%	51.7%	*51.0%*	*50.0%*	*51.0%*
Total Capital ($mill)							800.8	829.3	914.7	978.4	1069.4	1051.6	1090.2	1514.9	1509.2	1708.0	*1755*	*1810*	*1900*
Net Plant ($mill)							941.7	990.6	1047.0	1072.0	1114.7	1158.5	1812.3	1849.8	1939.1	2075.0	*2100*	*2150*	*2350*
Return on Total Cap'l							8.9%	9.2%	8.1%	8.3%	7.9%	7.8%	8.6%	7.8%	8.2%	7.1%	*7.0%*	*7.5%*	*7.0%*
Return on Shr. Equity							13.1%	13.2%	11.8%	12.1%	11.7%	10.6%	11.8%	11.1%	11.5%	11.0%	*11.5%*	*11.5%*	*11.5%*
Return on Com Equity							13.1%	13.2%	11.8%	12.1%	11.7%	10.6%	11.8%	11.1%	11.5%	11.0%	*11.5%*	*11.5%*	*11.5%*
Retained to Com Eq							4.6%	4.7%	3.3%	3.5%	3.0%	1.7%	3.1%	3.7%	3.6%	2.8%	*3.5%*	*3.5%*	*3.0%*
All Div'ds to Net Prof							65%	65%	72%	71%	75%	83%	74%	66%	68%	74.6%	*72%*	*70%*	*74%*

CAPITAL STRUCTURE as of 10/31/06
Total Debt $995.0 mill. **Due in 5 Yrs** $150.0 mill.
LT Debt $825.0 mill. **LT Interest** $50.0 mill.
(LT interest earned: 4.0x; total interest coverage: 4.0x)

Pension Assets-10/06 $211.9 mill.
Oblig. $236.3 mill.

Pfd Stock None

Common Stock 74,606,758 shs.
as of 1/8/07

MARKET CAP: $1.9 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2004	2005	10/31/06
Cash Assets	5.7	7.1	8.9
Other	329.5	497.8	467.1
Current Assets	335.2	504.9	476.0
Accts Payable	99.6	182.8	80.3
Debt Due	109.5	193.5	170.0
Other	97.1	152.3	150.1
Current Liab.	306.2	528.6	400.4
Fix. Chg. Cov.	378%	400%	325%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	7.5%	11.0%	*5.5%*
"Cash Flow"	7.0%	5.5%	*3.0%*
Earnings	5.5%	5.0%	*3.0%*
Dividends	5.5%	5.0%	*4.0%*
Book Value	6.5%	6.5%	*2.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2004	618.8	482.4	214.7	213.8	1529.7
2005	680.6	508.0	232.9	339.6	1761.1
2006	921.4	483.2	237.9	282.2	1924.7
2007	*900*	*550*	*250*	*300*	*2000*
2008	*925*	*575*	*275*	*325*	*2100*

Fiscal Year Ends	EARNINGS PER SHARE A B F Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2004	1.03	.54	d.11	d.21	1.27
2005	.93	.52	d.06	d.07	1.32
2006	.94	.57	d.16	d.08	1.27
2007	*.96*	*.58*	*d.09*	*d.05*	*1.40*
2008	*.95*	*.60*	*d.06*	*d.04*	*1.45*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.20	.208	.208	.208	.82
2004	.208	.215	.215	.215	.85
2005	.215	.23	.23	.23	.91
2006	.23	.24	.24	.24	.95
2007					

BUSINESS: Piedmont Natural Gas Company is primarily a regulated natural gas distributor, serving over 1,016,000 customers in North Carolina, South Carolina, and Tennessee. 2006 revenue mix: residential (44%), commercial (26%), industrial (11%), other (19%). Principal suppliers: Transco and Tennessee Pipeline. Gas costs: 72.8% of revenues. '06 deprec. rate: 3.5%. Estimated plant age: 8.7 years. Non-regulated operations: sale of gas-powered heating equipment; natural gas brokering; propane sales. Has about 2,051 employees. Officers & directors own less than 1% of common stock (1/07 proxy). Chairman, CEO, & President: Thomas E. Skains. Inc.: NC. Addr.: 4720 Piedmont Row Drive, Charlotte, NC 28210. Telephone: 704-731-4226. Internet: www.piedmontng.com.

We expect Piedmont Natural Gas' earnings for the first quarter of fiscal 2007 (ends October 31st) to rise by $0.02 a share. Customers continue to be added in Piedmont's North Carolina, South Carolina, and Tennessee service areas. In addition to South Carolina's increased large-volume customers, the 2006 Rate Stabilization Act filing was settled. Both of these factors should increase margins. We expect earnings for the full fiscal year to rise 10%, to $1.40 a share. That's the midpoint of Piedmont's target of $1.35-$1.45.

The Public Service Commission of South Carolina approved a gas cost hedging plan for the purpose of cost stabilization. The plan targets 30% to 60% of annual normalized sales volumes. Any benefits recognized are deemed to be reductions in gas cost and are refunded to South Carolina customers in rates.

The capitalization ratios of 48% long-term debt and 52% common equity were both in the target ranges. Maintaining sufficient cash flows and achieving this capital structure will allow PNY to have an attractive credit rating, which will facilitate obtaining capital for future infrastructure expenditures.

Piedmont's joint venture is performing well. Piedmont Energy's 30% equity interest in SouthStar Energy services, a Georgia-based unregulated retail natural gas marketer, earned $22.9 million of PNY's $29.9 million overall joint venture pretax earnings in fiscal 2006. We expect similar results to continue due to growth in joint markets.

In the three-state service area of the Carolinas and Tennessee, the overall customer growth rate was 3.5% in 2006. The gas distribution system serves a million customers company-wide with an increase last year of a near record 34,400. The growth rate is among the highest in the nation for natural gas distribution companies. A record was set in 2006 for residential construction customer growth.

Untimely Piedmont stock offers an attractive yield. Investors should note that the company offers a 5% discount on dividend reinvestment. Good dividend growth over the next 3 to 5 - years should produce worthwhile total return over that time.

Enzo DiCostanzo *March 16, 2007*

(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. At 10/31/05: $4.0 million, 5¢/share.
(E) In millions, adjusted for stock splits.
(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	75
Earnings Predictability	80

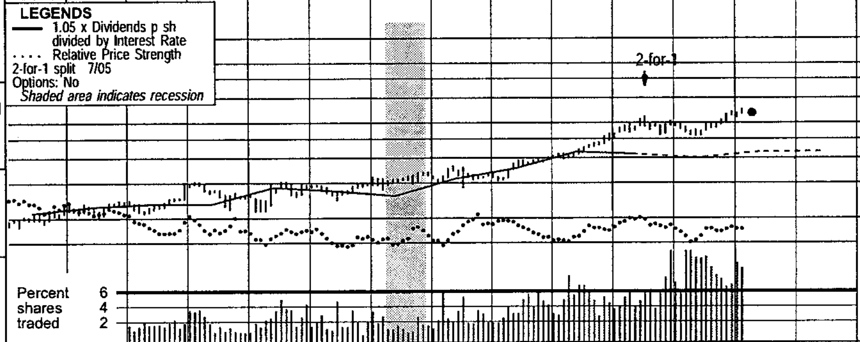
SOUTH JERSEY INDS. NYSE-SJI

RECENT PRICE 33.74 | P/E RATIO 12.7 (Trailing: 17.2, Median: 14.0) | RELATIVE P/E RATIO 0.70 | DIV'D YLD 2.9% | VALUE LINE

TIMELINESS 3 Raised 3/9/07
SAFETY 2 Lowered 1/4/91
TECHNICAL 3 Lowered 1/26/07
BETA .70 (1.00 = Market)

High:	12.3	15.3	15.4	15.4	15.1	17.0	18.3	20.3	26.5	32.4	34.3	35.3
Low:	10.1	10.5	11.0	10.8	12.3	13.8	14.1	15.3	19.7	24.9	25.6	31.8

LEGENDS
— 1.05 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 7/05
Options: No
Shaded area indicates recession



Target Price Range 2010 | 2011 | 2012

2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+65%)	*15%*
Low	40	(+20%)	*7%*

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	0

Institutional Decisions

	2Q2006	3Q2006	4Q2006
to Buy	64	50	58
to Sell	46	47	44
Hld's(000)	15700	15711	15568

% TOT. RETURN 2/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	24.9	12.0
3 yr.	81.3	41.4
5 yr.	174.1	88.2

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
15.10	16.67	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	30.85	*32.75*	*34.35*	Revenues per sh	*38.70*
1.37	1.56	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	3.39	*3.65*	*3.85*	"Cash Flow" per sh	*4.30*
.64	.81	.78	.61	.83	.85	.86	.64	1.01	1.08	1.15	1.22	1.37	1.58	1.71	2.46	*2.70*	*2.90*	Earnings per sh A	*3.30*
.71	.71	.72	.72	.72	.72	.72	.72	.72	.73	.74	.75	.78	.82	.86	.92	*.98*	*1.05*	Div'ds Decl'd per sh B ■	*1.20*
2.17	1.69	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	2.52	*2.70*	*3.00*	Cap'l Spending per sh	*3.40*
6.77	6.95	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	15.12	*16.05*	*16.65*	Book Value per sh C	*18.55*
18.48	19.00	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	29.30	*29.60*	*30.00*	Common Shs Outst'g D	*31.00*
14.5	13.2	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	14.9	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.93	.80	.93	1.06	.82	.83	.80	1.10	.76	.85	.70	.74	.76	.74	.88	.81	*Value Line*		Relative P/E Ratio	*.95*
7.6%	6.6%	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%	*estimates*		Avg Ann'l Div'd Yield	*3.3%*

CAPITAL STRUCTURE as of 12/31/06
Total Debt $555.0 mill. Due in 5 Yrs $232.5 mill.
LT Debt $358.0 mill. LT Interest $21.0 mill.
(Total interest coverage: 5.4x)

Pension Assets-12/06 $117.1 mill. Oblig. $132.6 mill.

Pfd Stock none

Common Stock 29,340,537 common shs. as of 2/23/07

MARKET CAP: $1.0 billion (Mid Cap)

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008		10-12
348.6	450.2	392.5	515.9	837.3	505.1	696.8	819.1	921.0	903.9	*970*	*1030*	Revenues ($mill)	*1200*
18.4	13.8	22.0	24.7	26.8	29.4	34.6	43.0	48.6	72.1	*80.0*	*85.0*	Net Profit ($mill)	*100*
36.8%	46.2%	42.8%	43.1%	42.2%	41.4%	40.6%	40.9%	41.5%	40.7%	*40.5%*	*40.5%*	Income Tax Rate	*40.5%*
5.3%	3.1%	5.6%	4.8%	3.2%	5.8%	5.0%	5.2%	5.3%	8.0%	*8.2%*	*8.3%*	Net Profit Margin	*8.3%*
54.6%	57.3%	53.8%	54.1%	57.0%	53.6%	50.8%	48.7%	44.9%	44.7%	*44.4%*	*44.4%*	Long-Term Debt Ratio	*42.5%*
35.8%	33.5%	37.0%	37.6%	35.9%	46.1%	49.0%	51.0%	55.1%	55.3%	*55.6%*	*55.6%*	Common Equity Ratio	*57.5%*
387.1	401.1	405.9	443.5	516.2	512.5	608.4	675.0	710.3	801.1	*855*	*900*	Total Capital ($mill)	*1000*
456.5	504.3	533.3	562.2	607.0	666.6	748.3	799.9	877.3	920.0	*975*	*1025*	Net Plant ($mill)	*1200*
6.7%	5.3%	7.4%	7.4%	6.9%	7.6%	7.3%	7.9%	8.3%	10.2%	*10.5%*	*10.5%*	Return on Total Cap'l	*11.5%*
10.5%	8.1%	11.7%	12.1%	12.1%	12.4%	11.5%	12.4%	12.4%	16.3%	*17.0%*	*17.0%*	Return on Shr. Equity	*17.5%*
13.3%	10.3%	14.6%	14.8%	12.8%	12.5%	11.6%	12.5%	12.4%	16.3%	*17.0%*	*17.0%*	Return on Com Equity	*17.5%*
2.1%	NMF	4.2%	4.8%	3.5%	4.7%	5.0%	5.9%	6.2%	10.2%	*10.5%*	*11.0%*	Retained to Com Eq	*11.0%*
84%	112%	72%	67%	76%	62%	57%	52%	50%	37%	*36%*	*37%*	All Div'ds to Net Prof	*37%*

CURRENT POSITION ($MILL.)	2004	2005	12/31/06
Cash Assets	10.6	4.9	7.9
Other	273.3	352.6	363.8
Current Assets	283.9	357.5	371.7
Accts Payable	118.8	179.0	101.6
Debt Due	97.6	149.7	197.0
Other	68.9	74.4	124.2
Current Liab.	285.3	403.1	422.8
Fix. Chg. Cov.	426%	486%	527%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	5.5%	7.5%	*4.0%*
"Cash Flow"	4.5%	6.5%	*7.5%*
Earnings	8.0%	11.5%	*9.5%*
Dividends	1.5%	2.5%	*5.5%*
Book Value	5.5%	13.0%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	307.6	136.5	129.5	245.5	819.1
2005	328.6	154.0	157.0	281.4	921.0
2006	365.0	155.5	133.1	250.3	903.9
2007	*375*	*170*	*155*	*270*	*970*
2008	*390*	*190*	*170*	*280*	*1030*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.91	.15	.02	.50	1.58
2005	.96	.27	.09	.39	1.71
2006	1.06	.20	.51	.69	2.46
2007	*1.12*	*.30*	*.55*	*.73*	*2.70*
2008	*1.15*	*.35*	*.60*	*.80*	*2.90*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	--	.193	.193	.395	.78
2004	--	.202	.202	.415	.82
2005	--	.213	.213	.438	.86
2006	--	.225	.225	.470	.92
2007					

BUSINESS: South Jersey Industries, Inc. is a holding company. Its subsidiary, South Jersey Gas Co., distributes natural gas to 330,049 customers in New Jersey's southern counties, which covers 2,500 square miles and includes Atlantic City. Gas revenue mix '06: residential, 43%; commercial, 24%; cogeneration and electric generation 3%; Industrial, 30%. Non-utility operations include: South Jersey Energy, South Jersey Resources Group, Marina Energy, and South Jersey Energy Service Plus. Has 611 employees. Off./dir. cntrl. 1.5% of com. shares; Dimensional Fund Advisors, 7.9%; Barclays, 5.3% (3/06 proxy). Chrmn. & CEO: Edward Graham. Incorp.: NJ. Address: 1 South Jersey Plaza, Folsom, NJ 08037. Tel.: 609-561-9000. Internet: www.sjindustries.com.

South Jersey Industries has restated its earnings. In February, the company determined that its documentation of certain hedge transactions did not contain the specificity required by FASB 133. Therefore, the hedges did not qualify for hedge accounting treatment. As a result, SJI restated its financial statements for 2004, 2005, and the first three quarters of 2006. We have adjusted our 2006 figures accordingly. In keeping with *Value Line* convention, we have not restated figures from previous years.

The company's earnings per share advanced significantly in 2006. The Conservation Incentive Program (discussed below) boosted net income by $4.6 million. The Wholesale Commodity Marketing business reported impressive bottom-line growth, as volatility in natural gas prices and increased storage capacity created lucrative opportunities. Pension and other postretirement benefit costs declined. Strong performance will probably continue, although mark-to-market accounting will make earnings more volatile.

The company has implemented its Conservation Incentive Program. This initiative allows South Jersey Gas to promote energy conservation, while insulating the company from the negative impact of reduced customer usage (as a result of warmer weather, higher prices, or more efficient heating equipment).

Several projects at Marina Energy may benefit SJI in the coming years. Marina develops, owns, and operates onsite energy plants, which provide income streams as part of long-term contracts. It brought three projects on line during the second half of 2006. In addition, Marina has three projects scheduled to commence operations by early 2008.

The board of directors has increased the dividend by 9%. The board raised the quarterly payout from $0.225 a share to $0.245. SJI has increased its dividend at a solid clip in recent years and will probably continue to do so.

This stock is ranked to pace the broader market for the year ahead. At the current quotation, the yield is low (by utility standards), although the issue does have worthwhile total-return potential for the pull to late decade.

Michael F. Napoli *March 16, 2007*

(A) Based on avg. shs. Excl. nonrecur. gain: '01, $0.13. Excl gain (losses) from discont. ops.: '96, $1.14; '97, ($0.24); '98, ($0.26); '99, ($0.02); '00, ($0.04); '01, ($0.02); '02, ($0.04); '03, ($0.09); '05, ($0.02); '06, ($0.02). Excl. gains due to acct'g change: '93, $0.04; '01, $0.14. Next egs. report due early May.
(B) Dividends paid early Apr., Jul., Oct, and late Dec. ■ Div. reinvest. plan avail. (2% disc.).
(C) Incl. regulatory assets ($197.0 mill.): at 12/31/06, $6.72 per shr.
(D) In millions, adjusted for split.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	95
Earnings Predictability	90

SOUTHWEST GAS NYSE-SWX

RECENT PRICE	P/E RATIO	(Trailing / Median)	RELATIVE P/E RATIO	DIV'D YLD
36.49	17.3	(Trailing: 18.4 Median: 20.0)	0.96	2.4%

VALUE LINE

TIMELINESS 3 Raised 5/12/06

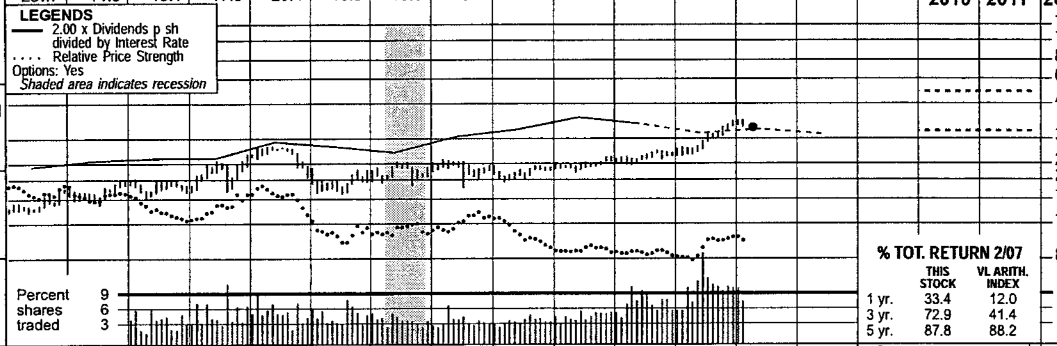
SAFETY 3 Lowered 1/4/91

TECHNICAL 3 Lowered 1/12/07

BETA .85 (1.00 = Market)

High:	19.9	20.3	26.9	29.5	23.0	24.7	25.3	23.6	26.2	28.1	39.4	39.9	
Low:	14.9	16.1	17.3	20.4	16.9	18.6	18.1	19.3	21.5	23.5	26.0	35.3	

Target Price Range 2010 | 2011 | 2012



2010-12 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+50%)	13%
Low	35	(-5%)	1%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	3	0	0	0	1	0	1	0	0
Options	1	5	5	2	5	2	1	8	2
to Sell	1	6	6	2	5	2	1	8	4

Institutional Decisions

	2Q2006	3Q2006	4Q2006
to Buy	82	82	92
to Sell	46	50	65
Hld's(000)	29036	29706	30129

% TOT. RETURN 2/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	33.4	12.0
3 yr.	72.9	41.4
5 yr.	87.8	88.2

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
24.99	25.93	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	*49.40*	*50.35*	Revenues per sh A	*52.65*
1.53	3.34	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	6.07	*6.20*	*6.35*	"Cash Flow" per sh	*6.65*
d.76	.81	.63	1.22	.10	.25	.77	1.65	1.27	1.21	1.15	1.16	1.13	1.66	1.25	1.98	*2.12*	*2.25*	Earnings per sh AB	*2.60*
.88	.70	.74	.80	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	*.86*	*.86*	Div'ds Decl'd per sh C■	*.90*
3.76	5.02	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	*8.70*	*9.10*	Cap'l Spending per sh	*9.45*
15.88	15.99	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	*22.10*	*22.75*	Book Value per sh	*25.25*
20.60	20.60	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	*43.00*	*44.00*	Common Shs Outst'g D	*47.50*
--	16.6	26.5	14.0	NMF	69.3	24.1	13.2	21.1	16.0	19.0	19.9	19.2	14.3	20.6	15.9	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
--	1.01	1.57	.92	NMF	4.34	1.39	.69	1.20	1.04	.97	1.09	1.09	.76	1.10	.87	*Value Line*		Relative P/E Ratio	*1.20*
7.0%	5.2%	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%	*estimates*		Avg Ann'l Div'd Yield	*1.8%*

CAPITAL STRUCTURE as of 12/31/06

Total Debt $1413.9 mill. Due in 5 Yrs $270.0 mill.
LT Debt $1386.4 mill. LT Interest $98.0 mill.
(Total interest coverage: 2.4x)

Pension Assets-12/06 $413.5 mill.
Oblig. $534.9 mill.

Pfd Stock None

Common Stock 41,997,015 shs.
as of 2/15/07

MARKET CAP: $1.5 billion (Mid Cap)

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008		10-12
732.0	917.3	936.9	1034.1	1396.7	1320.9	1231.0	1477.1	1714.3	2024.8	*2125*	*2215*	Revenues ($mill) A	*2500*
20.8	47.5	39.3	38.3	37.2	38.6	38.5	58.9	48.1	81.1	*90.0*	*100*	Net Profit ($mill)	*120*
29.2%	43.4%	35.5%	26.2%	34.5%	32.8%	30.5%	34.8%	29.7%	34.7%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
2.8%	5.2%	4.2%	3.7%	2.7%	2.9%	3.1%	4.0%	2.8%	4.0%	*4.2%*	*4.5%*	Net Profit Margin	*4.8%*
63.6%	60.2%	60.3%	60.2%	56.2%	62.5%	66.0%	64.2%	63.8%	60.6%	*60.0%*	*59.5%*	Long-Term Debt Ratio	*57.0%*
31.5%	35.3%	35.5%	35.8%	39.6%	34.1%	34.0%	35.8%	36.2%	39.4%	*40.0%*	*40.5%*	Common Equity Ratio	*43.0%*
1224.7	1349.3	1424.7	1489.9	1417.6	1748.3	1851.6	1968.6	2076.0	2287.8	*2375*	*2475*	Total Capital ($mill)	*2800*
1360.3	1459.4	1581.1	1686.1	1825.6	1979.5	2175.7	2336.0	2489.1	2668.1	*2800*	*3000*	Net Plant ($mill)	*3500*
3.9%	5.8%	4.8%	4.6%	5.1%	4.3%	4.2%	5.0%	4.3%	5.5%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
4.7%	8.9%	7.0%	6.5%	6.0%	5.9%	6.1%	8.3%	6.4%	9.0%	*9.5%*	*10.0%*	Return on Shr. Equity	*10.0%*
5.4%	10.0%	7.8%	7.2%	6.6%	6.5%	6.1%	8.3%	6.4%	9.0%	*9.5%*	*10.0%*	Return on Com Equity	*10.0%*
NMF	5.0%	2.8%	2.4%	1.9%	1.9%	1.7%	4.3%	2.2%	5.3%	*5.5%*	*6.5%*	Retained to Com Eq	*6.5%*
107%	50%	64%	67%	71%	70%	72%	49%	65%	41%	*41%*	*37%*	All Div'ds to Net Prof	*34%*

CURRENT POSITION ($MILL.)	2004	2005	12/31/06
Cash Assets	13.6	29.6	18.8
Other	418.4	513.1	482.8
Current Assets	432.0	542.7	501.6
Accts Payable	165.9	259.5	265.7
Debt Due	129.8	107.2	27.5
Other	187.3	254.3	202.9
Current Liab.	483.0	621.0	496.1
Fix. Chg. Cov.	166%	167%	220%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	4.5%	5.0%	*3.0%*
"Cash Flow"	4.0%	3.5%	*3.0%*
Earnings	7.5%	-0.5%	*8.0%*
Dividends	0.5%	--	*1.5%*
Book Value	2.0%	3.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) E Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	473.4	278.7	264.5	460.5	1477.1
2005	542.9	361.1	313.3	497.0	1714.3
2006	676.9	430.9	351.8	565.1	2024.8
2007	*700*	*460*	*380*	*585*	*2125*
2008	*725*	*480*	*400*	*610*	*2215*

Cal-endar	EARNINGS PER SHARE B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	1.18	d.24	d.51	1.23	1.66
2005	.88	d.07	d.43	.87	1.25
2006	1.11	.02	d.26	1.11	1.98
2007	*1.15*	*.05*	*d.20*	*1.12*	*2.12*
2008	*1.20*	*.05*	*d.15*	*1.15*	*2.25*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.205	.205	.205	.205	.82
2004	.205	.205	.205	.205	.82
2005	.205	.205	.205	.205	.82
2006	.205	.205	.205	.205	.82
2007	.205	.215			

BUSINESS: Southwest Gas Corporation is a regulated gas distributor serving approx. 1.8 million customers in sections of Arizona, Nevada, and California. '06 margin mix: resid. and small commercial, 85%; large commercial and industrial, 6%; transportation, 9%. Total throughput: 2.4 billion therms. Principal suppliers: El Paso Natural Gas Co. and Northwest Pipeline Corp. Acquired gas utility assets from Arizona Public Service in 1984. Sold PriMerit Bank (acq. in '86) in 7/96. Has about 4,902 employees. Officers & Directors own 2.3% of common stock (3/06 Proxy). Chairman: LeRoy Hanneman. Chief Executive Officer: Jeffrey W. Shaw. Incorporated: California. Address: 5241 Spring Mountain Rd., Las Vegas, Nevada 89193. Telephone: 702-876-7237. Internet: www.swgas.com.

Southwest Gas finished the year on a strong note. Revenues and share earnings advanced by roughly 14% and 28%, respectively, in the fourth quarter. For full-year 2006, the top line increased by 18%. Southwest Gas increased its customer base by 4% during the year. This augmented gross margin by $26 million. Rate relief in California and Arizona added $37 million more to margin. The company also benefited from closer-to-normal weather in the recent interim, compared to the warmer temperatures it had experienced in the same period of 2005. Earnings per share came in at $1.98, well above the prior year's tally.

We anticipate moderate growth in the current year. The company's focus on obtaining rate relief and improving rate design is encouraging, as Southwest Gas depends upon approved revenue increases to help it cope with higher costs. Customer growth should continue to benefit the company, as well. However, as Southwest Gas expands, it is likely to incur upfront costs and increased operating expenses. Improvements in technology may offset these costs somewhat.

The company recently announced a dividend increase. The June quarterly payout will now be $0.215. As the first dividend increase in more than a decade, this move is refreshing. Still, income-oriented investors should note that the company's dividend yield of 2.4% remains lower than that of most utility stocks.

Investors should be aware of several caveats. The share count at Southwest Gas has risen steadily in recent years. This pattern appears likely to continue and may hinder growth in earnings per share. Also, long-term debt currently comprises over 60% of total capital. Debt should continue to increase, although probably at a slower pace than shareholders' equity. Warmer-than-normal weather or lagging rate relief could also hurt the company's revenues and earnings.

Shares of Southwest Gas are neutrally ranked for Timeliness. We anticipate steady bottom-line growth at SWX for the pull to late decade. Nonetheless, total return potential is unexciting for that timeframe, as the stock is currently trading within our Target Price Range.

Michael F. Napoli *March 16, 2007*

(A) Incl. income for PriMerit Bank on the equity basis through 1994. (B) 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¢. Next egs. report due early May. (C) Dividends historically paid early March, June, September, December. ■ Div'd reinvest. plan avail. (D) In millions. (E) Quarterly figures may not sum due to rounding.

Company's Financial Strength	B
Stock's Price Stability	95
Price Growth Persistence	65
Earnings Predictability	65

WGL HOLDINGS NYSE-WGL

RECENT PRICE **30.81** | P/E RATIO **15.7** (Trailing: 16.0; Median: 15.0) | RELATIVE P/E RATIO **0.87** | DIV'D YLD **4.4%** | VALUE LINE

TIMELINESS	4	Raised 8/4/06
SAFETY	1	Raised 4/2/93
TECHNICAL	3	Lowered 1/5/07

BETA .85 (1.00 = Market)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
High:	25.0	31.4	30.8	29.4	31.5	30.5	29.5	28.8	31.4	34.8	33.6	33.0
Low:	19.1	20.9	23.1	21.0	21.8	25.3	19.3	23.2	26.7	28.8	27.0	30.4

Target Price Range 2010 | 2011 | 2012

2010-12 PROJECTIONS

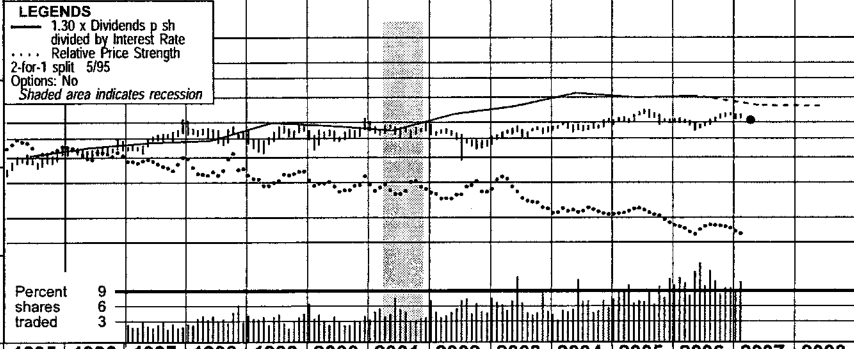
	Price	Gain	Ann'l Total Return
High	40	(+30%)	10%
Low	30	(-5%)	4%

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	1	6	0	1	6	1
to Sell	0	0	0	1	7	0	1	6	1

Institutional Decisions

	2Q2006	3Q2006	4Q2006
to Buy	73	86	81
to Sell	78	73	68
Hld's(000)	29760	30043	30408



% TOT. RETURN 2/07

	THIS STOCK	VL ARITH. INDEX
1 yr.	7.0	12.0
3 yr.	24.0	41.4
5 yr.	48.4	88.2

1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
17.50	18.37	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	*54.90*	*56.70*	Revenues per sh A	*62.50*
2.04	2.17	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	3.93	*4.00*	*4.15*	"Cash Flow" per sh	*4.40*
1.14	1.27	1.31	1.42	1.45	1.85	1.85	1.54	1.47	1.79	1.88	1.14	2.30	1.98	2.11	1.94	*1.96*	*2.05*	Earnings per sh B	*2.20*
1.05	1.07	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	1.34	*1.38*	*1.42*	Div'ds Decl'd per sh C■	*1.45*
2.05	2.17	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	*2.45*	*2.45*	Cap'l Spending per sh	*2.55*
9.63	10.66	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	18.28	*18.90*	*19.60*	Book Value per sh D	*22.0*
39.89	40.62	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	*48.91*	*48.92*	Common Shs Outst'g E	*49.0*
12.8	13.6	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	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.82	.82	.92	.92	.85	.72	.73	.89	.99	.95	.75	1.26	.63	.75	.78	.81	*Value Line*		Relative P/E Ratio	*1.0*
7.2%	6.2%	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%	*estimates*		Avg Ann'l Div'd Yield	*4.3%*

CAPITAL STRUCTURE as of 12/31/06
Total Debt $882.8 mill. Due in 5 Yrs $290.0 mill.
LT Debt $605.1 mill. LT Interest $40.6 mill.
(LT interest earned: 4.8x; total interest coverage: 4.2x)
Pension Assets-9/06 $699.9 mill. **Oblig.** $697.4 mill.
Preferred Stock $28.2 mill. **Pfd Div'd** $1.3 mill.

Common Stock 49,141,163 shs.

MARKET CAP: $1.5 billion (Mid Cap)

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	© VALUE LINE PUB., INC.	10-12
1055.8	1040.6	972.1	1031.1	1446.5	1584.8	2064.2	2089.6	2186.3	2637.9	*2685*	*2775*	Revenues ($mill) A	*3050*
82.0	68.6	68.8	84.6	89.9	55.7	112.3	98.0	104.8	95.1	*98*	*102*	Net Profit ($mill)	*110*
36.9%	35.6%	36.0%	36.1%	39.6%	34.0%	38.0%	38.2%	37.4%	39.0%	*38.0%*	*38.0%*	Income Tax Rate	*38.0%*
7.8%	6.6%	7.1%	8.2%	6.2%	3.5%	5.4%	4.7%	4.8%	3.6%	*3.6%*	*3.7%*	Net Profit Margin	*3.6%*
41.1%	40.3%	41.5%	43.1%	41.7%	45.7%	43.8%	40.9%	39.5%	38.5%	*39.0%*	*38.8%*	Long-Term Debt Ratio	*36.0%*
56.2%	57.1%	56.1%	54.8%	56.3%	52.4%	54.3%	57.2%	58.6%	61.5%	*61.0%*	*61.5%*	Common Equity Ratio	*64.0%*
1049.0	1064.8	1218.5	1299.2	1400.8	1462.5	1454.9	1443.6	1478.1	1497.8	*1560*	*1615*	Total Capital ($mill)	*1720*
1217.1	1319.5	1402.7	1460.3	1519.7	1606.8	1874.9	1915.6	1969.7	2068	*2170*	*2280*	Net Plant ($mill)	*2640*
9.3%	8.0%	7.1%	7.9%	7.9%	5.3%	9.1%	8.2%	8.5%	7.7%	*7.5%*	*7.5%*	Return on Total Cap'l	*7.5%*
13.3%	10.8%	9.7%	11.4%	11.0%	7.0%	13.7%	11.5%	11.7%	10.3%	*10.0%*	*10.5%*	Return on Shr. Equity	*10.0%*
13.7%	11.1%	9.9%	11.7%	11.2%	7.2%	14.0%	11.7%	12.0%	10.2%	*10.5%*	*10.7%*	Return on Com Equity	*10.5%*
5.1%	2.5%	1.8%	3.7%	3.8%	NMF	6.2%	4.1%	4.6%	3.1%	*3.2%*	*3.5%*	Retained to Com Eq	*4.0%*
63%	78%	82%	69%	67%	112%	56%	65%	62%	70%	*68%*	*67%*	All Div'ds to Net Prof	*65%*

CURRENT POSITION ($MILL.)	2005	2006	12/31/06
Cash Assets	4.8	4.4	12.2
Other	476.2	556.9	798.8
Current Assets	481.0	561.3	811.0
Accts Payable	204.9	208.5	313.1
Debt Due	91.0	238.4	277.7
Other	115.5	113.9	214.4
Current Liab.	411.4	560.8	805.2
Fix. Chg. Cov.	460%	450%	450%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '04-'06 to '10-'12
Revenues	7.5%	14.5%	*4.0%*
"Cash Flow"	5.0%	6.5%	*2.0%*
Earnings	4.5%	6.0%	*1.0%*
Dividends	1.5%	1.5%	*1.5%*
Book Value	4.0%	3.0%	*3.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2004	585.3	862.2	356.9	285.2	2089.6
2005	623.4	929.8	349.0	284.1	2186.3
2006	902.9	1064.5	346.9	323.6	2637.9
2007	732.9	*1095*	*440*	*417.1*	*2685*
2008	*970*	*1040*	*390*	*375*	*2775*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2004	.81	1.62	d.08	d.37	1.98
2005	.88	1.63	d.17	d.23	2.11
2006	.93	1.17	d.01	d.15	1.94
2007	.92	*1.20*	*d.01*	*d.15*	*1.96*
2008	*.95*	*1.26*	*d.01*	*d.15*	*2.05*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2003	.32	.325	.325	.325	1.30
2004	.325	.333	.333	.333	1.32
2005	.33	.33	.333	.333	1.33
2006	.333	.333	.338	.338	1.34
2007	.34				

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 (1,031,916 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 9.6% of common stock; Off./dir. less than 1% (1/07 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, Inc.'s consolidated operating revenues were down 2% to $733 million for the first three months of fiscal 2007. The biggest declines were in the regulated utility segment, where gas delivery revenues were down 30% due to warm weather and customer conservation. In addition the nonutility operation HVAC segment was down 60% owning to the completion of large projects for its customers at the end of fiscal 2006 that have not yet been replaced in the segment's revenue stream. The regulated utility segment is WGL's core business; it represents 91% of the holding company's total assets. Even so, corporate income increased 2% to $45.1 million thanks to a 20% decrease in operating expenses.

Washington Gas is continuing to address the natural gas leaks in its distribution system in Maryland. Gas used in the system from a liquefied natural gas terminal has a lower concentration of heavy hydrocarbons, that, when introduced into the overall distribution system, can cause the seals in the pipe couplings to leak. These gas service lines and couplings are being replaced and rehabilitated in the distribution system. The project is expected to be completed by December, 2007 at an estimated cost of $144 million. This project is necessary to provide safe and reliable utility service. It is anticipated that these costs will be recognized in the rate-making process. Washington Gas' financial condition, results of operations, and cash flows will, of course, be affected by the Public Service Commission of Maryland's rate-making judgment.

WGL Holdings expects to benefit from robust economic growth in its service area. The DC market is one of the most prosperous in the United States. New customers have been added at an average of 20,000 per year for the last few years. And attention will be focused on residential customer conversions to natural gas from other forms of energy.

These shares are trading within our Target Price Range, and we see negligible price appreciation for the 3- to 5-years ahead. The stock stands out for its yield, however, which is one of the highest among the gas distribution companies. Moreover, finances are strong.

Enzo DiCostanzo *March 16, 2007*

(A) Fiscal years end Sept. 30th.
(B) Based on diluted shares. Excludes nonrecurring losses: '01, (13¢); '02, (34¢); discontinued operations: '06, (15¢). 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. '05: $150.0 million, $3.08/sh.
(E) In millions, adjusted for stock split.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	70
Earnings Predictability	60

ATTACHMENT C

Zacks.com Quotes and Research

ATLANTA GAS LIGHT (NYSE)

Scottrade

ATG	41.74	▼-0.50	(-1.18%)	Vol. 99,000	12:26 CST

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

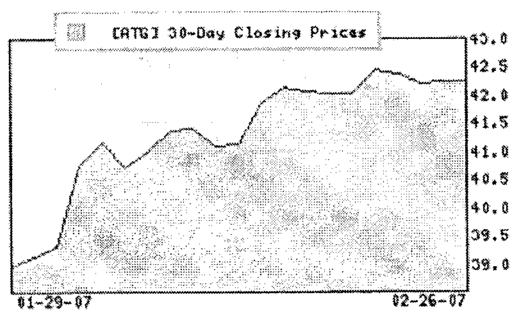
AGL RESOURCES
Ten Peachtree Place NE
Atlanta, GA 30309
Phone: 404 584-4000
Fax: 404 584-3945
Web: www.aglresources.com
Email: scave@aglresources.com

Industry	UTIL-GAS DISTR
Sector:	Utilities

Fiscal Year End	December
Last Reported Quarter	12/31/06
Next EPS Date	05/09/2007

Price and Volume Information

Zacks Rank	
Yesterday's Close	42.24
52 Week High	42.45
52 Week Low	34.75
Beta	0.35
20 Day Moving Average	454,960.94
Target Price Consensus	42.42



% Price Change		% Price Change Relative to S&P 500	
4 Week	9.49	4 Week	7.05
12 Week	9.92	12 Week	5.71
YTD	8.51	YTD	5.28

Share Information		Dividend Information	
Shares Outstanding (millions)	77.70	Dividend Yield	3.88%
		Annual Dividend	$1.64
Market Capitalization (millions)	3,280.32	Payout Ratio	0.54
Short Ratio	10.00	Change in Payout Ratio	-0.02
Last Split Date	12/04/1995	Last Dividend Payout / Amount	11/15/2006 / $0.37

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	1.40	Current (1=Strong Buy, 5=Strong Sell)	2.57
Current Year EPS Consensus Estimate	2.78	30 Days Ago	2.38
Estimated Long-Term EPS Growth Rate	5.00	60 Days Ago	2.38
Next EPS Report Date	05/09/2007	90 Days Ago	2.38

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	15.18	vs. Previous Year	-29.41%	vs. Previous Year	-28.80%
Trailing 12 Months:	15.52	vs. Previous Quarter	30.43%	vs. Previous Quarter:	62.90%
PEG Ratio	3.04				
Price Ratios		**ROE**		**ROA**	
Price/Book	2.04	12/31/06	13.36	12/31/06	3.61
Price/Cash Flow	9.37	09/30/06	14.81	09/30/06	3.91
Price / Sales	1.25	06/30/06	13.75	06/30/06	3.52
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/06	1.12	12/31/06	0.75	12/31/06	8.08
09/30/06	1.15	09/30/06	0.67	09/30/06	7.94
06/30/06	1.12	06/30/06	0.64	06/30/06	7.32
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/06	13.01	12/31/06	13.01	12/31/06	20.71
09/30/06	12.72	09/30/06	12.72	09/30/06	20.30
06/30/06	11.75	06/30/06	11.75	06/30/06	20.18
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/06	2.58	12/31/06	1.01	12/31/06	50.84
09/30/06	3.07	09/30/06	1.03	09/30/06	51.38
06/30/06	3.23	06/30/06	1.04	06/30/06	51.44

Zacks.com Quotes and Research

ATMOS ENERGY CP (NYSE)

ATO	31.36	▼-0.11	(-0.35%)	Vol. 158,700	12:57 CST

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

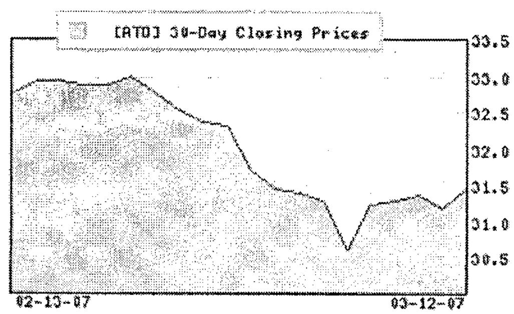
ATMOS ENERGY CP
Three Lincoln Centre, 5430 Lbj Freeway
Suite 1800
Dallas, TX 75240
Phone: 972 934-9227
Fax: -
Web: www.atmosenergy.com
Email: InvestorRelations@atmosenergy.com

Industry	UTIL-GAS DISTR
Sector:	Utilities

Fiscal Year End	September
Last Reported Quarter	12/31/06
Next EPS Date	05/10/2007

Price and Volume Information

Zacks Rank	
Yesterday's Close	31.47
52 Week High	33.01
52 Week Low	26.00
Beta	0.45
20 Day Moving Average	322,488.00
Target Price Consensus	33.9



% Price Change

4 Week	-2.07

% Price Change Relative to S&P 500

4 Week	2.02

12 Week	-2.37	12 Week	-0.88
YTD	-1.94	YTD	0.23
Share Information		**Dividend Information**	
Shares Outstanding (millions)	88.58	Dividend Yield	4.09%
		Annual Dividend	$1.28
Market Capitalization (millions)	2,771.57	Payout Ratio	0.54
Short Ratio	4.76	Change in Payout Ratio	-0.17
Last Split Date	05/17/1994	Last Dividend Payout / Amount	02/22/2007 / $0.32
EPS Information		**Consensus Recommendations**	
Current Quarter EPS Consensus Estimate	1.17	Current (1=Strong Buy, 5=Strong Sell)	2.50
Current Year EPS Consensus Estimate	1.95	30 Days Ago	2.40
Estimated Long-Term EPS Growth Rate	5.30	60 Days Ago	2.57
Next EPS Report Date	05/10/2007	90 Days Ago	2.57

Fundamental Ratios

P/E		**EPS Growth**		**Sales Growth**	
Current FY Estimate:	16.12	vs. Previous Year	10.23%	vs. Previous Year	-29.83%
Trailing 12 Months:	13.26	vs. Previous Quarter	288.00%	vs. Previous Quarter:	64.97%
PEG Ratio	3.07				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.42	12/31/06	11.18	12/31/06	3.29
Price/Cash Flow	7.33	09/30/06	11.03	09/30/06	3.07
Price / Sales	0.51	06/30/06	8.84	06/30/06	2.45
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/06	0.97	12/31/06	0.65	12/31/06	3.54
09/30/06	1.00	09/30/06	0.59	09/30/06	2.98
06/30/06	1.03	06/30/06	0.60	06/30/06	2.36
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/06	4.68	12/31/06	4.68	12/31/06	22.01
09/30/06	3.85	09/30/06	3.85	09/30/06	20.20
06/30/06	3.25	06/30/06	3.25	06/30/06	20.51
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/06	9.09	12/31/06	0.98	12/31/06	49.45

09/30/06	10.27	09/30/06	1.32	09/30/06	56.95
06/30/06	10.53	06/30/06	1.31	06/30/06	56.71

Zacks.com Quotes and Research

LACLEDE GROUP INC (NYSE)

LG	31.58	-0.39	(-1.22%)	Vol. 29,300	12:16 CST

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

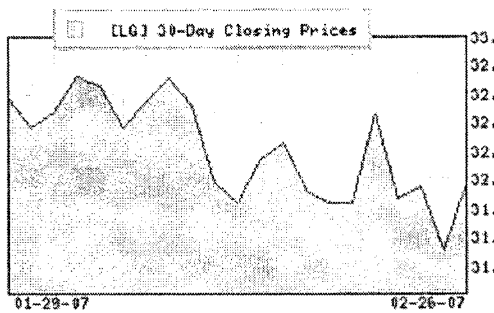
LACLEDE GRP INC
720 Olive Street
St. Louis, MO 63101
Phone: 314-342-0500
Fax: -
Web: www.thelacledegroup.com
Email: mkullman@lacledegas.com

Industry	UTIL-GAS DISTR
Sector:	Utilities

Fiscal Year End	September
Last Reported Quarter	12/31/06
Next EPS Date	04/27/2007

Price and Volume Information

Zacks Rank	
Yesterday's Close	31.97
52 Week High	36.95
52 Week Low	31.35
Beta	0.47
20 Day Moving Average	123,355.00
Target Price Consensus	N/A



% Price Change		% Price Change Relative to S&P 500	
4 Week	-2.41	4 Week	-4.59
12 Week	-12.66	12 Week	-16.00

YTD	-8.79	YTD	-11.43
Share Information		**Dividend Information**	
Shares Outstanding (millions)	21.53	Dividend Yield	4.57%
		Annual Dividend	$1.46
Market Capitalization (millions)	687.91	Payout Ratio	0.72
Short Ratio	22.64	Change in Payout Ratio	-0.07
Last Split Date	03/08/1994	Last Dividend Payout / Amount	12/07/2006 / $0.37

EPS Information		**Consensus Recommendations**	
Current Quarter EPS Consensus Estimate	0.98	Current (1=Strong Buy, 5=Strong Sell)	3.00
Current Year EPS Consensus Estimate	1.97	30 Days Ago	3.00
Estimated Long-Term EPS Growth Rate	-	60 Days Ago	3.00
Next EPS Report Date	04/27/2007	90 Days Ago	3.00

Fundamental Ratios

P/E		**EPS Growth**		**Sales Growth**	
Current FY Estimate:	16.22	vs. Previous Year	-27.64%	vs. Previous Year	-21.72%
Trailing 12 Months:	15.74	vs. Previous Quarter	2,325.00%	vs. Previous Quarter:	100.58%
PEG Ratio	-				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.64	12/31/06	10.61	12/31/06	2.79
Price/Cash Flow	8.13	09/30/06	12.54	09/30/06	3.27
Price / Sales	0.37	06/30/06	11.74	06/30/06	3.09
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/06	1.02	12/31/06	0.67	12/31/06	2.35
09/30/06	1.07	09/30/06	0.69	09/30/06	2.53
06/30/06	1.15	06/30/06	0.88	06/30/06	2.32
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/06	3.44	12/31/06	3.44	12/31/06	19.44
09/30/06	3.63	09/30/06	3.63	09/30/06	18.85
06/30/06	3.34	06/30/06	3.34	06/30/06	19.08
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/06	12.45	12/31/06	0.85	12/31/06	45.88
09/30/06	13.92	09/30/06	0.98	09/30/06	49.50

06/30/06	13.28	06/30/06	0.97	06/30/06	49.24

Zacks.com Quotes and Research

N J RESOURCES CP (NYSE)

NJR	49.22	▾-0.51	(-1.03%)	Vol. 62,200	13:11 CST

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

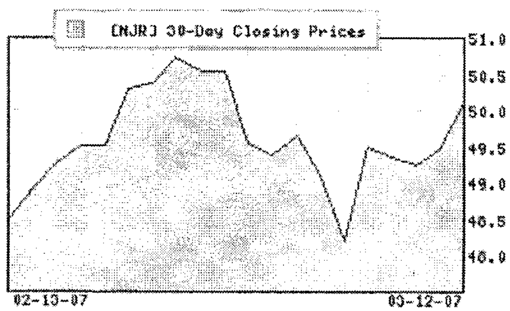
NJ RESOURCES
1415 Wyckoff Road
Wall, NJ 07719
Phone: 732 938-1480
Fax: -
Web: www2.njresources.com
Email: investcont@njresources.com

Industry	UTIL-GAS DISTR
Sector:	Utilities

Fiscal Year End	September
Last Reported Quarter	12/31/06
Next EPS Date	05/09/2007

Price and Volume Information

Zacks Rank	
Yesterday's Close	49.73
52 Week High	52.55
52 Week Low	42.91
Beta	-0.01
20 Day Moving Average	212,657.34
Target Price Consensus	48



% Price Change		% Price Change Relative to S&P 500	
4 Week	2.66	4 Week	6.94

12 Week	-3.29	12 Week	-1.82
YTD	1.61	YTD	3.38
Share Information		**Dividend Information**	
Shares Outstanding (millions)	27.83	Dividend Yield	3.08%
		Annual Dividend	$1.52
Market Capitalization (millions)	1,373.89	Payout Ratio	0.59
Short Ratio	10.88	Change in Payout Ratio	0.07
Last Split Date	03/04/2002	Last Dividend Payout / Amount	12/13/2006 / $0.38

EPS Information		**Consensus Recommendations**	
Current Quarter EPS Consensus Estimate	2.12	Current (1=Strong Buy, 5=Strong Sell)	2.33
Current Year EPS Consensus Estimate	2.91	30 Days Ago	2.33
Estimated Long-Term EPS Growth Rate	6.00	60 Days Ago	2.33
Next EPS Report Date	05/09/2007	90 Days Ago	2.33

Fundamental Ratios

P/E		**EPS Growth**		**Sales Growth**	
Current FY Estimate:	16.95	vs. Previous Year	-17.89%	vs. Previous Year	-36.33%
Trailing 12 Months:	19.13	vs. Previous Quarter	334.88%	vs. Previous Quarter:	38.72%
PEG Ratio	2.82				
Price Ratios		**ROE**		**ROA**	
Price/Book	2.12	12/31/06	11.68	12/31/06	3.15
Price/Cash Flow	12.20	09/30/06	13.30	09/30/06	3.49
Price / Sales	0.48	06/30/06	15.73	06/30/06	3.88
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/06	1.06	12/31/06	0.58	12/31/06	2.52
09/30/06	1.08	09/30/06	0.50	09/30/06	2.38
06/30/06	1.15	06/30/06	0.54	06/30/06	2.48
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/06	4.10	12/31/06	4.10	12/31/06	23.25
09/30/06	3.90	09/30/06	3.90	09/30/06	22.14
06/30/06	3.97	06/30/06	3.97	06/30/06	21.25
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/06	5.83	12/31/06	0.52	12/31/06	34.29

09/30/06	9.48	09/30/06	0.53	09/30/06	34.84
06/30/06	12.61	06/30/06	0.56	06/30/06	35.92

Zacks.com Quotes and Research

NICOR INC (NYSE)

GAS	46.61	▼-0.40	(-0.85%)	Vol. 184,200	13:14 CST

NICOR Inc. is a holding company. Its principal subsidiaries are Northern Illinois Gas Company, one of the nation's largest distributors of natural gas, and Tropical Shipping, one of the leading transporters of containerized freight in the Caribbean. Gas distribution is Nicor's primary business, representing the majority of consolidated operating income and assets. Nicor also owns several energy-related subsidiaries and is a partner in Nicor Energy, a provider of unregulated energy products and services.

General Information

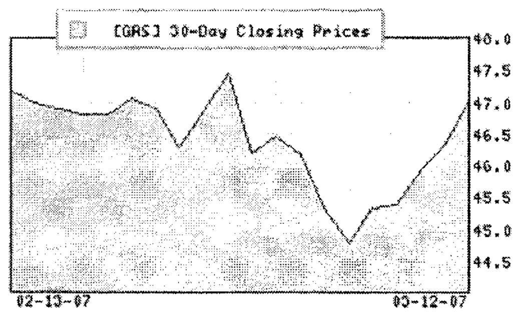
NICOR INC
1844 Ferry Road
Naperville, IL 60563-9600
Phone: 630 305-9500
Fax: 630 983-9328
Web: www.nicor.com
Email: None

Industry	UTIL-GAS DISTR
Sector:	Utilities

Fiscal Year End	December
Last Reported Quarter	12/31/06
Next EPS Date	05/08/2007

Price and Volume Information

Zacks Rank	
Yesterday's Close	47.01
52 Week High	49.66
52 Week Low	38.91
Beta	0.87
20 Day Moving Average	423,751.91
Target Price Consensus	46.38



% Price Change

4 Week	-1.77
12 Week	-7.91

% Price Change Relative to S&P 500

4 Week	2.32
12 Week	-6.51

YTD	-2.99	YTD	-0.97

Share Information		Dividend Information	
Shares Outstanding (millions)	44.91	Dividend Yield	4.10%
		Annual Dividend	$1.86
Market Capitalization (millions)	2,039.01	Payout Ratio	0.64
Short Ratio	19.32	Change in Payout Ratio	0.00
Last Split Date	04/27/1993	Last Dividend Payout / Amount	12/27/2006 / $0.47

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	1.00	Current (1=Strong Buy, 5=Strong Sell)	3.00
Current Year EPS Consensus Estimate	2.77	30 Days Ago	3.00
Estimated Long-Term EPS Growth Rate	2.00	60 Days Ago	3.00
Next EPS Report Date	05/08/2007	90 Days Ago	3.00

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	16.39	vs. Previous Year	26.47%	vs. Previous Year	-38.25%
Trailing 12 Months:	15.55	vs. Previous Quarter	360.71%	vs. Previous Quarter:	138.74%
PEG Ratio	8.19				
Price Ratios		**ROE**		**ROA**	
Price/Book	2.33	12/31/06	15.53	12/31/06	3.35
Price/Cash Flow	6.46	09/30/06	14.21	09/30/06	2.95
Price / Sales	0.69	06/30/06	12.56	06/30/06	2.55
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/06	0.80	12/31/06	0.63	12/31/06	4.42
09/30/06	0.69	09/30/06	0.49	09/30/06	3.38
06/30/06	0.71	06/30/06	0.67	06/30/06	2.95
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/06	5.88	12/31/06	5.88	12/31/06	19.52
09/30/06	4.52	09/30/06	4.52	09/30/06	18.60
06/30/06	3.65	06/30/06	3.65	06/30/06	18.66
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/06	19.96	12/31/06	0.57	12/31/06	36.29
09/30/06	21.86	09/30/06	0.55	09/30/06	35.67

06/30/06	16.93	06/30/06	0.57	06/30/06	36.22

Zacks.com Quotes and Research

NORTHWEST NAT GAS (NYSE)

NWN	45.23	▼-0.68	(-1.48%)	Vol. 59,000	Scottrade	12:36 CST

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

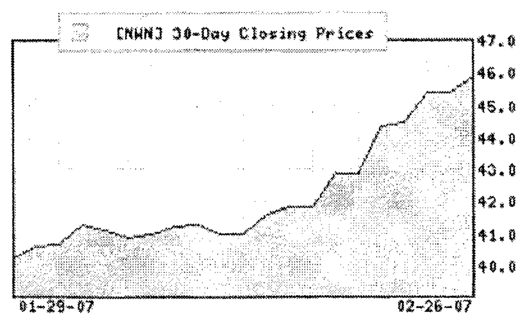
NORTHWEST NAT G
220 N.W. Second Avenue
Portland, OR 97209
Phone: 503 226-4211
Fax: 503 273-4824
Web: www.nwnatural.com
Email: investorinformation@nwnatural.com

Industry	UTIL-GAS DISTR
Sector:	Utilities

Fiscal Year End	December
Last Reported Quarter	12/31/06
Next EPS Date	05/10/2007

Price and Volume Information

Zacks Rank	
Yesterday's Close	45.91
52 Week High	45.40
52 Week Low	33.27
Beta	0.14
20 Day Moving Average	124,529.50
Target Price Consensus	44.67



% Price Change		% Price Change Relative to S&P 500	
4 Week	11.49	4 Week	9.01
12 Week	10.09	12 Week	5.87

YTD	6.97	YTD	-1.50
Share Information		**Dividend Information**	
Shares Outstanding (millions)	27.50	Dividend Yield	3.13%
		Annual Dividend	$1.42
Market Capitalization (millions)	1,248.73	Payout Ratio	0.62
Short Ratio	17.22	Change in Payout Ratio	0.00
Last Split Date	09/09/1996	Last Dividend Payout / Amount	01/29/2007 / $0.35

EPS Information		**Consensus Recommendations**	
Current Quarter EPS Consensus Estimate	1.54	Current (1=Strong Buy, 5=Strong Sell)	2.50
Current Year EPS Consensus Estimate	2.38	30 Days Ago	2.86
Estimated Long-Term EPS Growth Rate	5.30	60 Days Ago	2.86
Next EPS Report Date	05/10/2007	90 Days Ago	2.86

Fundamental Ratios

P/E		**EPS Growth**		**Sales Growth**	
Current FY Estimate:	19.11	vs. Previous Year	17.20%	vs. Previous Year	6.90%
Trailing 12 Months:	19.83	vs. Previous Quarter	411.43%	vs. Previous Quarter:	-2.86%
PEG Ratio	3.58				
Price Ratios		**ROE**		**ROA**	
Price/Book	2.11	12/31/06	10.44	12/31/06	3.49
Price/Cash Flow	10.44	09/30/06	9.81	09/30/06	3.15
Price / Sales	2.39	06/30/06	10.06	06/30/06	3.10
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/06	-	12/31/06	-	12/31/06	12.13
09/30/06	0.84	09/30/06	0.43	09/30/06	11.46
06/30/06	0.92	06/30/06	0.52	06/30/06	13.49
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/06	-	12/31/06	-	12/31/06	-
09/30/06	17.94	09/30/06	17.94	09/30/06	21.51
06/30/06	21.10	06/30/06	21.10	06/30/06	22.15
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/06	-	12/31/06	-	12/31/06	-
09/30/06	8.60	09/30/06	0.83	09/30/06	45.37

06/30/06	8.61	06/30/06	0.81	06/30/06	44.61

ZACKS PROFIT FROM THE PROS

Zacks.com Quotes and Research

PIEDMONT NAT GAS CO (NYSE)

PNY 26.02 ▼-0.43 (-1.63%) Vol. 107,500 12:37 CST

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

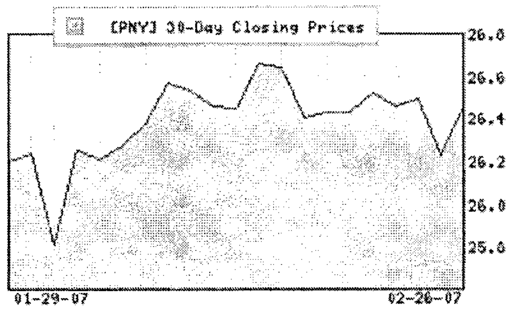
PIEDMONT NAT GA
4720 Piedmont Row Drive
Charlotte, NC 28210
Phone: 704 364-3120
Fax: 704 364-1395
Web: www.piedmontng.com
Email: margaret.griffith@piedmontng.com

Industry	UTIL-GAS DISTR
Sector:	Utilities

Fiscal Year End	October
Last Reported Quarter	01/31/07
Next EPS Date	03/13/2007

Price and Volume Information

Zacks Rank	
Yesterday's Close	26.45
52 Week High	28.28
52 Week Low	23.29
Beta	0.30
20 Day Moving Average	188,864.25
Target Price Consensus	27.5



% Price Change		% Price Change Relative to S&P 500	
4 Week	1.07	4 Week	-1.19

12 Week	-4.92	12 Week	-8.56
YTD	-0.93	YTD	-3.72

Share Information		Dividend Information	
Shares Outstanding (millions)	74.72	Dividend Yield	3.62%
		Annual Dividend	$0.96
Market Capitalization (millions)	1,980.00	Payout Ratio	0.00
Short Ratio	27.75	Change in Payout Ratio	0.00
Last Split Date	04/01/1993	Last Dividend Payout / Amount	12/19/2006 / $0.24

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.98	Current (1=Strong Buy, 5=Strong Sell)	3.00
Current Year EPS Consensus Estimate	1.42	30 Days Ago	3.00
Estimated Long-Term EPS Growth Rate	5.50	60 Days Ago	3.00
Next EPS Report Date	03/13/2007	90 Days Ago	2.89

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	18.68	vs. Previous Year	-33.33%	vs. Previous Year	-16.90%
Trailing 12 Months:	20.87	vs. Previous Quarter	50.00%	vs. Previous Quarter:	18.64%
PEG Ratio	3.40				
Price Ratios		**ROE**		**ROA**	
Price/Book	2.26	01/31/07	-	01/31/07	-
Price/Cash Flow	10.31	10/31/06	10.64	10/31/06	3.59
Price / Sales	-	07/31/06	10.76	07/31/06	3.67
Current Ratio		**Quick Ratio**		**Operating Margin**	
01/31/07	-	01/31/07	-	01/31/07	-
10/31/06	1.19	10/31/06	0.82	10/31/06	5.05
07/31/06	1.41	07/31/06	0.94	07/31/06	4.96
Net Margin		**Pre-Tax Margin**		**Book Value**	
01/31/07	-	01/31/07	-	01/31/07	-
10/31/06	8.29	10/31/06	8.29	10/31/06	11.72
07/31/06	8.12	07/31/06	8.12	07/31/06	11.98
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
01/31/07	-	01/31/07	-	01/31/07	-

10/31/06	9.67	10/31/06	0.93	10/31/06	48.30
07/31/06	9.96	07/31/06	0.91	07/31/06	47.77

ZACKS PROFIT FROM THE PROS

Zacks.com Quotes and Research

SOUTH JERSEY IND (NYSE)

Scottrade

SJI	34.36	▲0.81	(2.41%)	Vol. 174,800	14:41 CST

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

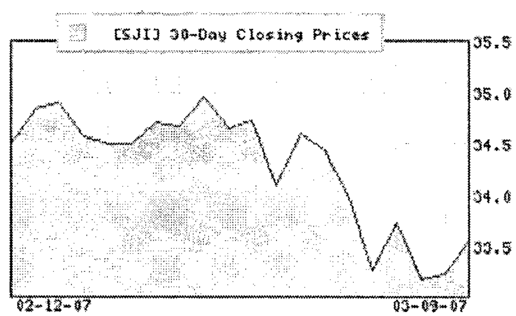
SOUTH JERSEY IN
1 South Jersey Plaza
Folsom, NJ 08037
Phone: 609 561-9000
Fax: 609-704-1608
Web: www.sjindustries.com
Email: investorrelations@sjindustries.com

Industry	UTIL-GAS DISTR
Sector:	Utilities

Fiscal Year End	December
Last Reported Quarter	12/31/06
Next EPS Date	05/11/2007

Price and Volume Information

Zacks Rank	
Yesterday's Close	33.55
52 Week High	34.97
52 Week Low	26.00
Beta	0.26
20 Day Moving Average	163,580.70
Target Price Consensus	36



% Price Change		% Price Change Relative to S&P 500	
4 Week	-3.29	4 Week	0.74
12 Week	-1.01	12 Week	0.50

YTD	-0.69	YTD	4.02
Share Information		**Dividend Information**	
Shares Outstanding (millions)	29.34	Dividend Yield	2.95%
		Annual Dividend	$0.98
Market Capitalization (millions)	973.53	Payout Ratio	0.50
Short Ratio	9.33	Change in Payout Ratio	0.00
Last Split Date	03/04/1993	Last Dividend Payout / Amount	12/07/2006 / $0.25

EPS Information		**Consensus Recommendations**	
Current Quarter EPS Consensus Estimate	0.98	Current (1=Strong Buy, 5=Strong Sell)	1.33
Current Year EPS Consensus Estimate	1.97	30 Days Ago	1.33
Estimated Long-Term EPS Growth Rate	6.50	60 Days Ago	1.33
Next EPS Report Date	05/11/2007	90 Days Ago	1.33

Fundamental Ratios

P/E		**EPS Growth**		**Sales Growth**	
Current FY Estimate:	16.87	vs. Previous Year	72.50%	vs. Previous Year	-11.04%
Trailing 12 Months:	16.93	vs. Previous Quarter	666.67%	vs. Previous Quarter:	88.14%
PEG Ratio	2.60				
Price Ratios		**ROE**		**ROA**	
Price/Book	2.24	12/31/06	13.44	12/31/06	3.96
Price/Cash Flow	12.63	09/30/06	11.58	09/30/06	3.35
Price / Sales	1.08	06/30/06	12.09	06/30/06	3.47
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/06	-	12/31/06	-	12/31/06	6.32
09/30/06	0.85	09/30/06	0.44	09/30/06	5.16
06/30/06	0.90	06/30/06	0.50	06/30/06	5.05
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/06	-	12/31/06	-	12/31/06	-
09/30/06	8.53	09/30/06	8.53	09/30/06	14.80
06/30/06	8.37	06/30/06	8.37	06/30/06	14.53
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/06	-	12/31/06	-	12/31/06	-
09/30/06	6.08	09/30/06	0.83	09/30/06	45.32

06/30/06	6.67	06/30/06	0.85	06/30/06	45.83

Zacks.com Quotes and Research

SOUTHWEST GAS CP (NYSE)

SWX	37.70	▲0.91	(2.47%)	Vol. 180,300	15:01 CST

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

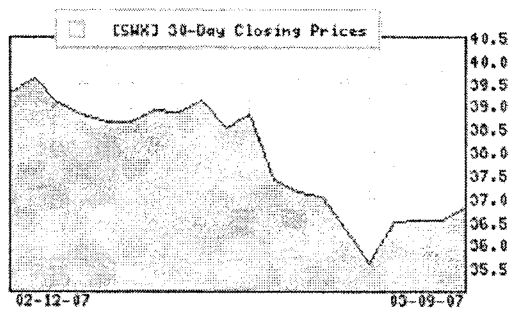
SOUTHWEST GAS
5241 Spring Mountain Road
P.O. Box 98510
Las Vegas, NV 89193-8510
Phone: 702 876-7237
Fax: 702 873-3820
Web: www.swgas.com
Email: None

Industry	UTIL-GAS DISTR
Sector:	Utilities

Fiscal Year End	December
Last Reported Quarter	12/31/06
Next EPS Date	05/08/2007

Price and Volume Information

Zacks Rank	
Yesterday's Close	36.79
52 Week High	39.68
52 Week Low	26.76
Beta	0.26
20 Day Moving Average	192,076.70
Target Price Consensus	37.33



% Price Change		% Price Change Relative to S&P 500	
4 Week	-7.71	4 Week	-3.86
12 Week	-4.82	12 Week	-3.37

YTD	-4.80	YTD	-3.27
Share Information		**Dividend Information**	
Shares Outstanding (millions)	42.00	Dividend Yield	2.24%
		Annual Dividend	$0.82
Market Capitalization (millions)	1,534.15	Payout Ratio	0.41
Short Ratio	8.92	Change in Payout Ratio	0.00
Last Split Date	N/A	Last Dividend Payout / Amount	02/13/2007 / $0.20
EPS Information		**Consensus Recommendations**	
Current Quarter EPS Consensus Estimate	1.21	Current (1=Strong Buy, 5=Strong Sell)	3.00
Current Year EPS Consensus Estimate	2.17	30 Days Ago	3.00
Estimated Long-Term EPS Growth Rate	-	60 Days Ago	3.00
Next EPS Report Date	05/08/2007	90 Days Ago	3.00

Fundamental Ratios

P/E		**EPS Growth**		**Sales Growth**	
Current FY Estimate:	16.83	vs. Previous Year	20.65%	vs. Previous Year	13.71%
Trailing 12 Months:	18.45	vs. Previous Quarter	526.92%	vs. Previous Quarter:	60.64%
PEG Ratio	-				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.81	12/31/06	10.02	12/31/06	2.59
Price/Cash Flow	6.93	09/30/06	8.97	09/30/06	2.24
Price / Sales	0.76	06/30/06	8.35	06/30/06	2.10
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/06	-	12/31/06	-	12/31/06	4.00
09/30/06	-	09/30/06	-	09/30/06	3.62
06/30/06	0.75	06/30/06	0.75	06/30/06	3.40
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/06	-	12/31/06	-	12/31/06	-
09/30/06	-	09/30/06	-	09/30/06	-
06/30/06	4.95	06/30/06	4.95	06/30/06	20.47
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/06	-	12/31/06	-	12/31/06	-
09/30/06	-	09/30/06	-	09/30/06	-

06/30/06	-	06/30/06	1.55 06/30/06	60.71

Zacks.com Quotes and Research

WGL Holdings (NYSE)

WGL	32.28	-0.52	(-1.59%)	Vol. 110,600	12:43 CST

WASHINGTON GAS LIGHT CO is a public utility that delivers and sells natural gas to metropolitan Washington, D.C. and adjoining areas in Maryland and Virginia. A distribution subsidiary serves portions of Virginia and West Virginia. The Company has four wholly-owned active subsidiaries that include: Shenandoah Gas Company (Shenandoah) is engaged in the delivery and sale of natural gas at retail in the Shenandoah Valley, including Winchester, Middletown, Strasburg, Stephens City and New Market, Virginia, and Martinsburg, West Virginia.

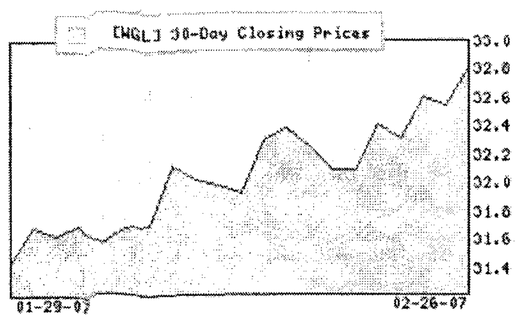
General Information

WGL HLDGS INC
101 Constitution Ave, N.W
Washington, DC 20080
Phone: 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	12/31/06
Next EPS Date	05/09/2007

Price and Volume Information

Zacks Rank	
Yesterday's Close	32.80
52 Week High	33.47
52 Week Low	27.38
Beta	0.24
20 Day Moving Average	239,499.75
Target Price Consensus	32



% Price Change		% Price Change Relative to S&P 500	
4 Week	4.15	4 Week	1.83
12 Week	-1.36	12 Week	-5.14

YTD	0.06	YTD	-4.02
Share Information		**Dividend Information**	
Shares Outstanding (millions)	48.89	Dividend Yield	4.14%
		Annual Dividend	$1.35
Market Capitalization (millions)	1,593.68	Payout Ratio	0.71
Short Ratio	21.85	Change in Payout Ratio	-0.10
Last Split Date	05/02/1995	Last Dividend Payout / Amount	01/08/2007 / $0.34

EPS Information		**Consensus Recommendations**	
Current Quarter EPS Consensus Estimate	1.18	Current (1=Strong Buy, 5=Strong Sell)	2.60
Current Year EPS Consensus Estimate	1.79	30 Days Ago	2.67
Estimated Long-Term EPS Growth Rate	3.00	60 Days Ago	2.67
Next EPS Report Date	05/09/2007	90 Days Ago	2.67

Fundamental Ratios

P/E		**EPS Growth**		**Sales Growth**	
Current FY Estimate:	18.21	vs. Previous Year	1.10%	vs. Previous Year	50.80%
Trailing 12 Months:	17.25	vs. Previous Quarter	611.11%	vs. Previous Quarter:	127.31%
PEG Ratio	6.07				
Price Ratios		**ROE**		**ROA**	
Price/Book	1.66	12/31/06	9.77	12/31/06	3.20
Price/Cash Flow	8.43	09/30/06	9.79	09/30/06	3.15
Price / Sales	1.06	06/30/06	9.48	06/30/06	3.08
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/06	1.01	12/31/06	0.67	12/31/06	6.14
09/30/06	1.00	09/30/06	0.44	09/30/06	7.28
06/30/06	1.17	06/30/06	0.71	06/30/06	7.64
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/06	12.32	12/31/06	12.32	12/31/06	19.62
09/30/06	5.91	09/30/06	5.91	09/30/06	18.90
06/30/06	9.88	06/30/06	9.88	06/30/06	19.41
Inventory Turnover		**Debt-to-Equity**		**Debt to Captial**	
12/31/06	8.74	12/31/06	0.63	12/31/06	38.00
09/30/06	7.91	09/30/06	0.62	09/30/06	37.75

06/30/06	3.29	06/30/06	0.61	06/30/06	37.38

ATTACHMENT D

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

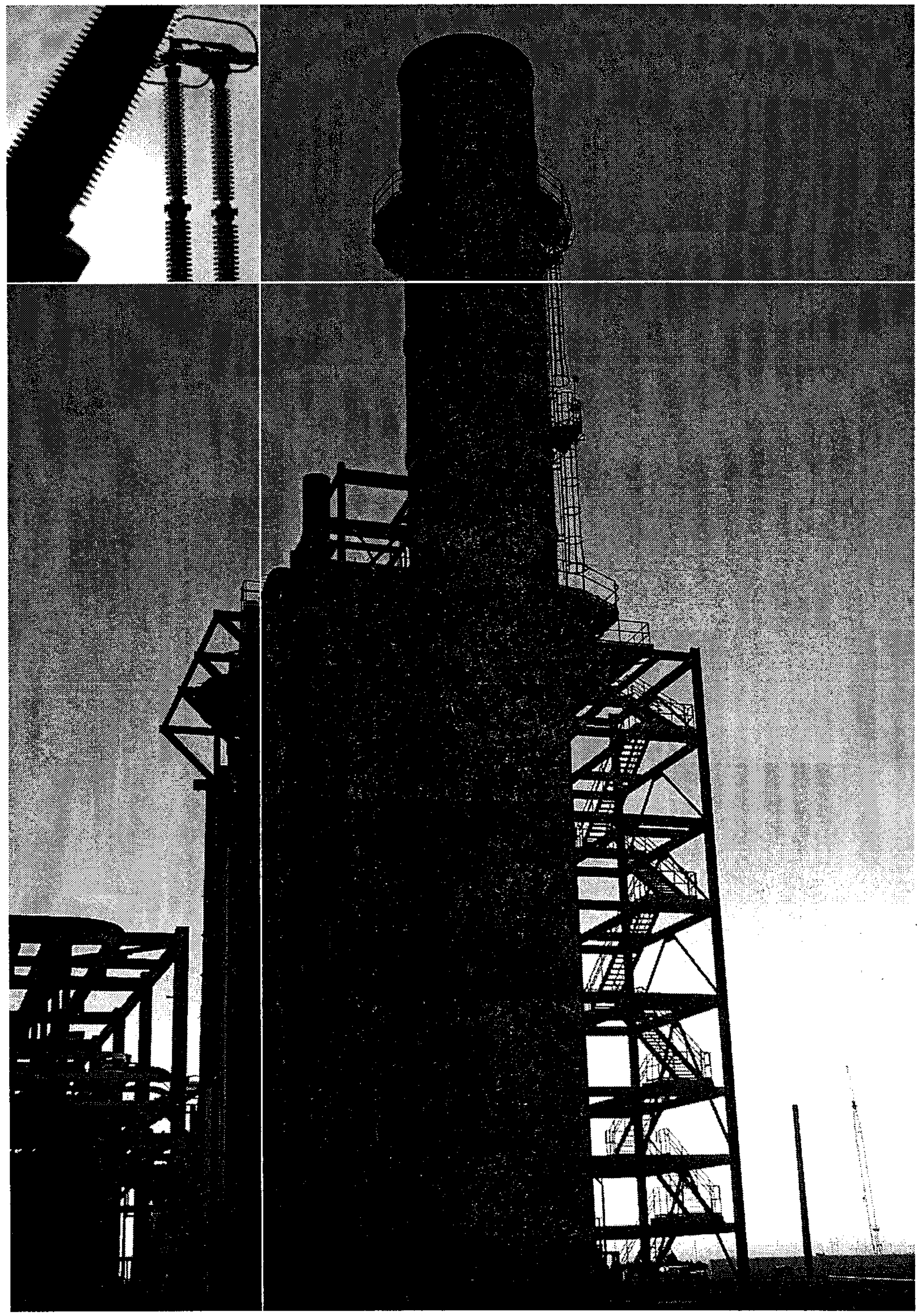
(DCF) analysis of a proxy group of publicly held natural gas companies. The Commission currently uses a two-stage Discounted Cash Flow (DCF) methodology. The two-stage method projects different rates of growth in projected dividend cash flows for each of the two stages, one stage reflecting short term 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.

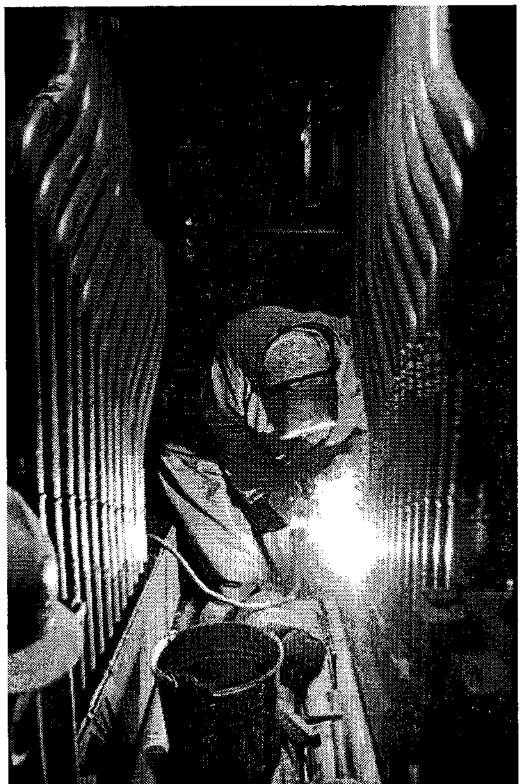
We have determined that a reasonable return on equity for Pipeline U.S.A. is 14.00%. This return was at the high end of our range of equity returns because Pipeline U.S.A. is a relatively new pipeline company with a high debt capitalization ratio. The equity portion of the return permitted to be collected in rates is $22,344,000 shown in column (5) of A-8.

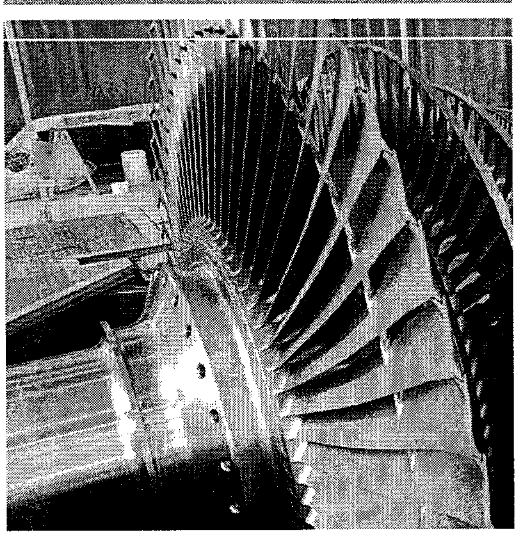
Pretax Return. Pretax return is the amount earned by a pipeline before income taxes and debt interest payments. Pretax return is often calculated for pipelines and used to further settlement negotiations. Using a pretax return figure can avoid the lengthy discussions and debates that surround the issues 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 E

UniSource Energy Corporation
Annual Report 2005







Generating Success

Generating

Confidence

Dear Fellow Shareholder,

In many ways, UniSource Energy Corporation is focused on a single, powerful concept: generation.

Utilities use that term to describe power production – the transformation of coal, natural gas, sunlight and other resources into the electricity that powers our modern lives. But generation means much more than power to UniSource Energy.

Our growing utility business generates positive returns for shareholders as it provides safe, reliable energy for customers. Our infusion of capital into Tucson Electric Power (TEP) and UniSource Energy Services (UES) in 2005 generated confidence in our financial standing, including a two-notch upgrade of TEP's credit rating from Moody's Investors Service. Our proposal to extend TEP's current rate agreement through 2010 would generate a level of price stability virtually unprecedented in today's volatile energy market. And our award-winning employee volunteer program continues to generate goodwill in the communities we serve.

In 2006, our commitment to generation will be apparent in its most literal sense. By year's end, we will have added two new plants to TEP's energy generating operations. The new units will complement the expanding operations of TEP and UES, which now combine to serve approximately 613,000 customers across Arizona.

These new facilities have been years in the making, and their completion will mark a historic expansion of our company's generating operations. But as our progress in other areas makes clear, UniSource Energy isn't just producing power – we're generating success.

Construction of a third unit at TEP's coal-fired Springerville Generating Station (SGS) remains on track with an accelerated timeline that calls for the 400-megawatt (MW) unit to be brought online during the third quarter of 2006. Crews working under the direction of project contractor Bechtel have made steady progress without sacrificing quality or safety. Through the end of 2005, workers had logged more than three million hours on the project without a single lost-time accident.

TEP will operate Unit 3. It also will purchase up to 100 MW of the unit's capacity for up to five years from Tri-State Generation and Transmission Association, a wholesale power cooperative that will lease the completed unit from a financial owner and control its output. In this way, we can capitalize on the expertise we've developed during two decades of power production at SGS while spreading the fixed costs of existing common facilities across an additional unit.

Phoenix-based Salt River Project (SRP), which will purchase 100 MW of Unit 3's output, also holds the right to build a fourth unit at SGS – a 400-MW generator that would be owned by SRP and operated by TEP. SRP has sought more time to evaluate its need for the unit's output.

While Unit 3 is still months away from completion, the expansion of SGS already has delivered significant benefits to TEP. As part of the project, Tri-State funded environmental improvements to Units 1 and 2 to ensure that the total regulated emissions from all four planned units will be significantly lower than previous emissions from the two existing 380-MW units.

Generating Growth

While the effects of those improvements are difficult to detect with the naked eye, they've had a noticeable impact on our bottom line. The reduction in sulfur dioxide (SO_2) output left TEP with a surplus of emissions allowances at a time when the price of this traded commodity was rising. The sale of SO_2 allowances contributed a $13 million pretax gain to TEP's results in 2005, and we're anticipating additional sales in 2006 and beyond.

The new gas-fired Luna Energy Facility, meanwhile, has been built from the ground up with state-of-the-art emissions controls and a combined cycle design that ensures it will serve as a clean, efficient source of power for decades to come.

TEP will share ownership of the facility with Phelps Dodge Energy Services and PNM, an Albuquerque-based utility. PNM will oversee operations of the plant, which is located two miles north of Deming in southern New Mexico. TEP and its partners each hold a one-third stake in the 570-MW facility and will split its output three ways.

Duke Energy had begun construction of the facility in October 2001, but it suspended work about a year later after investing $275 million in the project. TEP, Phelps Dodge and PNM bought the unfinished plant in November 2004 for $40 million. TEP invested about $50 million of internally generated cash toward the purchase and completion of the facility.

The power TEP will receive from both Luna and SGS 3 will expand our wholesale sales opportunities while ensuring our ability to meet the growing needs of our retail customers. Electric usage by TEP customers peaked at 2,225 MW in the summer of 2005, a nearly 7 percent increase over the previous year's peak. Usage should continue to rise along with Tucson's population. TEP's customer base is growing between 2 and 3 percent each year, well ahead of the nation's 1 percent annual population growth rate.

TEP has served this growth without sacrificing reliability or customer service. Our ability to minimize outages and to restore service promptly when interruptions do occur ranked well ahead of recent regional averages in 2005. Meanwhile, TEP once again finished among the leaders in customer satisfaction for western electric utilities last year, according to J.D. Power and Associates' 2005 Electric Utility Residential Customer Satisfaction Study.

Growth also is a defining characteristic of UniSource Energy Services, which serves some of Arizona's fastest growing communities. UES' gas utility, which operates in northern Arizona as well as Santa Cruz County on the U.S.-Mexico border, enjoyed greater than 4 percent customer growth last year. The customer base for the company's electric operations in Santa Cruz and Mohave Counties grew nearly 5 percent in 2005.

To help TEP and UES manage these dramatic growth levels, we completed a financial restructuring in 2005 that bolstered the stability of both utilities. Taking advantage of favorable financial markets, UniSource Energy issued $240 million in debt and used the proceeds, along with internal cash, to retire $320 million of debt obligations at TEP while contributing $20 million to UNS Electric and UNS Gas, the operating subsidiaries of UES. The transactions significantly improved the equity position of TEP while providing additional resources to help UES fund its growing needs.

Generating Stability

While skyrocketing natural gas prices and other cost increases have put upward pressure on utility expenses, retail customers of both TEP and UES enjoy the stability and predictability that come from long-term rate freezes. The base rates for UES service are frozen through at least August 2007, while TEP's rates are capped through the end of 2008.

Rising operational costs and increasing capital investments will compel us to file requests later this year for increased UES gas and electric rates that would take effect after the current rate freeze expires. In the meantime, we've asked the Arizona Corporation Commission (ACC) to update the formula used to calculate how wholesale gas costs are passed along to UNS Gas customers. At times, the current formula hasn't kept up with dramatic price increases, delaying recovery of our gas purchase costs.

For TEP, though, we're looking to extend the period of rate stability for customers for another two years. We've asked the ACC to maintain TEP's current rates through 2010 with the addition of an energy cost provision that would take effect in 2009. This new mechanism would help account for changes in market power costs since the settlement agreement establishing TEP's current rates was signed in 1999. This proposed extension was designed to provide TEP with some protection from market volatility while sparing customers from dramatic cost increases that could result from the initiation of market pricing contemplated under that settlement agreement.

The extended cap on TEP's rates has not prevented our Board of Directors from rewarding shareholders with rising dividend payments. Earlier this year, the Board voted to increase the quarterly payments to $0.21 per share, the sixth annual increase since the dividend was established at $.08 per share in 2000.

The Board's vote of confidence is particularly meaningful in light of our disappointing financial performance in 2005. UniSource Energy's year-end earnings of $46.1 million, or $1.33 per basic share of common stock, reflect the heavy toll of an extended shutdown of SGS Unit 2 and other plant outages. The unplanned outage struck SGS Unit 2 in August, when customer demand was high and energy prices were boosted by the impact of Gulf Coast hurricane activity. The outage contributed to an 82 percent increase in TEP's purchased power expense in 2005, offsetting our utility revenue growth and the benefits of our financial restructuring.

As a result, we did not achieve my 2005 earnings goal of $1.50 to $1.75 per share. And while the $276 million in operating cash produced by UniSource Energy was strong by most measures, it fell short of my $300 million goal for the year. Despite this shortfall, we internally funded our entire capital expenditure requirements of $203 million, including the Luna Energy Facility project.

I was further disappointed by increased losses at Millennium Energy Holdings, which contains UniSource Energy's unregulated investments. The increase was almost entirely due to higher costs at Global Solar Energy, a company that develops thin-film photovoltaic material. We have agreed to sell Global Solar in a transaction that would allow us to repurchase between 5 and 10 percent of the company for a nominal fee, giving us an opportunity to capitalize on its future success. The sale is consistent with our strategy of scaling back Millennium's involvement in actively managed investments to focus on UniSource Energy's core utility operations.

Generating

Goodwill

That focus will continue to include a strong emphasis on community service. Employees at both TEP and UES joined their friends and families in contributing nearly 39,000 hours of their own time to charitable activities in 2005. We've also asked our employees to provide direction for UniSource Energy's corporate giving program, rewarding their efforts with critical support for the causes most important to them. This strategy, which continues to attract significant national acclaim, has served to strengthen the bonds between our employees and the communities we serve together.

Our bond with some of TEP's most critical employees was solidified earlier this year when the International Brotherhood of Electrical Workers Local 1116 ratified a comprehensive three-year labor agreement. The agreement, which will remain in effect through January 2009, provides a balanced wage and benefit package that serves the long-term interests of both the company and our employees.

With a committed work force, a solid financial base and expanding utility operations, UniSource Energy is in a strong position to produce improving results in 2006 and beyond. In addition to the completion of SGS 3 and the Luna Energy Facility, my goals for this year include improved availability from our existing generating units, particularly during the critical summer months. We'll also press for resolution of the disagreement over the basis of TEP's future rates while addressing the need to increase the rates charged by UNS Gas and UNS Electric.

Other goals include the successful implementation of a new billing system that will improve customer service and streamline the operations of TEP, UNS Gas and UNS Electric. The upgrade, which replaces three separate older systems, is a highlight of our ongoing campaign to improve our business processes – an effort that will receive even greater emphasis this year. The success of these measures and the continued growth of our utility businesses should help us achieve year-end earnings between $1.65 and $2.05 per share for 2006.

I would like to thank you, my fellow shareholders, for your continued faith in UniSource Energy. I would also like to thank our employees, who have pursued our goals with admirable resolve. Together, we've invested in our future and followed a course that leaves us poised to capitalize on growth instead of falling victim to it. Such strategic planning is key for regulated utilities because we operate in a unique environment; unlike other companies, we provide a product far more valuable than the price our customers pay. In so doing, we create significant benefits for customers at the same time we're producing value for our shareholders. In 2006 and beyond, UniSource Energy will remain committed to generating success on both these fronts.

Your fellow shareholder,

James S. Pignatelli
Chairman, President and CEO
UniSource Energy Corporation

UNS GAS, INC.

DOCKET NO. G-04204A-06-0463

TABLE OF CONTENTS TO SURREBUTTAL SCHEDULES WAR

WEIGHTED 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	DEBT	$ 98,859	$ -	$ 98,859	50.00%	6.60%	3.30%
2	PREFERRED STOCK	-	-	-	0.00%	0.00%	0.00%
3	COMMON EQUITY	98,859	-	98,859	50.00%	9.84%	4.92%
4	TOTAL CAPITALIZATION	$ 197,718	$ -	$ 197,718	100.00%		
5	**WEIGHTED COST OF CAPITAL**						8.22%

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-1
COLUMN (B): TESTIMONY, WAR
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COLUMN (C) ÷ COLUMN (C), LINE 4
COLUMN (E): LINE 1 - TESTIMONY, WAR; LINE 3 - SCHEDULE WAR-1, PAGE 2
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	9.16%	SCHEDULE WAR-2, COLUMN (C), LINE 11
3	**CAPM METHODOLOGY**		
4	CAPM - GEOMETRIC MEAN ESTIMATE	9.68%	SCHEDULE WAR-7 PAGE 1, COLUMN (B), LINE 11
5	CAPM - ARITHMETIC MEAN ESTIMATE	11.33%	SCHEDULE WAR-7 PAGE 2, COLUMN (B), LINE 11
6	AVERAGE OF CAPM ESTIMATES	10.51%	(LINE 4 + LINE 5) ÷ 2
7	**AVERAGE**	$\boxed{9.84\%}$	(LINE 2 + LINE 6) ÷ 2

UNS GAS, INC.
TEST YEAR ENDED DECEMBER 31, 2005
DCF COST OF EQUITY CAPITAL

DOCKET NO. G-04204A-06-0463
SURREBUTTAL SCHEDULE WAR - 2

LINE NO.	STOCK SYMBOL	COMPANY	(A) DIVIDEND YIELD	+	(B) GROWTH RATE (g)	=	(C) DCF COST OF EQUITY CAPITAL
1	ATG	AGL RESOURCES, INC.	4.00%	+	5.99%	=	9.99%
2	ATO	ATMOS ENERGY CORPORATION	4.02%	+	5.54%	=	9.57%
3	LG	LACLEDE GROUP, INC.	4.66%	+	3.71%	=	8.37%
4	NJR	NEW JERSEY RESOURCES CORP.	3.11%	+	6.14%	=	9.25%
5	GAS	NICOR, INC.	3.99%	+	3.71%	=	7.70%
6	NWN	NORTHWEST NATURAL GAS CO.	3.29%	+	5.09%	=	8.38%
7	PNY	PIEDMONT NATURAL GAS COMPANY	3.67%	+	3.69%	=	7.36%
8	SJI	SOUTH JERSEY INDUSTIES, INC.	2.77%	+	11.17%	=	13.94%
9	SWX	SOUTHWEST GAS CORP.	2.25%	+	7.22%	=	9.47%
10	WGL	WGL HOLDINGS, INC.	4.29%	+	3.33%	=	7.62%
11	**NATURAL GAS LDC AVERAGE**						9.16%

REFERENCES:
COLUMN (A): SCHEDULE WAR - 3, COLUMN C
COLUMN (B): SCHEDULE WAR - 4, PAGE 1, COLUMN C

UNS GAS, INC.
TEST YEAR ENDED DECEMBER 31, 2005
DIVIDEND YIELD CALCULATION

DOCKET NO. G-04204A-06-0463
SURREBUTTAL SCHEDULE WAR - 3

LINE NO.	STOCK SYMBOL	COMPANY	(A) ESTIMATED DIVIDEND (PER SHARE)	÷	(B) AVERAGE STOCK PRICE (PER SHARE)	=	(C) DIVIDEND YIELD
1	ATG	AGL RESOURCES, INC.	$1.64	÷	$40.99	=	4.00%
2	ATO	ATMOS ENERGY CORPORATION	1.28	÷	31.83	=	4.02%
3	LG	LACLEDE GROUP, INC.	1.46	÷	31.32	=	4.66%
4	NJR	NEW JERSEY RESOURCES CORP.	1.52	÷	48.91	=	3.11%
5	GAS	NICOR, INC.	1.86	÷	46.61	=	3.99%
6	NWN	NORTHWEST NATURAL GAS CO.	1.42	÷	43.14	=	3.29%
7	PNY	PIEDMONT NATURAL GAS COMPANY	0.96	÷	26.15	=	3.67%
8	SJI	SOUTH JERSEY INDUSTIES, INC.	0.96	÷	34.65	=	2.77%
9	SWX	SOUTHWEST GAS CORP.	0.86	÷	38.29	=	2.25%
10	WGL	WGL HOLDINGS, INC.	1.36	÷	31.71	=	4.29%
11	**NATURAL GAS LDC AVERAGE**						3.61%

REFERENCES:
COLUMN (A): ESTIMATED 12 MONTH DIVIDEND REPORTED IN VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 03/16/2006.
COLUMN (B): EIGHT WEEK AVERAGE OF CLOSING PRICES FROM 01/28/2007 TO 03/23/2007 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 DECEMBER 31, 2005
DIVIDEND GROWTH RATE CALCULATION

LINE NO.	STOCK SYMBOL	COMPANY	(A) INTERNAL GROWTH (br)	+	(B) EXTERNAL GROWTH (sv)	=	(C) DIVIDEND GROWTH (g)
1	ATG	AGL RESOURCES, INC.	5.75%	+	0.24%	=	5.99%
2	ATO	ATMOS ENERGY CORPORATION	4.50%	+	1.04%	=	5.54%
3	LG	LACLEDE GROUP, INC.	3.00%	+	0.71%	=	3.71%
4	NJR	NEW JERSEY RESOURCES CORP.	5.50%	+	0.64%	=	6.14%
5	GAS	NICOR, INC.	3.65%	+	0.06%	=	3.71%
6	NWN	NORTHWEST NATURAL GAS CO.	4.75%	+	0.34%	=	5.09%
7	PNY	PIEDMONT NATURAL GAS COMPANY	3.25%	+	0.44%	=	3.69%
8	SJI	SOUTH JERSEY INDUSTIES, INC.	10.50%	+	0.67%	=	11.17%
9	SWX	SOUTHWEST GAS CORP.	6.25%	+	0.97%	=	7.22%
10	WGL	WGL HOLDINGS, INC.	3.25%	+	0.08%	=	3.33%
11	**NATURAL GAS LDC AVERAGE**						5.56%

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 DECEMBER 31, 2005
DIVIDEND GROWTH RATE CALCULATION

LINE NO.	STOCK SYMBOL	COMPANY	(A) SHARE GROWTH	x	(B) { [((M ÷ B) + 1) ÷ 2] - 1 }	=	(C) EXTERNAL GROWTH (sv)
1	ATG	AGL RESOURCES, INC.	0.50%	x	{ [((1.96) + 1) ÷ 2] - 1 }	=	0.24%
2	ATO	ATMOS ENERGY CORPORATION	5.00%	x	{ [((1.42) + 1) ÷ 2] - 1 }	=	1.04%
3	LG	LACLEDE GROUP, INC.	2.75%	x	{ [((1.51) + 1) ÷ 2] - 1 }	=	0.71%
4	NJR	NEW JERSEY RESOURCES CORP.	1.25%	x	{ [((2.03) + 1) ÷ 2] - 1 }	=	0.64%
5	GAS	NICOR, INC.	0.10%	x	{ [((2.27) + 1) ÷ 2] - 1 }	=	0.06%
6	NWN	NORTHWEST NATURAL GAS CO.	0.75%	x	{ [((1.90) + 1) ÷ 2] - 1 }	=	0.34%
7	PNY	PIEDMONT NATURAL GAS COMPANY	0.75%	x	{ [((2.18) + 1) ÷ 2] - 1 }	=	0.44%
8	SJI	SOUTH JERSEY INDUSTIES, INC.	1.15%	x	{ [((2.16) + 1) ÷ 2] - 1 }	=	0.67%
9	SWX	SOUTHWEST GAS CORP.	2.65%	x	{ [((1.73) + 1) ÷ 2] - 1 }	=	0.97%
10	WGL	WGL HOLDINGS, INC.	0.25%	x	{ [((1.68) + 1) ÷ 2] - 1 }	=	0.08%
11	**NATURAL GAS LDC AVERAGE**						0.52%

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): VALUE LINE INVESTMENT SURVEY RATINGS & REPORTS DATED 03/16/2006
COLUMN (C): COLUMN (A) x COLUMN (B)

UNS GAS, INC.
TEST YEAR ENDED DECEMBER 31, 2005
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	NATURAL GAS LDC NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	ATG	AGL RESOURCES, INC.	2002	0.4066		14.50%		5.90%	12.52	56.70	
2			2003	0.4663		14.00%		6.53%	14.66	64.50	
3			2004	0.4956		11.00%		5.45%	18.06	76.70	
4			2005	0.4758		12.90%		6.14%	19.29	77.70	
5			2006	0.4559		13.00%		5.93%	20.69	77.75	
6			GROWTH 2002 - 2006					5.99%	8.50%		8.21%
7			2007	0.4143		13.50%		5.59%		78.00	0.32%
8			2008	0.4345		14.00%		6.08%		79.00	0.80%
9			2010-12	0.4194		14.00%		5.87%	2.50%	80.00	0.57%
10											
11	ATO	ATMOS ENERGY CORPORATION	2002	0.1862		10.40%		1.94%	13.75	41.68	
12			2003	0.2982		9.30%		2.77%	16.66	51.48	
13			2004	0.2278		7.60%		1.73%	18.05	62.80	
14			2005	0.2791		8.50%		2.37%	19.90	80.54	
15			2006	0.3700		9.90%		3.66%	20.16	81.74	
16			GROWTH 2002 - 2006					2.50%	8.50%		18.34%
17			2007	0.3600		9.00%		3.24%		89.50	9.49%
18			2008	0.3810		9.50%		3.62%		92.50	6.38%
19			2010-12	0.4600		10.00%		4.60%	4.00%	107.00	5.53%
20											
21	LG	LACLEDE GROUP, INC.	2002	-0.1356		7.80%		NMF	15.07	18.96	
22			2003	0.2637		11.60%		3.06%	15.65	19.11	
23			2004	0.2582		10.10%		2.61%	16.96	20.98	
24			2005	0.2789		10.90%		3.04%	17.31	21.17	
25			2006	0.4093		12.50%		5.12%	18.85	21.36	
26			GROWTH 2002 - 2006					3.46%	3.50%		3.02%
27			2007	0.2368		9.00%		2.13%		21.50	0.66%
28			2008	0.2550		9.50%		2.42%		22.00	1.49%
29			2010-12	0.3191		10.00%		3.19%	5.00%	25.00	3.20%
30											
31	NJR	NEW JERSEY RESOURCES CORP.	2002	0.4258		15.70%		6.69%	13.06	27.67	
32			2003	0.4790		15.60%		7.47%	15.38	27.23	
33			2004	0.4902		15.30%		7.50%	16.87	27.74	
34			2005	0.4868		17.00%		8.28%	15.90	27.55	
35			2006	0.4857		12.60%		6.12%	22.50	27.63	
36			GROWTH 2002 - 2006					7.21%	8.50%		-0.04%
37			2007	0.4759		12.50%		5.95%		28.00	1.34%
38			2008	0.4800		12.00%		5.76%		28.50	1.56%
39			2010-12	0.4667		11.00%		5.13%	8.00%	29.50	1.32%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 03/16/2007
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 & 26, SIMPLE AVERAGE GROWTH, 2001 - 2005

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

LINE NO.	STOCK SYMBOL	NATURAL GAS LDC NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	GAS	NICOR, INC.	2002	0.3611		17.50%		6.32%	16.55	44.01	
2			2003	0.1185		12.30%		1.46%	17.13	44.04	
3			2004	0.1622		13.10%		2.12%	16.99	44.10	
4			2005	0.1878		12.50%		2.35%	18.36	44.18	
5			2006	0.3861		14.00%		5.41%	19.35	44.70	
6			GROWTH 2002 - 2006					3.53%	1.50%		0.39%
7			2007	0.2963		13.00%		3.85%		44.60	-0.22%
8			2008	0.3091		13.00%		4.02%		44.70	0.00%
9			2010-12	0.3103		12.00%		3.72%	4.50%	45.00	0.13%
10											
11	NWN	NORTHWEST NATURAL GAS CO.	2002	0.2222		8.50%		1.89%	18.88	25.59	
12			2003	0.2784		9.00%		2.51%	19.52	25.94	
13			2004	0.3011		8.90%		2.68%	20.64	27.55	
14			2005	0.3744		9.90%		3.71%	21.28	27.58	
15			2006	0.3930		10.60%		4.17%	21.96	27.28	
16			GROWTH 2002 - 2006					2.99%	3.50%		1.61%
17			2007	0.4000		10.50%		4.20%		27.50	0.81%
18			2008	0.4118		11.00%		4.53%		27.50	0.40%
19			2010-12	0.3898		12.00%		4.68%	3.50%	29.00	1.23%
20											
21	PNY	PIEDMONT NATURAL GAS COMPANY	2002	0.1579		10.60%		1.67%	8.91	66.18	
22			2003	0.2613		11.80%		3.08%	9.36	67.31	
23			2004	0.3307		11.10%		3.67%	11.15	76.67	
24			2005	0.3106		11.50%		3.57%	11.53	76.70	
25			2006	0.2520		11.00%		2.77%	11.83	74.61	
26			GROWTH 2002 - 2006					2.95%	6.50%		3.04%
27			2007	0.2929		11.50%		3.37%		73.80	-1.09%
28			2008	0.2897		11.50%		3.33%		73.00	-1.08%
29			2010-12	0.2581		11.50%		2.97%	2.50%	71.80	-0.76%
30											
31	SJI	SOUTH JERSEY INDUSTIES, INC.	2002	0.3852		12.50%		4.82%	9.67	24.41	
32			2003	0.4307		11.60%		5.00%	11.26	26.46	
33			2004	0.4810		12.50%		6.01%	12.41	27.76	
34			2005	0.4971		12.40%		6.16%	13.50	28.98	
35			2006	0.6260		16.30%		10.20%	15.12	29.30	
36			GROWTH 2002 - 2006					6.44%	13.00%		4.67%
37			2007	0.6370		17.00%		10.83%		29.60	1.02%
38			2008	0.6379		17.00%		10.84%		30.00	1.19%
39			2010-12	0.6364		17.50%		11.14%	5.00%	31.00	1.13%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 03/16/2007
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 & 26, SIMPLE AVERAGE GROWTH, 2002 - 2006

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

UNS GAS, INC.
TEST YEAR ENDED DECEMBER 31, 2005
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	NATURAL GAS LDC NAME	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	SWX	SOUTHWEST GAS CORP.	2002	0.2931		6.50%		1.91%	17.91	33.29	
2			2003	0.2743		6.10%		1.67%	18.42	34.23	
3			2004	0.5060		8.30%		4.20%	19.18	36.79	
4			2005	0.3440		6.40%		2.20%	19.10	39.33	
5			2006	0.5859		9.00%		5.27%	21.58	41.77	
6			GROWTH 2002 - 2006					3.05%	3.00%		5.84%
7			2007	0.5943		9.50%		5.65%		43.00	2.94%
8			2008	0.6178		10.00%		6.18%		44.00	2.63%
9			2010-12	0.6538		10.00%		6.54%	4.00%	47.50	2.60%
10											
11	WGL	WGL HOLDINGS, INC.	2002	-0.1140		7.20%		NMF	15.78	48.56	
12			2003	0.4435		7.20%		3.19%	16.25	48.63	
13			2004	0.3434		11.70%		4.02%	16.95	48.67	
14			2005	0.3744		12.00%		4.49%	17.80	48.65	
15			2006	0.3093		10.20%		3.15%	18.28	48.89	
16			GROWTH 2002 - 2006					3.71%	3.00%		0.17%
17			2007	0.2959		10.50%		3.11%		48.91	0.04%
18			2008	0.3073		10.70%		3.29%		48.92	0.03%
19			2010-12	0.3409		10.50%		3.58%	3.00%	49.00	0.04%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 03/16/2007
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 & 26, SIMPLE AVERAGE GROWTH, 2002 - 2006

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

UNS GAS, INC.
TEST YEAR ENDED DECEMBER 31, 2005
GROWTH RATE COMPARISON

DOCKET NO. G-04204A-06-0463
SURREBUTTAL SCHEDULE WAR - 6

NATURAL GAS LDC SAMPLE:

LINE NO.	STOCK SYMBOL	(A) (br) + (sv)	(B) ZACKS EPS	(C) VALUE LINE PROJECTED EPS	DPS	BVPS	(D) VALUE LINE HISTORIC EPS	DPS	BVPS	(E) VALUE LINE & ZACKS AVGS.	(F) 5 - YEAR COMPOUND HISTORY EPS	DPS	BVPS
1	ATG	5.99%	5.00%	3.50%	5.50%	2.50%	13.50%	2.00%	8.50%	5.79%	10.57%	8.20%	13.38%
2	ATO	5.54%	5.30%	5.00%	1.50%	4.00%	10.00%	2.00%	8.50%	5.19%	8.37%	1.65%	10.04%
3	LG	3.71%	-	2.00%	2.50%	5.00%	6.50%	0.50%	3.50%	3.33%	19.05%	1.10%	5.75%
4	NJR	6.14%	6.00%	2.50%	3.00%	8.00%	8.00%	3.50%	8.50%	5.64%	7.59%	4.66%	14.57%
5	GAS	3.71%	2.00%	4.00%	1.00%	4.50%	-3.50%	3.50%	1.50%	1.86%	1.28%	0.27%	3.99%
6	NWN	5.09%	5.30%	7.00%	4.00%	3.50%	5.00%	1.00%	3.50%	4.19%	9.04%	2.49%	3.85%
7	PNY	3.69%	5.50%	3.00%	4.00%	2.50%	5.00%	5.00%	6.50%	4.50%	7.53%	4.39%	7.34%
8	SJI	11.17%	6.50%	9.50%	5.50%	5.00%	11.50%	2.50%	13.00%	7.64%	19.16%	5.24%	11.82%
9	SWX	7.22%	-	8.00%	1.50%	4.00%	-0.50%	-	3.00%	3.20%	14.30%	-	4.77%
10	WGL	3.33%	3.00%	1.00%	1.50%	3.00%	6.00%	1.50%	3.00%	2.71%	14.22%	1.35%	3.75%
11				4.55%	3.00%	4.20%	6.15%	2.39%	5.95%		11.11%	2.93%	7.93%
12	AVERAGES	5.56%	4.83%		3.92%			4.83%		4.40%		7.32%	

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 03/16/2007
COLUMN (D): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 03/16/2007
COLUMN (E): SIMPLE AVERAGE OF COLUMNS (B) THRU (D) LINES 1, 3, 5 AND 7
COLUMN (F): 5-YEAR ANNUAL GROWTH RATE CALCULATED WITH DATA COMPILED FROM VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 03/16/2007

BASED ON A GEOMETRIC MEAN:

LINE NO.	STOCK SYMBOL	k	=	r_f	+ [	(A) ß	x	(	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
1	ATG	k	=	5.10%	+ [	0.95	x	(	10.40%	-	5.10%	)]	=	10.13%
2	ATO	k	=	5.10%	+ [	0.80	x	(	10.40%	-	5.10%	)]	=	9.34%
3	LG	k	=	5.10%	+ [	0.85	x	(	10.40%	-	5.10%	)]	=	9.60%
4	NJR	k	=	5.10%	+ [	0.80	x	(	10.40%	-	5.10%	)]	=	9.34%
5	GAS	k	=	5.10%	+ [	1.30	x	(	10.40%	-	5.10%	)]	=	11.99%
6	NWN	k	=	5.10%	+ [	0.75	x	(	10.40%	-	5.10%	)]	=	9.07%
7	PNY	k	=	5.10%	+ [	0.80	x	(	10.40%	-	5.10%	)]	=	9.34%
8	SJI	k	=	5.10%	+ [	0.70	x	(	10.40%	-	5.10%	)]	=	8.81%
9	SWX	k	=	5.10%	+ [	0.85	x	(	10.40%	-	5.10%	)]	=	9.60%
10	WGL	k	=	5.10%	+ [	0.85	x	(	10.40%	-	5.10%	)]	=	9.60%
11	**NATURAL GAS LDC AVERAGE**					0.87								9.68%

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$$k = r_f + [\, ß\, (r_m - r_f)\,]$$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) A 6-WEEK AVERAGE OF THE 91-DAY T-BILL RATES THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 02/23/2007 THROUGH 03/30/2007 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE MARKET RATE PROXY USED WAS THE GEOMETRIC MEAN FOR S&P 500 RETURNS OVER THE 1926 - 2005 PERIOD. THE DATA WAS OBTAINED FROM IBBOTSON ASSOCIATES' STOCKS, BONDS, BILLS AND INFLATION: 2005 YEARBOOK.

BASED ON AN ARITHMETIC MEAN:

LINE NO.	STOCK SYMBOL	k	=	r_f	+ [	(A) ß	x (	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
1	ATG	k	=	5.10%	+ [	0.95	x (	12.30%	-	5.10%	)]	=	11.94%
2	ATO	k	=	5.10%	+ [	0.80	x (	12.30%	-	5.10%	)]	=	10.86%
3	LG	k	=	5.10%	+ [	0.85	x (	12.30%	-	5.10%	)]	=	11.22%
4	NJR	k	=	5.10%	+ [	0.80	x (	12.30%	-	5.10%	)]	=	10.86%
5	GAS	k	=	5.10%	+ [	1.30	x (	12.30%	-	5.10%	)]	=	14.46%
6	NWN	k	=	5.10%	+ [	0.75	x (	12.30%	-	5.10%	)]	=	10.50%
7	PNY	k	=	5.10%	+ [	0.80	x (	12.30%	-	5.10%	)]	=	10.86%
8	SJI	k	=	5.10%	+ [	0.70	x (	12.30%	-	5.10%	)]	=	10.14%
8	SWX	k	=	5.10%	+ [	0.85	x (	12.30%	-	5.10%	)]	=	11.22%
9	WGL	k	=	5.10%	+ [	0.85	x (	12.30%	-	5.10%	)]	=	11.22%
10	**NATURAL GAS LDC AVERAGE**					0.87							11.33%

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$$k = r_f + [\,ß\,(r_m - r_f)\,]$$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) A 6-WEEK AVERAGE OF THE 91-DAY T-BILL RATES THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 02/23/2007 THROUGH 03/30/2007 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE MARKET RATE PROXY USED WAS THE ARITHMETIC MEAN FOR S&P 500 RETURNS OVER THE 1926 - 2005 PERIOD. THE DATA WAS OBTAINED FROM IBBOTSON ASSOCIATES' STOCKS, BONDS, BILLS AND INFLATION: 2005 YEARBOOK.

UNS GAS, INC.
TEST YEAR ENDED DECEMBER 31, 2005
ECONOMIC INDICATORS - 1990 TO PRESENT

DOCKET NO. G-04204A-06-0463
SURREBUTTAL 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	5.40%	1.90%	10.01%	6.98%	8.10%	7.49%	7.49%	9.86%	10.06%
2	1991	4.21%	-0.20%	8.46%	5.45%	5.69%	5.38%	5.38%	9.36%	9.55%
3	1992	3.01%	3.30%	6.25%	3.25%	3.52%	3.43%	3.43%	8.69%	8.86%
4	1993	2.99%	2.70%	6.00%	3.00%	3.02%	3.00%	3.00%	7.59%	7.91%
5	1994	2.56%	4.00%	7.14%	3.60%	4.20%	4.25%	4.25%	8.31%	8.63%
6	1995	2.83%	2.50%	8.83%	5.21%	5.84%	5.49%	5.49%	7.89%	8.29%
7	1996	2.95%	3.70%	8.27%	5.02%	5.30%	5.01%	5.01%	7.75%	8.17%
8	1997	1.70%	4.50%	8.44%	5.00%	5.46%	5.06%	5.06%	7.60%	8.12%
9	1998	1.60%	4.20%	8.35%	4.92%	5.35%	4.78%	4.78%	7.04%	7.27%
10	1999	2.70%	4.50%	7.99%	4.62%	4.97%	4.64%	4.64%	7.62%	7.88%
11	2000	3.40%	3.70%	9.23%	5.73%	6.24%	5.82%	5.82%	8.24%	8.36%
12	2001	1.60%	0.80%	6.92%	3.41%	3.88%	3.38%	5.95%	7.59%	8.02%
13	2002	2.40%	1.60%	4.67%	1.17%	1.66%	1.60%	5.38%	7.41%	7.98%
14	2003	1.90%	2.50%	4.12%	2.03%	1.13%	1.01%	4.92%	6.18%	6.64%
15	2004	3.30%	3.90%	4.34%	2.35%	1.35%	1.37%	5.03%	5.77%	6.20%
16	2005	3.40%	3.20%	6.16%	4.16%	3.16%	3.17%	4.57%	5.38%	5.78%
17	2006	2.50%	3.30%	7.97%	5.97%	4.97%	4.83%	4.88%	5.94%	6.30%
18	CURRENT	2.50%	2.50% (a)	8.25%	6.25%	5.25%	5.03%	4.72%	5.86%	6.01%

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 (F): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 03/30/2007
COLUMN (G) THROUGH (I): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 03/30/2007
COLUMN (H) THROUGH (J): 1990 - 2000, MOODY'S PUBLIC UTILITY REPORTS
COLUMN (H) THROUGH (I): 2001, MERGENT 2002 PUBLIC UTILITY MANUAL
COLUMN (H) THROUGH (I): 2003 MERGENT NEWS REPORTS

NOTES
(a) FOURTH QUARTER 2006 GDP REVISED UPWARD ON 03/28/2007

UNS GAS, INC.
TEST YEAR ENDED DECEMBER 31, 2005
CAPITAL STRUCTURES OF SAMPLE COMPANIES

DOCKET NO. G-04204A-06-0463
SURREBUTTAL SCHEDULE WAR - 9

LINE NO.		ATG	PCT.	ATO	PCT.	LG	PCT.	NJR	PCT.	GAS	PCT.
1	DEBT	$ 1,615.0	51.9%	$ 1,602.4	42.3%	$ 340.5	48.1%	$ 317.2	42.0%	$ 1,071.8	56.9%
3	PREFERRED STOCK	0.0	0.0%	0.0	0.0%	0.9	0.1%	0.0	0.0%	0.6	0.0%
5	COMMON EQUITY	1,499.0	48.1%	2,183.1	57.7%	366.5	51.8%	438.1	58.0%	811.3	43.1%
7	TOTALS	$ 3,114.0	100%	$ 3,785.5	100%	$ 707.9	100%	$ 755.3	100%	$ 1,883.7	100%

LINE NO.		NWN	PCT.	PNY	PCT.	SJI	PCT.	SWX	PCT.	WGL	PCT.
12	DEBT	$ 521.5	47.0%	$ 625.0	41.4%	$ 328.9	48.7%	$ 1,224.9	59.0%	$ 584.2	38.8%
14	PREFERRED STOCK	0.0	0.0%	0.0	0.0%	1.6	0.2%	100.0	4.8%	28.2	1.9%
16	COMMON EQUITY	586.9	53.0%	884.2	58.6%	344.4	51.0%	751.1	36.2%	894.0	59.3%
18	TOTALS	$ 1,108.4	100%	$ 1,509.2	100%	$ 674.9	100%	$ 2,076.0	100%	$1,506.4	100%

LINE NO.		NATURAL GAS LDC AVERAGE	PCT.
24	DEBT	$ 823.1	48.1%
26	PREFERRED STOCK	13.1	0.8%
28	COMMON EQUITY	875.9	51.2%
30	TOTALS	$ 1,712.1	100%

REFERENCE:
MOST RECENT SEC 10-K FILINGS OR ANNUAL REPORTS

UNS Gas, Inc.
Test Year Ended December 31, 2005

Rate Base	Unadjusted 2005		CWIP Balance to be Allocated
302 Franchises and Consents	$383,214.73	0.132%	$ 9,467
303 Miscellaneous Intangible Plant	900,696.23	0.310%	22,251
365 Land and Land Rights	102,605.64	0.035%	2,535
366 Structures & Improvements	16,852.75	0.006%	416
367 Mains	22,159,137.05	7.615%	547,436
369 Measuring and Reg. Station Equipment	3,574,096.70	1.228%	88,297
371 Other Equipment	183,581.23	0.063%	4,535
374 Land and Land Rights	257,989.14	0.089%	6,374
375 Structures & Improvements	10,947.47	0.004%	270
376 Mains	144,881,931.52	49.787%	3,579,274
378 Meas. and Reg. Station Equipment - General	2,012,458.24	0.692%	49,717
379 Meas. and Reg. Station Equipment - City Gate Check Station	2,334,479.95	0.802%	57,673
380 Services	71,193,116.46	24.464%	1,758,809
381 Meters	12,936,282.48	4.445%	319,588
382 Meter Installations	6,624,931.21	2.277%	163,667
383 House Regulators	2,565,287.23	0.882%	63,375
384 House Regulatory Installations	1,135,503.55	0.390%	28,052
385 Industrial Meas. & Reg. Station Equipment	1,212,928.59	0.417%	29,965
387 Other Equipment	1,540,462.87	0.529%	38,057
389 Land and Rights	194,034.73	0.067%	4,794
390 Structures & Improvements	1,270,786.99	0.437%	31,394
391 Office Furniture and Equipment	6,387,394.77	2.195%	157,799
392 Transportation Equipment	5,020,349.89	1.725%	124,027
393 Stores Equipment	111,289.49	0.038%	2,749
394 Tools, Shop and Garage Equipment	1,628,264.79	0.560%	40,226
395 Laboratory Equipment	730,667.23	0.251%	18,051
396 Power Operated Equipment	389,812.01	0.134%	9,630
397 Communication Equipment	985,331.92	0.339%	24,342
398 Miscellaneous Equipment	261,519.56	0.090%	6,461
Total	$291,005,954.42	100.0%	$7,189,231.00

EXHIBIT
tabbies
RUCO 9
admitted

4/11/2007 10:15 AM

UNS GAS, INC.
RATE BASE PRO FORMA ADJUSTMENT
TEST YEAR ENDED DECEMBER 31, 2005

ADJUSTMENT NAME:	CWIP in Rate Base
ADJUSTMENT TO:	Rate Base
DATE SUBMITTED:	April 6, 2006
PREPARED BY:	Dallas Dukes
CHECKED BY:	Toby Voge
REVIEWED BY:	

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
302	Franchises and Consents	$9,467	
303	Miscellaneous Intangible Plant	$22,251	
365	Land and Land Rights	$2,535	
366	Structures & Improvements	$416	
367	Mains	$547,436	
369	Measuring and Reg. Station Equipment	$88,297	
371	Other Equipment	$4,535	
374	Land and Land Rights	$6,374	
375	Structures & Improvements	$270	
376	Mains	$3,579,274	
378	Meas. and Reg. Station Equipment - General	$49,717	
379	Meas. and Reg. Station Equipment - City Gate Check Station	$57,673	
380	Services	$1,758,809	
381	Meters	$319,588	
382	Meter Installations	$163,667	
383	House Regulators	$63,375	
384	House Regulatory Installations	$28,052	
385	Industrial Meas. & Reg. Station Equipment	$29,965	
387	Other Equipment	$38,057	
389	Land and Rights	$4,794	
390	Structures & Improvements	$31,394	
391	Office Furniture and Equipment	$157,799	
392	Transportation Equipment	$124,027	
393	Stores Equipment	$2,749	
394	Tools, Shop and Garage Equipment	$40,226	
395	Laboratory Equipment	$18,051	
396	Power Operated Equipment	$9,630	
397	Communication Equipment	$24,342	
398	Miscellaneous Equipment	$6,461	
	ENTRY TOTAL	**$7,189,231**	**$0**

Reason for Adjustment

To include CWIP in rate base.

EXHIBIT
tabbies
RUCO 10
admitted

10/3/2006 8:47 AM