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Transcript Exhibit(s)

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

G-04204A-06-0013

G-04204A-05-0831

Exhibit # : UNSG15 – UNSG37

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
JEFF HATCH-MILLER- CHAIRMAN
WILLIAM A. MUNDELL
MARC SPITZER
MIKE GLEASON
KRISTIN K. MAYES

EXHIBIT
UNSG-15
Admitted

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-06-____

Direct Testimony of

Gary A. Smith

on Behalf of

UNS Gas, Inc.

July 13, 2006

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Gary A. Smith. My business address is 2901 West Shamrell Blvd., Suite 110 Flagstaff, Arizona 86001.

Q. What is your position with UNS Gas, Inc. ("UNS Gas" or the "Company")?

A. I am employed by UNS Gas as Vice President and General Manager.

Q. What are your duties and responsibilities?

A. I am responsible for directing the operations of UNS Gas. Our service territory includes much of northern Arizona as well as Santa Cruz County in southern Arizona. My chief responsibilities include oversight of the operations, maintenance, construction, and expansion of our gas systems. I also have management responsibility for UNS Gas employees.

Q. Please outline your educational background.

A. I have a Masters degree in Information Technology from the University of Phoenix and a Bachelor of Science degree in Civil Engineering from Arizona State University. I also have Associate of Arts degrees in Fire Science from Mesa Community College in Arizona and Emergency Medical Training from Monroe County Community College in Michigan.

Q. Please state your work experience.

A. I have 28 years of public utility experience, including 24 years of senior management experience. I have been with the Company since August 11, 2003. I worked at Citizens Communications Company ("Citizens") as Vice President and General Manager, Arizona Gas Division for six years. Prior to my position at Citizens, I worked at the Arizona

Corporation Commission ("Commission") for 19 years. During my tenure at the Commission, I served as Chief of Safety (1988-1998) and Chief of Pipeline Safety (1983-1988).

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

A. I will provide an overview of UNS Gas operations and explain some of the investments we've made to help meet the needs of our rapidly growing customer base. I also will describe the Company's low-income assistance programs and the Demand Side Management ("DSM") programs we've proposed. Finally, I will detail some proposed changes to UNS Gas' Rules and Regulations, including a new line extension tariff.

II. <u>OVERVIEW OF GAS COMPANY OPERATIONS.</u>

Q. Please describe UNS Gas.

A. UNS Gas serves a rapidly growing base of customers in northern Arizona and Santa Cruz County. These two territories comprise approximately 50 percent of Arizona's geographic area. During 2005, UNS Gas sold or transported over 17.6 billion cubic feet of gas.

Q. What is the makeup of UNS Gas' customers?

A. By number of customers, approximately 90 percent of UNS Gas customers are residential, 9 percent are commercial customers, and one percent are transportation and industrial customers.

Q. Please provide more specific information about your operations in northern Arizona.

A. We provide natural gas service in parts of Coconino, Mohave, Navajo, and Yavapai counties to a customer base that had grown to 131,490, as of the end of the test year. This service area includes the towns and cities of Flagstaff, Winslow, Joseph City, Holbrook, Belmont, Williams, Ashfork, Seligman, Kingman, Lake Havasu, Prescott, Prescott Valley, Chino Valley, Mayer, Dewey-Humboldt, Black Canyon City, Spring Valley, Cottonwood, Clarkdale, Jerome, Sedona, Village of Oak Creek, Verde Village, Cornville, Show Low, Taylor, Pinetop-Lakeside, and Camp Verde.

Q. **How does that compare with your operations in southern Arizona?**

A. We serve a Santa Cruz County customer base that had grown to 7,325 as of the end of the test year. The county covers approximately 1,200 square miles near the U.S.-Mexico border and includes Nogales, Tubac, Patagonia, Amado, Kino Springs, and Rio Rico.

Q. **Please provide more detail regarding the customer growth UNS Gas has experienced.**

A. Our customer base grew four percent in 2005, a rate more than double the industry average. The customer bases in two of our fastest growing communities, Prescott and Verde Valley, expanded by 6.7 percent and 4.6 percent, respectively, during 2005.

Q. **Do you expect a similar level of growth in the future?**

A. We expect our customer base will continue to expand at the current rate for at least the next few years. That expansion is likely to be driven by significant population growth in the Kingman, Chino Valley, Prescott Valley, and Dewey-Humboldt areas. Recent conversations with Mohave County developers and the local economic development agency suggest that our annual customer growth rate in that region could reach as high as six percent.

III. CAPITAL SPENDING SINCE ACQUISITION.

Q. Please describe the significant capital investment made by UNS Gas since the last rate case.

A. The last rate case for the gas properties utilized a 2001 test year and was resolved as part of the Settlement Agreement and Commission order approving the purchase of the system by UniSource Energy. Since then, UNS Gas has spent $61,616,006 through the end of the test year on its transmission and distribution facilities. Most of this investment has been related to growth in its natural gas system in a number of communities in both northern and southern Arizona.

Q. Please describe the capital investment for the upgrade and reinforcement of the system.

A. It has been necessary for UNS Gas to acquire from El Paso Pipeline Company some of its lateral pipelines that supply the natural gas services to some of our distribution systems. These acquisitions gave us better control of system pressure and flow, allowing us to provide safe, reliable, and continual service to our customers. The growth of our customer base also has compelled us to reinforce our distribution systems back at the receipt point to maintain reliable flow rates.

Q. Please describe the capital investment directly related to growth.

A. Since the acquisition of Citizens' Arizona Gas Division properties, UNS Gas has expended significant capital investment funds and incurred significantly increased operating expenses. UNS Gas has made substantial additions to utility plant and equipment that increase the reliability in serving existing customers and meet the demand of customer growth. The increased capital costs have exceeded the growth in sales and revenues. The requested rate increases are required to recognize the increased investment and to provide the Company with a reasonable opportunity to realize a fair rate of return.

Q. Please describe how these expenditures have been utilized.

A. UNS Gas has constructed and installed a total of 180 miles of gas distribution mains and 10,183 service lines since acquiring the Citizens' properties in August 2003. At the end of 2003, the gas system included 2,531 miles of gas distribution mains and 133,061 service lines. At the end of 2004, the system had grown to 2,641 miles of gas distribution mains with 137,874 service lines. On December 31, 2005, the distribution system had been expanded to include 2,711 miles of gas distribution mains and 143,244 service lines. As described previously, UNS Gas also has acquired three El Paso Natural Gas lateral lines to provide greater service reliability.

Q. Why are these investments necessary?

A. UNS Gas' goal is to provide safe, reliable, affordable service to the consumer. These investments are necessary to ensure this goal.

IV. PRODUCTIVITY GAINS, TECHNOLOGY IMPROVEMENTS AND OTHER COST CONTAINMENT STRATEGIES.

Q. What has UNS Gas done to control the costs of serving its growing customer base?

A. We have improved our engineering modeling system to better anticipate needed system improvements, upgrades and expansions and to provide more time for accurate cost assessments. UNS Gas supplies all system materials to its contractors, allowing us to better control material costs. Finally, UNS Gas has made it a priority to improve productivity through operational changes and targeted technology investments, helping us maximize our efforts to serve customers' growing needs.

Q. How has UNS Gas been able to increase productivity through information technology?

A. UNS Gas has employed new computer systems to more fully automate our customer service and work management processes. In addition to eliminating the use of paper orders, these systems allow our technicians to electronically access system maps, Company Standard Practices, customer information, and meter-reading data in the field.

Other technology improvements have played a part in productivity increases, including: the expansion of our internal computer network; Voice over Internet Protocol ("VoIP") telephone systems; tools utilizing the Global Positioning System; cell phone/direct-connect communications; and key-hole excavation techniques. The Company's recent transition to a computerized Geographic Information System ("GIS") offers perhaps the best example of how investments in technology have benefited UNS Gas customers.

Q. What prompted UNS Gas to invest in a new GIS?

A. UNS Gas installed its GIS in response to a directive from Commission Safety Staff ("Staff'), which indicated during a 2002 Annual Commission Pipeline Safety Audit that the Company needed to complete mapping of its service lines in a more timely basis. We enlisted outside contractors to set up the system after determining that doing so would be more cost effective and avoid the need to hire and train short-term employees for this task.

Q. What are the benefits of the Company's GIS?

A. State and federal regulations require gas pipeline operators to maintain accurate maps of their facilities – including gas mains, fittings, service lines, meter locations, regulator stations and other equipment – in relation to base map components such as roads and land parcels. UNS Gas had previously relied on drafted paper maps, which take longer to produce and cannot be updated on a daily basis. The GIS helps UNS Gas maintain an accurate, up-to-date record of its facilities, easing compliance with state and federal laws and providing numerous benefits to the Company and its customers, including:

- **Improved response** – The GIS can quickly identify the location of system controls, helping UNS Gas comply with the Commission's requirement that any emergency caused by a release of natural gas from a pipeline that may cause danger to the public and/or employees be controlled in two hours or less. The GIS also identifies customers likely to lose service due to a leak incident, allowing UNS Gas personnel to provide notification to the affected customers.
- **Better-informed decisions** – The GIS allows gas system planners to use computer models that help them evaluate proposed design alternatives. GIS data also can be used to evaluate the impact of future growth on the current distribution system for budget and planning purposes.
- **Faster work processes** – Map changes that might take weeks or months with conventional hand drafting methods can be completed in hours or days with the GIS at a much lower cost. The system also allows more timely reporting of facility assets for making management decisions and for internal accounting purposes.
- **Increased accuracy** – Employees can access up-to-date GIS maps from the field with laptop computers, allowing them to locate lines more quickly and accurately. This reduces the likelihood of line damage from construction projects or other outside forces, increasing system reliability and improving service to customers.

In these ways, the Company's GIS has significantly improved productivity and reduced costs for UNS Gas and its customers.

Q. What else has UNS Gas done to improve productivity?

A. UNS Gas has made several logistical planning improvements that have increased our employees' productivity. We have adopted a remote storage strategy that has moved parts, materials and other necessary supplies into numerous warehouses spread out across our vast service territory. This allows technicians and construction personnel to more quickly find what they need while working in the field. UNS Gas also has worked with the Arizona Blue Stake Center to automate line location requests, greatly reducing the time needed to locate and mark Company facilities. Most importantly, we have reorganized our staffing to enhance the Company's emergency response, meter reading, inspection, quality assurance, maintenance and call center operations.

Q. What changes have been made to the Company's call center operations, and how have they benefited customers?

A. In the interest of improving productivity and upgrading service, UNS Gas has combined its call center operations with those of UNS Electric, Inc. ("UNS Electric") and Tucson Electric Power Company ("TEP") in a joint call center located at TEP's operational headquarters in Tucson. This change has provided UNS Gas customers with access to a greater number of inbound telephone lines and a larger group of customer service representatives during longer hours of operation. As a result, the Company has provided its customers with a quicker response to requests while reducing the long-term costs associated with meeting their needs.

Q. What have been the results of UNS Gas' efforts to increase productivity?

A. While the Company's customer base has expanded significantly over the past three years, the number of UNS Gas employees has remained essentially flat. When UNS Gas began operations on August 11, 2003, it had one employee for every 616 customers. By December 31, 2005 – the last day of the test year in this case – UNS Gas had one employee for every 666 customers. This equates to a productivity gain of nearly 11 percent during a period when customer service has demonstrably improved. That increase in productivity, if converted to dollars, generated a savings of nearly $1.8 million in labor and benefit costs alone through the end of the test year.

V. LOW-INCOME ASSISTANCE PROGRAMS.

Q. Please describe the low-income assistance programs offered by UNS Gas.

A. We offer three programs designed to assist low-income customers: the Customer Assistance Residential Energy Support ("CARES") pricing plan, Warm Spirit, and Low-Income Weatherization.

A. Customer Assistance Residential Energy Support.

Q. Please describe the current CARES pricing plan

A. The current program offers a discount of $0.15 per therm on the first 100 therms of usage during the period from November through April.

Q. How does a residential customer qualify for CARES discounts?

A. A customer's household gross income must not exceed 150 percent of the Federal Poverty Guidelines ("FPG"), which vary for households of different sizes. For example, a family of two must have a monthly income of less than $1,604 to qualify for discounts, while a family of six must have a monthly income lower than $3,234.

In December 2004, the Commission approved UNS Gas' request to modify the CARES pricing plan to make it easier for customers to apply for the program. As a result, UNS Gas' low-income participants can be enrolled in the program in less than 20 days rather than the 30 to 45 days it took under the previous program. UNS Gas also reduced the burden to participants to re-certify themselves for the program every year and was authorized by the Commission to re-certify random samples of participants every two years.

Q. Is UNS Gas proposing any change to the CARES pricing plan?

A. Yes. The Company proposes eliminating the current volumetric discount and creating a fixed, year-round discount of $6.50 off the monthly residential customer charge. This change, which is described in more detail in Mr. Tobin L. Voge's testimony, is expected to increase the average annual discount enjoyed by CARES customers.

Q. Do CARES program participants enjoy any other benefits?

A. UNS Gas customers enrolled in the CARES program are exempt from paying the Purchase Gas Adjustor ("PGA") surcharge approved by the Commission in Decision No. 68241 (October 25, 2005). Exempting CARES customers from this surcharge resulted in a reduced PGA bank balance collection of $79,528 for November and December 2005. UNS Gas projects that this exemption will reduce surcharge proceeds by $477,000 in 2006.

B. <u>Warm Spirit Program</u>.

Q. How does the Warm Spirit program assist low-income customers?

A. Warm Spirit is a customer-funded program that helps provide emergency bill payment assistance to low-income customers. UES promotes Warm Spirit through bill inserts and bill messages that encourage customers to contribute to the program. All proceeds are distributed to local social service agencies that use the funds to assist qualified UES customers, typically during the winter home heating season.

Q. Does UNS Gas help fund the Warm Spirit Program?

A. UNS Gas matches customers' donations dollar-for-dollar with funds provided by UniSource Energy Corporation's shareholders. In 2004, UNS Gas kicked-off its sponsorship of the program with a one-time donation of $50,000. In 2005, UNS Gas matched customers' donations dollar for dollar in the amount of $24,000.

Q. Is UNS Gas proposing any change to the Warm Spirit program?

A. No. The Company will continue to tap shareholder funds to match customer contributions to the Warm Spirit program, which have averaged between $20,000 and $25,000 per year.

C. Low-Income Weatherization ("LIW").

Q. Please describe the UNS Gas LIW program.

A. The LIW program provides weatherization services to customers whose household income does not exceed 150 percent of the FPG. UNS Gas contracts with community action agencies throughout its service territory to make energy efficiency improvements to homes occupied by low-income residents, including the elderly and disabled. LIW provides up to $2,000 per home for increased insulation, weather stripping, furnace replacement and other improvements at no cost to the customer. The resulting improvements in energy efficiency are intended to produce long term savings on customers' utility bills.

Q. Is UNS Gas proposing any changes to its LIW program?

A. UNS Gas is seeking to extend the benefits of LIW to additional qualified low-income customers by increasing the annual funding level from $75,000 to $135,000. The Company also has proposed funding LIW through a proposed DSM charge to be adjusted annually, discussed in Mr. Voge's testimony. The cost allocation is removed from base rates in the CARES program expense adjustment sponsored by Mr. Dallas J. Dukes and LIW would become one of the residential programs in the DSM program portfolio. Finally, UNS Gas has proposed allocating $21,600 of LIW program funds to a new emergency bill assistance program for low-income customers.

Q. **Under what circumstances would this emergency bill assistance program be used?**

A. The program would be used to pay the natural gas bills for customers in crisis situations. Three categories of crisis, as defined by the Arizona Department of Economic Security's Community Services Division, are: (i) loss or reduction of income; (ii) unexpected or unplanned expenses that cause lack of resources; or (iii) a condition that endangers the health or safety of the household.

Q. **How would the proposed emergency bill assistance program work?**

A. The program would be administered by the community action agencies under contract with UNS Gas to implement LIW. Customers would qualify for emergency bill assistance if they meet the eligibility guidelines for the federal Low Income Home Energy Assistance Program ("LIHEAP"). To qualify, an individual must: (i) have a household income that does not exceed 150 percent of the FPG; (ii) be a utility customer; (iii) provide a utility delinquent or unpaid bill; and (iv) not have received emergency bill assistance in the previous 12 months. Customers who satisfy these criteria can receive up to $400 in assistance no more than once in a 12-month period, with the amount determined by their household's energy burden.

VI. DEMAND SIDE MANAGEMENT PROGRAMS.

Q. **Does UNS Gas offer any DSM programs to its customers?**

A. The Company offers the LIW program discussed above. In Arizona, LIW historically has been categorized as a DSM program and is funded in the same manner as DSM. However, UNS Gas' LIW program is currently funded through base rates. UNS Gas is requesting that its LIW program be included as a part of its DSM program portfolio, and that its associated program costs be included in the proposed DSM charge.

Q. Is the Company proposing to offer new DSM programs to its customers?

A. Yes. Contingent upon Commission approval and funding, UNS Gas proposes to add new DSM programs for residential and commercial customers.

A. <u>Proposed New Conservation and Energy Efficiency Programs.</u>

Q. What new conservation and energy efficiency programs does the Company propose?

A. Including the enhanced LIW program described above, UNS Gas is proposing five DSM programs and associated funding for residential and commercial customers.

Q. What new programs is UNS Gas proposing for residential customers?

A. In addition to enhancing LIW and including it as part of the residential DSM program portfolio, we are proposing a Residential Furnace Retrofit program and a Residential New Construction Program.

Q. Please describe the Residential Furnace Retrofit Program.

A. The proposed Residential Furnace Retrofit program provides prescriptive incentives to encourage residential and multi-family homeowners to invest in energy-efficient gas-fueled furnaces with a 90 percent or greater Annual Fuel Utilization Efficiency ("AFUE") rating. In addition, the program would provide training, qualification and promotion for contractors who are knowledgeable and meet UNS Gas standards for the installation and operation of high-efficiency residential gas furnace systems.

The proposed annual cost for the program is $204,243, with a targeted annual savings for the program of 74,240 therms.

Q. Please describe the Residential New Construction Program.

A. The proposed Residential New Construction Program provides prescriptive incentives to home builders for installation of energy efficiency measures in new residential construction projects. This program targets energy savings in heating, cooling, and hot water use. These savings are typically achieved through a combination of building envelope upgrades, high-performance windows, controlled air filtration, upgraded heating and air conditioning systems, tight air duct systems, and upgraded water-heating equipment.

The proposed annual cost for the program is $418,201, with a targeted annual savings for the program of 72,651 therms, a coincident peak kW reduction of 914, and annual kWh reduction of 1,415,646.

Q. What is the proposed annual funding level for all of the residential DSM programs?

A. The proposed funding level for the new DSM residential programs is $622,444. Including the enhanced LIW program funding of $135,000, the total proposed funding level is $757,444 annually.

Q. What new programs is UNS Gas proposing for commercial customers?

A. UNS Gas is proposing a Commercial HVAC Retrofit Program and a Commercial Gas Cooking Efficiency Program.

Q. Please describe the Commercial HVAC Retrofit Program.

A. This proposed program provides prescriptive incentives to encourage business owners to invest in energy efficiency improvements for their gas fueled water heating and space heating systems. The program will offer training, qualification and promotion for contractors who are knowledgeable and meet UNS Gas standards. Participating contractors will be allowed to take part in a qualified contractors' referral program.

The proposed annual cost for the program is $150,500, with a targeted annual savings for the program of 22,136 therms.

Q. Please describe the Commercial Gas Cooking Efficiency Program.

A. This proposed program provides prescriptive incentives to encourage business owners to make energy efficiency improvements in commercial gas-fueled cooking applications. The market for participating facilities includes restaurants as well as numerous kitchens located in schools, hospitals, and lodging facilities.

The proposed annual cost for the program is $143,672, with a targeted annual savings for the program of 42,806 therms.

Q. What is the proposed annual funding level for all of the commercial DSM programs?

A. The proposed funding level for the commercial programs is $294,172 annually.

Q. What is the proposed funding level for the entire DSM program portfolio?

A. The proposed funding level for the new residential and commercial DSM programs is $916,616. A listing of the proposed DSM programs, the associated funding, targeted annual savings and the results of the Total Resource Cost ("TRC") and Participant Test

("PT") test ratios are provided in Exhibit GAS-1. The total proposed funding to be collected through the DSM charge, including the LIW, is $1,051,616.

Q. What does UNS Gas expect to achieve from its new DSM program portfolio?

A. The DSM program portfolio will provide customers with the opportunity to participate in programs never offered in the UNS Gas service territory. Based on the Company's projections, the proposed DSM program portfolio is expected to achieve a savings of 211,833 therms annually.

Q. Have you reviewed the DSM programs from other states?

A. Yes. UNS Gas investigated a wide range of program options and identified those that have the greatest relevance to the local market. The Company reviewed 32 programs that are either operating or proposed for operation in Arizona and the surrounding region. Programs specifically reviewed are from TEP, Arizona Public Service, Southwest Gas Corporation and Public Service Company of New Mexico.

Q. How did you determine what programs to propose for UNS Gas?

A. In order to identify how a regional program may be applicable to the UNS Gas program portfolio design, the 32 programs previously mentioned were ranked according to seven criteria. High-ranking programs provided UNS Gas with further insight into product offerings, program design, budgeting, and marketing approaches that might be useful. The seven criteria include:

(i) Applicable to existing customer base;

(ii) Consistency with area demographic/growth trends;

(iii) Potential cost effectiveness;

(iv) High incentive value;

(v) Consistency with societal goals;

(vi) Delivery infrastructure in place; and

(vii) Whether a program compliments existing, ongoing programs.

Q. How were the DSM programs evaluated for cost-effectiveness?

A. UNS Gas utilized the TRC test and the PT to evaluate its recommended residential and commercial program portfolio. The TRC test measures the net costs of an energy efficiency program as a resource option based on the total costs of the program, including both the participants' and the utility's costs. The PT was utilized to measure the quantifiable benefits and costs to the customer due to participation in the program.

B. Cost Recovery and Approval Process.

Q. How would UNS Gas recover the costs of the programs, if approved?

A. The Company is proposing an annually adjusted charge to provide cost recovery for the approved DSM program portfolio. The DSM charge is discussed in more detail in Mr. Voge's testimony and would initially be set at $.007608 per therm.

Q. How will UNS Gas obtain approval for the proposed programs?

A. If the requested funding is approved, UNS Gas would like to file a joint DSM program portfolio with UNS Electric, a UES company.

Q. Why does UNS Gas want to file a joint program proposal with UNS Electric?

A. UNS Electric expects to file documents for a proposed rate case in late 2006. In that proceeding, UNS Electric will request an increase in funds to its current DSM program portfolio. UNS Gas and UNS Electric would like to take advantage of program synergies in Mohave and Santa Cruz Counties, where their service territories are the same. Taking advantage of program synergies requires a joint filing of a DSM program portfolio for

Commission approval. The DSM program portfolio for UNS Gas and UNS Electric would be filed 120 days after the resolution of the proposed UNS Electric rate case proceedings.

Q. What program synergies can be developed as a result of combining the DSM program portfolio?

A. The utilities can gain greater efficiencies and reduce program costs where service territories are the same by jointly administering the direct implementation, internal administration and marketing costs for the programs. Administering joint programs in Mohave and Santa Cruz Counties also will reduce customer confusion about program details and how to participate in a program. If the programs are jointly administered in these areas, local customers will not have to contact each utility to participate in a program.

Q. What programs will be jointly administered in Mohave and Santa Cruz Counties?

A. The Residential New Construction, Residential HVAC/Furnace Retrofit, and Commercial HVAC Retrofit programs will be jointly administered. These programs will be made available throughout the entire UNS Gas service territory. However, the aforementioned programs will be jointly administered in Mohave and Santa Cruz Counties.

VII. RULES AND REGULATIONS.

Q. Why has UNS Gas proposed changes to its Rules and Regulations?

A. Generally, the current Rules and Regulations were inherited from Citizens. UNS Gas has updated some of these Rules and Regulations as well as other tariffs and is seeking Commission approval of these changes.

Q. Please describe some of these changes.

A. The definitions for Cubic feet per Hour ("CFH"), Incremental Contribution Study ("ICS"), Law, Meter Set Assembly ("MSA"), Pricing Plan, Rules and Regulations, and Standard Conditions have been added to Section 2 of the Rules and Regulations.

In Section 6.B. 2. b., the amount that the customer will reimburse the Company for the gas service line on the customer's property was increased from $8.00 per foot to $16.00 per foot to reflect current costs. Also, the customer is now responsible for locating facilities on private property and removing landscaping prior to installation or is to be subject to applicable charges. For customers who provide the trench for the service line on their own property, the rate at which the customer will reimburse the Company has been increased to $12.00 per foot for the excess footage. These changes stem from increased costs and a requirement for 100 percent inspection, pursuant to Decision No. 66028.

In Section 10. C., "Billing Terms", the due date for bills for gas service was changed to ten days from the date the bill is rendered. Any payment not received within this time shall be considered past due and may be subject to a late payment penalty charge. The date for all past due bills for gas service was changed to be due and payable within fifteen days. Any payment not received within this time shall be considered delinquent and the customer will be issued a suspension of service notice. This change was made in order to align UNS Gas' Rules and Regulations with the Arizona Administrative Code.

Section 10. J., "Electronic Billing" was added. The previous Rules and Regulations did not include language to address this option for customers.

In Section 11. E, "Timing of Terminations with Notice", the advance written notice prior to the termination date was changed to at least five days. This change was made in order to align UNS Gas' Rules and Regulations with the Arizona Administrative Code.

Q. Is UNS Gas requesting any change to its Line Extension tariff?

A. UNS Gas is proposing several changes to our main line extension tariff, which is part of our Rules and Regulations. These changes would update our tariff to reflect current market conditions and make them consistent with our policy of asking developers to pay a fair cost for infrastructure installed to serve their facilities. For more details on these changes, please review the attached redline copy of the Rules and Regulations.

Q. Is a copy of the proposed modification to the Rules and Regulations attached?

A. Yes, redlined and clean copies of the revised Rules and Regulations are attached as Exhibit GAS-2.

Q. Does that conclude your testimony?

A. Yes.

EXHIBIT

GAS-1

Residential Programs

Programs by Market or Customer Segment	Program Name	Residential Electric Program Description	Proposed Average Annual Budget	Targeted Annual Savings	Benefit Costs Ratios
Residential Gas	Residential Furnace Retrofit	• Provides prescriptive incentives for residential single and multifamily home owners for energy efficiency improvements in residential gas fueled furnace applications. • Utilizes the existing UES online 'Residential Energy Advisor', or Department of Energy online energy audit, as part of the program application process. • Provide training, qualification and promotion of contractors who are knowledgeable and meet UES standards installing and operating high efficiency HVAC systems. • All residential structures in the UESE and UESG service territories served by UESG gas are eligible for the furnace efficiency measures. • Annual installation of approximately 800 furnaces with 90% or greater AFUE ratings.	$204,243	Coincident Peak kW = 0 Annual kWh = 0 Annual Therms = 74,240	TRC Ratio = 1.26 PT Ratio = 2.23
	Residential New Construction	• Provides prescriptive incentives to home builders for installation of energy efficiency measures in new residential construction projects. • Provide educational and promotional pieces and design tools to assistance to developers of new residential structures and associated middle market trade allies (A&Es, contractors, etc.) with the installation of high-efficiency homes that meet or exceed the UES Efficient Home and ENERGY STAR program standards. • Uses the UES Efficient Home (Energy Star) program savings measures, plus additional appliance measures. • Provides incentives to builders to install Energy Star labeled dishwashers, clothes washers, and refrigerators. • All new single family and multifamily buildings in the UESE and UESG service territories are eligible. • Annual participation is estimated to be 5% of new units, or approximately 580 homes in 2007.	$418,201	Coincident Peak kW = 914 Annual kWh = 1,415,646 Annual Therms = 72,651	TRC Ratio = 1.98 PT Ratio = 4.06
Residential Gas Subtotal			$622,444	Coincident Peak kW = 914 Annual kWh = 1,415,646 Annual Therms = 146,891	TRC Ratio = 1.72 PT Ratio = 3.29

Commercial Programs

Programs Organized by Market or Customer Segment	Program Name	Commercial Gas Program Description	Proposed Average Annual Budget	Targeted Annual Savings	Benefit Costs Ratios
C&I Gas	Commercial HVAC Retrofit	• Provides prescriptive incentives for business owners for energy efficiency improvements in gas fueled heating (space and water) applications. • Utilizes the existing UES online 'Business energy Advisor', or Department of Energy online energy audit, as part of the program application process. • Provide training, qualification and promotions of contractors who are knowledgeable and meet UES standards • Participating allies will be allowed to participate in a qualified allies referral program. • The target market includes all commercial facilities in the UESE and UESG service territories served by UESG gas are eligible for the efficiency measures • Annual participation is estimated at approximately 130 facilities.	$150,500	Coincident Peak kW = 0 Annual kWh = 0 Annual Therms = 22,136	TRC Ratio = 1.11 PT Ratio = 2.93
	Commercial Gas Cooking Efficiency	• Provides prescriptive incentives for business owners for energy efficiency improvements in commercial gas fueled cooking applications. • The target market includes all commercial kitchens in the UESE and UESG service territories served by UESG gas are eligible for the efficiency measures • The market for participating facilities in all UES service territories is estimated at 700 restaurants, and numerous kitchens located in schools, hospital, and lodging facilities.	$143,672	Coincident Peak kW = 0 Annual kWh = 0 Annual Therms = 42,806	TRC Ratio = 1.26 PT Ratio = 2.81
Commercial & Industrial Gas Subtotal			$294,172	Coincident Peak kW = 0 Annual kWh = 0 Annual Therms = 64,942	TRC Ratio = 1.19 PT Ratio = 2.86

EXHIBIT

GAS-2

UNS Gas, Inc.
Rules & Regulations

CLEAN VERSION

TABLE OF CONTENTS

SECTION NO. 1
APPLICABILITY OF RULES AND REGULATIONS AND DESCRIPTION OF SERVICE

A. Company is a gas utility operating within portions of the state of Arizona. The Company will provide service to any person, institution or business located within its service area in accordance with the provisions of its Pricing Plans and the terms and conditions of these Rules and Regulations.

B. All gas delivered to any Customer is for the sole use of such Customer on that Customer's premises only. Gas delivered by the Company shall not be redelivered or resold, or the use thereof by others permitted unless otherwise expressly agreed to in writing by the Company. However, those Customers purchasing gas for redistribution to the Customer's own tenants (only on the Customer's premises) may separately meter each tenant distribution point for the purpose of prorating the Customer's actual purchase price of gas delivered among the various tenants on a per unit basis.

C. These Rules and Regulations shall apply to all gas service furnished by the Company to its Customers.

D. These Rules and Regulations are part of the Company's Pricing Plans on file with, and duly approved by, the ACC. These Rules and Regulations shall remain in effect until modified, amended, or deleted by order of the ACC. No employee, agent or representative of the Company is authorized to modify the Company rules.

E. These Rules and Regulations shall be applied uniformly to all similarly situated Customers.

F. In case of any conflict between these Rules and Regulations and the ACC's rules, these Rules and Regulations shall apply.

G. Whenever the Company and an Applicant or a Customer are unable to agree on the terms and conditions under which such Applicant or Customer is to be served, or are unable to agree on the proper interpretation of the these Rules and Regulations, either party may request assistance from the Consumer Services Section of the Utilities Division of the ACC. The Applicant or Customer also has the option to file an application with the ACC for a proper order, after notice and hearing.

H. The Company's supplying gas service to the Customer and the acceptance thereof by the Customer shall be deemed to constitute an agreement by and between the Company and the Customer for delivery, acceptance of and payment for gas service under the Company's Rules and Regulations and applicable Pricing Plans[t1].

SECTION NO. 2
DEFINITIONS

A. In these Rules and Regulations, the following definitions shall apply unless the context requires otherwise:

1. "Advance in Aid of Construction" or "Advance" – Funds provided to the Company by an Applicant under the terms of a main extension agreement, the value of which may be refundable.
2. "Applicant" – A person requesting the Company to supply gas service.
3. "Application" – A request to the Company for gas service, as distinguished from any inquiry as to the availability or charges for such service.
4. "Arizona Corporation Commission" ("ACC") – The regulatory body established by Article XV of the Arizona Constitution.
5. "Billing Month" – The time interval between any two (2) regular readings of the Company's meters at approximately thirty (30) day intervals.
6. "Billing Period" – The time period between two (2) consecutive meter readings that are taken for billing purposes.
7. "British Thermal Unit" ("BTU") – The amount of heat required to raise the temperature of one (1) pound of water one (1) degree Fahrenheit, at Standard Conditions.
8. "CCF" – One hundred (100) cubic feet.
9. "CFH" – Cubic feet per hour.
10. "Commodity Charge" – The unit cost for billed usage as set forth in the Company's Pricing Plans.
11. "Company" – UNS Gas, Inc.
12. "Contributions in Aid of Construction" or "Contribution" – Funds provided to the Company by the Applicant under the terms of a main extension agreement and/or service connection tariff, the value of which are not refundable.

SECTION NO. 2
DEFINITIONS
(continued)

13. "Cubic Foot" –

    a. In cases where gas is supplied and metered to Customers at Standard Delivery Pressure, a cubic foot of gas is the volume of gas, which at the temperature and pressure existing in the meter occupies one (1) cubic foot.

    b. Regardless of the pressure supplied to the Customer, the volume of gas metered will be converted to the volume which the gas would occupy at Standard Conditions.

    c. The standard cubic foot of gas used for testing the gas for heating value shall be that volume of gas which, when saturated with water vapor and at a temperature of sixty (60) degrees Fahrenheit and under a pressure equivalent to that of thirty (30) inches of mercury (mercury at thirty-two (32) degrees Fahrenheit and under standard gravity), occupies one (1) cubic foot.

14. "Curtailment Priority" – The order in which gas service is to be curtailed to various classifications of Customers, as set forth in the Company's Pricing Plans.

15. "Customer" – The person in whose name service is rendered, as evidenced by the signature on the application or contract for that service, or by the receipt and/or payment of bills regularly issued in the person's name regardless of the identity of the actual user of the service.

16. "Customer Charge" – The amount the Customer must pay the Company for the availability of gas service, excluding any gas used, as specified, in the Company's Pricing Plans.

17. "Customer Service Complaint" - Written complaint received from a Customer, or through the ACC on behalf of a Customer.

18. "Day" – Calendar day.

19. "Decatherm" – Ten (10) therms or 1,000,000 BTU.

20. "Distribution Main" – A gas line of the Company from which service lines may be extended to Customers.

21. "Handicapped" – A person with a physical or mental condition which substantially contributes to the person's inability to manage his or her own resources, carry out activities of daily living, or protect themselves from neglect or hazardous situations without assistance from others.

SECTION NO. 2
DEFINITIONS
(continued)

22. "Illness" – A medical ailment or sickness for which a residential Customer obtains a verifiable document from a licensed medical physician stating the nature of the illness and that discontinuance of service would be especially dangerous to the Customer's health.

23. "Inability to Pay" – Circumstances where a residential Customer:

    a. Is not gainfully employed and is unable to pay; or

    b. Qualifies for government welfare assistance, but has not begun to receive assistance on the date that the bill is received and can obtain verification from the government welfare agency; or

    c. Has an annual income below the published federal poverty level and can produce evidence of this; and

    d. Signs a declaration verifying that the Customer meets one of the above criteria and is either a senior citizen, handicapped, or suffers from an illness.

24. "Incremental Contribution Study" ("ICS") - The study described in Section 7.B.5 of these Rules and Regulations.

25. "Interruptible Gas Service" – Gas service that is subject to interruption or curtailment as specified in the Company's Pricing Plans.

26. "Law" – Any rule or requirement established and enforced by government authorities.

27. "Main Extension" – The lines and equipment necessary to extend the existing gas distribution system to provide service to additional Customers.

28. "Master Meter" – An instrument for measuring or recording the flow of gas at a single location from which said gas is transported through a piping system to tenants or occupants for their individual consumption.

29. "MCF" – One thousand (1,000) cubic feet.

30. "Meter" – The instrument for measuring and indicating or recording the volume of gas that has passed through it.

31. "Meter Set Assembly" ("MSA") – All gas components downstream of the Customer's inlet service valve[t2] to the Customer's Point of Delivery.

SECTION NO. 2
DEFINITIONS
(continued)

32. "Minimum Charge" – The amount the Customer must pay for the availability of gas service and may include an amount of usage, as specified in the Company's Pricing Plans.[13]

33. "Permanent Customer" – A Customer who is a tenant or owner of a service location who applies for and receives gas service.

34. "Permanent Service" – Service which, in the opinion of the Company, is of a permanent and established character. The use of gas may be continuous, intermittent, or seasonal in nature.

35. "Person" – Any individual, partnership, corporation, governmental agency, or other organization operating as a single entity.

36. "Point of Delivery" – The Point of Delivery for all gas delivered to any Customer shall be at the point of interconnection between the facilities of the Company and those of such Customer.

37. "Premises" – All of the real property and apparatus employed in a single enterprise or residence on an integral parcel of land undivided by public streets, alleys or railways.

38. "Pricing Plan" – A part of the Company's Tariffs which sets forth the rates and charges related to specific categories of Customers, and related terms and conditions.

39. "Residential Subdivision" – Any tract of land which has been divided into four or more contiguous lots for use in the construction of residential buildings or permanent mobile homes for either single or multiple occupancy.

40. "Residential Use" – Service to Customers using gas for domestic purposes such as space heating, air conditioning, water heating, cooking, clothes drying, and other residential uses and includes use in apartment buildings, mobile home parks, and other multi-unit residential buildings.

41. "Restricted Apparatus" – An apparatus prohibited by the ACC, another governmental agency, or the Company.

42. "Rules and Regulations" or "Company rules" – These Rules and Regulations, which are part of the Company's Tariffs and Pricing Plans.

SECTION NO. 2
DEFINITIONS
(continued)

43. "Senior Citizen" – A person who is sixty-two (62) years of age or older.

44. "Service Areas" – The territory in which the Company has been granted a certificate of convenience and necessity and is authorized by the ACC to provide gas service.

45. "Service Establishment Charge" – A charge, as specified in the Company's Pricing Plans, which covers the cost of establishing a new account.

46. "Service Line" – A gas pipe that transports gas from a common source or supply (normally a distribution main) to the Customer's Point of Delivery.

47. "Service Reconnection Charge" – A charge specified in the Company's Pricing Plans that must be paid by the Customer prior to re-establishment of gas service each time the gas is disconnected for nonpayment, or for failure to comply with the Company's Pricing Plans.

48. "Service Re-Establishment Charge" – A charge specified in the Company's Pricing Plans for the re-establishment of service at the same location where the same Customer had ordered a service disconnect within the preceding twelve (12) month period. In addition to the Service Re-Establishment Charge, such returning Customer shall pay the sum of the applicable monthly Customer Charges which would have accrued had the Customer not ordered the disconnect.

49. "Single Family Dwelling" – A house, an apartment, or a mobile home permanently affixed to a lot, or any other permanent residential unit which is used as permanent home.

50. "Standard Conditions" - 14.73 pounds per square inch absolute at sixty (60) degrees Fahrenheit.

51. "Standard Delivery Pressure" – 0.25 pounds per square inch gauge at the meter or Point of Delivery.

52. "Tampering" – A situation where a meter has been illegally altered. Common examples are meter bypassing and other unauthorized connections. Tampering also includes any action defined as "tampering" under A.R.S. § 40-491(4).

53. "Tariffs" – The documents filed with the ACC that list the services offered by the Company and set forth the terms and conditions and a schedule of the rates and charges for those services and products. These Rules and Regulations are part of the Company's Tariffs. The Company's Pricing Plans are also part of the Company's Tariffs.

54. "Temporary Service" – Service to premises or enterprises that are temporary in character, or where it is known in advance that the service will be of limited duration. Service that, in the opinion of the Company, is for operations of speculative character is also considered temporary service.

SECTION NO. 2
DEFINITIONS
(continued)

55. "Therm" – A unit of heating value, equivalent to one hundred thousand (100,000) BTUs.

56. "Third Party Notice" – A notice sent to a person willing to receive notification of the pending discontinuance of service to a Customer of record, in order to make arrangements on behalf of said Customer that are satisfactory to the Company.

57. "Transmission Line" - A gas line for delivering natural gas that operates at a hoop stress of twenty percent (20%) or more of Specified Minimum Yield Strength ("SMYS")[t4], as defined in CFR 49, Part 192 or that transports gas to a single large volume Customer such as a distribution center, factory, power plant or institutional user.

58. "Unauthorized" – Use of gas services that is not in accordance with ACC rules, the Company's Rules and Regulations, or the Company's Pricing Plans.

59. "Weather Especially Dangerous to Health" – That period of time, commencing with the scheduled termination date, when the local weather forecast as predicted by the National Oceanic and Atmospheric Administration, indicates that the temperature will not exceed thirty-two (32) degrees Fahrenheit for the next day's forecast. The ACC may determine that other weather conditions are especially dangerous to health as the need arises.

60. "Working Hours" – The period of time during which the Company's offices are open for business.

61. "Yardline" – A gas pipe that transports gas from the Customer's Point of Delivery to the point of entry into the Customer's residence or other place of consumption.

SECTION NO. 3
ESTABLISHMENT OF SERVICE

A. Information From Applicants

1. The Company may obtain the following minimum information from each Applicant:

    a. Name or names of Applicant(s);

    b. Service address or location and telephone number;

    c. Billing address or location and telephone number, if different than service address;

    d. Address where service was provided previously;

    e. Date Applicant will be ready for service;

    f. Indication of whether premises have been supplied with gas service previously;

    g. Purpose for which service is to be used;

    h. Indication of whether Applicant is owner or tenant of or agent for, the premises;

    i. Information concerning the gas usage and demand requirements of the Customer; and

    j. Type and kind of life-support equipment, if any, used by the Customer.

2. The Company may require a new Applicant for service to appear at the Company's designated place of business to produce proof of identity and sign the Company's application form.

3. Where service is requested by two or more individuals, the Company shall have the right to collect the full amount owed to the Company from any one of the Applicants.

4. An Applicant for gas service to new construction or a new extension shall complete the following Company forms:

    a. New Service Application; and

    b. Excess Flow Valve Customer Notification (applies to Residential only).

The Customer is responsible for completing and returning both forms. Failure on the part of the Customer to provide completed forms shall be grounds for the Company to delay or refuse service. For the purpose of this Rule, the definition of new construction/extension is where there is a need to run a new service line or install new gas facilities to a property that has never had prior natural gas service.

SECTION NO. 3
ESTABLISHMENT OF SERVICE
(continued)

B. Deposits

1. The Company may require from any present or prospective Customer a security deposit to guarantee payment of all bills. This deposit may be retained by the Company until service is discontinued and all bills have been paid; except as provided in Subsection B.4 below. Upon proper application by the Customer, the Company shall then return said deposit, together with any unpaid interest accrued thereon from the date of commencement of service or the date of making the deposit, whichever is later. The Company shall be entitled to apply said deposit together with any unpaid interest accrued thereon, to any indebtedness for the same class of service owed to the Company for gas service furnished to the Customer making the deposit. When said deposit has been applied to any such indebtedness, the Customer's gas service may be discontinued until all such indebtedness of the Customer is paid and a like deposit is again made with the Company by the Customer. No interest shall accrue on any deposit after discontinuance of the service to which the deposit relates.

   The Company shall not require a deposit from a new Applicant for residential service if the Applicant is able to meet any of the following requirements:

   a. The Applicant has had service of a comparable nature with the Company at another service location within the past two (2) years and was not delinquent in payment more than twice during the last twelve (12) consecutive months, or was not disconnected for nonpayment; or

   b. The Applicant can produce a letter regarding credit or verification from a gas or electric utility which states that the Applicant has had service of a comparable nature with that utility at another service location within the past two (2) years and was not delinquent in payment more than twice during the last twelve (12) consecutive months, or was not disconnected for nonpayment; or

   c. In lieu of a cash deposit, a new Applicant may provide a Letter of Guarantee from an existing Customer of the Company who is acceptable to the Company, a surety bond, or similar alternative acceptable to the Company, such as a Certificate of Deposit, as security for Company in the sum equal to the required deposit; or

   d. If a credit check is offered by the Company, the Applicant authorizes a credit check and meets the standards established by the Company.

2. The Company may issue a non-assignable, non-negotiable receipt to the Applicant for the deposit. The inability of the Customer to produce such a receipt shall in no way impair the Customer's right to receive a refund of the deposit which is reflected on the Company's records.

SECTION NO. 3
ESTABLISHMENT OF SERVICE
(continued)

3. Cash deposits held by the Company twelve (12) months or longer shall earn interest at the established one year Treasury Constant Maturities rates, effective on the first business day of each year, as published in the Federal Reserve website. No interest will be paid on deposits for which Customers have turned service on and off within the same calendar month. Such payment of interest shall be made during January of each year for Customers served by the Company for at least six (6) months and will cover all interest accrued up to the end of the preceding calendar year or on the date the deposit is returned to the Customer, pursuant to Subsection B.4 below. At the Company's option, the above payments may be made either by check or by credit on the monthly bill.

4. All deposits of residential or commercial Customers received and held by the Company shall be returned to the Customer by the Company (with interest, as provided by Subsection B.3 above), at such time as the affected Customers shall have maintained for a period of twelve (12) consecutive months (from and after the date when the deposit was made), their accounts with the Company. The Customer's accounts shall have been maintained in such a manner that they shall not have been delinquent in the payment of more than two (2) bills during such twelve (12) month period, whether at the same address or at a different address, nor have had their gas service, whether at the same address or at a different address, discontinued, in accordance with these Rules and Regulations, for failure to pay for gas service previously rendered.

5. The Company may require a Customer to establish or re-establish a deposit if the Customer became delinquent in the payment of three (3) or more bills within a twelve (12) consecutive month period, or has been disconnected from service during the last twelve (12) months.

6. The Company may review the Customer's usage after service has been connected and adjust the deposit amount based upon the Customer's actual usage.

7. A separate deposit may be required for each meter installed.

8. Residential Customer deposits shall not exceed two (2) times that Customer's estimated average monthly bill. Non-residential Customer deposits shall not exceed two and one-half (2.5) times that Customer's maximum estimated monthly bill. If actual usage history is available, then that usage, adjusted for normal weather, will be the basis for the estimate.

9. The posting of a deposit shall not preclude the Company from terminating service when the termination is due to the Customer's failure to perform any obligation under the agreement for service or any of these Rules and Regulations.[16]

SECTION NO. 3
ESTABLISHMENT OF SERVICE
(continued)

C. Grounds For Refusal Of Service

The Company may refuse to establish service if any of the following conditions exist:

1. The Applicant has an outstanding amount due for the same class of gas service with the Company and the Applicant is unwilling to make arrangements with the Company for payment; or
2. A condition exists which, in the Company's judgment, is unsafe or hazardous to the Applicant, the general population, or the Company's personnel or facilities; or
3. The Applicant refuses to provide the Company with a deposit when the Customer has failed to meet the credit criteria for waiver of deposit requirements; or
4. Customer is known to be in violation of the Company's Pricing Plans; or
5. Customer fails to furnish such funds, service, equipment, and/or rights-of-way necessary to serve the Customer and which have been specified by the Company as a condition for providing service; or
6. Applicant falsifies his or her identity for the purpose of obtaining service.

D. Service Establishments, Re-establishment or Reconnection Charge

1. The Company may make a charge as approved by the ACC for the establishment, re-establishment, or reconnection of service.
2. Should service be established during a period other than the Company's regular working hours at the Customer's request, the Customer may be required to pay an after-hour charge for the service connection. Where the Company's scheduling will not permit service establishment on the same day as requested, the Customer can elect to pay the after-hour charge for establishment that day, or his service will be established on the next available working day.
3. For the purpose of this Rule, the definition of service establishments are where the Customer's facilities are ready and acceptable to the Company, and the Company needs only to install a meter, read a meter, or turn the service on.

SECTION NO. 3
ESTABLISHMENT OF SERVICE
(continued)

E. Temporary Service

1. Applicants for temporary service may be required to pay to the Company, in advance of service establishment, the estimated cost of installing and removing the facilities necessary for furnishing the desired service.

2. Where the duration of service is to be less than one (1) month, the Applicant may also be required to advance a sum of money equal to the estimated bill for service.

3. Where the duration of service is to exceed one (1) month, the Applicant may also be required to meet the deposit requirements of the Company, as outlined in Subsection B.1 above.

4. If at any time during the term of the agreement for service the character of a temporary Customer's operations changes so that, in the opinion of the Company, the Customer is classified as permanent, the terms of the Company's main extension rules shall apply.

SECTION NO. 4
MINIMUM CUSTOMER INFORMATION REQUIREMENTS

A. Information for Residential Customers

1. The Company shall make available upon Customer request, no later than sixty (60) days from the date of request, a concise summary of the rate schedule applied for by such Customer. The summary shall include the following:

   a. Monthly minimum or Customer charge, identifying the amount of the charge and the specific amount of usage included in the minimum charge, where applicable;

   b. Rate blocks, where applicable; and

   c. Any adjustment factor(s) and method of calculation.

2. Upon application or upon request, the Applicant or the Customer shall elect the applicable Pricing Plan best suited to their requirements. The Company may assist in making such election, but shall not be held responsible for notifying the Customer of the most favorable Pricing Plan and shall not be required to refund the difference in charges under different Pricing Plans.[t7]

   However, new non-residential Customers whose projected consumption is near the threshold between "large" and "small" Pricing Plans, may elect the "small" rate, subject to refund, if their usage qualifies them as a "large" Customer. An existing non-residential Customer will be moved to the "large" rate, or once moved, back to the "small" rate, only if their consumption history or a clear permanent change in consumption makes it clear the Customer will meet the volume requirements of one Pricing Plan.

   A review may be initiated by either the Company or the Customer. Any change of Pricing Plan, if appropriate, will be effective with the first bill issued seven (7) days after the initiation of the review. No adjustment of past billings due to Pricing Plan selection will be made to either the Company or the Customer, except for a new Customer who qualifies for the "large" Pricing Plan based on twelve (12) months of usage as set forth in this Rule.

SECTION NO. 4
MINIMUM CUSTOMER INFORMATION REQUIREMENTS
(continued)

3. Upon Customer request, the Company shall make available to the Customer, a copy of the ACC's Rules and Regulations (Arizona Administrative Code, Title 14, Article 3 - Gas Utilities) concerning:

    a. Deposits;

    b. Termination of Service;

    c. Billing and Collection; and

    d. Complaint Handling.

4. The Company, upon Customer request, shall transmit a written statement of actual consumption by the Customer for each billing period during the prior twelve (12) months unless such data is not reasonably ascertainable.

5. The Company shall inform all new Customers of their rights to obtain the information specified above.

6. The Company shall notify each Customer of the following information, in writing, within ninety (90) days after the Customer first receives gas service at a particular location:

    a. The Company does not maintain the Customer's buried piping;

    b. If the Customer's buried piping is not maintained, it may be subject to the potential hazards of corrosion and leakage;

    c. Buried gas piping should be periodically inspected for leaks, periodically inspected for corrosion if the piping is metallic, and repaired if any unsafe condition is discovered;

    d. When excavating near buried gas piping, the piping must be located in advance, and the excavation done by hand;

    e. Plumbing contractors and heating contractors may assist in locating, inspecting, and repairing the Customer's buried piping; and

    f. In order to reduce damage by outside forces, the Company is a member of the statewide one call system in all areas in which the Company has underground natural gas piping.

SECTION NO. 4
MINIMUM CUSTOMER INFORMATION REQUIREMENTS
(continued)

B. Information Required Due to Changes in Rates and Charges

1. The Company shall transmit to affected Customers a concise summary of any changes in the Company's rates and charges significantly impacting those Customers.

2. This information shall be transmitted to the affected Customer(s) within sixty (60) days of the effective date of the change in the Company's rates and charges.

SECTION NO. 5
MASTER METERING

A. Mobile Home Parks – New Construction/Expansion

1. The Company shall refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion are individually metered by the Company. Main extensions and service line connections to serve such new construction or expansion shall be governed by the main extension and/or service line connection policies of these rules and regulations.

2. Permanent residential mobile home parks for the purpose of this rule shall mean mobile home parks where the average length of stay for an occupant is a minimum of six (6) months.

3. For the purpose of this rule, expansion means construction which has been started for additional permanent residential spaces after the effective date of this rule.

SECTION NO. 6
SERVICE LINES AND ESTABLISHMENTS

A. Priority and Timing of Service Establishments

1. After an Applicant has complied with the Company's application and deposit requirements and has been accepted for service by the Company, the Company shall schedule that Customer for service establishment.

2. Service establishment shall be scheduled for completion within five (5) working days of the date the Customer has been accepted for service, except in those instances when the Customer requests service establishment beyond the five (5) working day limitation.

3. When the Company has made arrangements to meet with a Customer for service establishment purposes and the Company or the Customer cannot make the appointment during the prearranged time, the Company shall reschedule the service establishment appointment to the satisfaction of both parties.

4. The Company shall schedule service establishment appointments within a maximum range of four (4) hours during normal working hours, unless another time frame is mutually acceptable to the Company and the Customer.

5. Service establishments shall be made only by qualified service personnel of the Company or its authorized representatives.

6. For the purpose of this rule, service establishments can occur only when the Customer's facilities are ready and acceptable to the Company and the Company needs only to install, read the meter, or turn the service on.

7. A fee for service establishment, re-establishment, or reconnection of service may be charged at a rate on file with and approved by the ACC. Whenever the Applicant requests after-hours handling of his request, the Company shall charge an additional fee on file with and approved by the ACC unless a special call out is required. If a special call out is required, the charge shall be for a minimum of one (1) hour at the Company's then prevailing after-hours rate for the service work on the Customer's premises. Special handling of calls and the related charges shall be made only on request of the Applicant.

SECTION NO. 6
SERVICE LINES AND ESTABLISHMENTS
(continued)

B. Facilities

1. Customer Provided Facilities

   a. An Applicant for service shall be responsible for the safety and maintenance of all Customer piping from the Point of Delivery to the point of consumption.

   b. Meters shall be installed in a location suitable to the Company where the meters will be safe from street traffic, readily and safely accessible for reading, testing and inspection, and where such activities will cause the least interference and inconvenience to the Customer. The Customer shall provide, without cost to the Company and at a suitable and easily accessible location, sufficient and proper space for the installation of meters.

   c. Where the meter or service line location on the Customer's premises is changed at the request of the Customer or due to alterations on the Customer's premises, the Customer shall provide, and have installed at his expense, all Customer piping necessary for relocating the meter and the Company may make a charge for moving the meter and/or service line.

   d. On all newly-constructed Customer piping at the meter interconnection, the Customer will be required to install necessary piping and equipment before the meter is installed.

2. Company Provided Facilities

   a. The Company will install, at its own expense, the meter set assembly ("MSA") at a suitable location near the side wall of the Customer's building approximately three (3) feet or more from that front corner of the building nearest to the street in which the Company's distribution main is located. However, the Company, at its option, has the right to locate the meter at any location meeting the criteria of Subsection B.1.b of this section.

      The three (3) feet as noted above refers to the approximate location of the meter from the corner of the building that is nearest to the street in which the distribution main servicing that Customer is located. The gas service riser, service cock, regulator and meter are all above ground. The service from the Company's distribution main to the building is below ground.

SECTION NO. 6
SERVICE LINES AND ESTABLISHMENTS
(continued)

b. The Company or authorized representative will install the gas service line and make all connections of the gas service line from the distribution main to the service riser. The Company will in all cases be responsible for the cost of construction of the service line from the Company's distribution main to the Customer's gas service riser for an amount not to exceed the allowable investment as calculated by the Incremental Contribution Study (see Section No. 7, Subsection B), with the Customer reimbursing the Company for the difference. The Customer will reimburse the Company for the gas service line on the Customer's property at a rate of sixteen dollars ($16.00) per foot. The Customer is responsible for locating facilities on private property and removal of landscaping prior to installation or be subject to applicable charges. For Customers who provide the trench for the service line on the Customer's property, Section No. 7, Subsection B.5.d will apply and the Customer will reimburse the Company at a rate of twelve dollars ($12.00) per foot for the excess footage. The Customer, at the Customer's own expense, shall furnish, install, and be responsible for all other pipe, fittings, connections, and appurtenances between the Point of Delivery and each point of consumption.

c. No Customer-owned pipe shall be directly connected with the Company's distribution mains or services. No connection shall be made by the Customer between the facilities of the Company, including the meter, service cock and regulator and those of the Customer, nor shall any facilities of the Company be set, connected, disconnected, removed, repaired or altered except by the Company's representatives.

d. A single meter and a single Point of Delivery may be used to supply a group of buildings, such as those of a hospital or industrial establishment under single ownership or control. Such applications may fall under the Master Meter rule[t8] as defined in the Arizona Administrative Code.

e. The Company may decline service to mobile residences or portable or other temporary structures if the conditions do not afford adequate protection for the occupant(s) thereof, or the persons or property of others. In no event will gas service be permitted, if to the Company's knowledge, the Customer or the Customer's facilities fail to meet applicable requirements of law, of the State, or of any local code.

SECTION NO. 6
SERVICE LINES AND ESTABLISHMENTS
(continued)

3. Easements and Right-of-Way

Each Customer shall grant, at no cost to the Company, adequate an easement and right-of-way, satisfactory to the Company to ensure proper service connection. Failure on the part of the Customer to grant an adequate easement and right-of-way shall be grounds for the Company to refuse service.

4. Unauthorized work or facilities

When the Company discovers that a Customer or the Customer's Agent has performed work or has constructed facilities that has altered the installation of the Company's facilities to the point that work is necessary to restore the previously installed Company facilities to meet regulatory or Company requirements, the Company shall notify the Customer or the Customer's Agent and the Company shall take whatever actions are necessary to eliminate the hazard or violation at the Customer's expense.

5. Point of Delivery

The Point of Delivery for all gas delivered to any Customer shall be at the point of interconnection between the facilities of the Company and those of the Customer.

SECTION NO. 7
EXTENSION OF LINES

Extensions of gas distribution services and mains necessary to furnish permanent service to Applicants will be made in accordance with this rule.

A. General

The Company will construct, own, operate and maintain service line and distribution main extensions.

1. Gas service lines will be designed and installed so that suitable capacity from the Company's distribution main to a meter location on the property of the Applicantis satisfactory to the Company. If downstream usage changes or is altered by the Customer, the Customer may be responsible for costs to upgrade or enlarge the service line to accommodate additional capacity requirements.
2. Gas distribution main extensions will be only along public streets, roads, and highways, which the Company has legal right to occupy, and on public lands and private property across which rights-of-way, satisfactory to the Company, may be obtained.
3. All Company distribution mains and service lines shall be installed in accordance with all applicable Company standards.

B. Service and Main Extensions to Applicants for Service

General Policy – All service line and main line extension agreements are made on the basis of economic feasibility.

1. Facility Charge – If any Applicant fails to use natural gas for equipment stated in the application and used as the basis for estimating the allowable investment (ICS) within four (4) months of the completion of the main, the Company may bill the Applicant for the Incremental Cost allowed towards the extension of service. The Applicant shall pay within forty-five (45) days the charge as a non-refundable contribution towards the cost of extending service.

SECTION NO. 7
EXTENSION OF LINES
(continued)

2. At its option, the Company may require a performance bond or other surety guaranteeing bona fide operation of the facility for which the extension is requested, in accordance with Applicant's representation in the contract.

3. Master Meter Extensions – If the residential Customers are tenants in a fully improved master-metered mobile home park ("MMP") and the MMP is currently or was formerly served as a master-metered mobile home park, the allowable investment for the MMP will be calculated by the following Incremental Contribution Method and formula:

$$AI = (FR - CR) \times 5$$

where: AI = Allowable Investment

FR = The MMP's estimated future total annual revenue, assuming conversion to individual residential service, using the MMP's average park occupancy for the past two (2) years, less the Company's current average cost of purchased gas.

CR = The MMP's current total annual revenue, under the applicable schedule, averaged for the past two (2) years, less the Company's current average cost of purchased gas. If the MMP is not a current Customer of the Company, the CR will be determined on the basis of engineering estimates of occupancy and usage.

The Company will install that portion of each service in excess of the Allowed Investment subject to a nonrefundable contribution to be paid by the Applicant MMP prior to construction. In no event shall costs above the allowable investment be borne by the Company.

4. Incremental Contribution Method – Gas service line and main line extensions will be made by the Company at its expense for an amount not to exceed the Allowable Investment as calculated by an Incremental Contribution Study ("ICS").

   a. Allowable investment shall mean a determination by the Company that the revenues less the incremental gas cost to serve the Applicant provides a rate of return on the Company's investment no greater than the weighed average cost of capital authorized by the ACC in the Company's most recent general rate case.

   b. If the ICS has an allowable investment that is more than the cost of the main extension, then the excess amount may be applied to reduce the cost of service line installation.

SECTION NO. 7
EXTENSION OF LINES
(continued)

c. The Company, after conducting an ICS, may at its option, extend its facilities to Customers whose usage does not satisfy the definition of economic feasibility, but who otherwise are permanent Customers, provided the Customer pays a nonrefundable advance, necessary to make the extension economically feasible.

d. Applicants may provide trenching for service lines and/or distribution mains to the Company's specifications and the Applicant's costs will be reduced accordingly.

e. Customers provided with line extensions using the ICS shall be reviewed annually for a period of five (5) years to determine the amount of any refund, as described in Subsection B.6 below.

f. For the purposes of this rule, "economic feasibility" means that the estimated incremental revenues derived from serving the Applicant, less the incremental gas cost to serve the Applicant, meets the estimated costs of serving the Applicant, including meeting capital costs as determined by the weighed average cost of capital authorized by the ACC in the Company's most recent general rate case. An extension will not be considered economically feasible if the Applicant does not install a functioning water heater and furnace within four (4) months of the completion of the main.

5. Method of Refund

Amounts advanced by the Customer (s) in accordance with this rule, less any unpaid Facility Charges, shall be refunded, without interest, in the following manner:

a. Refunds of an advance shall be made for each additional separately metered permanent service connected to the main extension for which an advance was collected using an ICS that includes the additional Customer(s).

b. No refunds will be made for additional Customers connecting to a further extension or series of extensions constructed beyond the original extension.

c. The Customer may request an annual survey to determine if additional Customers have been connected to and are using service from the extension. In no case shall the amount of the refund exceed the amount originally advanced.

d. The refund period shall be five (5) years from the date of the completion of the extension. No refunds will be made by the Company after the termination of the refund period. Any portion of the advance that remains unrefunded at the end of the refund period shall be considered an unrefundable contribution.

e. Any assignment by a Customer of their interest in any part of an advance, which at the time remains unrefunded, must be made in writing and approved by the Company.

f. Amounts advanced under a gas main extension rule previously in effect will be refunded in accordance with the provisions of that rule.

SECTION NO. 7
EXTENSION OF LINES
(continued)

C. Service and Main Extensions to Service Individually Metered Subdivisions, Tracts, Housing Projects, Multi-Family Dwellings and Mobile Home Parks or Estates

1. Advances

   a. Gas distribution service and main extensions to and within individually metered subdivisions, tracts, housing projects, multi-family dwellings and mobile home parks or estates will be constructed, owned and maintained by the Company in advance of applications for service by bona fide Customers only when the entire estimated cost of such extensions as determined by the Company, is advanced to the Company, and a main extension agreement is executed. This advance may include the cost of any gas facilities installed at the Company's expense in conjunction with a previous service or main extension in anticipation of the current extension.

   b. The Company may require a subdivider, builder or developer to provide trenching for service lines and/or distribution mains and may also require the subdivider, builder or developer to provide bedding & shading material to Company specifications.

   c. For developers who have entered into a main extension agreement and facilities have been installed and then they or some other party request subsequent reconfiguring of facilities or other changes requiring additional expenditures by the Company, these new costs will be entirely paid for with a non-refundable contribution and any refunds will be made in accordance with the original agreement. No additional agreement or extension of the time for refunds will be made to cover the area piped under the original extension agreement.

   d. Upon completion of installation, the Company will perform a reconciliation of the estimate to actual costs incurred and may bill the Customer for any variance with the new amount included in the refundable balance, or at the Company's option withhold refunds until the underpayment is satisfied.

   e. See Subsection B.4 above for requests to serve MMP through individual residential meters if the MMP is currently or was formerly served under an MMP schedule.

   f. Refunds will be made to developers as described in Subsection B.6 above.

D. General Conditions

1. Postponement of Advance

   The Company, at its option, may postpone, for a period not to exceed five (5) years that portion of an advance which it estimates would be refunded under the provisions of this rule. At the end of such refund period, the Company shall collect all such amounts not previously advanced. When advances are postponed, the Applicant may be required to furnish to the Company, a Company-approved surety, to assure payment of any postponed amounts throughout the term of the facilities extension agreement up until the end of the postponement period.

SECTION NO. 7
EXTENSION OF LINES
(continued)

2. The Applicants or developer will provide property location, tax identification numbers, lot numbers, street names and other property information helpful to planning an extension.

3. Contracts

   a. Each Applicant requesting an extension in advance of applications for service will be required to execute a main extension agreement covering the terms under which the Company will install distribution mains in accordance with the provisions of the Company's Pricing Plans.

   b. At the time service is requested, the Applicant will submit a list of natural gas equipment to be used including the BTU input.

4. One Service for a Single Premise

   a. The Company will not install more than one service line to supply a single premise, unless it is for the convenience of the Company or an Applicant requests an additional service, and in the opinion of the Company, an unreasonable burden would be placed on the Applicant if the additional service were denied. When an additional service is installed at the Applicant's request, the Applicant shall make a nonrefundable contribution for the additional service based on the Company's estimated cost.

   b. When a service extension is made to a meter location upon private property which is subsequently subdivided into separate premises, with the ownership portions thereof divested to other than the Applicant or the Customers, the Company shall have the right, upon written notice, to discontinue service without obligation or liability. Gas service, as required by the Applicant or Customer, will be reestablished in accordance with the applicable provisions of the Company's rules.

5. Branch Services

   The Company, at its option, may install a branch service for units on adjoining premises.

SECTION NO. 7
EXTENSION OF LINES
(continued)

6. Main Extension Agreement Requirements

   a. Upon request by an Applicant for a main extension, the Company shall prepare, without charge, a preliminary sketch and rough estimate of the cost of the installation to be advanced by the Applicant.

   b. Any Applicant for a main extension requesting the Company to prepare detailed plans, specifications, or cost estimates may be required to deposit with the Company an amount equal to the estimated cost of preparation. The Company shall, upon request, make available within ninety (90) days after receipt of the deposit referred to above, such plans, specifications, or cost estimates of the proposed main extension. Where the Applicant authorizes the Company to proceed with the construction of the extension, the deposit shall be credited to the cost of construction; otherwise, the deposit shall be nonrefundable. If the extension is to include oversizing of facilities to be done at the Company's expense, appropriate details shall be set forth in the plans, specifications and cost estimates. Subdividers providing the Company with approved subdivision plats shall be provided with plans, specifications or cost estimates within forty-five (45) days after receipt of the deposit referred to above.

   c. The estimated cost of main extension and any resulting Main Extension Agreement is valid for ninety (90) days from the date of Company issue. Any signed agreement with appropriate payment where construction does not commence within ninety (90) days may be subject to review, recalculation and adjustment of advance requirements.

   d. Where the Company requires an Applicant to advance funds for a main extension, the Company shall furnish the Applicant with a copy of this rule prior to the Applicant's acceptance of the Company's extension agreement.

SECTION NO. 7
EXTENSION OF LINES
(continued)

e. All main extension agreements requiring payment by the Applicant shall be in writing, signed by each party and shall include the following:

   i. Name and address of Applicant(s);

   ii. Proposed service address(es) or location(s);

   iii. Description and sketch of the requested main extension;

   iv. Description of requested service differentiated by Customer class;

   v. Number of Customers served;

   vi. Estimated cost to construct facilities;

   vii. The Company's estimated start date and completion date for construction of the main extension;

   viii. Each Applicant shall be provided a copy of the approved main extension agreements;

   ix. Payment terms; and

   x. A concise explanation of any refunding provisions, if applicable.[19]

7. Relocation of Service Lines and Distribution Mains

   a. When, in the judgment of the Company, the relocation of a distribution main or service line is necessary and is due either to maintenance of adequate service or the operating convenience of the Company, the Company shall perform such work at its own expense.

   b. If relocation of a distribution main or service line is due solely to meet the convenience or the requirements of the Applicant or the Customer, such relocation, including metering and regulating facilities, shall be performed by the Company at the expense of the Applicant or the Customer.

   c. Relocation of facilities will be mandatory and at the Customer's expense when actions of the Customer restrict the Company's access to or the safety of the facility.

SECTION NO. 7
EXTENSION OF LINES
(continued)

[t10]

8. Standby Service or Residential Pool Heating

No allowance will be made for equipment used for standby or emergency purposes only or for equipment used for residential pool heating under Section No. 7, Subsection B.4.

9. Temporary Service

Extensions for temporary service or for operations, which in the opinion of the Company are of a speculative character or are of questionable permanency, will require an advance for the entire cost of the facilities needed, with provision for a refund using an ICS calculated annually, or at the termination of the temporary service.

10. Length and Location

The length of distribution mains or service lines required for an extension will be considered as the distance along the shortest practical and available route, as determined by the Company, from the Company's nearest permanent distribution main.

11. Service Impairment to Other Customers

When, in the judgment of the Company, providing service to an Applicant would impair service to other Customers, the cost of necessary reinforcement to eliminate such impairment may be included in the cost calculation for the extension.

12. Service From Transmission Lines

The Company will not tap a gas transmission main except when, in its sole opinion, conditions justify such a tap. Where such taps are made, the Applicant will pay the Company the cost of the tap, and extensions from the tap will be made in accordance with the provisions of this rule.

13. Other Types of Connections

Where an Applicant or Customer requests a type of service connection other than standard such as curb meters and vaults, etc., the Company will consider each such request and will grant such reasonable allowance as it may determine. The Company shall install only those facilities that it determines are necessary to provide standard natural gas service in accordance with the Company's Pricing Plans. Where the Applicant requests the Company to install special facilities which are in addition to, or in substitution for, or which result in higher costs than the standard facilities which the Company would normally install, the extra cost thereof shall be borne by the Applicant.

SECTION NO. 7
EXTENSION OF LINES
(continued)

14. Excess Flow Valve Installation Option

In accordance with Title 49, Section 192.383 of the Code of Federal Regulations, the installation of an excess flow valve, as defined in Rule No. 1, shall be performed by the Company on a new or replaced single residence service line at the request of a Customer. The installation of an excess flow valve is not mandatory. If a Customer elects this installation, the Company shall perform the installation subject to the Customer assuming responsibility for all costs associated with installation, maintenance and replacement. Each Customer requesting the installation of an excess flow valve will be required to execute a written agreement.

15. Exceptional Cases

In unusual circumstances, when the application of this rule appears impractical or unjust to either party, the Company or the Applicant may refer the matter to the ACC for special ruling or for the approval of special conditions which may be mutually agreed upon, prior to commencing construction.

16. Taxes Associated with Nonrefundable Contributions and Advances

Any federal, state or local income taxes resulting from a nonrefundable contribution or advance by the Customer in compliance with this rule will be recorded as a deferred tax and appropriately reflected in the Company's rate base. However, if the estimated cost of facilities for any service line or distribution main extension exceeds $500,000, the Company may require the Applicant to include in the contribution or advance an amount (the "gross up amount") equal to the estimated federal, state or local income tax liability of the Company resulting from the contribution or advance, computed as follows:

$$\text{Gross Up Amount} = \frac{\text{Estimated Construction Cost}}{(1 - \text{Combined Federal-State-Local Income Tax Rate})}$$

After the Company's tax returns are completed, and actual tax liability is known, to the extent that the computed gross up amount exceeds the actual tax liability resulting from the contribution or advance, the Company shall refund to the Applicant an amount equal to such excess. When a gross-up amount is to be obtained in connection with an extension agreement, the contract will state the tax rate used to compute the gross up amount, and will also disclose the gross-up amount separately from the estimated cost of facilities. In subsequent years, as tax depreciation deductions are taken by the Company on its tax returns for the constructed assets with tax bases that have been grossed-up, a refund will be made to the Applicant in an amount equal to the related tax benefit. Such refunds will be in addition to any required refunds of actual construction costs required by the extension agreement. In lieu of scheduling such refunds over the remaining tax life of the constructed assets, a reduced lump sum refund may be made at the time when actual construction costs are refunded in full. This lump sum payment shall reflect the net present value of remaining tax depreciation deductions discounted at the company's authorized rate of return.

SECTION NO. 8
PROVISION OF SERVICE

A. Company Responsibility

1. The Company shall be responsible for the safe transmission and distribution of gas until it passes the Point of Delivery to the Customer.

2. The Company shall be responsible for maintaining in safe operating condition all meters, regulators, service pipe or other fixtures installed on the Customer's premises by the Company for the purpose of delivering gas to the Customer.

3. The Company may, at its option, refuse service until the Customer's pipes and appliances have been tested and found to be safe, free from leaks, and in good operating condition. Proof of such testing shall be in the form of a certificate executed by a licensed plumber or local inspector certifying that the Customer's facilities have been tested and are in safe operating condition.

4. The Company shall be required to test the Customer's piping for leaks when the gas is turned on. If such tests indicate leakage in the Customer's piping, the Company shall refuse to provide service until such time as the Customer has had the leakage corrected.

5. The Company shall be responsible for the operation and maintenance of all facilities up to the outlet of the meter installed by the Company or its authorized agent.

B. Customer Responsibility

1. Each Customer shall be responsible for maintaining in safe operating condition all Customer piping fixtures and appliances on the Customer's side of the Point of Delivery.

2. Each Customer shall be responsible for safeguarding all Company property installed in or on the Customer's premises for the purpose of supplying gas service.

3. Each Customer shall exercise all reasonable care to prevent loss or damage to Company property, excluding ordinary wear and tear. The Customer shall be responsible for loss of, or damage to, Company property on the Customer's premises arising from neglect, carelessness, or misuse and shall reimburse the Company for the cost of necessary repairs and replacements that arise from neglect, carelessness, or misuse.

SECTION NO. 8
PROVISION OF SERVICE
(continued)

4. Each Customer shall be responsible for payment for any equipment damage and/or estimated unmetered usage resulting from unauthorized breaking of seals, interfering, Tampering, or bypassing the Company's meters. This remedy is cumulative to any other remedy available to Company under law or ACC rules.

5. Each Customer shall be responsible for promptly notifying the Company of any gas leakage identified in the Customer's or the Company's equipment.

6. The Customer will be responsible for the loss of gas or damage caused by gas in piping beyond the Company's meter.[t11]

7. No rent or other charge whatsoever will be made by the Customer against the Company for placing or maintaining meters, regulators, service lines, fixtures, etc. upon the Customer's premises.[t12]

C. Continuity of Service

The Company shall make reasonable efforts to supply a satisfactory and continuous level of service.

D. Liability

1. The Company shall not be responsible for any damage or claim of damage attributable to any interruption or discontinuation of service resulting from the following:

   a. Any cause against which the Company could not have reasonably foreseen or made provision for;

   b. Intentional service interruptions to make repairs or perform routine maintenance; or

   c. Curtailment.

SECTION NO. 8
PROVISION OF SERVICE
(continued)

2. Neither the Company nor the Customer shall be liable to the other for any act, omission or circumstances (including, with respect to the Company, but not limited to, inability to provide service) occasioned by or in consequence of flood, rain, wind, storm, lightning, earthquake, fire, landslide, washout or other acts of the elements, or accident or explosion, or war, rebellion, civil disturbance, mobs, riot, blockade, terrorist actions, or other act of the public enemy, or acts of God, or interference of civil and/or military authorities, or strikes, lockouts or other labor difficulties, or vandalism, sabotage or malicious mischief, or usurpation of power, or the laws, rules, regulations or orders made or adopted by any regulatory or other governmental agency or body (federal, state or local) having jurisdiction of any of the business or affairs of the Company or the Customer, direct or indirect, or breakage or accidents to equipment or facilities, or lack, limitation or loss of electrical or gas supply, or any other casualty or cause beyond the reasonable control of the Company or the Customer, whether or not specifically provided herein and without limitation to the types enumerated, and which by the exercise of due diligence such party is unable to prevent or overcome; provided, however, that nothing contained herein shall excuse the Customer from the obligation of paying for gas delivered or services rendered.

3. A failure to settle or prevent any strike or controversy with employees or with anyone purporting or seeking to represent employees shall not be considered to be a matter within the control of the Company.[t13]

4. Company will not be responsible for any third-party claims against Company that arise from Customer's use of Company's gas.

5. Customer will indemnify, defend and hold harmless the Company (including the costs of reasonable attorney's fees) against all claims (including, without limitation, claims for damages to any business or property, or injury to, or death of, any person) arising out of any act or omission of the Customer, or the Customer's agents, in connection with the Company's service or facilities.[t14]

6. The liability of the Company for damages of any nature arising from errors, mistakes, omissions, interruptions, or delays of the Company, its agents, servants, or employees, in the course of establishing, furnishing, rearranging, moving, terminating, or changing the service or facilities or equipment shall not exceed an amount equal to the charges applicable under the Company's Pricing Plan (calculated on a proportionate basis where appropriate) to the period during which such error, mistake, omission, interruption or delay occurs.[t15]

7. In no event shall the Company be liable for any incidental, indirect, special, or consequential damages (including lost revenue or profits) of any kind whatsoever regardless of the cause or foreseeability thereof.

8. The Company shall not be responsible for any loss or damage occasion or caused by the negligence or wrongful act of the Customer or any of his agents, employees or licensees in installing, maintaining, using, operating or interfering with any regulators, gas piping, appliances, fixtures or apparatus.[t16]

SECTION NO. 8
PROVISION OF SERVICE
(continued)

[t17]

E. Change in Character of Service

1. When a change is made by the Company in the type of service rendered which would adversely affect the efficiency of operation or require the adjustment of the equipment of Customers, all Customers who may be affected shall be notified by the Company at least thirty (30) days in advance of the change or, if such notice is not possible, as early as feasible. Where adjustments or replacements of the Company's standard equipment must be made to permit use under such changed condition, adjustments shall be made by the Company without charge to the Customers.

F. Service Interruptions

1. The Company shall make reasonable efforts to reestablish service within the shortest possible time when service interruptions occur.

2. The Company shall make reasonable provisions to meet emergencies resulting from failure of service and shall issue instructions to its employees covering procedures to be followed in the event of emergencies in order to prevent or mitigate interruption or impairment of service.

3. In the event of a national emergency or local disaster resulting in disruption of normal service, the Company may, in the public interest, interrupt service to other Customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

4. When the Company plans to interrupt service for more than four (4) hours to perform necessary repairs or maintenance, the Company shall attempt to inform affected Customers of the scheduled date and estimated duration of the service interruption at least twenty-four (24) hours in advance. Such repairs shall be completed in the shortest possible time to minimize the inconvenience to the Customers.

5. The ACC shall be notified of interruptions in service affecting the entire system or any major division of the entire system. The interruption of service and the cause shall be reported by telephone to the ACC within one (1) hour after the responsible representative of the Company becomes aware of said interruption, and shall be followed by a written report to the ACC.

SECTION NO. 8
PROVISION OF SERVICE
(continued)

G. Heat Value Standard for Natural Gas

The Company shall supply gas to its Customers with an average total heating value of not less than nine hundred (900) BTUs per cubic foot. The number of BTUs per cubic foot actually delivered through the Customer's meter will vary according to the altitude and elevation of the location where the Customer is being provided service.

H. Standard Delivery Pressure

1. The Company shall maintain Standard Delivery Pressure of at the outlet of the Customer's meter, subject to variation under load conditions.

2. In cases where a Customer desires service at greater than Standard Delivery Pressure, the Company may supply, at its option, such greater pressure if and only as long as the furnishing of gas to such Customer at higher than standard delivery pressure will not be detrimental to the service of other Customers of the Company. The Company reserves the right to lower the delivery pressure or discontinue the delivery of gas at higher pressure at any time upon reasonable notice to the Customer. Where service is provided at pressure higher than Standard Delivery Pressure, the meter volumes shall be corrected to that higher pressure.

SECTION NO. 8
PROVISION OF SERVICE
(continued)

I. Determination of Therms for Billing

1. Heating Value – The heating value (BTU per cubic foot) of the natural gas delivered will vary depending on the source of supplies received by the Company. The average heating values will be determined from the volumetric weighted average heating values of the supplies received by the Company.

2. Metered Volumes – The number of therms to be billed will be determined by multiplying the difference in meter readings by an appropriate billing factor.

   a. Therms are determined from the volumes measured by the following:

$$\underset{A}{\frac{\text{Atmospheric Pressure at Elevation + Delivery Pressure}}{\text{14.73 Atmospheric Pressure at Sea Level}}} \times \underset{B}{\frac{\text{Average Heating Value (BTU per cubic foot)}}{\text{100,000 BTU per Therm}}} \times \underset{C}{\text{Super Compressibility Factor}}$$

   Where:
   A = Correction for atmospheric pressure at elevation and applicable delivery pressure
   B = Applicable heating value of natural gas received
   C = Correction for super compressibility ratio

   b. Atmospheric Pressures at Elevations within the Company's service territory are outlined in the following table. At such time additional elevation bands are needed within the various areas served by the Company, new geographical zones will be added.

Northern Arizona:

Geographical Zone Description	Atmospheric Pressure Base
ASHFORK AZ E4801-5000	12.3264800
ASHFORK AZ E5001-5200	12.2366800
BAGD CPR AZ E3601-3800	12.8782000
BAGD ML AZ E2601-2800	13.3555800
BAGDAD MINE E0401-0600	14.4666500
BLACK CANYON CITY AZ E1601-1800	13.8498700

SECTION NO. 8
PROVISION OF SERVICE
(continued)

Geographical Zone Description	Atmospheric Pressure Base
BLACK CANYON CITY AZ E1801-2000	13.7496200
CAMP VERDE AZ E2801-3000	13.2587800
CAMP VERDE AZ E3001-3200	13.1626500
CHINO VALLEY AZ E4201-4400	12.5995400
CHINO VALLEY AZ E4401-4600	12.5079100
CHINO VALLEY AZ E4601-4800	12.4168900
CLARKDALE AZ E3001-3200	13.1626500
CLARKDALE AZ E3201-3400	13.0671800
CLARKDALE AZ E3401-3600	12.9723700
CORNVILLE AZ E3001-3200	13.1626500
CORNVILLE AZ E3201-3400	13.0671800
COTTONWOOD AZ E3001-3200	13.1626500
COTTONWOOD AZ E3201-3400	13.0671800
COTTONWOOD AZ E3401-3600	12.9723700
COTTONWOOD AZ E3601-3800	12.8782000
DUVAL AZ E3201-3400	13.0671800
FLAGSTAFF AZ E6201-6400	11.7102300
FLAGSTAFF AZ E6401-6600	11.6244900
FLAGSTAFF AZ E6601-6800	11.5393200
FLAGSTAFF AZ E6801-7000	11.4546900
FLAGSTAFF AZ E7001-7200	11.3706100
FLAGSTAFF AZ E7201-7400	11.2870800
HOLBROOK AZ E4801-5000	12.3264800
HOLBROOK AZ E5001-5200	12.2366800
HUMBOLDT AZ E4201-4400	12.5995400
HUMBOLDT AZ E4401-4600	12.5079100
HUMBOLDT AZ E4601-4800	12.4168900
INDPK AZ E6201-6400	11.7102300
JEROME AZ E4201-4400	12.5995400
JEROME AZ E4401-4600	12.5079100
JEROME AZ E4601-4800	12.4168900
JEROME AZ E4801-5000	12.3264800
JEROME AZ E5001-5200	12.2366800
JOSEPH CITY AZ E4601-4800	12.4168900
JOSEPH CITY AZ E4801-5000	12.3264800
KINGMAN AZ E3001-3200	13.1626500

SECTION NO. 8
PROVISION OF SERVICE
(continued)

Geographical Zone Description	Atmospheric Pressure Base
KINGMAN AZ E3201-3400	13.0671800
KINGMAN AZ E3401-3600	12.9723700
KINGMAN AZ E3601-3800	12.8782000
KINGMAN AZ E3801-4000	12.7846800
LAKE HAVASU CITY AZ E0201-0400	14.5720600
LAKE HAVASU CITY AZ E0401-0600	14.4666500
LAKE HAVASU CITY AZ E0601-0800	14.3620000
LAKE HAVASU CITY AZ E0801-1000	14.2581000
LAKE HAVASU CITY AZ E1001-1200	14.1549500
LAKE HAVASU CITY AZ E1201-1400	14.0525300
LAKE HAVASU CITY AZ E1401-1600	13.9508400
MAYER AZ E4001-4200	12.6917900
MAYER AZ E4201-4400	12.5995400
MOUNTAIN VIEW AZ E6401-6600	11.6244900
NAVAJO ARMY DEPOT E5401-5600	12.0588700
PAULDEN AZ E4001-4200	12.6917900
PAULDEN AZ E4201-4400	12.5995400
PAULDEN AZ E4401-4600	12.5079100
PHX CMT AZ E3401-3600	12.9723700
PINETOP/LAKESIDE AZ E6201-6400	11.7102300
PINETOP/LAKESIDE AZ E6401-6600	11.6244900
PINETOP/LAKESIDE AZ E6601-6800	11.5393200
PINETOP/LAKESIDE AZ E6801-7000	11.4546900
PINETOP/LAKESIDE AZ E7001-7200	11.3706100
PRESCOTT VALLEY AZ E4201-4400	12.5995400
PRESCOTT VALLEY AZ E4401-4600	12.5079100
PRESCOTT VALLEY AZ E4601-4800	12.4168900
PRESCOTT VALLEY AZ E4801-5000	12.3264800
PRESCOTT VALLEY AZ E5001-5200	12.2366800
PRESCOTT AZ E4601-4800	12.4168900
PRESCOTT AZ E4801-5000	12.3264800
PRESCOTT AZ E5001-5200	12.2366800
PRESCOTT AZ E5201-5400	12.1474800
PRESCOTT AZ E5401-5600	12.0588700
PRESCOTT AZ E5601-5800	11.9708400
PRESCOTT AZ E5801-6000	11.8834000

SECTION NO. 8
PROVISION OF SERVICE
(continued)

Geographical Zone Description	Atmospheric Pressure Base
SEDONA AZ E3401-3600	12.9723700
SEDONA AZ E3601-3800	12.8782000
SEDONA AZ E3801-4000	12.7846800
SEDONA AZ E4001-4200	12.6917900
SEDONA AZ E4201-4400	12.5995400
SEDONA AZ E4401-4600	12.5079100
SEDONA AZ E4601-4800	12.4168900
SELIGMAN AZ E5001-5200	12.2366800
SHOW LOW AZ E5801-6000	11.8834000
SHOW LOW AZ E6001-6200	11.7965300
SHOW LOW AZ E6201-6400	11.7102300
SHOW LOW AZ E6401-6600	11.6244900
SNOWFLAKE AZ E5201-5400	12.1474800
SNOWFLAKE AZ E5401-5600	12.0588700
SPRING VALLEY AZ E3601-3800	12.8782000
SPRING VALLEY AZ E3801-4000	12.7846800
STONE CONTAINER E6001-6200	11.7965300
TAYLOR AZ E5401-5600	12.0588700
VERDE VALLEY AZ E3401-3600	12.9723700
VILLAGE OF OAK CREEK AZ E3601-3800	12.8782000
VILLAGE OF OAK CREEK AZ E3801-4000	12.7846800
VILLAGE OF OAK CREEK AZ E4001-4200	12.6917900
WILLIAMS AZ E6401-6600	11.6244900
WILLIAMS AZ E6601-6800	11.5393200
WILLIAMS AZ E6801-7000	11.4546900
WINSLOW AZ E4601-4800	12.4168900

SECTION NO. 8
PROVISION OF SERVICE
(continued)

Southern Arizona:

Geographical Zone Description	Atmospheric Pressure Base
AMADO AZ E2801-3000	13.2587800
AMADO AZ E3001-3200	13.1626500
NOGALES AZ E3201-3400	13.0671800
NOGALES AZ E3401-3600	12.9723700
NOGALES AZ E3601-3800	12.8782000
NOGALES AZ E3801-4000	12.7846800
PATAGONIA AZ E3601-3800	12.8782000
PATAGONIA AZ E3801-4000	12.7846800
PATAGONIA AZ E4001-4200	12.6917900
RIO RICO AZ E3001-3200	13.1626500
RIO RICO AZ E3201-3400	13.0671800
RIO RICO AZ E3401-3600	12.9723700
RIO RICO AZ E3601-3800	12.8782000
RIO RICO AZ E3801-4000	12.7846800
RIO RICO AZ E4001-4200	12.6917900
TUBAC AZ E2801-3000	13.2587800
TUBAC AZ E3001-3200	13.1626500
TUBAC AZ E3201-3400	13.0671800
TUBAC AZ E3401-3600	12.9723700

J. Construction Standards and Safety

The Company's pipelines and pipeline facilities for the transportation of gas within the State of Arizona shall conform with and be subject to the Federal Safety Standards as adopted by the United States Department of Transportation, Pipeline and Hazardous Materials Safety Administration. The Company maintains and updates an Operation and Maintenance plan and an Emergency plan. Upon discovery of occurrence, the Company will report all incidents as required under the Arizona Administrative Code, R14-5-203.

SECTION NO. 9
METER READING

A. Company or Customer Meter Reading

1. The Company may, at its discretion, allow for Customer reading of meters.

2. It shall be the responsibility of the Company to inform the Customer how to properly read the Customer's meter.

3. Where a Customer reads the meter, the Company will read the Customer's meter at least once every six (6) months.

4. The Company shall specify the timing requirements for the Customer to submit the monthly meter reading to conform to the Company's billing cycle.

5. In the event the Customer fails to submit the meter reading on time, the Company may issue the Customer an estimated bill.

6. Meters shall be read monthly on as close to the same day each month as practical.

B. Measuring of Service

1. All gas sold by the Company shall be metered, except in the case of gas sold according to a fixed charge schedule, or when otherwise authorized by the ACC.

2. When there is more than one (1) meter at a location, the metering equipment shall be so tagged or plainly marked as to indicate the facilities being metered.

3. If and when the Company installs multiple meters or service lines to serve a single Customer for the Company's convenience, meter readings may be combined for billing purposes.

C. Customer - Requested Rereads

1. At the request of a Customer, the Company will reread that Customer's meter within ten (10) working days after such request by the Customer.

2. Any reread may be charged to the Customer at a rate on file and approved by the ACC, provided that the original reading was not in error.

3. When a reading is found to be in error, the reread shall be at no charge to the Customer.

SECTION NO. 9
METER READING
(continued)

D. Access to Customer Premises

The Company shall have the right of safe ingress to and egress from the Customer's premises at all reasonable hours for any purpose reasonably connected with the furnishing of service and the exercise of any and all rights secured to the Company by law or the ACC's rules or the Company's Pricing Plans.

E. Customer-Requested Meter Tests

The Company shall test a meter upon Customer request and shall be authorized to charge the Customer for such meter test. However, if the meter is found to be in error by more than three percent (3%), no fee will be charged to the Customer.

SECTION NO. 10
BILLING AND COLLECTION

A. Frequency and Estimated Bills

1. The Company shall bill monthly for services rendered. Meter readings shall be scheduled for periods of not less than twenty-five (25) days or more than thirty-five (35) days.

2. If the Company is unable to read a meter on the scheduled meter read date, the Company will estimate the consumption for the billing period, giving consideration to the following factors where applicable:

   a. The Customer's usage history in the previous twelve (12) months; and

   b. The amount of usage during the preceding month.

3. After the second consecutive month of estimating the Customer's bill for reasons other than severe weather, the Company will attempt to secure an accurate reading of the meter.

4. Failure on the part of the Customer to comply with a reasonable request by the Company for access to the Customer's meter may lead to the discontinuance of service.

5. Estimated bills will be issued only under the following conditions:

   a. Failure of a Customer who reads his or her own meter to deliver the meter reading card to the Company in accordance with the requirements of the Company's billing cycle;

   b. Severe weather conditions which prevent the Company from reading the meter; or

   c. Circumstances that make it impossible to read the meter, such as locked gates, blocked meters, and vicious or dangerous animals, etc.

6. Each bill based on estimated usage will indicate that it is an estimated bill.

SECTION NO. 10
BILLING AND COLLECTION
(continued)

B. Combining Meters - Minimum Bill Information

1. Each meter at a Customer's premises will be considered separately for billing purposes, and the readings of two (2) or more meters will not be combined unless approved by the Company.

2. Each bill for sales service will contain the following minimum information:

    a. Date and meter reading at the start of billing period or number of days in the billing period;

    b. Date and meter reading at the end of the billing period;

    c. Billed usage;

    d. Rate schedule number;

    e. Company's telephone number;

    f. Customer's name;

    g. Service account number;

    h. Amount due and due date;

    i. Past due amount;

    j. Adjustment factor, where applicable;

    k. Taxes; and

    l. The Arizona Corporation Commission address.

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 (10^{th}) 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.

SECTION NO. 10
BILLING AND COLLECTION
(continued)

D. Applicable Pricing Plans, Prepayments, Failure to Receive, Commencement Date

1. Each Customer shall be billed under the Pricing Plan indicated in the Customer's application for service.
2. The Company shall make provisions for advance payment for Company services.
3. Failure to receive bills or notices which have been properly placed in the United States mail shall not prevent such bills from becoming delinquent and does not relieve the Customer of the Customer's obligations therein.
4. Charges for service commence when the service is installed and connection made, whether used or not.

E. Meter Error Corrections

1. If, after testing, any meter is found to be more than three percent (3%) in error, either fast or slow, proper correction between three percent (3%) and the amount of the error shall be made on previous readings, and adjusted bills shall be rendered according to the following terms:
   a. For the period of three (3) months immediately preceding the removal of such meter from service for testing or from the time the meter was in service since last tested, but not exceeding three (3) months since the meter shall have been shown to be in error by such test.
   b. From the date the error occurred, if the date of the cause can be definitely fixed.
2. No adjustment shall be made by the Company except to the Customer last served by the meter tested.

SECTION NO. 10
BILLING AND COLLECTION
(continued)

F. Nonsufficient Funds ("NSF") Checks and Denied Electronic Funds Transfers

1. The Company shall be allowed to recover a fee, according to the Company's Pricing Plans, for each instance where a Customer tenders payment for a Company service with an NSF check. This fee shall also apply when an electronic funds transfer ("EFT") is denied for any reason, including for lack of sufficient funds.[t18]

2. When the Company is notified by the Customer's bank that there are insufficient funds to cover the check tendered for service, or an EFT has been denied for any reason, the Company may require the Customer to make payment in cash, by money order or certified check, or by other means which guarantee the Customer's payment to the Company.

3. A Customer who tenders an NSF check or for whom an EFT is denied, shall in no way be relieved of the obligation to render payment to the Company under the original terms of the bill, nor defer the Company's provision for termination of service for nonpayment of bills.

G. Elevation/Pressure Adjustment

The Company shall adjust for pressure according to the procedures in Section 8.H of these Rules and Regulations.

SECTION NO. 10
BILLING AND COLLECTION
(continued)

H. Deferred Payment Plan

1. The Company may, prior to termination of service, offer a deferred payment plan to qualifying residential Customers for the payment of unpaid bills for gas service.

2. Each deferred payment agreement entered into by the Company and the Customer, due to the Customer's inability to pay an outstanding bill in full, shall provide that service will not be discontinued if:

   a. The Customer agrees to pay a reasonable amount of the outstanding bill at the time the parties enter into the deferred payment agreement;

   b. The Customer agrees to pay all future bills for gas service in accordance with the Company's Pricing Plans; and

   c. The Customer agrees to pay a reasonable portion of the remaining outstanding balance in installments.

3. For the purposes of determining a reasonable installment payment schedule under these Rules, the Company and the Customer shall give consideration to the following conditions:

   a. The size of the delinquent account.

   b. The Customer's ability to pay.

   c. The Customer's payment history.

   d. The length of time that the debt has been outstanding.

   e. The circumstances which resulted in the debt being outstanding.

   f. Any other relevant factors related to the circumstances of the Customer.

4. Any Customer who desires to enter into a deferred payment agreement shall establish such agreement prior to the Company's scheduled service termination date for nonpayment of bills. The Customer's failure to execute a deferred payment agreement prior to the scheduled service termination date shall not prevent the Company from terminating service for nonpayment.

5. Deferred payment agreements may be in writing and may be signed by the Customer and an authorized Company representative.

SECTION NO. 10
BILLING AND COLLECTION
(continued)

6. A deferred payment agreement may include a finance charge of one and one-half percent (1.5%) per month.

7. If a Customer does not fulfill the terms of a deferred payment agreement, the Company shall have the right to disconnect service pursuant to the Company's termination of service rules (Section No. 11 of these Rules) and, under such circumstances, it shall not be required to offer subsequent negotiation of a deferred payment agreement prior to disconnection.

I. Change of Occupancy

1. Not less than three (3) working days advance notice must be given in person at the Company's office, in writing, or by telephone to discontinue service or to change occupancy.

2. The outgoing party shall be responsible for all Company services provided and/or consumed up to the scheduled turn-off date.

J. Electronic Billing

Electronic Billing is an optional billing service whereby Customers may elect to receive, view, and pay their bills electronically. Electronic Billing includes the "UES e-bill" service and the "Sure No Hassle Automatic Payment ("SNAP") service. The Company may modify its electronic billing services from time to time. A Customer electing an electronic billing service may receive an electronic bill in lieu of a paper bill. Customers electing an electronic billing service may be required to complete additional forms and agreements. Electronic billing may be discontinued at any time by the Company or the Customer. An electronic bill will be considered rendered at the time it is electronically sent to the Customer. Failure to receive bills or notices which have been properly sent by an electronic billing system does not prevent such bills from becoming delinquent and does not relieve the Customer of the Customer's obligations therein. Any notices which Company is required to send to a Customer who has elected an electronic billing service may be sent by electronic means at the option of the Company. Except as otherwise provided in this subsection, all other provisions of the Company's Rules and Regulations and other applicable Pricing Plans are applicable to electronic billing.[t19]

SECTION NO. 11
TERMINATION OF SERVICE

A. Non-Permissible Reasons to Disconnect Service

1. The Company may not disconnect service for any of the reasons stated below:

   a. Delinquency in payment for services rendered to a prior Customer at the premises where service is being provided, except in the instance where the prior Customer continues to reside on the premises.

   b. Failure of the Customer to pay for services or equipment that are not regulated by the ACC.

   c. Nonpayment of a bill related to another class of service.

   d. Failure to pay a bill to correct a previous under-billing due to an inaccurate meter or meter failure, if the Customer agrees to pay over a reasonable period of time.

   e. The Company may not terminate residential service where the Customer has an inability to pay and:

      i. The Customer can establish through medical documentation that, in the opinion of a licensed medical physician, termination of service would be especially dangerous to the health of the Customer or to the health of a permanent resident residing on the Customer's premises;

      ii. Life-supporting equipment is used in the home that is dependent on Company service for operation of such apparatus; or

      iii. Where weather will be especially dangerous to health as defined herein or as determined by the ACC.

   f. Residential service to persons who have an inability to pay and who have an Illness, are a Senior Citizen, or who are Handicapped will not be terminated until all of the following have been attempted:

      i. The Customer has been informed of the availability of funds from various government and social assistance agencies; and

      ii. A third party previously designated by the Customer has been notified and has not made arrangement to pay the outstanding Company bill.

   A Customer utilizing the provisions of Subsection A.1.e or A.1.f above may be required to enter into a deferred payment agreement with the Company within ten (10) days after the scheduled service termination date.

   g. Failure to pay the bill of another Customer as guarantor thereof.

   h. Disputed bills where the Customer has complied with the ACC's rules on Customer bill disputes.

SECTION NO. 11
TERMINATION OF SERVICE
(continued)

D. Termination Notice Requirements

1. The Company may not terminate service to any of its Customers without providing advance written notice to the Customer of the Company's intent to disconnect service, except under those conditions specified where advance written notice is not required.

2. Such advance written notice shall contain, at a minimum the following information:

    a. The name of the person whose service is to be terminated and the address where service is being rendered;

    b. The Pricing Plans that was violated and explanation of the violation or the amount of the bill, which the Customer has failed to pay in accordance with the payment policy of the Company, if applicable;

    c. The date on or after which service may be terminated; and

    d. A statement advising the Customer that the Company's stated reason for the termination of services may be disputed by contacting the Company at a specific address or phone number, advising the Company of the dispute and making arrangements to discuss the cause for termination with a responsible employee of the Company in advance of the scheduled date of termination. The responsible employee shall be empowered to resolve the dispute and the Company shall retain the option to terminate service after affording this opportunity for a meeting, concluding that the reason of terminating is just, and advising the Customer of his right to file a complaint with the ACC.

3. Where applicable, a copy of the termination notice will be simultaneously forwarded to designated third parties.

E. Timing of Terminations With Notice

1. The Company shall be required to give at least five (5) days advance written notice prior to the termination date. For Customers under the jurisdiction of a bankruptcy court, a shorter notice may be provided, if permitted by that court.

2. Such notice shall be considered to be given to the Customer when a copy of the notice is left with the Customer or posted first class in the United States mail, and addressed to the Customer's last known address.

3. If, after the period of time allowed by the notice has elapsed, the delinquent account has not been paid nor arrangements made with the Company for the payment of the bill, or in the case of a violation of the Company's rules the Customer has not satisfied the Company that such violation has ceased, the Company may terminate service on or after the day specified in the notice without giving further notice.

SECTION NO. 11
TERMINATION OF SERVICE
(continued)

4. Service may only be disconnected in conjunction with a personal visit to the premises by an authorized representative of the Company.

5. The Company shall have the right, but not the obligation, to remove any or all of its property installed on the Customer's premises upon the termination of service.

F. Landlord/Tenant Rule

1. In situations where service is rendered at an address different from the mailing address of the bill or where the Company knows that a landlord/tenant relationship exists and that the landlord is the Customer of the Company, and where the landlord as Customer would otherwise be subject to disconnection of service, the Company may not disconnect service until the following actions have been taken:

    a. Where it is feasible to provide service, the Company, after providing notice as required in these rules, shall offer the occupant the opportunity to subscribe for service in the occupant's own name. If the occupant then declines to subscribe, the Company may disconnect service pursuant to the rules.

    b. The Company shall not attempt to recover payment of any outstanding bills or other charges due on the outstanding account of the landlord from a tenant. The Company shall not condition service to a tenant based on the payment of any outstanding bills or other charges due upon the outstanding account of the landlord.

SECTION NO. 12
ADMINISTRATIVE AND HEARING REQUIREMENTS

A. Customer Service Complaints

1. The Company shall make a full and prompt investigation of all service complaints made by its Customers, either directly to the Company or through the ACC.

2. The Company shall respond to the complainant and/or the ACC representative within five (5) working days as to the status of the Company's investigation of the complaint.

3. The Company shall notify the complainant and/or the ACC representative of the final disposition of each complaint. Upon request of the complainant or the ACC representative, the Company shall report the findings of its investigation in writing.

4. The Company shall inform the Customer of the right of appeal to the ACC.

5. The Company shall keep a record of all written service complaints received and which shall contain, at a minimum, the following data:

   a. Name and address of complainant.

   b. Date and nature of complaint.

   c. Disposition of the complaint.

   d. A copy of any correspondence between the Company, the Customer, and/or the ACC.

   This record shall be maintained for a minimum period of one (1) year and shall be available for inspection by the ACC.

SECTION NO. 12
ADMINISTRATIVE AND HEARING REQUIREMENTS
(continued)

B. Customer Bill Disputes

1. Any Customer who disputes a portion of a bill rendered for gas service shall pay the undisputed portion of the bill prior to the delinquent date of the bill, and notify the Company's designated representative that any unpaid amount is in dispute.

2. Upon receipt of the Customer's notice of dispute, the Company shall:

   a. Notify the Customer within five (5) working days of the receipt of a written dispute notice.

   b. Initiate a prompt investigation as to the source of the dispute.

   c. Withhold disconnection of service until the investigation is completed and the Customer is informed of the results. Upon request of the Customer, the Company shall report the results of the investigation in writing.

   d. Inform the Customer of the right of appeal to the ACC.

3. Once the Customer has received the results of the Company's investigation, the Customer shall submit payment within five (5) working days to the Company for any disputed amounts. Failure to make full payment shall be grounds for termination of service.

C. ACC Resolution of Service and/or Bill Disputes

1. In the event a Customer and the Company cannot resolve a service and/or bill dispute, the Customer shall file a written statement with the ACC. By submitting such written notice to the ACC, the Customer shall be deemed to have filed an informal complaint against the Company.

2. Within thirty (30) days of the receipt of a written statement of Customer dissatisfaction related to a service or bill dispute, a designated representative of the ACC shall endeavor to resolve the dispute by correspondence and/or by telephone with the Company and the Customer. If resolution of the dispute is not achieved within twenty (20) days of the ACC representative's initial effort, the ACC shall hold an informal hearing to arbitrate the resolution of the dispute. The informal hearing shall be governed by the following rules:

   a. Each party may be represented by legal counsel, if desired;

   b. All such informal hearings may be recorded or held in the presence of a stenographer;

SECTION NO. 12
ADMINISTRATIVE AND HEARING REQUIREMENTS
(continued)

c. All parties will have the opportunity to present written or oral evidentiary material to support the positions of the individual parties; and

d. All parties and the ACC's representative shall be given an opportunity for cross-examination of the various parties.

The ACC's representative will render a written decision to all parties within five (5) working days after the date of the informal hearing. Such written decision of the ACC's representative is not binding on any of the parties and the parties will still have the right to make a formal complaint to the ACC.

3. The Company may implement normal termination procedures if the Customer fails to pay all bills rendered during the resolution of the dispute by the ACC.

4. The Company shall maintain a record of written statements of dissatisfaction and their resolution for a minimum of one (1) year and make such records available for ACC inspection.

D. Notice by Company of Responsible Officer or Agent

1. The Company shall file with the ACC a written statement containing the name, business address and telephone numbers (office and mobile) of at least one officer, agent or employee responsible for the general management of its operations as a Company in Arizona.

2. The Company shall give notice, by filing a written statement with the ACC, of any change in the information required herein within five (5) days from the date of any such change.

SECTION NO. 13
BUDGET BILLING PAYMENT PLAN

A. Residential Customers may elect to participate in the Company's Budget Billing Payment Plan ("Plan") for payment of charges for gas service.

B. Upon Customer request, the Company will develop an estimate of the Customer's levelized billing for a twelve (12) month period based on:

1. The Customer's actual consumption history at the service location, which may be adjusted for weather or other known variations. If sufficient history is not available, then an estimate will be prepared based on other similar service locations and Customer's anticipated load requirements; and

2. The applicable Pricing Plan, the estimated gas costs for the Plan year, and applicable taxes.

C. The Company shall provide the Customer with a concise explanation of how the levelized billing estimate was developed, the impact of levelized billing on a Customer's monthly bill, and the Company's right to adjust the Customer's billing for any variation between the Company's estimated billing and actual billing.

D. The Plan's monthly payment shall be determined as follows:Settlement month will be the Customer's anniversary date, 12 months from the time the Customer is set up on the Budget Billing Payment Plan. The Company reserves the right to adjust the remaining monthly Plan semi-annually to reduce the likelihood of an excessive debt or credit balance in rates due to dramatic PGA increases or PGA surcharges.

1. The Company reserves the right to adjust the remaining monthly Plan payments of any Customer at any time if the Company's estimate of the Customer's usage and/or cost varies significantly from the Customer's actual usage and/or cost. Such review may also be initiated by the Customer. Any change resulting from such a review will be effective on a subsequent bill and no further notice is required.

2. The Customer shall continue to pay the monthly Plan payment amount each month, notwithstanding the current gas service charge shown on the bill.

3. Any other charges incurred by the Customer shall be paid monthly when due in addition to the monthly Plan payment.

4. Interest will not be charged the Customer on accrued debit balances nor paid by the Company on accrued credit balances.

5. Any amount due the Company will be settled and paid at the time a Customer, for any reason, ceases to be a participant in the Plan. If an amount due to the Customer exceeds fifty dollars ($50.00), the Customer has the option to receive a bill credit or a refund; otherwise the credit will remain as a bill credit.

SECTION NO. 13
BUDGET BILLING PAYMENT PLAN
(continued)

6. Any Customer's participation in the Plan may be discontinued by the Company if the monthly Plan payment has not been paid on or before the billing date of the next monthly Plan payment.

7. If a Customer in the Plan shall cease, for any reason, to participate in the Plan, then the Company may refuse that Customer's re-entry in the Plan until the following August or for six (6) months, whichever is longer.

8. For those Customers being billed under the Plan, the Company shall show, at a minimum, the following information on the Customer's monthly bill:

    a. Actual consumption;

    b. Amount due for actual consumption;

    c. Levelized billing amount due; and

    d. Accumulated variation in actual versus levelized billing amount.

SECTION NO. 14
CURTAILMENT PLAN

A. The Company shall use reasonable diligence in its operations to render continuous service to all its Customers other than those Customers served under Pricing Plans expressly permitting interruptions of service for peak shaving purposes. If for any reason, however, the Company is unable to supply the demand for gas in any one or more of its systems, interruptions or curtailments of service shall be made in accordance with the provisions of this section. The Company shall not be liable for damages because of the operation of this section.

B. Applicability

1. The order of curtailment shall be in inverse order of the curtailment priorities set forth in Subsection C below.
2. Curtailment priorities shall apply to both sales and transportation Customers.
3. Customers being served under a discounted transportation or sales rate schedule shall be curtailed first. Customers paying the least will be curtailed first within an affected priority.
4. Each priority shall be curtailed in full before the next priority in order is curtailed.
5. When Priority 1 Customers would be curtailed due to system supply failure (either upstream capacity or supply failure), the Company is authorized to "preempt" deliveries of lower priority transportation Customers' gas and divert such supplies to the otherwise affected Priority 1 Customers. Affected transportation Customers will be curtailed to the same extent as sales Customers of the same priority. Such transportation Customers will be compensated for the preemption of their gas supply by either crediting the Customer's account with a like quantity of gas for use on a subsequent gas day, or by providing a cash payment or credit to the Customer's bill at the cost of gas per unit paid by the Customer. If the gas supply of an alternate fuel-capable transportation Customer is preempted according to this provision, the Company shall provide additional compensation to such Customer for the incremental cost of using the alternate fuel, (the difference between the actual cost of using the alternate fuel and the actual cost of gas paid by the Customer for the preempted gas). Such credit shall be applied to the Company's next scheduled billing after the Customer has furnished adequate proof to the Company concerning alternate fuel costs, replacement volumes, and gas costs.
6. The installation of a cogeneration facility shall not affect the underlying end-use priority of the establishment.
7. Natural gas utilized as compressed natural gas for vehicle fuel shall be classified as a commercial end-use.

SECTION NO. 14
CURTAILMENT PLAN
(continued)

8. Application of curtailment priorities will normally be done on a scheduled basis as part of the daily gas requirement nomination and confirmation routine. Operational emergency curtailment will conform to these priorities to the extent possible and practical.

9. A transportation Customer may be curtailed to the level of actual supply scheduled for that Customer, regardless of end-use priority.

C. Priorities

Priority 1: Residential, small commercial (less than five hundred (500) therms on a peak day), schools, hospitals, police protection, fire protection, sanitation facility, correctional facility, and emergency situation uses.

Priority 2A: Essential agricultural uses as certified by the Secretary of Agriculture.

Priority 2B: Essential industrial process and feedstock uses.

Priority 2C: Large Commercial (five hundred (500) therms or more on a peak day) and storage injection requirements, industrial requirements for plant protection, feedstock, process, ignition and flame stabilization needs not specified in Priority 2B.

Priority 3A: Industrial requirements not specified in Priorities 2, 4, and 5, of less than one thousand (1,000) therms on a peak day.

Priority 3B: All industrial requirements not specified in Priorities 2, 3A, 4, and 5.

Priority 4: Industrial requirements for boiler fuel use at less than thirty thousand (30,000) therms per peak day, but more than fifteen thousand (15,000) therms per peak day, where alternate fuel capabilities can meet such requirements.

Priority 5: Industrial requirements for large volume (thirty thousand (30,000) therms per peak day or more) boiler fuel use where alternate fuel capabilities can meet such requirements.

D. In the event of isolated incidents in order to avoid hazards and protect the public, the Company may temporarily interrupt service to certain Customers without regard to priority or any other Customer classification.

SECTION NO. 14
CURTAILMENT PLAN
(continued)

E. Definitions

1. "Alternate Fuel Capability" – A situation where an alternate fuel can be utilized whether or not the facilities for such usehave actually been installed.

2. "Correctional Facility Uses" – A facility, the primary function of which is to house, confine, or otherwise limit the activities of a person who has been assigned to such facilities as punishment by a court of law.

3. "Essential Agricultural Use" – Any use of natural gas which is certified by the Secretary of Agriculture as an "essential agricultural use."

4. "Essential Industrial Process and Feedstock Uses" – Any use of natural gas by an industrial Customer as process gas, or as a feedstock, or gas used for human comfort to protect health and hygiene in an industrial installation.

5. "Feedstock Gas" – Natural gas use for which alternate fuels are not technically feasible, such as in applications requiring precise temperature controls and precise flame characteristics. For the purposes of this definition, propane and other gaseous fuels shall not be considered alternate fuels.

6. "Fire Protection Uses" – Natural gas used by and for the benefit of fire fighting agencies in the performance of their duties.

7. "Flame Stabilization Gas" – Natural gas which is burned by igniters, main gas burners, or warm-up burners for the purpose of maintaining stable combustion of an alternate fuel.

8. "Hospital" – A facility, the primary function of which is delivering medical care to patients who remain at the facility (facility includes nursing and convalescent homes). Outpatient clinics or doctors' offices are not included in this definition.

9. "Ignition Gas" – Natural gas supplied to gas igniters in boilers to light main burners, whether the main burners are operated by gas, oil, or coal.

10. "Industrial Boiler Fuel" – Natural gas used in a boiler as a fuel for the generation of steam or electricity.

11. "Industrial Use" – Natural gas used primarily in a process which creates or changes raw or unfinished materials into another form or product, including electric power generation.

12. "Peak Day" – Maximum daily Customer use as determined by the best practical method available.

SECTION NO. 14
CURTAILMENT PLAN
(continued)

13. "Plant Protection Gas" – Minimum natural gas volumes required to prevent physical harm to the plant facilities or danger to plant personnel when such protection cannot be afforded through the use of an alternate fuel. This includes the protection of such material in process as would otherwise be destroyed, but shall not include deliveries required to maintain plant production. For the purposes of this definition, propane and other gaseous fuels shall not be considered alternate fuels.

14. "Police Protection Uses" – Natural gas used by law enforcement agencies in the performance of their duties.

15. "Process Gas" – Natural gas use for which alternate fuels are not technically feasible, such as in applications requiring precise temperature controls and precise flame characteristics. For the purposes of this definition, propane and other gaseous fuels shall not be considered alternate fuels.

16. "Sanitation Facility Uses" – Natural gas use in a facility where natural gas is used to a) dispose of refuse, or b) protect and maintain the general sanitation requirements of the community at large.

17. "School" – A facility, the primary function of which is to provide instruction to regularly enrolled students in attendance at such facility. Facilities used for both educational and non-educational activities are not included under this definition unless the latter activities are merely incidental to the provision of instruction.

18. "Small Commercial Establishment" – Any establishment (including institutions and local, state, and federal government agencies) engaged primarily in the sale of goods or services where natural gas is used:

    a. in amounts of less than fifty (50) MCF on a peak day; and

    b. for purposes other than those involving manufacturing or electric power generation.

19. "Storage Injection Gas" – Natural gas injected by a distributor into storage for later use.

SECTION NO. 15
RATES AND UNIT MEASUREMENT

A. The rates and charges for gas service shall be those of the Company legally in effect and on file with the ACC.

B. All rates set forth in the Company's Pricing Plans are stated in therms. Unless otherwise provided by special contract, the number of therms delivered to any Customer shall be determined by measuring the volume of gas passing through that Customer's meter during the month to the nearest one hundred (100) cubic feet and applying the procedures of Section 8.H of these Rules and Regulations.

C. The unit of volume for measurement of gas sold shall be one (1) Cubic Foot of gas, as defined in Section 2, Subsection A.13 of these Rules and Regulations. The volume of gas measured shall be rounded to the nearest one hundred (100) cubic feet for any given period.

D. The atmospheric pressure will be the standard atmospheric pressure for the location.

E. The standard serving pressure shall be seven (7) inches of water pressure (four (4) ounces per square inch gauge) above the atmospheric pressure.

F. The standard temperature of sixty (60) degrees Fahrenheit will be used for volume determination unless stated otherwise under special contract. The Company shall retain the right, but shall not be obligated, to install temperature recording or compensating equipment as part of the measuring facilities. When such temperature recording equipment is used, the arithmetic average temperature of the gas each day, during periods of flow only, shall be used in computing the quantity of gas delivered by that day.

G. The Company, at its own option, may elect to serve a Customer at a pressure higher than the standard serving pressure. The Company shall correct such volume to Standard Conditions by the use of compensating equipment or the use of a factor. The Company retains the right to determine the method used for applying such correction. The factor used to correct the measured volume shall be in accordance with American Gas Association Report 3[t20].

H. The therm conversion factor shall be determined each month and shall be the product of the conversion factor and the most recent heating value content available using the weighted average delivered pressure by office. The weighted average delivered pressure is derived monthly using the delivered pressure for each town code served which is reflective of each town code's elevation, weighted by the sales distribution among assigned gas distribution systems within each respective office.[t21] Further explained in Section 8.H. of these Rules and Regulations.

SECTION NO. 16
GAS METER TESTING AND MAINTENANCE PLAN

A. General Plan

The Company will annually sample groups of meters to determine the continuing accuracy and performance of the group. Certain safe and proper standards are defined, and meters will remain in service as long as they meet these standards. This program will allow the Company to obtain all the useful service available from a meter until the meter no longer meets prescribed standards. At that time, then it is proper for the meter to be removed, tested, repaired, or retired.

This procedure is for the purpose of testing and controlling the performance of small gas meters that are two hundred fifty (250) CFH or less. The program will identify and remove meters that do not meet the standards of performance described in Subsection D below, and identify and retain in service meters that do meet or exceed the stated standards. Meters are classified into groups, samples of each group are tested annually, and groups are removed from service when they do not meet performance standards.

B. Meter Groups

1. Meters are segregated into groups on the following basis:

    a. Year last repaired or purchased;

    b. Manufacturer;

    c. Diaphragm type (leather or synthetic), when available; and

    d. Geographic district.

2. For meters repaired or purchased in a given year, the groups are established at the beginning of the next year. When a new group being established is found to contain less than one thousand (1,000) meters, this group may be combined with another group having meters of the same or similar operating characteristics. An existing group may be divided into two or more groups, if experience characteristics of part of the group are sufficiently different from the remainder of the group to warrant separate sampling of the parts.

C. Sampling

A representative random sample is selected from each group of meters. The samples are used in determining the performance of each group of meters each year. If the initial order for meter removals does not produce an adequate sample, additional meters are drawn on a random basis. These meters are combined with the original sample for determining acceptability of the group. Samples are taken annually from all groups that have been in service for ten years or longer.

SECTION NO. 16
GAS METER TESTING AND MAINTENANCE PLAN
(continued)

D. Performance Standard

The criteria for acceptability for a group to remain in service are:

1. No more than ten percent (10%) of the meters tested in the group are more than three percent (3%) fast.

2. At least eighty percent (80%) of the meters tested in the group are within +/- three percent (3%) of zero error. This results in a condition wherein a minimum of ninety percent (90%) of the meters remaining in service are either within +/- three percent (3%) or are more than three percent (3%) slow and in the Customer's favor.

E. Records

The test results for each group are kept in appropriate records that indicate the number of meters in the sample versus the test results, expressed as a percent.

F. Removal of Groups

1. A test result falling on or above the prescribed standards is satisfactory and the groups will remain in service.

2. A test falling below the prescribed standards is not satisfactory and the group will be removed from service.

3. The Company, for its convenience, may remove a group (or part of a group) even though the group meets the requirements for remaining in service.

SECTION NO. 16
GAS METER TESTING AND MAINTENANCE PLAN
(continued)

G. Annual Reports

A report of the meter performance control program will be filed annually with the ACC, which will contain the following:

1. A description of each group, showing its identification, size and composition;
2. A list of the total number of meters tested, at Company initiative or upon Customer request;
3. A detailed list of the performance results of each group, showing the number of meters in the group, the number of meters removed during the year, the number of meters not tested (dead, non-registering, damaged, etc.), the number or meters tested, the number of meters slow - minus three percent (-3%), the number of meters accurate, the percent of meters accurate, the number of meters fast - plus three percent (+3%), and the percent of meters fast;
4. A summary of results for each year of service; and
5. A summary or the overall results.

EXHIBIT

GAS-2

UNS Gas, Inc.
Rules & Regulations

REDLINED VERSION

TABLE OF CONTENTS

SECTION NO. 1
APPLICABILITY OF RULES AND REGULATIONS AND DESCRIPTION OF SERVICE

~~1.~~A. ~~UniSource Energy Services' UNS Gas, Inc. ("~~Company~~")~~ is a gas utility operating within portions of the state of Arizona. The Company will provide service to any person, institution or business located within its service area in accordance with the provisions of its Pricing Plans~~rate schedules~~ and the terms and conditions of ~~its rules as filed with and approved by the Arizona Corporation Commission ("ACC")~~these Rules and Regulations.

~~2.~~B. All gas delivered to any Customer is for the sole use of such Customer on that Customer's premises only. Gas delivered by the Company shall not be redelivered or resold, or the use thereof by others permitted unless otherwise expressly agreed to in writing by the Company. However, those Customers purchasing gas for redistribution to the Customer's own tenants (only on the Customer's premises) may separately meter each tenant distribution point for the purpose of prorating the Customer's actual purchase price of gas delivered among the various tenants on a per unit basis.

~~3.~~C. The ~~Company rules~~se Rules and Regulations shall apply to all gas service furnished by the Company to its Customers.

~~4.~~D. These Rules and Regulations ~~Company rules~~ are part of the Company's Pricing Plans~~tariffs~~ on file with, and duly approved by, the ACC. These Rules and Regulations shall remain in effect until modified, amended, or deleted by order of the ACC. No employee, agent or representative of the Company is authorized to modify the Company rules.

E. The ~~Company rules~~se Rules and Regulations shall be applied uniformly to all similarly situated Customers.

~~5.~~F. ~~It is intended that the Company rules comply in all respects with the rules of the ACC.~~ In case of ~~conflict~~any conflict between these Rules and Regulations and the ACC's rules, these Rules and Regulations shall apply~~, the rules of the ACC shall govern, except those for which the ACC has procedurally suspended or excused compliance therewith, in which event the Company rules shall govern~~.

~~6.~~G. Whenever the Company and an ~~applicant~~Applicant or a Customer are unable to agree on the terms and conditions under which such ~~applicant~~Applicant or Customer is to be served, or are unable to agree on the proper interpretation of the ~~Company rules~~these Rules and Regulations, either party may request assistance from the Consumer Services Section of the Utilities Division of the ACC. The ~~applicant~~Applicant or Customer also has the option to file an application with the ACC for a proper order, after notice and hearing.

H. The Company's supplying gas service to the Customer and the acceptance thereof by the Customer shall be deemed to constitute an agreement by and between the Company and the Customer for delivery, acceptance of and payment for gas service under the Company's Rules and Regulations and applicable Pricing Plans.

SECTION NO. 2
DEFINITIONS

A. In these Rules and Regulations~~rules~~, the following definitions shall apply unless the context requires otherwise:

1. "Advance in Aid of Construction" or "Advance" – Funds provided to the Company by an ~~applicant~~Applicant under the terms of a main extension agreement, the value of which may be refundable.

2. "Applicant" – A person ~~or entity~~ requesting the Company to supply gas service.

3. "Application" – A request to the Company for gas service, as distinguished from any inquiry as to the availability or charges for such service.

4. "Arizona Corporation Commission" ("ACC") – The ~~regulatory authority of the State of Arizona having jurisdiction over public service corporations operating in Arizona~~regulatory body established by Article XV of the Arizona Constitution.

5. "Billing Month" – The time interval between any two (2) regular readings of the Company's meters at approximately thirty (30) day intervals.

6. "Billing Period" – The time period between two (2) consecutive meter readings that are taken for billing purposes.

7. "British Thermal Unit" ("BTU") – The amount of heat required to raise the temperature of one (1) pound of water one (1) degree Fahrenheit, at ~~s~~Standard ~~c~~Conditions.

8. "CCF" – One hundred (100) cubic feet.

9. "CFH" – Cubic feet per hour.

~~9.~~10. "Commodity Charge" – The unit cost for billed usage as set forth in the Company's Pricing Plans~~Tariffs~~.

~~10.~~11. "Company" – UNS Gas, Inc.

~~11.~~12. "Contributions in Aid of Construction" or "Contribution" – Funds provided to the Company by the ~~applicant~~Applicant under the terms of a main extension agreement and/or service connection tariff, the value of which are not refundable.

SECTION NO. 2
DEFINITIONS
(continued)

~~12.~~13. "Cubic Foot" –

~~1.~~a. In cases where gas is supplied and metered to ~~Customer~~Customers at ~~the s~~Standard ~~d~~Delivery ~~p~~Pressure, a cubic foot of gas is the volume of gas, which at the temperature and pressure existing in the meter occupies one (1) cubic foot.

~~2.~~b. Regardless of the pressure supplied to the Customer, the volume of gas metered will be converted to the volume~~,~~ which the gas would occupy at ~~s~~Standard ~~c~~Conditions. ~~of 14.73 pounds per square inch absolute at sixty (60) degrees Fahrenheit.~~

~~3.~~c. The standard cubic foot of gas used for testing the gas for heating value shall be that volume of gas which, when saturated with water vapor and at a temperature of sixty (60) degrees Fahrenheit and under a pressure equivalent to that of thirty (30) inches of mercury (mercury at thirty-two (32) degrees Fahrenheit and under standard gravity), occupies one (1) cubic foot.

~~13.~~14. "Curtailment Priority" – The order in which gas service is to be curtailed to various classifications of ~~Customer~~Customers, as set forth in the Company's Pricing Plans~~tTariffs~~.

~~14.~~15. "~~Customer~~Customer" – The person ~~or entity~~ in whose name service is rendered, as evidenced by the signature on the application or contract for that service, or by the receipt and/or payment of bills regularly issued in the person's ~~his or her~~ name regardless of the identity of the actual user of the service.

~~15.~~16. "~~Customer~~Customer Charge" – The amount the Customer must pay the Company for the availability of gas service, excluding any gas used, as specified, in the Company's Pricing Plans~~tTariffs~~.

~~15.~~17. "~~Customer~~Customer Service Complaint" - Written complaint received from a C~~customer~~ustomer, or through the ACC on behalf of a ~~customer~~Customer.

~~16.~~18. "Day" – Calendar day.

~~17.~~19. "De~~k~~catherm" – Ten (10) therms or 1,000,000 BTU.

~~18.~~20. "Distribution Main" – A gas line of the Company from which service lines may be extended to ~~Customer~~Customers.

~~19.~~21. "Handicapped" – A person with a physical or mental condition which substantially contributes to the person's inability to manage his o~~r~~f her own resources, carry out activities of daily living, or protect themselves~~oneself~~ from neglect or hazardous situations without assistance from others.

SECTION NO. 2
DEFINITIONS
(continued)

~~20.~~22. "Illness" – A medical ailment or sickness for which a residential ~~Customer~~Customer obtains a verifiable document from a licensed medical physician stating the nature of the illness and that discontinuance of service would be especially dangerous to the ~~Customer~~Customer's health.

~~21.~~23. "Inability to Pay" – Circumstances where a residential ~~Customer~~Customer:

a. Is not gainfully employed and is unable to pay; or

b. Qualifies for government welfare assistance, but has not begun to receive assistance on the date that the bill is received and can obtain verification from the government welfare agency; or

c. Has an annual income below the published federal poverty level and can produce evidence of this; and

d. Signs a declaration verifying that the ~~Customer~~Customer meets one of the above criteria and is either a senior citizen, handicapped, or suffers from an illness.

24. "~~"Incremental Gas Cost"~~Incremental Contribution Study" ~~(ICS)~~ ("ICS") ~~– An analysis which determines a Customer's contribution to the cost of his or her service and main line extension. The analysis utilizes estimates of revenues collected from the Customer, expenses incurred by the Company, and the Company's authorized rate of return~~ Tthe study described in Section 7.B.5 of these Rules and Regulations.

~~22.~~25. "Interruptible Gas Service" – Gas service that is subject to interruption or curtailment as specified in the ~~company'~~Company's Pricing Plans~~Tariffs~~.

26. "Law" – Any rule or requirement established and enforced by government authorities.

~~23.~~27. "Main Extension" – The lines and equipment necessary to extend the existing gas distribution system to provide service to additional ~~customers~~Customers.

~~24.~~28. "Master Meter" – An instrument for measuring or recording the flow of gas at a single location from which said gas is transported through a piping system to tenants or occupants for their individual consumption.

~~25.~~29. "MCF" – One thousand (1,000) cubic feet.

~~26.~~30. "Meter" – The instrument for measuring and indicating or recording the volume of gas that has passed through it.

31. "Meter Set Assembly" ("MSA") – All gas components downstream of the ~~c~~Customer's inlet service valve ~~gas service stop~~ to the ~~Customer~~Customer's ~~point of delivery~~Point of Delivery.

SECTION NO. 2
DEFINITIONS
(continued)

~~27. "Meter Tampering" – A situation where a meter has been illegally altered. Common examples are meter bypassing and other unauthorized connections. Tampering also includes any action defined as "tampering" under A.R.S. § 40-491(4).~~

~~28.~~32. "Minimum Charge" – The amount the ~~Customer~~Customer must pay for the availability of gas service and~~,~~ may include ~~including~~ an amount of usage, as specified in the Company's Pricing Plans~~Tariffs~~.

~~29.~~33. "Permanent ~~Customer~~Customer" – A ~~Customer~~Customer who is a tenant or owner of a service location who applies for and receives gas service.

~~30.~~34. "Permanent Service" – Service which, in the opinion of the Company, is of a permanent and established character. The use of gas may be continuous, intermittent, or seasonal in nature.

~~31.~~35. "Person" – Any individual, partnership, corporation, governmental agency, or other organization operating as a single entity.

36. "Point of Delivery" – The ~~point of delivery~~Point of Delivery for all gas delivered to any ~~Customer~~Customer shall be at the point of interconnection between the facilities of the Company and those of such ~~Customer~~Customer.

~~32.~~37. "Premises" – All of the real property and apparatus employed in a single enterprise or residence on an integral parcel of land undivided by public streets, alleys or railways.

38. "Pricing Plan" – A part of the Company's Tariffs which sets forth the rates and charges related to specific categories of Customers, and related terms and conditions.

~~33.~~39. "Residential Subdivision" – Any tract of land which has been divided into four or more contiguous lots for use in the construction of residential buildings or permanent mobile homes for either single or multiple occupancy.

~~34.~~40. "Residential Use" – Service to ~~Customer~~Customers using gas for domestic purposes such as space heating, air conditioning, water heating, cooking, clothes drying, and other residential uses and includes use in apartment buildings, mobile home parks, and other multi-unit residential buildings.

~~35.~~41. "Restricted Apparatus" – An apparatus prohibited by the ACC, another~~or other~~ governmental agency, or the Company.

42. "Rules and Regulations" or "Company rules" – These Rules and Regulations, which are part of the Company's Tariffs and Pricing Plans.

SECTION NO. 2
DEFINITIONS
(continued)

~~36.~~43. "Senior Citizen" – A person who is sixty-two (62) years of age or older.

~~37.~~44. "Service Areas" – ~~the~~The territory in which the Company has been granted a certificate of convenience and necessity and is authorized by the ACC to provide gas service.

~~38.~~45. "Service Establishment Charge" – A charge, as specified in the Company's Pricing Plans~~Tariffs~~, which covers the cost of establishing a new account.

~~39.~~46. "Service Line" – A gas pipe that transports gas from a common source or supply (normally a distribution main) to the ~~Customer~~Customer's ~~p~~Point of ~~d~~Delivery.

~~40.~~47. "Service Reconnection Charge" – A charge ~~as~~ specified in the Company's Pricing Plans~~Tariffs~~ ~~which~~that must b~~y~~e paid by the ~~Customer~~Customer prior to re-establishment of gas service each time the gas is disconnected for nonpayment, or ~~whenever service is discontinued~~ for failure to comply with the Company's Pricing Plans~~Tariffs~~.

~~41.~~48. "Service Re-Establishment Charge" – A charge ~~as~~ specified in the Company's Pricing Plans~~Tariffs~~ for the re-establishment of service at the same location where the same ~~Customer~~Customer had ordered a service disconnect within the preceding twelve (12) month period. In addition to the Service Re-Establishment Charge, such returning Customer shall pay the sum of the applicable monthly Customer Charges which would have accrued had the Customer not ordered the disconnect.

~~42.~~49. "Single Family Dwelling" – A house, an apartment, a~~and a~~or a -mobile home permanently affixed to a lot, or any other permanent residential unit which is used as permanent home.

50. "Standard Conditions" - 14.73 pounds per square inch absolute at sixty (60) degrees Fahrenheit.

~~43.~~51. "Standard Delivery Pressure" – 0.25 pounds per square inch gauge at the meter or ~~point of delivery~~Point of Delivery.

52. "Tampering" – A situation where a meter has been illegally altered. Common examples are meter bypassing and other unauthorized connections. Tampering also includes any action defined as "tampering" under A.R.S. § 40-491(4).

~~44.~~53. "Tariffs" – The documents filed with the ACC that list the services offered by the Company and set forth the terms and conditions and a schedule of the rates and charges for those services and products. These Rules and Regulations are part of the Company's Tariffs. The Company's Pricing Plans are also part of the Company's Tariffs.

~~45.~~54. "Temporary Service" – Service to premises or enterprises that are temporary in character, or where it is known in advance that the service will be of limited duration. Service that, in the opinion of the Company, is for operations of speculative character is also considered temporary service.

SECTION NO. 2
DEFINITIONS
(continued)

~~46.~~55. "Therm" – A unit of heating value, equivalent to one hundred thousand (100,000) BTUs.~~British Thermal Units.~~

~~**SECTION NO. 2**~~
~~**DEFINITIONS**~~
~~(continued)~~

~~47.~~56. "Third Party Notice" – A notice sent to a~~n~~ person ~~individual or a public entity~~ willing to receive notification of the pending discontinuance of service to~~of~~ a ~~Customer~~Customer of record, in order to make arrangements on behalf of said ~~Customer~~Customer that are satisfactory to the Company.

~~48.~~57. "Transmission Line" - A gas line for delivering natural gas that operates at a ~~H~~hoop stress of twenty percent (20%) or more of ~~SYMS~~ Specified Minimum Yield Strength ("SMYS")~~,~~, as defined in CFR 49, Part 192 or that transports gas to ~~a~~ a single large volume ~~customer~~Customer such as a distribution center, factory, power plant or institutional user.

~~49.~~58. "Unauthorized" – Use of gas services that is not in accordance with ~~the~~ ACC~~'s~~ rules, ~~and/or~~ the Company's Rules and Regulations, ~~rules, regulations~~ or~~and~~ the Company's Pricing Plans~~Tariffs~~.

~~50. "Utility" – The public service corporation providing gas service to the public in compliance with state law.~~

~~51.~~59. "Weather Especially Dangerous to Health" – That period of time, commencing with the scheduled termination date, when the local weather forecast~~,~~ as predicted by the National ~~Oceanographic and Administration Service~~Oceanic and Atmospheric Administration, indicates that the temperature will not exceed thirty-two (32) degrees Fahrenheit for the next day's forecast. The ACC may determine that other weather conditions are especially dangerous to health as the need arises.

~~52.~~60. "Working Hours" – The period of time during which the Company's offices are open for business.

~~53.~~61. "Yardline" – A gas pipe that transports gas from the ~~Customer~~Customer's ~~point of delivery~~Point of Delivery to the point of entry into the ~~Customer~~Customer's residence or other place of consumption.

SECTION NO. 3
ESTABLISHMENT OF SERVICE

~~1.~~A. Information From ~~Applicant~~Applicants

1. The Company may obtain the following minimum information from each ~~applicant~~Applicant ~~of service~~:

   a. Name or names of ~~applicant~~Applicant(s);

   b. Service address or location and telephone number;

   c. Billing address or location and telephone number, if different than service address;

   d. Address where service was provided previously;

   e. Date ~~applicant~~Applicant will be ready for service;

   f. Indication of whether premises have been supplied with gas service previously;

   g. Purpose for which service is to be used;

   h. Indication of whether ~~applicant~~Applicant is owner or tenant of~~,~~ or agent for, the premises;

   i. Information concerning the gas usage and demand requirements of the ~~Customer~~Customer; and

   j. Type and kind of life-support equipment, if any, used by the ~~Customer~~Customer.

2. The Company may require a new ~~applicant~~Applicant for service to appear at the Company's designated place of business to produce proof of identity and sign the Company's application form.

3. Where service is requested by two or more individuals, the Company shall have the right to collect the full amount owed to the Company from any one of the ~~applicant~~Applicants.

4. ~~The company shall provide to the Customer customer making application for~~An Applicant for -gas service to ~~a~~ new construction/ or a new ~~expansion~~extension shall complete the following Company forms~~both a~~:

   a. New Service Application; and

   b. Excess Flow Valve ~~Customer~~Customer Notification (applies to Residential only).

   The ~~customer~~Customer is responsible ~~to complete and return~~ for completing and returning both forms. ~~.~~ Failure on the part of the ~~Customer~~Customer to provide completed forms shall be grounds for the Company to delay or refuse service. For the purpose of this Rule, the definition of new construction/~~expansion~~extension is where there is a need to run a new service line or install new gas facilities to a property that has never had prior natural gas service.

SECTION NO. 3
ESTABLISHMENT OF SERVICE
(continued)

~~2.~~B. Deposits

~~a.~~1. The Company may require from any present or prospective ~~Customer~~Customer a security deposit to guarantee payment of all bills. This deposit may be retained by the Company until service is discontinued and all bills have been paid; except as provided in Subsection B.4 below. Upon proper application by the ~~Customer~~Customer, the Company shall then return said deposit, together with any unpaid interest accrued thereon from the date of commencement of service or the date of making the deposit, whichever is later. The Company shall be entitled to apply said deposit together with any unpaid interest accrued thereon, to any indebtedness for the same class of service owed to the Company for gas service furnished to the ~~Customer~~Customer making the deposit. When said deposit has been applied to any such indebtedness, the ~~Customer~~Customer's gas service may be discontinued until all such indebtedness of the ~~Customer~~Customer is paid and a like deposit is again made with the Company by the ~~Customer~~Customer. No interest shall accrue on any deposit after discontinuance of the service to which the deposit relates.

The Company shall not require a deposit from a new ~~applicant~~Applicant for residential service if the ~~applicant~~Applicant is able to meet any of the following requirements:

a. The~~ applicant~~Applicant has had service of a comparable nature with the Company at another service location within the past two (2) years and was not delinquent in payment more than twice during the last twelve (12) consecutive months, or was not disconnected for nonpayment; or

b. The ~~applicant~~Applicant can produce a letter regarding credit or verification from a gas or electric utility which states that the ~~applicant~~Applicant has had service of a comparable nature with that utility at another service location within the past two (2) years and was not delinquent in payment more than twice during the last twelve (12) consecutive months, or was not disconnected for nonpayment; or

c. In lieu of a cash deposit, a new Aapplicant may provide a Letter of Guarantee from an existing ~~Customer~~Customer of the Company who is acceptable to the Company, a surety bond, or similar alternative acceptable to the Company, such as a Certificate of Deposit, as security for Company in the sum equal to the required deposit; or

d. If a credit check is offered by the Company, the ~~applicant~~Applicant authorizes a credit check and meets the standards established by the Company.

~~b.~~2. The Company may issue a non-assignable, non-negotiable receipt to the ~~applicant~~Applicant for the deposit. The inability of the ~~Customer~~Customer to produce such a receipt shall in no way impair the ~~Customer~~Customer's right to receive a refund of the deposit which is reflected on the Company's records.

SECTION NO. 3
ESTABLISHMENT OF SERVICE
(continued)

3. Cash deposits held by the Company twelve (12) months or longer shall earn interest at the established one year Treasury Constant Maturities rates, effective on the first business day of each year, as published in the Federal Reserve website. ~~Simple interest at the rate of six percent (6.0%) per annum will be paid by the Company upon each such deposit for the time such deposit was held by the Company and the Customer was served by the Company, except that n~~No interest will be paid on deposits for which ~~Customer~~Customers have turned service on and off within the same calendar month. Such payment of interest shall be made during January of each year for ~~Customer~~Customers served by the Company for at least six (6) months and will cover all interest accrued up to the end of the preceding calendar year or on the date the deposit is returned to the ~~Customer~~Customer, pursuant to Subsection B.4 below. At the Company's option, the above payments may be made either by check or by credit on the monthly bill.

~~c.~~4. All deposits of residential or commercial ~~Customer~~Customers received and held by the Company shall be returned to the ~~Customer~~Customer by the Company (with interest, as provided by Subsection B.3 above), at such time as the affected ~~Customer~~Customers shall have maintained for a period of twelve (12) consecutive months (from and after the date when the deposit was made), their accounts with the Company. The ~~Customer~~Customer's accounts shall have been maintained in such a manner that they shall not have been delinquent in the payment of more than two (2) bills during such twelve (12) month period, whether at the same address or at a different address, nor have had their gas service, whether at the same address or at a different address, discontinued, in accordance with these Rules and Regulations~~rules~~, for failure to pay for gas service previously rendered.

~~d.~~5. The Company may require a ~~Customer~~Customer to establish or re-establish a deposit if the ~~Customer~~Customer became delinquent in the payment of three (3) or more bills within a twelve (12) consecutive month period, or has been disconnected from service during the last twelve (12) months.

~~e.~~6. The Company may review the ~~Customer~~Customer's usage after service has been connected and adjust the deposit amount based upon the ~~Customer~~Customer's actual usage.

~~f.~~7. A separate deposit may be required for each meter installed.

~~g.~~8. Residential ~~customer~~Customer deposits shall not exceed two (2) times that ~~customer~~Customer's estimated average monthly bill. Non-residential ~~customer~~Customer deposits shall not exceed two and one-half (2.5) times that ~~customer~~Customer's maximum estimated monthly bill. If actual usage history is available, then that usage, adjusted for normal weather, will be the basis for the estimate.

9. The posting of a deposit shall not preclude the Company from terminating service~~, because t, because of ahe~~ when the termination is due to the -Customer's failure to~~ make timely payment of any bill, Customer's failure to~~ perform any obligation under the agreement for service or ~~for service or Customer's violation of~~ any of these Rules and Regulations.

SECTION NO. 3
ESTABLISHMENT OF SERVICE
(continued)

~~3.~~C. Grounds For Refusal Of Service

The Company may refuse to establish service if any of the following conditions exist:

~~2.~~1. The Applicant has an outstanding amount due for the same class of gas service with the Company and the Applicant is unwilling to make arrangements with the Company for payment; or

2. A condition exists which, in the Company's judgment, is unsafe or hazardous to the ~~applicant~~Applicant, the general population, or the Company's personnel or facilities; or

3. The ~~applicant~~Applicant refuses to provide the Company with a deposit when the ~~Customer~~Customer has failed to meet the credit criteria for waiver of deposit requirements; or

4. ~~Customer~~Customer is known to be in violation of the Company's Pricing Plans~~Tariffs filed with the ACC~~; or

5. ~~Customer~~Customer fails to furnish such funds, service, equipment, and/or rights-of-way necessary to serve the ~~Customer~~Customer and which have been specified by the Company as a condition for providing service; or

6. ~~Applicant~~Applicant falsifies his or her identity for the purpose of obtaining service.

~~4.~~D. Service Establishments, Re-establishment or Reconnection Charge

1. The Company may make a charge as approved by the ACC for the establishment, re-establishment, or reconnection of service.

2. Should service be established during a period other than the Company's regular working hours at the ~~Customer~~Customer's request, the ~~Customer~~Customer may be required to pay an after-hour charge for the service connection. Where the Company's scheduling will not permit service establishment on the same day as requested, the ~~Customer~~Customer can elect to pay the after-hour charge for establishment that day, or his service will be established on the next available working day.

3. For the purpose of this Rule, the definition of service establishments are where the ~~Customer~~Customer's facilities are ready and acceptable to the Company, and the Company needs only to install a meter, read a meter, or turn the service on.

SECTION NO. 3
ESTABLISHMENT OF SERVICE
(continued)

~~5.~~E. Temporary Service

1. ~~Applicant~~Applicants for temporary service may be required to pay to the Company, in advance of service establishment, the estimated cost of installing and removing the facilities necessary for furnishing the desired service.

2. Where the duration of service is to be less than one (1) month, the ~~applicant~~Applicant may also be required to advance a sum of money equal to the estimated bill for service.

3. Where the duration of service is to exceed one (1) month, the ~~applicant~~Applicant may also be required to meet the deposit requirements of the Company, as outlined in Subsection B.1 above.

4. If at any time during the term of the agreement for service the character of a temporary ~~Customer~~Customer's operations changes so that, in the opinion of the Company, the ~~Customer~~Customer is classified as permanent, the terms of the Company's main extension rules shall apply.

SECTION NO. 4
MINIMUM CUSTOMER INFORMATION REQUIREMENTS

A. Information for Residential ~~Customer~~Customers

~~a.~~1. The Company shall make available upon ~~Customer~~Customer request, no later than sixty (60) days from the date of request, a concise summary of the rate schedule applied for by such ~~Customer~~Customer. The summary shall include the following:

a. Monthly minimum or ~~Customer~~Customer charge, identifying the amount of the charge and the specific amount of usage included in the minimum charge, where applicable;

b. Rate blocks, where applicable; and

c. Any adjustment factor(s) and method of calculation.

2. ~~The Company shall, to the extent practical, identify the tariff most advantageous to the CustomerCustomer and notify the CustomerCustomer of such tariff prior to service commencement~~Upon aApplication~~,~~ or upon request, the Applicant or the Customer shall elect the applicable Pricing Plan best suited to their requirements. The Company may~~will~~ assist in making such election, but shall not be held responsible for notifying the Customer of the most favorable Pricing Plan and shall not be required to refund the difference in charges under different Pricing Plans~~.~~

However, ~~For~~ new non-residential ~~customers~~Customers whose projected consumption is near the threshold between "large" and "small" Pricing Plans~~rates~~, ~~they will~~may elect the ~~be placed on the~~ "small" rate, subject to refund, if their usage qualifies them as a "large" ~~customer~~Customer. An existing non-residential ~~customer~~Customer will be moved to the "large" rate, or once moved, back to the "small" rate, only if ~~theirhis or her~~their consumption history or a clear permanent change in consumption makes it clear the ~~customer~~Customer will meet the volume requirements of one ~~rate or the other~~Pricing Plan.

A review may be initiated by either the Company or the ~~Customer~~Customer. Any change of Pricing Plan~~rate schedule~~, if appropriate, will be effective with the first bill issued seven (7) days after the ~~review~~ initiation of the review. No adjustment of past billings due to Pricing Plan~~rate~~ selection will be made to either the Company or the ~~Customer~~Customer, except for a new ~~customer~~Customer who qualifies for the "large" ~~rate based on its first~~Pricing Plan based on -twelve (12) months of usage as set forth in this Rule.

SECTION NO. 4
MINIMUM CUSTOMER INFORMATION REQUIREMENTS
(continued)

~~b.~~3. Upon ~~Customer~~Customer request, the Company shall make available to the ~~Customer~~Customer, a copy of the ACC's Rules and Regulations (Arizona Administrative Code, Title 14, Article 3 - Gas Utilities) concerning:

~~A.~~a. Deposits;

~~B.~~b. Termination of Service;

~~C.~~c. Billing and Collection; and

~~D.~~d. Complaint Handling.

~~c.~~4. The Company, upon ~~request of a Customer~~Customer request, shall transmit a written statement of actual consumption by the ~~Customer~~Customer for each billing period during the prior twelve (12) months unless such data is not reasonably ascertainable.

~~d.~~5. The Company shall inform all new ~~Customer~~Customers of their rights to obtain the information specified above.

6. The Company shall notify each ~~customer~~Customer of the following information, in writing, within ninety (90) days after the ~~customer~~ Customer first receives gas service at a particular location:

   a. The Company does not maintain the ~~Customer~~Customer's buried piping;

   b. If the ~~Customer~~Customer's buried piping is not maintained, it may be subject to the potential hazards of corrosion and leakage;

   c. Buried gas piping should be periodically inspected for leaks, periodically inspected for corrosion if the piping is metallic, and repaired if any unsafe condition is discovered;

   d. When excavating near buried gas piping, the piping must be located in advance, and the excavation done by hand;

   e. Plumbing contractors and heating contractors may assist in locating, inspecting, and repairing the ~~Customer~~Customer's buried piping; and

   f. In order to reduce damage by outside forces, the Company is a member of the statewide one call system in all areas in which the Company has underground natural gas piping.

SECTION NO. 4
MINIMUM CUSTOMER INFORMATION REQUIREMENTS
(continued)

B. Information Required Due to Changes in Rates and Charges

1. The Company shall transmit to affected ~~Customer~~Customers a concise summary of any changes in the Company's rates and charges significantly impacting those ~~Customer~~Customers.

2. This information shall be transmitted to the affected ~~Customer~~Customer(s) within sixty (60) days of the effective date of the change in the Company's rates and charges.

SECTION NO. 5
MASTER METERING

A. Mobile Home Parks – New Construction/Expansion

~~A.~~1. The Company shall refuse service to all new construction and/or expansion of existing permanent residential mobile home parks unless the construction and/or expansion are individually metered by the Company. Main extensions and service line connections to serve such new construction or expansion shall be governed by the main extension and/or service line connection policies of these rules and regulations.

~~B.~~2. Permanent residential mobile home parks for the purpose of this rule shall mean mobile home parks where the average length of stay for an occupant is a minimum of six (6) months.

~~C.~~3. For the purpose of this rule, expansion means construction which has been started for additional permanent residential spaces after the effective date of this rule.

SECTION NO. 6
SERVICE LINES AND ESTABLISHMENTS

A. Priority and Timing of Service Establishments

1. After an ~~applicant~~Applicant has complied with the Company's application and deposit requirements and has been accepted for service by the Company, the Company shall schedule that ~~Customer~~Customer for service establishment.

2. Service establishment shall be scheduled for completion within five (5) working days of the date the ~~Customer~~Customer has been accepted for service, except in those instances when the ~~Customer~~Customer requests service establishment beyond the five (5) working day limitation.

3. When the Company has made arrangements to meet with a ~~Customer~~Customer for service establishment purposes and the Company or the ~~Customer~~Customer cannot make the appointment during the prearranged time, the Company shall reschedule the service establishment appointment to the satisfaction of both parties.

4. The Company shall schedule service establishment appointments within a maximum range of four (4) hours during normal working hours, unless another time frame is mutually acceptable to the Company and the ~~Customer~~Customer.

5. Service establishments shall be made only by qualified ~~Company~~ service personnel of the Company or its authorized representatives.

6. For the purpose of this rule, service establishments can occur only when the ~~Customer~~Customer's facilities are ready and acceptable to the Company and the Company needs only to install, ~~or~~ read the~~a~~ meter, or turn the service on.

7. A fee for service establishment, re-establishment, or reconnection of service may be charged at a rate on file with and approved by the ACC. Whenever the ~~applicant~~Applicant requests after-hours handling of his request, the Company shall charge an additional fee on file with and approved by the ACC unless a special call out is required. If a special call out is required, the charge shall be for a minimum of one (1) hour at the Company's then prevailing after-hours rate for the service work on the ~~Customer~~Customer's premises. Special handling of calls and the related charges shall be made only on request of the ~~applicant~~Applicant.

SECTION NO. 6
SERVICE LINES AND ESTABLISHMENTS
(continued)

B. Facilities

1. ~~Customer~~Customer Provided Facilities

   a. An ~~applicant~~Applicant for service shall be responsible for the safety and maintenance of all ~~Customer~~Customer piping from the ~~point of delivery~~Point of Delivery to the point of consumption.

   ~~1.~~b. Meters shall be installed in a location suitable to the Company where the meters will be safe from street traffic, readily and safely accessible for reading, testing and inspection, and where such activities will cause the least interference and inconvenience to the ~~Customer~~Customer. The ~~Customer~~Customer shall provide, without cost to the Company and at a suitable and easily accessible location, sufficient and proper space for the installation of meters.

   ~~2.~~c. Where the meter or service line location on the ~~Customer~~Customer's premises is changed at the request of the ~~Customer~~Customer or due to alterations on the ~~Customer~~Customer's premises, the ~~Customer~~Customer shall provide, and have installed at his expense, all ~~Customer~~Customer piping necessary for relocating the meter and the Company may make a charge for moving the meter and/or service line.

   ~~3.~~d. On all newly-constructed ~~customer~~Customer piping at the meter interconnection, the ~~customer~~Customer will be required to install necessary piping and equipment before the meter is installed.

2. Company Provided Facilities

   ~~A.~~a. The Company will install, at its own expense, the meter set assembly ("MSA") ~~gas service riser, service cock, regulator and meter~~ at a suitable location near the side wall of the ~~Customer~~Customer's building approximately three (3) feet or more from that front corner of the building nearest to the street in which the Company's distribution main is located. However, the Company, at its option, has the right to locate the meter at any location meeting the criteria of Subsection B.1.b of this section.

   The three (3) feet as noted above refers to the approximate location of the meter from the corner of the building that is nearest to the street in which the distribution main servicing that ~~Customer~~Customer is located. The gas service riser, service cock, regulator and meter are all above ground. The service from the Company's distribution main to the building is below ground.

SECTION NO. 6
SERVICE LINES AND ESTABLISHMENTS
(continued)

b. The Company or authorized representative will install the gas service line and make all connections of the gas service line from the distribution main to the service riser. The Company will in all cases be responsible for the cost of construction of the service line from the Company's distribution main to the ~~Customer~~Customer's gas service riser~~property line~~ for an amount not to exceed the allowable investment as calculated by the Incremental Contribution Study (see Section No. 7, Subsection B), with the ~~Customer~~Customer reimbursing the Company for the difference. The ~~customer~~Customer will reimburse the Company for the gas~~-~~ service line on the ~~Customer~~Customer's property at a rate of ~~eight~~ sixteen~~twenty-one~~ dollars ($162~~18~~.00) per foot. The ~~customer~~Customer is responsible for locating facilities on private property and removal of landscaping prior to installation or be subject to applicable charges. For ~~customers~~Customers who provide the trench for the service line on the ~~Customer~~Customer's propertys~~lines~~, Section No. 7, Subsection B.4~~5~~.d will apply and ~~. For customers who provide the trench for the entire service line,~~ the ~~Customer~~Customer will reimburse the Company at a rate of ~~five~~ twelve dollars ($12~~5~~.00) per foot for the excess footage ~~described above~~. The ~~Customer~~Customer, at the ~~Customer~~Customer's own expense, shall furnish, ~~and~~ install, and be responsible for all other pip~~e, fittings~~, fittings, ~~connections~~, connections, and ~~appertanences~~appurtenances ~~and connections~~ between the ~~point of delivery~~Point of Delivery and each point of consumption.

~~B~~.c. No ~~Customer~~Customer-owned pipe shall be directly connected with the Company's distribution mains or servicess~~.~~. No connection shall be made by the ~~Customer~~Customer between the facilities of the Company, including the meter, service cock and regulator and those of the ~~Customer~~Customer, nor shall any facilities of the Company be set, connected, disconnected, removed, repaired or altered except by the Company's representatives.

~~C~~.d. A single meter and a single ~~point of delivery~~Point of Delivery may be used to supply a group of buildings, such as those of a hospital or industrial establishment under single ownership or control.~~,~~ Such applications may fall under the Master Meter rule as defined in the Arizona Administrative Code.~~.~~ ~~Buildings located on separate lots are to be supplied with individual service connections as provided for in Subsections 2.a and 2.b above.~~

~~D~~.e. The Company may decline service to mobile residences or portable or other temporary structures if the conditions do not afford adequate protection for the occupant(s) thereof, or the persons or property of others. In no event will gas service be permitted, if to the Company's knowledge, the ~~Customer~~Customer or the ~~Customer~~Customer's facilities fail to meet applicable requirements of law, of the State, or of any local code.

SECTION NO. 6
SERVICE LINES AND ESTABLISHMENTS
(continued)

3. Easements and Right-of-Way

Each Customer shall grant, at no cost to the Company, adequate an easement and right-of-way, satisfactory to the Company to ensure proper service connection. Failure on the part of the Customer to grant an adequate easement and right-of-way shall be grounds for the Company to refuse service.

4. Unauthorized work or facilities
   ~~1.Each Customer~~Customer ~~shall grant, at no cost to the company~~Company, ~~grant adequate easement and right-of-way, at no cost, satisfactory~~ satisfactory ~~to the Company, at no cost, to ensure proper service connection. Failure on the part of the Customer~~Customer ~~to grant adequate easement and right-of-way shall be grounds for the Company to refuse service.~~

   ~~2.When the Company discovers that a Customer~~Customer ~~or the Customer~~Customer~~'s Agent is performing work or has constructed facilities adjacent to or within an easement or right-of-way and such work, construction or facility poses a hazard or is in violation of Federal, State or local laws, ordinances, statutes, rules or regulations or significantly interferes with the Company's access to equipment, the Company shall notify the Customer~~Customer ~~or the Customer~~Customer~~'s Agent and shall take whatever actions are necessary to eliminate the hazard, obstruction or violation at the Customer~~Customer~~'s expense.~~

When the Company discovers that a ~~Customer~~Customer or the ~~Customer~~Customer's Agent has performed work or has constructed ~~facilites~~facilities that has altered the installation of the Company's facilities to the point that work is necessary to restore the previously installed ~~company~~Company facilities to meet regulatory ~~and~~ or Company~~company~~ requirements, the Company shall notify the ~~Customer~~Customer or the ~~Customer~~Customer's Agent and the Company shall take whatever actions are necessary to eliminate the hazard or violation at the ~~Customer~~Customer's expense.

~~4.~~5. ~~Point of Delivery~~Point of Delivery

The ~~point of delivery~~Point of Delivery for all gas delivered to any ~~Customer~~Customer shall be at the point of interconnection between the facilities of the Company and those of the ~~Customer~~Customer.

SECTION NO. 7
EXTENSION OF LINES

Extensions of gas distribution services and mains necessary to furnish permanent service to ~~applicant~~Applicants will be made in accordance with this rule.

A. General

The Company will construct, own, operate and maintain service line -and distribution main ~~line~~ extensions.

1. Gas service lines will be designed and installed so that ~~of s~~suitable capacity from the Company's ~~gas~~distribution main to a meter location on the property of the ~~applicant~~Applicant ~~that~~ is satisfactory to the Company~~ and to the CustomerCustomer at the time of original installation~~. If downstream ~~useage~~usage changes or is altered by the ~~Customer~~Customer, the ~~Customer~~Customer may be responsible for costs to upgrade or enlarge the service line to accommodate additional capacity requirements~~ from the Customer.~~.

2. Gas distribution main extensions will be only along public streets, roads, and highways, which the Company has legal right to occupy, and on public lands and private property across which rights-of-way, satisfactory to the Company, may be obtained.

~~2.~~3. All ~~Compnay~~Company distribution mains and ~~servicelines~~service lines shall be installed in accordance with all applicable Company standards.

B. Service and Main Extensions to ~~Applicant~~Applicants for Service

~~1.~~General Policy – All service line and main line extensions agreements are made on the basis of economic feasibility.~~ except those for master-metered mobile home parks ("MMP"), whose extensions shall be made in accordance with the provisions in Subsection B.3 below. The economic feasibility will be calculated by the Incremental Contribution Method as described in Subsection B.4 below. H; however, owever, at a minimum, the Company will extend thirty (30) feet of main for each applicant who connects a functioning water heater or furnace within four (4) months of the completion of the main.~~

1. Facility Charge – If any ~~applicant~~Applicant fails to use natural gas for equipment stated in the application and used as the basis for estimating the allowable investment ~~(ICS) within~~) within four (4) months of the completion of the main, the Company may ~~may calculate and~~ bill the ~~applicant~~Applicant for the Incremental Cost allowed towards the extension of service. ~~Th~~Thee ~~and the applicant~~Applicant shall pay within forty-five (45) days the charge as a non-refundablele contribution towards the ~~c~~cost of extending service.~~a nonrefundable Facilities Charge according to the Company's extension rule in effect at the time the extension was made, as though service had been requested on the basis of the actual equipment installed and utilized.~~

SECTION NO. 7
EXTENSION OF LINES
(continued)

2. At its option, the Company may require a performance bond or other surety guaranteeing bona fide operation of the facility for which the extension is requested, in accordance with ~~applicant~~Applicant's representation in the contract.

3. Master Meter Extensions – If the residential ~~customer~~Customers are tenants in a fully improved master-metered mobile home park ("MMP") and the MMP is currently or was formerly served as a master-metered mobile home park, the allowable investment for the MMP will be calculated ~~determined~~ by the following Incremental Contribution Method and formula:

$$AI = (FR - CR) \times 5$$

where: AI = Allowable Investment

FR = The MMP's estimated future total annual revenue, assuming conversion to individual residential service, using the MMP's average park occupancy for the past two (2) years, less the Company's current average cost of purchased gas.

CR = The MMP's current total annual revenue, under the applicable schedule, averaged for the past two (2) years, less the Company's current average cost of purchased gas. If the MMP is not a current ~~customer~~Customer of the Company, the CR will be determined on the basis of engineering estimates of occupancy and usage.

The Company will install that portion of each service in excess of the ~~allowance~~Allowed Investment subject to a nonrefundable contribution to be paid by the ~~applicant~~Applicant MMP prior to construction. In no event shall costs above the allowable investment be borne by the Company.

4. Incremental Contribution Method – Gas service line and main line extensions will be made by the Company at its expense for ~~the~~ an amount not to exceed the ~~a~~Allowable ~~i~~Investment as calculated by an Incremental Contribution Study ("ICS").

   a. Allowable investment shall mean a determination by the Company that the revenues less the incremental gas cost to serve the ~~applicant~~Applicant ~~customer~~ provides a rate of return on the Company's investment no greater than the weighed average cost of capital authorized by the ACC in the Company's most recent general rate case~~most recent overall rate of return authorized by the ACC in a general rate case for the Company~~.

   b. ~~All applicants will pay for the entire length of their service lines on their property.~~ If the ICS has an allowable investment that is more than the cost of the main extension, then the excess amount ~~can~~~~will~~may~~will~~ be applied ~~evenly to all applicants~~ to reduce the~~ir~~ cost of service line installation.

SECTION NO. 7
EXTENSION OF LINES
(continued)

c. The Company, after conducting an ICS, may at its option, extend its facilities to ~~Customer~~Customers whose usage does not satisfy the definition of economic feasibility, but who otherwise are permanent ~~customer~~Customers, provided the ~~Customer~~Customer ~~signs an extension agreement and advances as much of the cost, and/or agrees to~~ pays a nonrefundable ~~Facility~~ advance~~Charge~~, necessary to make the extension economically feasible.

d. ~~Applicant~~Applicants may provide trenching for service lines and/or distribution mains to the Company's specifications and the ~~Company applicant~~Applicant's costs will be reduced accordingly ~~by an amount equal to this avoided cost in the ICS~~.

e. ~~Customer~~Customers provided with line extensions using the ICS ~~Incremental Contribution Method~~ shall be reviewed annually for a period of five (5) years to determine the amount of any refund, as described in Subsection B.~~5~~6 below.

f. For the purposes of this rule, "economic feasibility" means that the estimated incremental revenues derived from serving the Applicant, less the incremental gas cost to serve the Applicant, meets the estimated costs of serving the Applicant, including meeting capital costs as determined by the weighed average cost of capital authorized by the ACC in the Company's most recent general rate case. An extension will not be considered economically feasible if the Applicant does not install a functioning water heater and furnace within four (4) months of the completion of the main.

5. Method of Refund

Amounts advanced by the Customer ~~customer~~(s) in accordance with this rule, less any unpaid Facility Charges, shall be refunded, without interest, in the following manner:

~~a.~~ Refunds of an advance shall be made for each additional separately metered permanent service connected to the main extension for which an advance was collected ~~when an excess allowable investment is calculated by~~using an ICS that includes the additional ~~customers~~Customer(s). ~~The calculation will use actual usage for existing customers. Usage for future years will be estimated on actual usage adjusted for normal weather.~~

a.

~~b. Customers adding on to an existing main covered by an extension agreement, still subject to refund, will pay the entire cost of their service line, will contribute an advance equal to the average advance, minus any refunds, provided by the existing contributors, and will be eligible for refunds of advances in subsequent annual reviews.~~

~~c.~~b. No refunds will be made for additional ~~customers~~Customers connecting to a further extension or series of extensions constructed beyond the original extension.

~~d.~~c. ~~Refunds will be made annually or intermittently within the annual period at the option of the Company. Amounts to be refunded may be accumulated by the Company to a maximum of $50 per customer, or the total refundable balance if less than $50 per customer. Refunds will only be made to customers, the assignees of customers, or developers.~~The ~~customer~~Customer may request an annual survey to determine if additional ~~customers~~Customers have been connected to and are using service from the extension. In no case shall the amount of the refund exceed the amount originally advanced.

~~e. When two or more parties make a joint advance on the same extension, refundable amounts will be distributed to these parties in the same proportion as their individual percentages of the total joint advance.~~

~~f.~~d. The refund period shall be five (5) years from the date of the completion of the extension. No refunds will be made by the Company after the termination of the refund period. Any portion of the advance that remains unrefunded at the end of the refund period shall be considered an unrefundable contribution~~remain the property of the Company~~.

~~g.~~e. Any assignment by a ~~customer~~Customer of their interest in any part of an advance, which at the time remains unrefunded, must be made in writing and approved by the Company.

~~h.~~f. Amounts advanced under a gas main extension rule previously in effect will be refunded in accordance with the provisions of that rule.

SECTION NO. 7
EXTENSION OF LINES
(continued)

C. Service and Main Extensions to Service Individually Metered Subdivisions, Tracts, Housing Projects, Multi-Family Dwellings and Mobile Home Parks or Estates

1. Advances

a. Gas distribution service and main extensions to and within individually metered subdivisions, tracts, housing projects, multi-family dwellings and mobile home parks or estates will be constructed, owned and maintained by the Company in advance of applications for service by bona fide ~~customers~~Customers only when the entire estimated cost of such extensions as determined by the Company, is advanced to the Company, and a main extension agreement~~contract~~ is executed. This advance may include the cost of any gas facilities installed at the Company's expense in conjunction with a previous service or main extension in anticipation of the current extension.

b. The Company may require a ~~When a subdivider/builder/developer is building a project in consecutive phases such that each phase is constructed separately and requires separate advances, unused allowances from one phase may be applied to an outstanding advance in any other phase so long as such outstanding advance is still eligible for refund.~~ Ssubdivider/, builder/ or developer ~~may~~to provide trenching for service lines and/or distribution mains and may also ~~be~~ required the subdivider, builder or developer to provide bedding & shading material to ~~UES~~Company specifications.

c. For developers who have entered into a ~~line~~main extension agreement and facilities have been installed and then they or some other party request subsequent reconfiguring of facilities or other changes requiring additional expenditures by the Company, these new costs will be entirely paid for with a non-refundable ~~advance~~ contribution and any refunds will be made in accordance with the original agreement. No additional agreement or extension of the time for refunds will be made to cover the area piped under the original extension agreement.

~~SECTION NO. 7~~
~~EXTENSION OF LINES~~
~~(continued)~~

d. Upon completion of installation, the Company will perform a reconciliation of the estimate to actual costs incurred and may bill the ~~Customer~~Customer for any variance with the new amount included in the refundable balance, or at the Company's option withhold refunds until the underpayment is satisfied.

~~d.~~e. See Subsection B.~~3~~4 above for requests to serve MMP through individual residential meters if the MMP is currently or was formerly served under an MMP schedule.

~~e.~~f. Refunds will be made to developers as described in Subsection B.~~5~~6 above.

D. General Conditions

1. Postponement of Advance

The Company, at its option, may postpone, for a period not to exceed five (5) years that portion of an advance which it estimates would be refunded under the provisions of this rule. At the end of such refund period, the Company shall collect all such amounts not previously advanced. ~~which were not then refundable.~~ When advances are postponed, the ~~applicant~~Applicant may be required to furnish to the Company, ~~evidence of the necessary approvals to commence construction and adequate financing. A surety bond satisfactory to the Company, or other~~ a Company-approved suret~~y~~y~~,~~ ~~may be required~~ , to assure payment of any postponed amounts ~~at~~throughout the term of the facilities extension agreement up until the end of the postponement period.

SECTION NO. 7
EXTENSION OF LINES
(continued)

2. The ~~applicant~~Applicants or developer will provide property location, tax identification numbers, lot numbers, street names and other property information helpful to planning an extension.

3. Contracts

a. Each ~~applicant~~Applicant requesting an extension in advance of applications for service will be required to execute a main extension agreement~~contract~~ covering the terms under which the Company will install distribution mains ~~lines~~ in accordance with the provisions of the ~~tariff schedules~~ Company's ~~Tariffs~~Pricing Plans.

b. At the time service is requested, the ~~applicant~~Applicant will submit a list of natural gas equipment to be used including the BTU input.

~~SECTION NO. 7~~
~~EXTENSION OF LINES~~
~~(continued)~~

4. One Service for a Single Premise

   a. The Company will not install more than one service line to supply a single premise, unless it is for the convenience of the Company or an ~~applicant~~Applicant requests an additional service, and in the opinion of the Company, an unreasonable burden would be placed on the ~~applicant~~Applicant if the additional service were denied. When an additional service is installed at the ~~applicant~~Applicant's request, the ~~applicant~~Applicant shall make a nonrefundable contribution for the additional service based on the Company's estimated cost.

   b. When a service extension is made to a meter location upon private property which is subsequently subdivided into separate premises, with the ownership portions thereof divested to other than the ~~applicant~~Applicant or the ~~customers~~Customers, the Company shall have the right, upon written notice, to discontinue service without obligation or liability. Gas service, as required by the ~~applicant~~Applicant or ~~customer~~Customer, will be reestablished in accordance with the applicable provisions of the Company's rules.

5. Branch Services

The Company, at its option, may install a branch service for units on adjoining premises. ~~"Branch Service" means a service line that is not connected to a distribution main and has as its source of supply another service line.~~

SECTION NO. 7
EXTENSION OF LINES
(continued)

6. Main Extension Agreement Requirements

   a. Upon request by an ~~applicant~~Applicant for a main extension, the Company shall prepare, without charge, a preliminary sketch and rough estimate of the cost of the installation to be advanced by the ~~applicant~~Applicant.

   b. Any ~~applicant~~Applicant for a main extension requesting the Company to prepare detailed plans, specifications, or cost estimates may be required to deposit with the Company an amount equal to the estimated cost of preparation. The Company shall, upon request, make available within ninety (90) days after receipt of the deposit referred to above, such plans, specifications, or cost estimates of the proposed main extension. Where the ~~applicant~~Applicant authorizes the Company to proceed with the construction of the extension, the deposit shall be credited to the cost of construction; otherwise, the deposit shall be nonrefundable. If the extension is to include oversizing of facilities to be done at the Company's expense, appropriate details shall be set forth in the plans, specifications and cost estimates. Subdividers providing the Company with approved ~~plans~~subdivision plats shall be provided with plans, specifications or cost estimates within forty-five (45) days after receipt of the deposit referred to above.

   c. The ~~E~~estimated cost of main extension and any resulting Main Extension Agreement is valid for ninety (90) days from the date of ~~company~~Company issue. Any signed agreement with appropriate payment where construction does ~~n't~~not commence within ninety (90) days may be subject to review, recalculation and adjustment of advance requirements~~..~~.

   d. Where the Company requires an ~~applicant~~Applicant to advance funds for a main extension, the Company shall furnish the ~~applicant~~Applicant with a copy of this rule prior to the ~~applicant~~Applicant's acceptance of the Company's extension agreement.

SECTION NO. 7
EXTENSION OF LINES
(continued)

~~d.~~

~~d.~~e. All main extension agreements requiring payment by the ~~applicant~~Applicant shall be in writing, signed by each party and shall include the following:

~~(1)~~i. –Name and address of ~~applicant~~Applicant(s);

~~(2)~~ii. -Proposed service address(es) or location(s);

~~(3)~~iii. –Description and sketch of the requested main extension;

~~(4)~~iv. –Description of requested service differentiated by ~~customer~~Customer class;~~;~~

v. –Number of ~~customer~~Customers served;

~~(5)~~vi. –~~A~~ Estimated ~~Cost~~cost to construct facilities;~~cost estimate to include materials, labor, and other costs as necessary;~~

~~(6) Payment terms;~~

~~(7) A concise explanation of any refunding provisions, if applicable;~~

~~(8)~~vii. –The Company's estimated start date and completion date for construction of the main extension;~~ and~~

~~(9) A summary of the results of the Incremental Contribution analysis (Allowance)performed by the Company to determine the amount of advance required from the applicant for the proposed main extensions; and~~

~~(10)~~viii. Each ~~applicant~~Applicant shall be provided a copy of the approved main extension agreements;~~.~~

ix. Payment terms; and

x. A concise explanation of any refunding provisions, if applicable.

~~SECTION NO. 7~~
~~EXTENSION OF LINES~~
~~(continued)~~

7. Relocation of Service~~s~~ Lines and Distribution Mains

   a. When, in the judgment of the Company, the relocation of a distribution main or service line is necessary and is due either to maintenance of adequate service or the operating convenience of the Company, the Company shall perform such work at its own expense.

   b. If relocation of a distribution main or service line is due solely to meet the convenience or the requirements of the ~~applicant~~Applicant or the ~~customer~~Customer, such relocation, including metering and regulating facilities, shall be performed by the Company at the expense of the ~~applicant~~Applicant or the ~~customer~~Customer.

   ~~c.~~ Relocation of facilities will be mandatory and at the ~~customer~~Customer's expense when actions of the ~~customer~~Customer restrict the Company's access to or the safety of the facility.

   c.

SECTION NO. 7
EXTENSION OF LINES
(continued)

~~When the Company discovers that a CustomerCustomer or the CustomerCustomer's Agent has performed work or has constructed facilitesfacilities that has altered the installation of the Company's facilities to the point that work is necessary to restore the previously installed company facilities to meet regulatory and company requirements, the Company shall notify the CustomerCustomer or the CustomerCustomer's Agent and shall take whatever actions are necessary to eliminate the hazard or violation at the CustomerCustomer's expense.~~

8. Standby Service or Residential Pool Heating

No allowance will be made for equipment used for standby or emergency purposes only or for equipment used for residential pool heating under Section No. 7, Subsection B.4.

9. Temporary Service

Extensions for temporary service or for operations, which in the opinion of the Company are of a speculative character or are of questionable permanency, will require an advance for the entire cost of the facilities needed, with provision for a refund using an ICS calculated annually,~~,~~ or at the termination of the temporary service.

10. Length and Location

The length of distribution mains or service lines required for an extension will be considered as the distance along the shortest practical and available route, as determined by the Company, from the Company's nearest permanent distribution main.

~~SECTION NO. 7~~
~~EXTENSION OF LINES~~
~~(continued)~~

11. Service Impairment to Other ~~Customer~~Customers

When, in the judgment of the Company, providing service to an ~~applicant~~Applicant would impair service to other ~~customer~~Customers, the cost of necessary reinforcement to eliminate such impairment may be included in the cost calculation for the extension.

12. Service From Transmission Lines

The Company will not tap a gas transmission main except when, in its sole opinion, conditions justify such a tap. Where such taps are made, the ~~applicant~~Applicant will pay the Company the cost of the tap, and extensions from the tap will be made in accordance with the provisions of this rule.

13. Other Types of Connections

Where an ~~applicant~~Applicant or ~~customer~~Customer -requests a type of service connection other than standard such as curb meters and vaults, etc., the Company will consider each such request and will grant such reasonable allowance as it may determine. The Company shall install only those facilities that it determines are necessary to provide standard natural gas service in accordance with ~~this tariff~~the Company's Pricing Plans~~Tariffs~~. Where the ~~applicant~~Applicant requests the Company to install special facilities which are in addition to, or in substitution for, or which result in higher costs than the standard facilities which the Company would normally install, the extra cost thereof shall be borne by the ~~applicant~~Applicant.

SECTION NO. 7
EXTENSION OF LINES
(continued)

14. Excess Flow Valve Installation Option

In accordance with Title 49, Section 192.383 of the Code of Federal Regulations, the installation of an excess flow valve, as defined in Rule No. 1, shall be performed by the Company on a new or replaced single residence service line at the request of a ~~customer~~Customer. The installation of an excess flow valve is not mandatory. If a ~~customer~~Customer elects this installation, the Company shall perform the installation subject to the ~~customer~~Customer assuming responsibility for all costs associated with installation, maintenance and replacement. Each ~~customer~~Customer requesting the installation of an excess flow valve will be required to execute a written agreement.

~~SECTION NO. 7~~
~~EXTENSION OF LINES~~
~~(continued)~~

15. Exceptional Cases

In unusual circumstances, when the application of this rule appears impractical or unjust to either party, the Company or the ~~applicant~~Applicant may refer the matter to the ACC for special ruling or for the approval of special conditions which may be mutually agreed upon, prior to commencing construction.

~~1.~~16. Taxes Associated with Nonrefundable Contributions and Advances

Any federal, state or local income taxes resulting from a nonrefundable contribution or advance by the ~~customer~~Customer in compliance with this rule will be recorded as a deferred tax and appropriately reflected in the Company's rate base. ~~These deferred taxes will be amortized over the remaining tax life of the asset.~~ However, if the estimated cost of facilities for any service line or distribution main extension exceeds $500,000, the Company may require the Applicant to include in the contribution or advance an amount (the "gross up amount") equal to the estimated federal, state or local income tax liability of the Company resulting from the contribution or advance, computed as follows:

$$\text{Gross Up Amount} = \frac{\text{Estimated Construction Cost}}{(1 - \text{Combined Federal-State-Local Income Tax Rate})}$$

After the Company's tax returns are completed, and actual tax liability is known, to the extent that the computed gross up amount exceeds the actual tax liability resulting from the contribution or advance, the Company shall refund to the Applicant an amount equal to such excess. When a gross-up amount is to be obtained in connection with an extension agreement, the contract will state the tax rate used to compute the gross up amount, and will also disclose the gross-up amount separately from the estimated cost of facilities. In subsequent years, as tax depreciation deductions are taken by the Company on its tax returns for the constructed assets with tax bases that have been grossed-up, a refund will be made to the Applicant in an amount equal to the related tax benefit. Such refunds will be in addition to any required refunds of actual construction costs required by the extension agreement. In lieu of scheduling such refunds over the remaining tax life of the constructed assets, a reduced lump sum refund may be made at the time when actual construction costs are refunded in full. This lump sum payment shall reflect the net present value of remaining tax depreciation deductions discounted at the company's authorized rate of return.

SECTION NO. 8
PROVISION OF SERVICE

~~a.~~A. Company Responsibility

1. The Company shall be responsible for the safe transmission and distribution of gas until it passes the ~~point of delivery~~Point of Delivery to the ~~Customer~~Customer.

2. The Company shall be responsible for maintaining in safe operating condition all meters, regulators, service pipe or other fixtures installed on the ~~Customer~~Customer's premises by the Company for the purpose of delivering gas to the ~~Customer~~Customer.

3. The Company may, at its option, refuse service until the ~~Customer~~Customer's pipes and appliances have been tested and found to be safe, free from leaks, and in good operating condition. Proof of such testing shall be in the form of a certificate executed by a licensed plumber or local inspector certifying that the ~~Customer~~Customer's facilities have been tested and are in safe operating condition.

4. The Company shall be required to test the ~~Customer~~Customer's piping for leaks when the gas is turned on. If such tests indicate leakage in the ~~Customer~~Customer's piping, the Company shall refuse to provide service until such time as the ~~Customer~~Customer has had the leakage corrected.

5. The Company shall be responsible for the operation and maintenance of all facilities up to the outlet of the meter installed by the Company or its authorized agent.

~~b.~~B. ~~Customer~~Customer Responsibility

1. Each Customer shall be responsible for maintaining in safe operating condition all Customer piping fixtures and appliances on the Customer's side of the Point of Delivery.

2. Each Customer shall be responsible for safeguarding all Company property installed in or on the Customer's premises for the purpose of supplying gas service.

3. Each Customer shall exercise all reasonable care to prevent loss or damage to Company property, excluding ordinary wear and tear. The Customer shall be responsible for loss of, or damage to, Company property on the Customer's premises arising from neglect, carelessness, or misuse and shall reimburse the Company for the cost of necessary repairs and replacements that arise from neglect, carelessness, or misuse.

SECTION NO. 8
PROVISION OF SERVICE
(continued)

4. Each Customer shall be responsible for payment for any equipment damage and/or estimated unmetered usage resulting from unauthorized breaking of seals, interfering, Tampering, or bypassing the Company's meters. This remedy is cumulative to any other remedy available to Company under law or ACC rules.

5. Each ~~Customer~~Customer shall be responsible for promptly notifying the Company of any gas leakage identified in the ~~Customer~~Customer's or the Company's equipment.

6. The Customer will be responsible for the loss of gas or damage caused by gas in piping beyond the Company's meter.

7. No rent or other charge whatsoever will be made by the Customer against the Company for placing or maintaining meters, regulators, service lines, fixtures, etc. upon the Customer's premises.

~~c.~~C. Continuity of Service

The Company shall make reasonable efforts to supply a satisfactory and continuous level of service.

D. Liability

1. The Company shall not be responsible for any damage or claim of damage attributable to any interruption or discontinuation of service resulting from the following:

   a. Any cause against which the Company could not have reasonably foreseen or made provision for ~~(such as force majeure)~~;

   b. Intentional service interruptions to make repairs or perform routine maintenance; or

   c. Curtailment.

SECTION NO. 8
PROVISION OF SERVICE
(continued)

~~A.~~2. Neither the Company nor the Customer shall be liable to the other for any act, omission or circumstances (including, with respect to the Company, but not limited to, inability to provide service) occasioned by or in consequence of flood, rain, wind, storm, lightning, earthquake, fire, landslide, washout or other acts of the elements, or accident or explosion, or war, rebellion, civil disturbance, mobs, riot, blockade, terrorist actions, or other act of the public enemy, or acts of God, or interference of civil and/or military authorities, or strikes, lockouts or other labor difficulties, or vandalism, sabotage or malicious mischief, or usurpation of power, or the laws, rules, regulations or orders made or adopted by any regulatory or other governmental agency or body (federal, state or local) having jurisdiction of any of the business or affairs of the Company or the Customer, direct or indirect, or breakage or accidents to equipment or facilities, or lack, limitation or loss of electrical or gas supply, or any other casualty or cause beyond the reasonable control of the Company or the Customer, whether or not specifically provided herein and without limitation to the types enumerated, and which by the exercise of due diligence such party is unable to prevent or overcome; provided, however, that nothing contained herein shall excuse the Customer from the obligation of paying for gas delivered or services rendered.

~~B.~~3. A failure to settle or prevent any strike or controversy with employees or with anyone purporting or seeking to represent employees shall not be considered to be a matter within the control of the Company.

4. Company will not be responsible for any third-party claims against Company that arise from Customer's use of Company's gas.

5. Customer will indemnify, defend and hold harmless the Company (including the costs of reasonable attorney's fees) against all claims (including, without limitation, claims for damages to any business or property, or injury to, or death of, any person) arising out of any act or omission of the Customer, or the Customer's agents, in connection with the Company's service or facilities.

6. The liability of the Company for damages of any nature arising from errors, mistakes, omissions, interruptions, or delays of the Company, its agents, servants, or employees, in the course of establishing, furnishing, rearranging, moving, terminating, or changing the service or facilities or equipment shall not exceed an amount equal to the charges applicable under the Company's Pricing Plan~~Tariff~~ (calculated on a proportionate basis where appropriate) to the period during which such error, mistake, omission, interruption or delay occurs.

7. In no event shall the Company be liable for any incidental, indirect, special, or consequential damages (including lost revenue or profits) of any kind whatsoever regardless of the cause or foreseeability thereof.

8. The Company shall not be responsible for any loss or damage occasion or caused by the negligence or wrongful act of the Customer or any of his agents, employees or licensees in installing, maintaining, using, operating or interfering with any regulators, gas piping, appliances, fixtures or apparatus.

SECTION NO. 8
PROVISION OF SERVICE
(continued)

~~d.~~E. Change in Character of Service

1. When a change is made by the Company in the type of service rendered which would adversely affect the efficiency of operation or require the adjustment of the equipment of ~~Customer~~Customers, all ~~Customer~~Customers who may be affected shall be notified by the Company at least thirty (30) days in advance of the change or, if such notice is not possible, as early as feasible. Where adjustments or replacements of the Company's standard equipment must be made to permit use under such changed condition, adjustments shall be made by the Company without charge to the ~~Customer~~Customers.

~~e.~~F. Service Interruptions

1. The Company shall make reasonable efforts to reestablish service within the shortest possible time when service interruptions occur.

2. The Company shall make reasonable provisions to meet emergencies resulting from failure of service and shall issue instructions to its employees covering procedures to be followed in the event of emergencies in order to prevent or mitigate interruption or impairment of service.

3. In the event of a national emergency or local disaster resulting in disruption of normal service, the Company may, in the public interest, interrupt service to other ~~Customer~~Customers to provide necessary service to civil defense or other emergency service agencies on a temporary basis until normal service to these agencies can be restored.

4. When the Company plans to interrupt service for more than four (4) hours to perform necessary repairs or maintenance, the Company shall attempt to inform affected ~~Customer~~Customers of the scheduled date and estimated duration of the service interruption at least twenty-four (24) hours in advance. Such repairs shall be completed in the shortest possible time to minimize the inconvenience to the ~~Customer~~Customers.

5. The ACC shall be notified of interruptions in service affecting the entire system or any major division of the entire system. The interruption of service and the cause shall be reported by telephone to the ACC within one (1) hour after the responsible representative of the Company becomes aware of said interruption, and shall be followed by a written report to the ACC.

SECTION NO. 8
PROVISION OF SERVICE
(continued)

~~f.~~G. Heat Value Standard for Natural Gas

The Company shall supply gas to its ~~Customer~~Customers with an average total heating value of not less than nine hundred (900) BTUs per cubic foot. The number of BTUs per cubic foot actually delivered through the ~~Customer~~Customer's meter will vary according to the altitude and elevation of the location where the ~~Customer~~Customer is being provided service.

~~g.~~H. Standard Delivery Pressure

1. The Company shall maintain ~~a s~~Standard ~~d~~Delivery ~~p~~Pressure of ~~approximately 0.25 pounds per square inch~~ at the outlet of the ~~Customer~~Customer's meter, subject to variation under load conditions.

2. In cases where a ~~Customer~~Customer desires service at greater than ~~s~~Standard ~~de~~Delivery ~~p~~Pressure, the Company may supply, at its option, such greater pressure if and only as long as the furnishing of gas to such ~~Customer~~Customer at higher than standard delivery pressure will not be detrimental to the service of other ~~Customer~~Customers of the Company. The Company reserves the right to lower the delivery pressure or discontinue the delivery of gas at higher pressure at any time upon reasonable notice to the ~~Customer~~Customer. Where service is provided at pressure higher than ~~s~~Standard ~~d~~Delivery ~~p~~Pressure, the meter volumes shall be corrected to that higher pressure.

SECTION NO. 8
PROVISION OF SERVICE
(continued)

~~h.~~I. Determination of Therms for Billing

1. Heating Value – The heating value (BTU per cubic foot) of the natural gas delivered will vary depending on the source of supplies received by the Company. The average heating values will be determined from the volumetric weighted average heating values of the supplies received by the Company.

2. Metered Volumes – The number of therms to be billed will be determined by multiplying the difference in meter readings by an appropriate billing factor.

   a. Therms are determined from the volumes measured by the following:

$$\underset{\textbf{A}}{\frac{\text{Atmospheric Pressure at Elevation + Delivery Pressure}}{\text{14.73 Atmospheric Pressure at Sea Level}}} \times \underset{\textbf{B}}{\frac{\text{Average Heating Value (BTU per cubic foot)}}{\text{100,000 BTU per Therm}}} \times \underset{\textbf{C}}{\text{Super Compressibility Factor}}$$

Where:
A = Correction for atmospheric pressure at elevation and applicable delivery pressure
B = Applicable heating value of natural gas received
C = Correction for super compressibility ratio

   b. Atmospheric Pressures at Elevations within the Company's service territory are outlined in the following table. At such time additional elevation bands are needed within the various areas served by the Company, new geographical zones will be added.

Northern Arizona:

Geographical Zone Description	Atmospheric Pressure Base
ASHFORK AZ E4801-5000	12.3264800
ASHFORK AZ E5001-5200	12.2366800
BAGD CPR AZ E3601-3800	12.8782000
BAGD ML AZ E2601-2800	13.3555800
BAGDAD MINE E0401-0600	14.4666500
BLACK CANYON CITY AZ E1601-1800	13.8498700

SECTION NO. 8
PROVISION OF SERVICE
(continued)

Geographical Zone Description	Atmospheric Pressure Base
BLACK CANYON CITY AZ E1801-2000	13.7496200
CAMP VERDE AZ E2801-3000	13.2587800
CAMP VERDE AZ E3001-3200	13.1626500
CHINO VALLEY AZ E4201-4400	12.5995400
CHINO VALLEY AZ E4401-4600	12.5079100
CHINO VALLEY AZ E4601-4800	12.4168900
CLARKDALE AZ E3001-3200	13.1626500
CLARKDALE AZ E3201-3400	13.0671800
CLARKDALE AZ E3401-3600	12.9723700
CORNVILLE AZ E3001-3200	13.1626500
CORNVILLE AZ E3201-3400	13.0671800
COTTONWOOD AZ E3001-3200	13.1626500
COTTONWOOD AZ E3201-3400	13.0671800
COTTONWOOD AZ E3401-3600	12.9723700
COTTONWOOD AZ E3601-3800	12.8782000
DUVAL AZ E3201-3400	13.0671800
FLAGSTAFF AZ E6201-6400	11.7102300
FLAGSTAFF AZ E6401-6600	11.6244900
FLAGSTAFF AZ E6601-6800	11.5393200
FLAGSTAFF AZ E6801-7000	11.4546900
FLAGSTAFF AZ E7001-7200	11.3706100
FLAGSTAFF AZ E7201-7400	11.2870800
HOLBROOK AZ E4801-5000	12.3264800
HOLBROOK AZ E5001-5200	12.2366800
HUMBOLDT AZ E4201-4400	12.5995400
HUMBOLDT AZ E4401-4600	12.5079100
HUMBOLDT AZ E4601-4800	12.4168900
INDPK AZ E6201-6400	11.7102300
JEROME AZ E4201-4400	12.5995400
JEROME AZ E4401-4600	12.5079100
JEROME AZ E4601-4800	12.4168900
JEROME AZ E4801-5000	12.3264800
JEROME AZ E5001-5200	12.2366800
JOSEPH CITY AZ E4601-4800	12.4168900
JOSEPH CITY AZ E4801-5000	12.3264800
KINGMAN AZ E3001-3200	13.1626500

SECTION NO. 8
PROVISION OF SERVICE
(continued)

Geographical Zone Description	Atmospheric Pressure Base
KINGMAN AZ E3201-3400	13.0671800
KINGMAN AZ E3401-3600	12.9723700
KINGMAN AZ E3601-3800	12.8782000
KINGMAN AZ E3801-4000	12.7846800
LAKE HAVASU CITY AZ E0201-0400	14.5720600
LAKE HAVASU CITY AZ E0401-0600	14.4666500
LAKE HAVASU CITY AZ E0601-0800	14.3620000
LAKE HAVASU CITY AZ E0801-1000	14.2581000
LAKE HAVASU CITY AZ E1001-1200	14.1549500
LAKE HAVASU CITY AZ E1201-1400	14.0525300
LAKE HAVASU CITY AZ E1401-1600	13.9508400
MAYER AZ E4001-4200	12.6917900
MAYER AZ E4201-4400	12.5995400
MOUNTAIN VIEW AZ E6401-6600	11.6244900
NAVAJO ARMY DEPOT E5401-5600	12.0588700
PAULDEN AZ E4001-4200	12.6917900
PAULDEN AZ E4201-4400	12.5995400
PAULDEN AZ E4401-4600	12.5079100
PHX CMT AZ E3401-3600	12.9723700
PINETOP/LAKESIDE AZ E6201-6400	11.7102300
PINETOP/LAKESIDE AZ E6401-6600	11.6244900
PINETOP/LAKESIDE AZ E6601-6800	11.5393200
PINETOP/LAKESIDE AZ E6801-7000	11.4546900
PINETOP/LAKESIDE AZ E7001-7200	11.3706100
PRESCOTT VALLEY AZ E4201-4400	12.5995400
PRESCOTT VALLEY AZ E4401-4600	12.5079100
PRESCOTT VALLEY AZ E4601-4800	12.4168900
PRESCOTT VALLEY AZ E4801-5000	12.3264800
PRESCOTT VALLEY AZ E5001-5200	12.2366800
PRESCOTT AZ E4601-4800	12.4168900
PRESCOTT AZ E4801-5000	12.3264800
PRESCOTT AZ E5001-5200	12.2366800
PRESCOTT AZ E5201-5400	12.1474800
PRESCOTT AZ E5401-5600	12.0588700
PRESCOTT AZ E5601-5800	11.9708400
PRESCOTT AZ E5801-6000	11.8834000

SECTION NO. 8
PROVISION OF SERVICE
(continued)

Geographical Zone Description	Atmospheric Pressure Base
SEDONA AZ E3401-3600	12.9723700
SEDONA AZ E3601-3800	12.8782000
SEDONA AZ E3801-4000	12.7846800
SEDONA AZ E4001-4200	12.6917900
SEDONA AZ E4201-4400	12.5995400
SEDONA AZ E4401-4600	12.5079100
SEDONA AZ E4601-4800	12.4168900
SELIGMAN AZ E5001-5200	12.2366800
SHOW LOW AZ E5801-6000	11.8834000
SHOW LOW AZ E6001-6200	11.7965300
SHOW LOW AZ E6201-6400	11.7102300
SHOW LOW AZ E6401-6600	11.6244900
SNOWFLAKE AZ E5201-5400	12.1474800
SNOWFLAKE AZ E5401-5600	12.0588700
SPRING VALLEY AZ E3601-3800	12.8782000
SPRING VALLEY AZ E3801-4000	12.7846800
STONE CONTAINER E6001-6200	11.7965300
TAYLOR AZ E5401-5600	12.0588700
VERDE VALLEY AZ E3401-3600	12.9723700
VILLAGE OF OAK CREEK AZ E3601-3800	12.8782000
VILLAGE OF OAK CREEK AZ E3801-4000	12.7846800
VILLAGE OF OAK CREEK AZ E4001-4200	12.6917900
WILLIAMS AZ E6401-6600	11.6244900
WILLIAMS AZ E6601-6800	11.5393200
WILLIAMS AZ E6801-7000	11.4546900
WINSLOW AZ E4601-4800	12.4168900

SECTION NO. 8
PROVISION OF SERVICE
(continued)

Southern Arizona:

Geographical Zone Description	Atmospheric Pressure Base
AMADO AZ E2801-3000	13.2587800
AMADO AZ E3001-3200	13.1626500
NOGALES AZ E3201-3400	13.0671800
NOGALES AZ E3401-3600	12.9723700
NOGALES AZ E3601-3800	12.8782000
NOGALES AZ E3801-4000	12.7846800
PATAGONIA AZ E3601-3800	12.8782000
PATAGONIA AZ E3801-4000	12.7846800
PATAGONIA AZ E4001-4200	12.6917900
RIO RICO AZ E3001-3200	13.1626500
RIO RICO AZ E3201-3400	13.0671800
RIO RICO AZ E3401-3600	12.9723700
RIO RICO AZ E3601-3800	12.8782000
RIO RICO AZ E3801-4000	12.7846800
RIO RICO AZ E4001-4200	12.6917900
TUBAC AZ E2801-3000	13.2587800
TUBAC AZ E3001-3200	13.1626500
TUBAC AZ E3201-3400	13.0671800
TUBAC AZ E3401-3600	12.9723700

~~I.~~J. Construction Standards and Safety

The Company's pipelines and pipeline facilities for the transportation of gas within the State of Arizona shall conform with and be subject to the Federal Safety Standards as adopted by the United States Department of Transportation, Pipeline and Hazardous Materials Safety Administration~~Office of Pipeline Safety~~. The Company maintains and updates an Operation and Maintenance plan and an Emergency plan. Upon discovery of occurrence, the Company will report all incidents as required under the Arizona Administrative Code, ~~Pipeline Incident Reports and Investigations rules~~R14-5-203.~~.~~

SECTION NO. 9
METER READING

A. Company or ~~Customer~~Customer Meter Reading

1. The Company may, at its discretion, allow for ~~Customer~~Customer reading of meters.

2. It shall be the responsibility of the Company to inform the ~~Customer~~Customer how to properly read the ~~Customer~~Customer's meter.

3. Where a ~~Customer~~Customer reads the meter, the Company will read the ~~Customer~~Customer's meter at least once every six (6) months.

4. The Company shall specify the timing requirements for the ~~Customer~~Customer to submit the monthly meter reading to conform to the Company's billing cycle.

5. In the event the ~~Customer~~Customer fails to submit the meter reading on time, the Company may issue the ~~Customer~~Customer an estimated bill.

6. Meters shall be read monthly on as close to the same day each month as practical.

B. Measuring of Service

~~a.~~1. All gas sold by the Company shall be metered, except in the case of gas sold according to a fixed charge schedule, or when otherwise authorized by the ACC.

~~b.~~2. When there is more than one (1) meter at a location, the metering equipment shall be so tagged or plainly marked as to indicate the facilities being metered.

~~c.~~3. If and when the Company installs multiple meters or service lines to serve a single ~~Customer~~Customer for the Company's convenience, meter readings may be combined for billing purposes.

~~SECTION NO. 9~~
~~METER READING~~
~~(continued)~~

C. ~~Customer~~Customer - Requested Rereads

~~i.~~1. At the request of a ~~Customer~~Customer, the Company will reread that ~~Customer~~Customer's meter within ten (10) working days after such request by the ~~Customer~~Customer.

~~ii.~~2. Any reread may be charged to the ~~Customer~~Customer at a rate on file and approved by the ACC, provided that the original reading was not in error.

~~iii.~~3. When a reading is found to be in error, the reread shall be at no charge to the ~~Customer~~Customer.

SECTION NO. 9
METER READING
(continued)

D. Access to ~~Customer~~Customer Premises

The Company shall have the right of safe ingress to and egress from the ~~Customer~~Customer's premises at all reasonable hours for any purpose reasonably connected with the furnishing of service and the exercise of any and all rights secured to ~~it~~the Company by law or ~~the rules of~~ the ACC's rules or the Company's Pricing Plans~~Tariffs~~.

E. ~~Customer~~Customer-Requested Meter Tests

The Company shall test a meter upon ~~Customer~~Customer request and shall be authorized to charge the ~~Customer~~Customer for such meter test. ~~according to the tariff on file and approved by the ACC~~Company~~.~~ However, if the meter is found to be in error by more than three percent (3%), no fee will be charged to the ~~Customer~~Customer.

~~F. Automatic Meter Reading ???????~~

~~[NOTE - DOES UNS USE OR PLAN ON USING AUTOMATIC METER READING SYSTEMS? - IF SO, IT MAY BE APPROPRIATE TO ADD SOME TARIFF PROVISIONS CONCERNING SUCH USE]~~

SECTION NO. 10
BILLING AND COLLECTION

~~a.~~A. Frequency and Estimated Bills

1. The Company shall bill monthly for services rendered. Meter readings shall be scheduled for periods of not less than twenty-five (25) days or more than thirty-five (35) days.

2. If the Company is unable to read a meter on the scheduled meter read date, the Company will estimate the consumption for the billing period, giving consideration to the following factors where applicable:

   a. The ~~Customer~~Customer's usage history in the previous twelve (12) months; and

   b. The amount of usage during the ~~preceeding~~preceding month.~~Weather during the billing period.~~

3. After the second consecutive month of estimating the ~~Customer~~Customer's bill for reasons other than severe weather, the Company will attempt to secure an accurate reading of the meter.

4. Failure on the part of the ~~Customer~~Customer to comply with a reasonable request by the Company for access to the ~~Customer~~Customer's meter may lead to the discontinuance of service.

5. Estimated bills will be issued only under the following conditions:

   ~~1.~~a. Failure of a ~~Customer~~Customer who reads his or her~~their~~ own meter to deliver the meter reading card to the Company in accordance with the requirements of the Company's billing cycle;

   ~~2.~~b. Severe weather conditions which prevent the Company from reading the meter; or

   ~~3.~~c. Circumstances that make it impossible to read the meter, such as locked gates, blocked meters, and vicious or dangerous animals, etc.

6. Each bill based on estimated usage will indicate that it is an estimated bill.

SECTION NO. 10
BILLING AND COLLECTION
(continued)

~~b.~~B. Combining Meters - Minimum Bill Information

~~a.~~1. Each meter at a ~~Customer~~Customer's premises will be considered separately for billing purposes, and the readings of two (2) or more meters will not be combined unless approved by the Company.

~~b.~~2. Each bill for sales service will contain the following minimum information:

~~1.~~a. Date and meter reading at the start of billing period or number of days in the billing period;

~~2.~~b. Date and meter reading at the end of the billing period;

~~3.~~c. Billed usage;

~~4.~~d. Rate schedule number;

~~5.~~e. Company's telephone number;

~~6.~~f. ~~Customer~~Customer's name;

~~7.~~g. Service account number;

~~8.~~h. Amount due and due date;

~~9.~~i. Past due amount;

~~10.~~j. Adjustment factor, where applicable;

~~11.~~k. Taxes; and

~~12.~~l. The Arizona Corporation Commission address.

SECTION NO. 10
BILLING AND COLLECTION
(continued)

~~c.~~C. Billing Terms

1. All bills for gas service are due and payable no later than fifteen (150) days ~~when~~ from the date the bill is -rendered. Any payment not received within this time-frame ~~by the twentieth (20th) day from the date the bill is rendered is~~shall be considered past due and may be subject to a late payment penalty charge. If the ~~twentieth~~fifteenth (~~20~~150th) day falls on a weekend or holiday, then the past due date is extended to the next business day. ~~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.~~

~~a.~~2. For purposes of this rule, the date the bill is rendered shall be the latest of the following:

~~i.~~a. The postmark date~~The date shown on the bill,~~;

~~ii.~~b. The mailing date~~Two days prior to the postmark 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.

~~Two days prior to the mailing date.~~

~~The billing date shall not differ from the postmark or mailing date by more than two (2) days.~~

~~2.~~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 ~~bills for which payment has not been received within thirty (30) days from the original bill rendered date~~and ~~will~~and will be issued a suspension of service notice. ~~Any delinquent payment not received within ten (10) days from the date of the suspension of service notice shall be subject to the provisions of the Company's suspension of service procedures.~~ For ~~Customer~~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 ~~exceen~~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 ~~recieved~~received within five (5) days shall be subject to the provisions of the Company's suspension of service procedures.

~~3.~~5. All payments shall be made at or mailed to the office of the Company or to the Company's duly authorized representative.

SECTION NO. 10
BILLING AND COLLECTION
(continued)

~~d.~~D. Applicable Pricing Plans~~Tariffs~~, Prepayments, Failure to Receive, Commencement Date~~, Taxes~~

1. Each ~~Customer~~Customer shall be billed under the ~~applicable tariff~~Pricing Plan indicated in the ~~Customer~~Customer's application for service.

2. The Company shall make provisions for advance payment for Company services.

3. Failure to receive bills or notices which have been properly placed in the United States mail shall not prevent such bills from becoming delinquent and does not relieve the ~~Customer~~Customer of the ~~Customer~~Customer's obligations therein.

4. Charges for service commence when the service is installed and connection made, whether used or not.

~~e.~~E. Meter Error Corrections

~~a.~~1. If, after testing, any meter is found to be more than three percent (3%) in error, either fast or slow, proper correction between three percent (3%) and the amount of the error shall be made on previous readings, and adjusted bills shall be rendered according to the following terms:

~~1.~~a. For the period of three (3) months immediately preceding the removal of such meter from service for testing or from the time the meter was in service since last tested, but not exceeding three (3) months since the meter shall have been shown to be in error by such test.

~~2.~~b. From the date the error occurred, if the date of the cause can be definitely fixed.

~~b.~~2. No adjustment shall be made by the Company except to the ~~Customer~~Customer last served by the meter tested.

SECTION NO. 10
BILLING AND COLLECTION
(continued)

~~f.~~F. Nonsufficient Funds ("NSF") Checks and Denied Electronic Funds Transfers

~~a.~~1. The Company shall be allowed to recover a fee, according to the ~~tariff on file and approved by the ACC~~Company's Pricing Plans~~Tariffs~~, for each instance where a ~~Customer~~Customer tenders payment for a Company service with an NSF check. This fee shall also apply when an electronic funds transfer ("EFT") is denied for any reason, including for lack of sufficient funds.

~~b.~~2. When the Company is notified by the ~~Customer~~Customer's bank that there are insufficient funds to cover the check tendered for service, or an EFT has been denied for any reason, the Company may require the ~~Customer~~Customer to make payment in cash, by money order or certified check, or by other means which guarantee the ~~Customer~~Customer's payment to the Company.

~~c.~~3. A ~~Customer~~Customer who tenders an NSF check or for whom an EFT is denied, shall in no way be relieved of the obligation to render payment to the Company under the original terms of the bill, nor defer the Company's provision for termination of service for nonpayment of bills.

~~g.~~G. Elevation/Pressure Adjustment

The Company shall~~, as a part of a general rate proceeding, file an adjustment factor to be applied to Customer~~~~Customer meter recordings to adjust for differences in pressure due to elevation.~~ adjust for pressure according to the procedures in Section 8.H of these Rules and Regulations.

SECTION NO. 10
BILLING AND COLLECTION
(continued)

~~h.~~H. Deferred Payment Plan

~~a.~~1. The Company may, prior to termination of service, offer a deferred payment plan to qualifying residential ~~Customer~~Customers for the payment of unpaid bills for gas service.

~~b.~~2. Each deferred payment agreement entered into by the Company and the ~~Customer~~Customer, due to the ~~Customer~~Customer's inability to pay an outstanding bill in full, shall provide that service will not be discontinued if:

~~1.~~a. The ~~Customer~~Customer agrees to pay a reasonable amount of the outstanding bill at the time the parties enter into the deferred payment agreement;

~~2.~~b. The ~~Customer~~Customer agrees to pay all future bills for gas service in accordance with the ~~billing and collection tariffs~~Company's Pricing Plans~~Tariffs of the Company~~; and

~~3.~~c. The ~~Customer~~Customer agrees to pay a reasonable portion of the remaining outstanding balance in installments.

~~c.~~3. For the purposes of determining a reasonable installment payment schedule under these Rules, the Company and the ~~Customer~~Customer shall give consideration to the following conditions:

~~1.~~a. The size of the delinquent account.

~~2.~~b. The ~~Customer~~Customer's ability to pay.

~~3.~~c. The ~~Customer~~Customer's payment history.

~~4.~~d. The length of time that the debt has been outstanding.

~~5.~~e. The circumstances which resulted in the debt being outstanding.

~~6.~~f. Any other relevant factors related to the circumstances of the ~~Customer~~Customer.

~~d.~~4. Any ~~Customer~~Customer who desires to enter into a deferred payment agreement shall establish such agreement prior to the Company's scheduled service termination date for nonpayment of bills. The ~~Customer~~Customer's failure to execute a deferred payment agreement prior to the scheduled service termination date shall not prevent the Company from terminating service for nonpayment.

~~e.~~5. Deferred payment agreements may be in writing and may be signed by the ~~Customer~~Customer and an authorized Company representative.

SECTION NO. 10
BILLING AND COLLECTION
(continued)

~~f.~~6. A deferred payment agreement may include a finance charge of one and one-half percent (1.5%) per month.

~~g.~~7. If a ~~Customer~~Customer does not fulfill the terms of a deferred payment agreement, the Company shall have the right to disconnect service pursuant to the Company's termination of service rules (Section No. 11 of these Rules) and, under such circumstances, it shall not be required to offer subsequent negotiation of a deferred payment agreement prior to disconnection.

~~i.~~I. Change of Occupancy

~~a.~~1. Not less than three (3) working days advance notice must be given in person at the Company's office, in writing, or by telephone to discontinue service or to change occupancy.

~~b.~~2. The outgoing party shall be responsible for all Company services provided and/or consumed up to the scheduled turn-off date.

J. Electronic Billing

Electronic Billing is an optional billing service whereby Customers may elect to receive, view, and pay their bills electronically. Electronic Billing includes the "UES e-bill" service and the "Sure No Hassle Automatic Payment ("SNAP") service. The Company may modify its e~~E~~lectronic b~~B~~illing services from time to time. A Customer electing an electronic billing service may receive an electronic bill in lieu of a paper bill. Customers electing an electronic billing service may be required to complete additional forms and agreements. Electronic b~~B~~illing may be discontinued at any time by the Company or the Customer. An e~~E~~lectronic b~~B~~ill will be considered rendered at the time it is electronically sent to the Customer. Failure to receive bills or notices which have been properly sent by an e~~E~~lectronic b~~B~~illing system does not prevent such bills from becoming delinquent and does not relieve the Customer of the Customer's obligations therein. Any notices which Company is required to send to a Customer who has elected an e~~E~~lectronic b~~B~~illing service may be sent by electronic means at the option of the Company. Except as otherwise provided in this subsection, all other provisions of the Company's Rules and Regulations and other applicable Pricing Plans~~Tariffs~~ are applicable to e~~E~~lectronic b~~B~~illing.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Rules & Regulations

SECTION NO. 11
TERMINATION OF SERVICE

A. Non-Permissible Reasons to Disconnect Service

~~A.~~1. The Company may not disconnect service for any of the reasons stated below:

~~1.~~a. Delinquency in payment for services rendered to a prior ~~Customer~~Customer at the premises where service is being provided, except in the instance where the prior ~~Customer~~Customer continues to reside on the premises.

~~2.~~b. Failure of the ~~Customer~~Customer to pay for services or equipment that are ~~which areis~~ not regulated by the ACC.

~~3.~~c. Nonpayment of a bill related to another class of service.

~~4.~~d. Failure to pay a bill to correct a previous under-billing due to an inaccurate meter or meter failure, if the ~~Customer~~Customer agrees to pay over a reasonable period of time.

~~5.~~e. The Company may not terminate residential service where the ~~Customer~~Customer has an inability to pay and:

~~a.~~i. The ~~Customer~~Customer can establish through medical documentation that, in the opinion of a licensed medical physician, termination of service would be especially dangerous to the health of the ~~Customer~~Customer or to the health of a permanent resident residing on the ~~Customer~~Customer's premises;

~~b.~~ii. Life-supporting equipment is used in the home that is dependent on Company service for operation of such apparatus; or

~~c.~~iii. Where weather will be especially dangerous to health as defined herein or as determined by the ACC.

~~6.~~f. Residential service to persons who have an inability to pay and who have an Iillness, are a Senior Citizen, or who are Handicapped ~~ill, senior citizen, or handicapped persons who have an inability to pay~~ will not be terminated until all of the following have been attempted:

~~1.~~i. The ~~Customer~~Customer has been informed of the availability of funds from various government and social assistance agencies; and

~~2.~~ii. A third party previously designated by the ~~Customer~~Customer has been notified and has not made arrangement to pay the outstanding Company bill.

A ~~Customer~~Customer utilizing the provisions of Subsection A.1.e or A.1.f above may be required to enter into a deferred payment agreement with the Company within ten (10) days after the scheduled service termination date.

~~SECTION NO. 11~~
~~TERMINATION OF SERVICE~~
~~(continued)~~

~~7.~~g. Failure to pay the bill of another ~~Customer~~Customer as guarantor thereof.

h. Disputed bills where the ~~Customer~~Customer has complied with the ACC's rules on ~~Customer~~Customer bill disputes.

~~8.~~

SECTION NO. 11
TERMINATION OF SERVICE
(continued)

B. Termination of Service Without Notice

1. The Company may ~~not~~ disconnect service without advance written notice ~~except~~ under the following conditions:

   ~~1.~~a. The existence of an obvious hazard to the safety or health of the ~~c~~~~Consumer~~ustomer, the general population or which imperils service to other ~~consumers~~Customers;

   ~~2.~~b. The Company has evidence of ~~meter t~~Tampering or fraud;

   ~~3.~~c. There is an unauthorized resale or use of gas services that is not in accordance with the ACC's rules and/or ~~the~~these Rules and Regulations or other Company Pricing Plans~~Tariffs~~ ~~Company's rules, regulations, and tariffs~~; or

   ~~4.~~d. The ~~Customer~~Customer has failed to comply with the curtailment procedures imposed by the Company ~~during supply shortages~~in accordance with the Company's Pricing Plans~~Tariffs~~.

2. The Company shall not be required to restore service until the conditions which resulted in the termination have been corrected to the satisfaction of the Company.

3. The Company shall maintain a record of all terminations of service without notice. This record shall be maintained for a minimum of one (1) year and shall be available for inspection by the ACC.

~~SECTION NO. 11~~
~~TERMINATION OF SERVICE~~
~~(continued)~~

C. Termination of Service With Notice

~~2.~~1. The Company may disconnect service to any ~~Customer~~Customer for any reason stated below, provided that the Company has met the notice requirements ~~established by the ACC~~described in Section 11.D below:

~~A.~~a. ~~Customer~~Customer violation of any of the Company's ~~t~~~~Tariff~~Pricing Planss;

~~B.~~b. Failure of the ~~Customer~~Customer to pay a delinquent bill for gas service;

~~C.~~c. Failure of the ~~Customer~~Customer to meet agreed upon deferred payment arrangements;

~~D.~~d. Failure to meet or maintain the Company's deposit requirements;

~~E.~~e. Failure of the ~~Customer~~Customer to provide the Company reasonable access to its equipment and property;

~~F.~~f. ~~Customer~~Customer breach of a written contract for service between the Company and ~~Customer~~Customer; or

~~G.~~g. When necessary for the Company to comply with an order of any governmental agency having such jurisdiction.

~~3.~~2. The Company shall maintain a record of all terminations of service with notice. This record shall be maintained for one (1) year and shall be available for ACC inspection.

SECTION NO. 11
TERMINATION OF SERVICE
(continued)

D. Termination Notice Requirements

~~A.~~1. The Company may not terminate service to any of its ~~Customer~~Customers without providing advance written notice to the ~~Customer~~Customer of the Company's intent to disconnect service, except under those conditions specified where advance written notice is not required.

~~B.~~2. Such advance written notice shall contain, at a minimum the following information:

a. The name of the person whose service is to be terminated and the address where service is being rendered;

b. The ~~t~~~~Tariff~~Pricing Plans that was violated and explanation of the violation or the amount of the bill, which the ~~Customer~~Customer has failed to pay in accordance with the payment policy of the Company, if applicable;

c. The date on or after which service may be terminated; and

~~SECTION NO. 11~~
~~TERMINATION OF SERVICE~~
~~(continued)~~

d. A statement advising the ~~Customer~~Customer that the Company's stated reason for the termination of services may be disputed by contacting the Company at a specific address or phone number, advising the Company of the dispute and making arrangements to discuss the cause for termination with a responsible employee of the Company in advance of the scheduled date of termination. The responsible employee shall be empowered to resolve the dispute and the Company shall retain the option to terminate service after affording this opportunity for a meeting, concluding that the reason of terminating is just, and advising the ~~Customer~~Customer of his right to file a complaint with the ACC.

~~C.~~3. Where applicable, a copy of the termination notice will be simultaneously forwarded to designated third parties.

E. Timing of Terminations With Notice

~~a.~~1. The Company shall be required to give at least ~~ten~~five (~~10~~5) days advance written notice prior to the termination date. For ~~Customer~~Customers under the jurisdiction of a bankruptcy court, a shorter notice may be provided, if permitted by that court.

~~b.~~2. Such notice shall be considered to be given to the ~~Customer~~Customer when a copy of the notice is left with the ~~Customer~~Customer or posted first class in the United States mail, and addressed to the ~~Customer~~Customer's last known address.

~~c.~~3. If, after the period of time allowed by the notice has elapsed, the delinquent account has not been paid nor arrangements made with the Company for the payment of the bill, or in the case of a violation of the Company's rules the ~~Customer~~Customer has not satisfied the Company that such violation has ceased, the Company may terminate service on or after the day specified in the notice without giving further notice.

SECTION NO. 11
TERMINATION OF SERVICE
(continued)

~~d.~~4. Service may only be disconnected in conjunction with a personal visit to the premises by an authorized representative of the Company.

~~e.~~5. The Company shall have the right, but not the obligation, to remove any or all of its property installed on the ~~Customer~~Customer's premises upon the termination of service.

~~SECTION NO. 11~~
~~TERMINATION OF SERVICE~~
~~(continued)~~

F. Landlord/Tenant Rule

1. In situations where service is rendered at an address different from the mailing address of the bill or where the Company knows that a landlord/tenant relationship exists and that the landlord is the ~~Customer~~Customer of the Company, and where the landlord as ~~Customer~~Customer would otherwise be subject to disconnection of service, the Company may not disconnect service until the following actions have been taken:

    ~~1.~~a. Where it is feasible to provide service, the Company, after providing notice as required in these rules, shall offer the occupant the opportunity to subscribe for service in the occupant's own name. If the occupant then declines to subscribe, the Company may disconnect service pursuant to the rules.

    ~~2.~~b. The Company shall not attempt to recover payment of any outstanding bills or other charges due on the outstanding account of the landlord from a tenant. The Company shall not condition service to a tenant based on the payment of any outstanding bills or other charges due upon the outstanding account of the landlord.

SECTION NO. 12
ADMINISTRATIVE AND HEARING REQUIREMENTS

~~a.~~A. ~~Customer~~Customer Service Complaints

1. The Company shall make a full and prompt investigation of all service complaints made by its ~~Customer~~Customers, either directly to the Company or through the ACC.

2. The Company shall respond to the complainant and/or the ACC representative within five (5) working days as to the status of the Company's investigation of the complaint.

3. The Company shall notify the complainant and/or the ACC representative of the final disposition of each complaint. Upon request of the complainant or the ACC representative, the Company shall report the findings of its investigation in writing.

4. The Company shall inform the ~~Customer~~Customer of the right of appeal to the ACC.

5. The Company shall keep a record of all written service complaints received and which shall contain, at a minimum, the following data:

   ~~1.~~a. Name and address of complainant.

   ~~2.~~b. Date and nature of complaint.

   ~~3.~~c. Disposition of the complaint.

   ~~4.~~d. A copy of any correspondence between the Company, the ~~Customer~~Customer, and/or the ACC.

   This record shall be maintained for a minimum period of one (1) year and shall be available for inspection by the ACC.

SECTION NO. 12
ADMINISTRATIVE AND HEARING REQUIREMENTS
(continued)

~~b.~~B. ~~Customer~~Customer Bill Disputes

1. Any ~~Customer~~Customer who disputes a portion of a bill rendered for gas service shall pay the undisputed portion of the bill prior to the delinquent date of the bill, and notify the Company's designated representative that any unpaid amount is in dispute.

2. Upon receipt of the ~~Customer~~Customer's notice of dispute, the Company shall:

   ~~1.~~a. Notify the ~~Customer~~Customer within five (5) working days of the receipt of a written dispute notice.

   ~~2.~~b. Initiate a prompt investigation as to the source of the dispute.

   ~~3.~~c. Withhold disconnection of service until the investigation is completed and the ~~Customer~~Customer is informed of the results. Upon request of the ~~Customer~~Customer, the Company shall report the results of the investigation in writing.

   ~~4.~~d. Inform the ~~Customer~~Customer of the right of appeal to the ACC.

3. Once the ~~Customer~~Customer has received the results of the Company's investigation, the ~~Customer~~Customer shall submit payment within five (5) working days to the Company for any disputed amounts. Failure to make full payment shall be grounds for termination of service.

~~c.~~C. ACC Resolution of Service and/or Bill Disputes

~~C.~~1. In the event a ~~Customer~~Customer and the Company cannot resolve a service and/or bill dispute, the ~~Customer~~Customer shall file a written statement with the ACC. By submitting such written notice to the ACC, the ~~Customer~~Customer shall be deemed to have filed an informal complaint against the Company.

~~D.~~2. Within thirty (30) days of the receipt of a written statement of ~~Customer~~Customer dissatisfaction related to a service or bill dispute, a designated representative of the ACC shall endeavor to resolve the dispute by correspondence and/or by telephone with the Company and the ~~Customer~~Customer. If resolution of the dispute is not achieved within twenty (20) days of the ACC representative's initial effort, the ACC shall hold an informal hearing to arbitrate the resolution of the dispute. The informal hearing shall be governed by the following rules:

   ~~2.~~a. Each party may be represented by legal counsel, if desired;

   ~~3.~~b. All such informal hearings may be recorded or held in the presence of a stenographer;

SECTION NO. 12
ADMINISTRATIVE AND HEARING REQUIREMENTS
(continued)

~~4.~~c. All parties will have the opportunity to present written or oral evidentiary material to support the positions of the individual parties; and

~~5.~~d. All parties and the ACC's representative shall be given an opportunity for cross-examination of the various parties.

The ACC's representative will render a written decision to all parties within five (5) working days after the date of the informal hearing. Such written decision of the ACC's representative is not binding on any of the parties and the parties will still have the right to make a formal complaint to the ACC.

~~E.~~3. The Company may implement normal termination procedures if the ~~Customer~~Customer fails to pay all bills rendered during the resolution of the dispute by the ACC.

~~F.~~4. The Company shall maintain a record of written statements of dissatisfaction and their resolution for a minimum of one (1) year and make such records available for ACC inspection.

~~d.~~D. Notice by Company of Responsible Officer or Agent

~~A.~~1. The Company shall file with the ACC a written statement containing the name, business address ~~(business, residence and post office)~~ and telephone numbers (~~business and residence~~office and mobile) of at least one officer, agent or employee responsible for the general management of its operations as a Company in Arizona.

~~B.~~2. The Company shall give notice, by filing a written statement with the ACC, of any change in the information required herein within five (5) days from the date of any such change.

SECTION NO. 13
BUDGET BILLING PAYMENT PLAN

~~A.~~A. Residential ~~Customer~~Customers may elect to participate in the Company's Budget Billing Payment Plan ("Plan") for payment of charges for gas service. ~~The Plan year shall be the twelve (12) billing months ending with the Customer's July bill.~~

~~1.~~B. Upon ~~Customer~~Customer request, the Company will develop an estimate of the ~~Customer~~Customer's levelized billing for a twelve (12) month period based on:

~~a.~~1. The ~~Customer~~Customer's actual consumption history at the service location, which may be adjusted for weather or other known variations. If sufficient history is not available, then an estimate will be prepared based on other similar service locations and ~~customer's~~Customer's anticipated load requirements; and

2. The applicable Pricing Plan~~Company's tariff schedules approved by the ACC applicable to that CustomerCustomer's class of service~~, the estimated gas costs for the Plan year, and applicable taxes.

~~2.~~C. The Company shall provide the ~~Customer~~Customer with a concise explanation of how the levelized billing estimate was developed, the impact of levelized billing on a ~~Customer~~Customer's monthly bill, and the Company's right to adjust the ~~Customer~~Customer's billing for any variation between the Company's estimated billing and actual billing.

~~3.~~D. The Plan's monthly payment shall be determined as follows:

Settlement month will be the ~~customer's~~Customer's anniversary date, 12 months from the time the ~~customer~~Customer is set up on the Budget Billing Payment Plan. The Company reserves the right to adjust the remaining monthly Plan semi-annually to reduce the likelihood of an excessive debt or credit balance in rates due to dramatic PGA increases or PGA surcharges.

~~1.For Customers starting with the August bill, make an estimate of the usage for the Plan year for this Customer at the applicable premise, calculate the bill over the Plan year as described in Subsection B above, add in the debit or credit balance from actual usage at the due date for the most recent bill, and divide by twelve (12) months. Customers with a debit balance with any portion coming from overdue amounts may be required to pay off all overdue portions of the balance before being placed on the Plan.~~

~~2.For Customers starting with the September or a later bill, use the same process as in Subsection D.1 above, but use the remaining months of the Plan year for the usage, bill estimates and the divisor to determine the monthly payment. Customers who wish to start with the December or later bills may be required to pay off any existing balance, if over $75.00, or may be excluded if they have two (2) or more bills in the last twelve (12) months that have not been paid by the billing date of the next bill.~~

~~SECTION NO. 13~~
~~BUDGET BILLING PAYMENT PLAN~~
~~(continued)~~

~~3.~~1. The Company reserves the right to adjust the remaining monthly Plan payments of any ~~Customer~~Customer at any time if the Company's estimate of the ~~Customer~~Customer's usage and/or cost varies significantly from the ~~Customer~~Customer's actual usage and/or cost. Such review may also be initiated by the ~~Customer~~Customer. Any change resulting from such a review will be effective on a subsequent bill and no further notice is required.

~~4.~~2. The ~~Customer~~Customer shall continue to pay the monthly Plan payment amount each month, notwithstanding the current gas service charge shown on the bill.

~~5.~~3. Any other charges incurred by the ~~Customer~~Customer shall be paid monthly when due in addition to the monthly Plan payment.

~~6.~~4. Interest will not be charged the ~~Customer~~Customer on accrued debit balances nor paid by the Company on accrued credit balances.

~~7.~~5. Any amount due the Company will be settled and paid at the time a ~~Customer~~Customer, for any reason, ceases to be a participant in the Plan. If an amount due to the ~~Customer~~Customer exceeds fifty dollars ($50.00), the ~~Customer~~Customer has the option to receive a bill credit or a refund; otherwise the credit will remain as a bill credit.

UniSourceEnergy SERVICES

SECTION NO. 13
BUDGET BILLING PAYMENT PLAN
(continued)

~~8.~~6. Any ~~Customer~~Customer's participation in the Plan may be discontinued by the Company if the monthly Plan payment has not been paid on or before the billing date of the next monthly Plan payment.

~~9.~~7. If a ~~Customer~~Customer in the Plan shall cease, for any reason, to participate in the Plan, then the Company may refuse that ~~Customer~~Customer's re-entry in the Plan until the following August or for six (6) months, whichever is longer.

~~10.~~8. For those ~~Customer~~Customers being billed under the Plan, the Company shall show, at a minimum, the following information on the ~~Customer~~Customer's monthly bill:

a. Actual consumption;

b. *Amount due for actual consumption;*

c. Levelized billing amount due; and

d. Accumulated variation in actual versus levelized billing amount.

SECTION NO. 14
CURTAILMENT PLAN

~~2.~~A. The Company shall use reasonable diligence in its operations to render continuous service to all its ~~Customer~~Customers other than those ~~Customer~~Customers served under Pricing Plans ~~rate schedules~~ expressly permitting interruptions of service for peak shaving purposes. If for any reason, however, the Company is unable to supply the demand for gas in any one or more of its systems, interruptions or curtailments of service shall be made in accordance with the provisions of this section. The Company shall not be liable for damages because of the operation of this section.

B. Applicability

1. The order of curtailment shall be in inverse order of the curtailment priorities set forth in Subsection C below.

2. Curtailment priorities shall apply to both sales and transportation ~~Customer~~Customers.

3. ~~Customer~~Customers being served under a discounted transportation or sales rate schedule shall be curtailed first. ~~Customer~~Customers paying the least will be curtailed first within an affected priority.

4. Each priority shall be curtailed in full before the next priority in order is curtailed.

5. When Priority 1 ~~Customer~~Customers would be curtailed due to system supply failure (either upstream capacity or supply failure), the Company is authorized to "preempt" deliveries of lower priority transportation ~~Customer~~Customers' gas and divert such supplies to the otherwise affected Priority 1 ~~Customer~~Customers. Affected transportation ~~Customer~~Customers will be curtailed to the same extent as sales ~~Customer~~Customers of the same priority. Such transportation ~~Customer~~Customers will be compensated for the preemption of their gas supply by either crediting the ~~Customer~~Customer's account with a like quantity of gas for use on a subsequent gas day, or by providing a cash payment or credit to the ~~customer~~Customer's bill at the cost of gas per unit paid by the ~~Customer~~Customer. If the gas supply of an alternate fuel-capable transportation ~~Customer~~Customer is preempted according to this provision, the Company shall provide additional compensation to such ~~Customer~~Customer for the incremental cost of using the alternate fuel, (the difference between the actual cost of using the alternate fuel and the actual cost of gas paid by the ~~Customer~~Customer for the preempted gas). Such credit shall be applied to the Company's next scheduled billing after the ~~Customer~~Customer has furnished adequate proof to the Company concerning alternate fuel costs, replacement volumes, and gas costs.

6. The installation of a cogeneration facility shall not affect the underlying end-use priority of the establishment.

7. Natural gas utilized as compressed natural gas for vehicle fuel shall be classified as a commercial end-use.

SECTION NO. 14
CURTAILMENT PLAN
(continued)

8. Application of curtailment priorities will normally be done on a scheduled basis as part of the daily gas requirement nomination and confirmation routine. Operational emergency curtailment will conform to these priorities to the extent possible and practical.

9. A transportation ~~Customer~~Customer may be curtailed to the level of actual supply scheduled for that ~~Customer~~Customer, regardless of end-use priority.

C. Priorities

Priority 1: Residential, small commercial (less than five hundred (500) therms on a peak day), schools, hospitals, police protection, fire protection, sanitation facility, correctional facility, and emergency situation uses.

Priority 2A: Essential agricultural uses as certified by the Secretary of Agriculture.

Priority 2B: Essential industrial process and feedstock uses.

Priority 2C: Large Commercial (five hundred (500) therms or more on a peak day) and storage injection requirements, industrial requirements for plant protection, feedstock, process, ignition and flame stabilization needs not specified in Priority 2B.

Priority 3A: Industrial requirements not specified in Priorities 2, 4, and 5, of less than one thousand (1,000) therms on a peak day.

Priority 3B: All industrial requirements not specified in Priorities 2, 3A, 4, and 5.

Priority 4: Industrial requirements for boiler fuel use at less than thirty thousand (30,000) therms per peak day, but more than fifteen thousand (15,000) therms per peak day, where alternate fuel capabilities can meet such requirements.

Priority 5: Industrial requirements for large volume (thirty thousand (30,000) therms per peak day or more) boiler fuel use where alternate fuel capabilities can meet such requirements.

~~SECTION NO. 14~~
~~CURTAILMENT PLAN~~
~~(continued)~~

D. In the event of isolated incidents in order to avoid hazards and protect the public, the Company may temporarily interrupt service to certain ~~Customer~~Customers without regard to priority or any other ~~Customer~~Customer classification.

~~E.~~

SECTION NO. 14
CURTAILMENT PLAN
(continued)

~~F.~~E. Definitions

1. "Alternate Fuel Capability" – A situation where an alternate fuel can be utilized whether or not the facilities for such use have actually been installed.

2. "Correctional Facility Uses" – A facility, the primary function of which is to house, confine, or otherwise limit the activities of a person who has been assigned to such facilities as punishment by a court of law.

3. "Essential Agricultural Use" – Any use of natural gas which is certified by the Secretary of Agriculture as an "essential agricultural use."

4. "Essential Industrial Process and Feedstock Uses" – ~~Means a~~Any use of natural gas by an industrial ~~customer~~Customer as process gas, or as a feedstock, or gas used for human comfort to protect health and hygiene in an industrial installation.

5. "Feedstock Gas" – Natural gas use for which alternate fuels are not technically feasible, such as in applications requiring precise temperature controls and precise flame characteristics. For the purposes of this definition, propane and other gaseous fuels shall not be considered alternate fuels.

6. "Fire Protection Uses" – Natural gas used by and for the benefit of fire fighting agencies in the performance of their duties.

7. "Flame Stabilization Gas" – Natural gas which is burned by ~~ignitors~~igniters, main gas burners, or warm-up burners for the purpose of maintaining stable combustion of an alternate fuel.

8. "Hospital" – A facility, the primary function of which is delivering medical care to patients who remain at the facility (facility includes nursing and convalescent homes). Outpatient clinics or doctors' offices are not included in this definition.

9. "Ignition Gas" – Natural gas supplied to gas ~~ignitors~~igniters in boilers to light main burners, whether the main burners are operated by gas, oil, or coal.

10. "Industrial Boiler Fuel" – Natural gas used in a boiler as a fuel for the generation of steam or electricity.

11. "Industrial Use" – Natural gas used primarily in a process which creates or changes raw or unfinished materials into another form or product, including electric power generation.

~~SECTION NO. 14~~
~~CURTAILMENT PLAN~~

~~(continued)~~

12. "Peak Day" – Maximum daily ~~customer~~Customer use as determined by the best practical method available.

SECTION NO. 14
CURTAILMENT PLAN
(continued)

~~12.~~

13. "Plant Protection Gas" – Minimum natural gas volumes required to prevent physical harm to the plant facilities or danger to plant personnel when such protection cannot be afforded through the use of an alternate fuel. This includes the protection of such material in process as would otherwise be destroyed, but shall not include deliveries required to maintain plant production. For the purposes of this definition, propane and other gaseous fuels shall not be considered alternate fuels.

14. "Police Protection Uses" – Natural gas used by law enforcement agencies in the performance of their duties.

15. "Process Gas" – Natural gas use for which alternate fuels are not technically feasible, such as in applications requiring precise temperature controls and precise flame characteristics. For the purposes of this definition, propane and other gaseous fuels shall not be considered alternate fuels.

16. "Sanitation Facility Uses" – Natural gas use in a facility where natural gas is used to a) dispose of refuse, or b) protect and maintain the general sanitation requirements of the community at large.

17. "School" – A facility, the primary function of which is to provide instruction to regularly enrolled students in attendance at such facility. Facilities used for both educational and non-educational activities are not included under this definition unless the latter activities are merely incidental to the provision of instruction.

18. "Small Commercial Establishment" – Any establishment (including institutions and local, state, and federal government agencies) engaged primarily in the sale of goods or services where natural gas is used:

    a. in amounts of less than fifty (50) MCF on a peak day; and

    b. for purposes other than those involving manufacturing or electric power generation.

19. "Storage Injection Gas" – Natural gas injected by a distributor into storage for later use.

SECTION NO. 15
RATES AND UNIT MEASUREMENT

~~1.~~A. The rates and charges for gas service shall be those of the Company legally in effect and on file with the ACC.

~~2.~~B. All rates set forth in the Company's ~~rate schedules~~Pricing Plans are stated in therms. ~~The term "therm" means one hundred thousand (100,000) BTU's.~~ Unless otherwise provided by special contract, the number of therms delivered to any ~~Customer~~Customer shall be determined by measuring the volume of gas passing through that ~~Customer~~Customer's meter during the month to the nearest one hundred (100) cubic feet and ~~multiplying that volume by an appropriate conversion factor~~applying the procedures of Section 8.H of these Rules and Regulations.

~~3.~~C. The unit of volume for measurement of gas sold shall be one (1) ~~cubic foot of gas at a base temperature of sixty (60) degrees Fahrenheit and a base pressure of fourteen and seventy three hundredths (14.73) pounds per square inch atmospheric ("PSIA").~~ Cubic Foot of gas, as defined in Section 2~~.~~, Subsection A.1~~2~~3 of these Rules and Regulations. The volume of gas measured shall be rounded to the nearest one hundred (100) cubic feet for any given period.

~~4.~~D. The atmospheric pressure will be the standard atmospheric pressure for the location.

~~5.~~E. The standard serving pressure shall be seven (7) inches of water pressure (four (4) ounces per square inch gauge) above the atmospheric pressure.

~~6.~~F. The standard temperature of sixty (60) degrees Fahrenheit will be used for volume determination unless stated otherwise under special contract. The Company shall retain the right, but shall not be obligated, to install temperature recording or compensating equipment as part of the measuring facilities. When such temperature recording equipment is used, the arithmetic average temperature of the gas each day, during periods of flow only, shall be used in computing the quantity of gas delivered by that day.

~~5.~~G. The Company, at its own option, may elect to serve a ~~Customer~~Customer at a pressure higher than the standard serving pressure. The Company shall correct such volume to Standard Conditions ~~the standard base pressure of fourteen and seventy three hundredths (14.73) PSIA and sixty (60) degrees Fahrenheit~~ by the use of compensating equipment or the use of a factor. The Company retains the right to determine the method used for applying such correction. The factor used to correct the measured volume shall be in accordance with American Gas Association Report 3.

~~SECTION NO. 15~~
~~RATES AND UNIT MEASUREMENT~~
~~(continued)~~

~~A standard cubic foot for determining the heating value of gas is defined as the quantity of gas saturated with water vapor, which at a pressure of thirty (30) inches or mercury and at a temperature sixty (60) degrees Fahrenheit occupies one (1) cubic foot.~~

~~7.~~H. The therm conversion factor shall be determined each month and shall be the product of the conversion factor and the most recent heating value content available using the weighted average delivered pressure by office. The weighted average delivered pressure is derived monthly using the delivered pressure for each town code served which is reflective of each town code's elevation, weighted by the sales distribution among assigned gas distribution systems within each respective office. Further explained in Section 8.H. of these Rules and Regulations.~~h, Provision of Service.~~

SECTION NO. 16
GAS METER TESTING AND MAINTENANCE PLAN

A. General Plan

The Company will annually sample groups of meters to determine the continuing accuracy and performance of the group. Certain safe and proper standards are defined, and meters will remain in service as long as they meet these standards. This program will allow the Company to obtain all the useful service available from a meter until the meter no longer meets prescribed standards. At that time, then it is proper for the meter to be removed, tested, repaired, or retired.

This procedure is for the purpose of testing and controlling the performance of small gas meters that are two hundred fifty (250) CFH ~~(WHAT IS CFH? NOT IN DEFINITIONS. NEED TO SPELL OUT)~~ or less. The program will identify and remove meters that do not meet the standards of performance described in Subsection D below, and identify and retain in service meters that do meet or exceed the stated standards. Meters are classified into groups, samples of each group are tested annually, and groups are removed from service when they do not meet performance standards.

B. Meter Groups

1. Meters are segregated into groups on the following basis:

   a. Year last repaired or purchased;

   b. Manufacturer;

   c. Diaphragm type (leather or synthetic), when available; and

   d. Geographic district.

2. For meters repaired or purchased in a given year, the groups are established at the beginning of the next year. When a new group being established is found to contain less than one thousand (1,000) meters, this group may be combined with another group having meters of the same or similar operating characteristics. An existing group may be divided into two or more groups, if experience characteristics of part of the group are sufficiently different from the remainder of the group to warrant separate sampling of the parts.

C. Sampling

A representative random sample is selected from each group of meters. The samples are used in determining the performance of each group of meters each year. If the initial order for meter removals does not produce an adequate sample, additional meters are drawn on a random basis. These meters are combined with the original sample for determining acceptability of the group. Samples are taken annually from all groups that have been in service for ten years or longer.

SECTION NO. 16
GAS METER TESTING AND MAINTENANCE PLAN
(continued)

D. Performance Standard

The criteria for acceptability for a group to remain in service are:

1. No more than ten percent (10%) of the meters tested in the group are more than three percent (3%) fast.
2. At least eighty percent (80%) of the meters tested in the group are within +/- three percent (3%) of zero error. This results in a condition wherein a minimum of ninety percent (90%) of the meters remaining in service are either within +/- three percent (3%) or are more than three percent (3%) slow and in the ~~Customer~~Customer's favor.

E. Records

The test results for each group are kept in appropriate records that indicate the number of meters in the sample versus the test results, expressed as a percent.

F. Removal of Groups

1. A test result falling on or above the prescribed standards is satisfactory and the groups will remain in service.
2. A test falling below the prescribed standards is not satisfactory and the group will be removed from service.
3. The Company, for its convenience, may remove a group (or part of a group) even though the group meets the requirements for remaining in service.

SECTION NO. 16
GAS METER TESTING AND MAINTENANCE PLAN
(continued)

G. Annual Reports

A report of the meter performance control program will be filed annually with the ACC, which will contain the following:

1. A description of each group, showing its identification, size and composition;
2. A list of the total number of meters tested, at Company initiative or upon ~~Customer~~Customer request;
3. A detailed list of the performance results of each group, showing the number of meters in the group, the number of meters removed during the year, the number of meters not tested (dead, non-registering, damaged, etc.), the number or meters tested, the number of meters slow - minus three percent (-3%), the number of meters accurate, the percent of meters accurate, the number of meters fast - plus three percent (+3%), and the percent of meters fast;
4. A summary of results for each year of service; and
5. A summary or the overall results.

BEFORE THE ARIZONA CORPORATION COMMISSION

EXHIBIT
tabbies
UNSG-16
Admitted

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

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-06-0463
IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. TO REVIEW AND REVISE ITS PURCHASE 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

Rebuttal Testimony of

Gary A. Smith

on Behalf of

UNS Gas, Inc.

March 16, 2007

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Gary A. Smith. My business address is 2901 West Shamrell Blvd., Suite 110 Flagstaff, Arizona 86001.

Q. Are you the same Gary A. Smith that filed Direct Testimony in this case?

A. Yes.

Q. What is the purpose of your Rebuttal Testimony in this proceeding?

A. The purpose of my Testimony is to respond to certain aspects of the Direct Testimonies filed by Ms. Julie McNeely-Kirwan and Mr. Ralph Smith on behalf of Commission Staff, Ms. Marylee Diaz Cortez on behalf of the Residential Utility Consumers Office ("RUCO"), and Ms. Miquelle Scheier on behalf of the Arizona Community Action Association ("ACAA").

Q. Please summarize your Rebuttal Testimony.

A. With regards to Staff witnesses Julie McNeely-Kirwan and Ralph Smith, the Company agrees with their recommendations on the Warm Spirit program and the modifications to the Company's Rules and Regulations. I, however, do not agree with RUCO witness Marylee Diaz Cortez's criticism of one of the Company's proposed modifications to its Rules and Regulations and I also disagree with the two operating income adjustments made by RUCO witness Rodney Moore. I also will make some comments in response to Ms. Scheier's Direct Testimony.

II. RESPONSE TO STAFF WITNESS JULIE MCNEELY-KIRWAN.

Q. Mr. Smith, have you had an opportunity to review Ms. McNeely-Kirwan's Direct Testimony?

A. Yes, I have. Ms. Denise Smith will respond to Ms. McNeely-Kirwan's comments on Demand Side Management ("DSM") and Mr. D. Bentley Erdwurm will respond to her comments on rate design and customer charges for the Company. I would like to briefly comment on one aspect of her Direct Testimony regarding the Customer Assistance Residential Energy Support ("CARES") expansion and her recommendation about the Warm Spirit program.

Q. Please respond to Ms. McNeely-Kirwan's recommendation with regard to CARES expansion.

A. In her Direct Testimony on page 2, lines 23-25, Ms. McNeely-Kirwan states that "Staff recognizes the improvement and recommends that UNS continue to work toward expanding participation in the CARES program to additional eligible households." UNS Gas agrees with Ms. McNeely-Kirwan about the importance of this program. We strive to add households by distributing CARES applications to local assistance agencies, public libraries, and town and city halls within our service territory. We also insert CARES applications in all residential customers' bills every calendar quarter, (beginning in February of every year). As customers have discussions with the Customer Call Center and indicate difficulty in making payments on their accounts, we provide them the information about and/or an application for the CARES program.

Q. Also in her Direct Testimony, Ms. McNeely-Kirwan recommends – on page 8, lines 6-13 and page 13, lines 20-24 – that the $21,600 in emergency bill assistance proposed by UNS Gas as part of the Low Income Weatherization ("LIW") program be moved into the Warm Spirit program and recovered through base rates. Do you have any response?

A. UNS Gas is amenable to Ms. McNeely-Kirwan's recommendation as long as the Company may recover the funds for the emergency bill assistance through base rates. I am aware that Mr. Ralph Smith made that adjustment for Staff and so the Company agrees to put that money into the Warm Spirit program.

III. <u>RESPONSE TO STAFF WITNESS RALPH SMITH</u>.

Q. Have you had an opportunity to review Staff Witness Ralph Smith's Direct Testimony in this case?

A. Yes, I have. Again, while other UNS Gas witnesses will respond to the majority of the issues raised by Mr. Smith, I would like to briefly comment on his Direct Testimony concerning the Company's Rules and Regulations modifications.

Q. Do the Staff and the Company agree on the Company's modifications to the Rules and Regulations?

A. Yes. Staff supports the modifications we have proposed to our Rules and Regulations.

Q. Does Mr. Smith make any recommendations with regard to implementation of those Rules and Regulations?

A. Yes. On pages 68 and 70 of his Direct Testimony, Mr. Smith recommends that we implement a six-month waiver of the change in the late payment penalty period and the period that customers have to respond to a termination of service notice. The Company is willing to implement such a waiver period and will not operate under the new Rules and Regulations with regard to the late payment penalty period and the period following a termination of service notice for six months.

IV. RESPONSE TO RUCO WITNESS MARYLEE DIAZ CORTEZ.

Q. Mr. Smith, on pages 35 to 36 in her Direct Testimony, RUCO Witness Marylee Diaz Cortez takes issue with the Company's proposed change to its Rules and Regulations that would shorten the time customers have to pay their gas bills to avoid late fees or disconnection notices. Do you have any response?

A. Yes. Ms. Diaz Cortez states that the changes are unreasonable and a customer on vacation could come home to find his gas shut-off. Further, she argues that, because UNS Gas receives a working capital allowance, it should not impose the payment terms on customers. Not only is this rationale irrelevant, review of the billing timeline shows that the proposed changes allow for adequate time for customers to pay their bills. Customers receive bills approximately two days after a billing period ends. A customer has 10 days to pay before a bill is considered late. Under the proposed changes, after that 10 day period, a customer has another 15 days before a late fee is assessed, for a total of 25 days since the bill was received. Only then would a bill be considered delinquent. Even so, under Subsection 10.C.4. of the Company's proposed Rules and Regulations, the Company would not commence suspension of service procedures unless it did not receive payment for a 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 of shut-off is issued. After that notice is issued, a customer could have several days before gas is actually disconnected. In addition, if a customer presented good cause to the Company for late payment, the Company has the ability to waive the late fee. Finally, as recognized by Commission witness Ralph Smith, the proposal by the Company is consistent with the specifications of the Arizona Administrative Code, R14-2-310.C. Thus, the time periods proposed by the Company are entirely reasonable.

V. RESPONSE TO RUCO WITNESS RODNEY MOORE.

Q. Have you had an opportunity to review RUCO witness Mr. Rodney Moore's Operating Income Adjustment Nos. 6 and 10?

A. Yes. Review of the proposed disallowances reveals that most are directly related to safety, system integrity and operator training; thus, the expenses are clearly both appropriate and necessary.

Most of the recommended amounts for disallowance refer to expenses incurred performing regulatory-mandated functions such as leak surveys, safety audits, and training. More specifically, annual and cycle leak surveys require teams to be on the road, sometimes for substantial periods of time leak surveying all locations. To best ensure the pipeline integrity and maintain a better-than-industry-average lost and unaccounted for rate, we also perform leak surveys on the residential sections of our distribution system every four years. Mr. Moore's proposed disallowances also include expenses for the preparation and participation in the annual-mandated Commission pipeline safety audit and required operator qualification training, welder qualification training, and emergency response testing. Regulatory mandated requirements dictate that every employee attend at least two modules and up to 19 modules of training, depending on their job classification and duties. For example, to maintain welder qualification, employees must attend classroom and hands-on training every six months. Additionally, every employee, including Call Center personnel, must attend Emergency Response training every year. I must complete two modules of training every year.

RUCO also proposes disallowance of $12,000 spent on communications in support of all our field communication equipment, and for lease of radio towers that are not only used for normal operations and maintenance but for public emergency situations as well, $12,000 for materials, small tools, or personnel protective equipment, and $4,800 for material related to our Circle of Safety employee awareness program. The Circle of Safety program, in addition to promoting safe parking practices, utilizes external cues (*i.e.*, door magnets and safety cones) to remind employees to "circle" their vehicles before leaving a parking spot. By heightening the awareness of the vehicles' surroundings, the goal of the program is to eliminate accidents involving hidden or difficult-to-see obstacles that employees frequently encounter on the job. The costs of this on-going program represent a fraction of the potential savings from the liability and vehicular damage costs avoided from eliminating accidents of this nature. A significant amount of the balance is spent for small tools that are necessary for maintaining the pipeline system.

Thus, the funds proposed for disallowance by Mr. Moore are directly related to the support of system integrity, safety, and operator training and are properly included.

VI. <u>RESPONSE TO ACAA WITNESS MIQUELLE SCHEIER</u>.

Q. Before you respond to Ms. Scheier's specific recommendations, do you have any general comments to make with regard to her Direct Testimony?

A. Yes. UNS Gas understands Ms. Scheier's concerns and is sympathetic to the stresses rising utility bills place on low-income customers. As always, the Company is ready and willing to meet with Ms. Scheier to determine how it can help with those stresses. However, the Company has experienced increased costs that it must cover in order to provide safe and reliable service. The customers from whom those costs are recovered ultimately is a policy question for this Commission. The Company has made some recommendations as to how it would distribute the rising costs, and has tried to maintain appropriate allowances for our low income customers. If this Commission determines that there is a better way in which to distribute the cost increase while retaining the Company's opportunity for full recovery of all prudently incurred expenses in delivering safe and reliable gas service to all customers, the Company will certainly abide by that decision.

Q. Turning to Ms. Scheier's first recommendation on pages 2 and 10 to 11 of her Direct Testimony – that the Commission hold low-income customers harmless by increasing the R12 discount to an amount commensurate with any residential rate increase and reject the Company's proposed structure for R12 – do you have any response?

A. The Commission can make a policy decision as to how it would prefer to spread any rate increase. However, consistent with Mr. Erdwurm's Rebuttal Testimony, the appropriate rate design should channel fixed costs into a fixed customer service charge and variable fuel charges into a per therm charge. The Company incurs fixed costs regardless of consumption. If consumption is reduced, then the Company will not recover the fixed costs expended to serve customers. The Company incurs those fixed costs even when those customers opt to not use gas.

Q. Do you have any response to Ms. Scheier's recommendation on pages 2 and 10 in her Direct Testimony that the Commission increase the marketing of the low-income programs, including the funding effort by Community Action Agencies ("CAA") to reach target low-income customers?

A. Again, the Commission can help the Company decide how to best allocate the dollars to these programs. Of course, as funding for marketing is increased, funding for weatherization and other low income assistance is decreased, assuming a fixed program amount.

Q. On page 2 in her Direct Testimony, Ms. Scheier recommends that the Commission require the automatic enrollment of Low Income Home Energy Assistance Program ("LIHEAP") eligible customers of record in the R12 discount rate program. Do you have any response to this recommendation?

A. While I am not clear if the recommendation is for the automatic enrollment of LIHEAP recipients or simply LIHEAP eligible customers, the Company is happy to enroll LIHEAP recipients who are also current UNS Gas customers of record in the R12 discount rate program. UNS Gas will work with ACAA in order to figure out how to best accomplish the sharing of LIHEAP customer information with the Company.

Q. Ms. Scheier raises concern over the referring of cash-paying customers to "predatory lenders" and the practice of charging additional fees for these customers on page 2 and pages 12-13 of her Direct Testimony. Do you have any response?

A. When UNS Gas closed some of its branch offices to save money for all ratepayers, we were very concerned about providing sufficient and convenient locations for our cash-paying customers. When ACAA first raised its concerns to us in November of 2006, I looked into each of its complaints.

First, on page 12, Ms. Scheier states that UNS Gas, in some instances, charges an additional fee for those customers paying their bills in cash. This is not accurate. In fact, UNS Gas pays any additional fee charged by payment locations as long as the customer does not have the option of paying at a nearby UNS Gas facility. If customers choose to visit a payment center, despite having the choice of paying at an UNS Gas office, then they will pay an additional charge. In all other areas, UNS Gas picks up the additional charge. The bill insert, attached hereto as Exhibit GAS-3, was sent to customers last year in anticipation of the lobby closures and clearly outlines each location's payment options, including use of various cash-payment vendors and courtesy drop boxes for checks and money orders—both of which are available without a fee in these locations. As discussed above, locations where lobbies remained open are listed on our website as having a fee apply when customers choose a cash agent instead of utilizing the customer lobby available to them. See Exhibit GAS-4.

Second, Ms. Scheier points to a Center for Responsible Lending report as evidence of excessive fees at pay day loan businesses. Again, UNS Gas covers those fees related to the payment of gas bills at locations where it does not have an office. 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. Customers could make the decision to enter into these agreements even if UNS Gas retained all of its branch offices and the customer needed cash to pay his or her gas bill, or even if there were "ATM-like Kiosks" as Ms. Scheier suggests in her Direct Testimony. After ACAA approached UNS Gas with this concern, I asked location managers whether or not they have experienced UNS Gas bill payers taking out loans to pay their bills. Of the managers asked, none could remember a time that this had happened.

UNS Gas is trying to keep costs for all of its customers down, while maintaining local payment options for those customers who would like to pay their bills in person. I have looked into Ms. Scheier's concerns and we are not encouraging our customers to utilize pay day loan services from these locations.

Q. In her Direct Testimony at pages 2, 10 and 11, Ms. Scheier recommends that UNS Gas bill assistance money be increased to $50,000 and be directed to the statewide non-profit Arizona fuel fund being created and managed by ACAA. What is your response to that?

A. I am uncertain whether Ms. Scheier is referring to the emergency bill assistance funds proposed by the Company to be part of LIW or the Warm Spirit bill assistance program. As I discuss above, we are willing to shift the emergency bill assistance money into the Warm Spirit program and recover for such in base rates. This will allow for more funds to help with bill assistance for our customers. UES Gas would support ACAA in managing the bill assistance money.

Q. Ms. Scheier also recommends on pages 2 and 9 of her Direct Testimony that the LIW funds be increased to $200,000. Do you have any response to this recommendation?

A. As is shown by our proposal to increase LIW funds, I do believe that more money can be used to help the Company's low-income customers. I do not have the necessary information to know just how much money the CAAs can utilize effectively – Ms. Scheier would better be able to provide that support. However, I believe that the CAAs need time to ramp up to support additional funding. The Company commits to work with CAAs prior to its next rate case to discuss additional opportunities. Again, the Company believes that the appropriate cost recovery mechanism for the LIW program, regardless of the amount the Commission ultimately deems appropriate, is through the DSM Adjustor Mechanism as a DSM program.

Q. Do you have any concerns over Ms. Scheier's recommendation that $20,000 in LIW funds be used to fund community volunteer weatherization efforts?

A. I would defer to Ms. Scheier as someone who sees the funds in action everyday to determine how they are best allocated.

Q. Finally, do you have any comments to Ms. Scheier's recommendation that the proposed changes in the Company's billing terms be rejected?

A. I would refer to the comments I made earlier in my Rebuttal Testimony in response to Ms. Diaz Cortez's Direct Testimony on this subject.

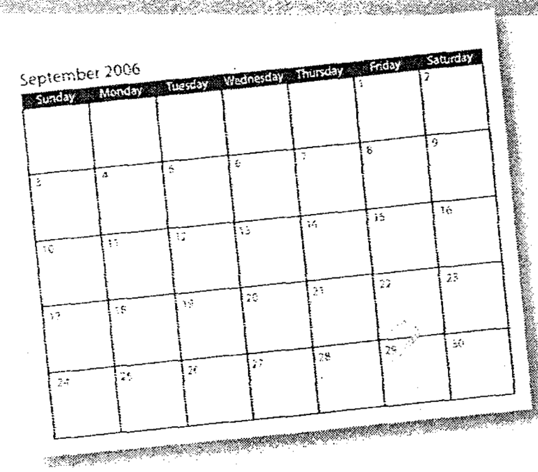
Q. Does this conclude your Rebuttal Testimony?

A. Yes.

EXHIBIT

GAS-3

The UES lobby in Cottonwood will be closing on Sept. 29th.



You'll still have plenty of ways to get what you need from UES.

We will be closing the walk-in lobbies at the UES offices in Cottonwood, Prescott, Flagstaff and Show Low because of several factors:

- More and more customers are discovering the convenience of online, telephone and other electronic payment methods (see back for all payment options).
- Cash-paying customers may now visit one of our independent payment agent locations in these four communities (see back for details).
- The handling of cash payments creates a personal safety issue for our employees.
- UES is constantly looking for ways to increase productivity and efficiency. Discontinuing these lobby operations helps keep our costs down, and that helps keep your gas rates down.
- *UES e-bill* is coming soon. It's the ultimate in convenience for receiving, viewing and paying your UES bill online.

Many other customer transactions and inquiries can be handled online at **uesaz.com**, or by calling UES toll-free at **877-UES-4YOU** (877-837-4968).

Our Customer Care Center is open Monday through Friday, 7 a.m. to 7 p.m. to serve you.

UniSourceEnergy SERVICES

See back for payment option details.

UES-Lobby Closure Area 83, 89-8/06

UES Payment Options

Cash Payment Agent

Prefer to pay your UES gas bill with cash? Visit ACE Cash Express:

- 989 S. Main, Ste. B, Cottonwood – 928-639-1000 (free service)

For other UES cash payment agents visit uesaz.com or call 877-UES-4YOU (877-837-4968).

Courtesy Drop Boxes

Deposit your check or money order payment in one of our convenient drop boxes:

- 500 S. Willard St., Cottonwood (outside of the UES office)
- Sedona Safeway, 2300 W. Highway 89A, Sedona – 928-282-0118

Credit Card, Debit Card or Bank Account Withdrawal

Web – Visit **uesaz.com** to pay your bill online using your credit card, debit card or bank account withdrawal (a convenience fee from a third-party payment processing company will apply).

Telephone – Use your credit card, debit card or bank account withdrawal to pay your UES gas bill via our toll-free payment hotline: **800-284-9730** (a convenience fee from a third-party payment processing company will apply).

SNAP

(Sure No-hassle Automatic Payment) – Enjoy the convenience of automatically paying your bill each month from your checking or savings account. It's easy. It's safe. It's free. Sign up at **uesaz.com**.

US Mail

It may not be high-tech, but it gets the job done for your check or money order payment. We supply the envelope, you supply the stamp.

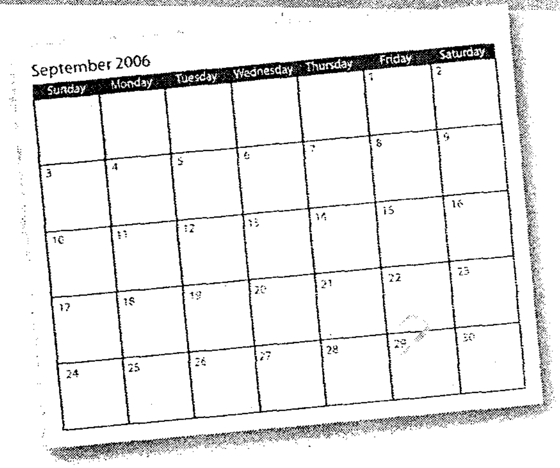
Coming Soon ... *UES e-bill*

UES e-bill is the online, fast, simple, convenient, secure, guaranteed, anywhere, anytime, FREE way to pay your UES gas bill. Visit **uesaz.com** and sign up to receive an e-mail notification when this service is available.

UniSourceEnergy
SERVICES

uesaz.com
877-UES-4YOU (877-837-4968)

The UES lobby in Flagstaff will be closing on Sept. 29th.



You'll still have plenty of ways to get what you need from UES.

We will be closing the walk-in lobbies at the UES offices in Flagstaff, Cottonwood, Prescott and Show Low because of several factors:

- More and more customers are discovering the convenience of online, telephone and other electronic payment methods (see back for all payment options).
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UniSourceEnergy SERVICES

See back for payment option details.

UES Payment Options

Cash Payment Agent

Prefer to pay your UES gas bill with cash? Visit Ozark Advanced Quick Cash:

- 3470 E. Route 66, Suite 101, Flagstaff – 928-526-5626 (free service)

For other UES cash payment agents visit uesaz.com or call 877-UES-4YOU (877-837-4968).

Courtesy Drop Boxes

Deposit your check or money order payment in one of our convenient drop boxes:

- 2901 W. Shamrell Blvd., Ste. 110, Flagstaff (outside of the UES office)
- Flagstaff Safeway, 1500 E. Cedar Avenue, Flagstaff – 928-774-3774
- Flagstaff Safeway, 4910 N. Highway 89, Flagstaff – 928-526-6116
- Flagstaff Safeway, 1201 S. Plaza Way, Flagstaff – 928-779-3401

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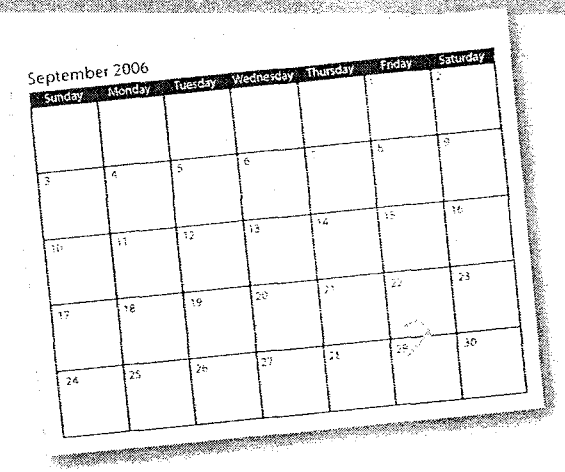

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UniSourceEnergy SERVICES

See back for payment option details.

UES Payment Options

Cash Payment Agent

Prefer to pay your UES gas bill with cash? Visit ACE Cash Express:

- 621 Miller Valley Road, Prescott – 928-777-0039 (free service)
- 8101 E. Hwy. 69, Ste A, Prescott Valley – 928-759-9939 (free service)
- 1578 N. US-89 Suite A, Chino Valley – 928-636-5545 (free service)

For other UES cash payment agents visit uesaz.com or call 877-UES-4YOU (877-837-4968).

Courtesy Drop Boxes

Deposit your check or money order payment in our convenient drop box:

- 6405 Wilkinson Drive, Prescott (outside of the new UES office)

Credit Card, Debit Card or Bank Account Withdrawal

Web – Visit **uesaz.com** to pay your bill online using your credit card, debit card or bank account withdrawal (a convenience fee from a third-party payment processing company will apply).

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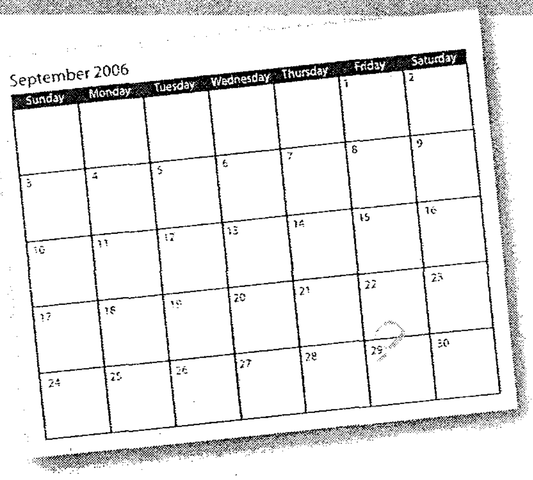

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UniSourceEnergy SERVICES

See back for payment option details.

UES Payment Options

Cash Payment Agent

Prefer to pay your UES gas bill with cash? Visit Audio Advantage/Radio Shack.

- 4431 S. White Mountain Road, Suite 1, Show Low – 928-532-0462 (free service)

For other UES cash payment agents visit uesaz.com or call 877-UES-4YOU (877-837-4968).

Courtesy Drop Boxes

Deposit your check or money order payment in one of our convenient drop boxes:

- 1480 N. 16th Street, Show Low (outside of the UES office)
- National Bank of Arizona, 902 E. Deuce of Clubs, Show Low – 928-537-2933
- National Bank of Arizona, 1820 E. White Mountain Blvd., Pinetop – 928-367-0650
- National Bank of Arizona, 718 N. Main Street, Taylor – 928-536-2143

Credit Card, Debit Card or Bank Account Withdrawal

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877-UES-4YOU (877-837-4968)

EXHIBIT

GAS-4

Payment Agents - Microsoft Internet Explorer

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tps://www.uesaz.com/gas/YourBill/Agents.html

rceEnergy SERVICES

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Gas Services

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)

Please note locations below have a UNS Gas, Inc. office nearby

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

Internet

Gas Cash Payment Agents - Microsoft Internet Explorer

File Edit View Favorites Tools Help

Address https://www.uesaz.com/gas/YourBill/Agents.html

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

Fee charged in this location is bolded

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.

Fee charged in these locations is bolded

Done Internet

Gas Cash Payment Agents - Microsoft Internet Explorer

File Edit View Favorites Tools Help

Address https://www.uesaz.com/gas/YourBill/Agents.html

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

OA 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

Winslow Document Express
118 B E. Second St.
Winslow AZ
928-289-3290
Hours: Monday through Friday 9AM to 5PM

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

Done Internet

BEFORE THE ARIZONA CORPORATION COMMISSION

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

EXHIBIT
tabbies
UNSG-17
Admitted

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-06-0463
IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. TO REVIEW AND REVISE ITS PURCHASE 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

Rejoinder Testimony of

Gary A. Smith

on Behalf of

UNS Gas, Inc.

April 11, 2007

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Gary A. Smith. My business address is 2901 West Shamrell Blvd., Suite 110 Flagstaff, Arizona 86001.

Q. Are you the same Gary Smith who filed Direct and Rebuttal Testimony in this proceeding?

A. Yes, I am.

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

A. The purpose of my testimony is to respond to certain comments made in the Surrebuttal Testimonies filed by Ms. Marylee Diaz Cortez and Mr. Rodney Moore on behalf of the Residential Utility Consumers Office ("RUCO"), Ms. Miquelle Scheier on behalf of the Arizona Community Action Association ("ACAA"), and Mr. Marshall Magruder. More specifically, I will respond to: (a) criticisms made by Ms. Diaz Cortez and Mr. Magruder concerning UNS Gas, Inc.'s ("UNS Gas" or the "Company") proposed changes to the Rules and Regulations; (b) RUCO Operating Adjustment Nos. 6 and 10 made by Mr. Moore; and (c) comments made by Ms. Scheier with respect to (1) the Company's efforts to enroll eligible customers in the Customer Assistance Residential Energy Support ("CARES") program; (2) the use of alternate locations to accept cash payments from customers; and (3) the increase in funding for community action agencies ("CAAs").

II. RESPONSE TO MS. DIAZ CORTEZ.

Q. At page 19 of her Surrebuttal Testimony, Ms. Diaz Cortez again takes issue with the Company's proposal to modify the billing time periods in its Rules and Regulations. Do you have any response?

A. Yes. Ms. Diaz Cortez criticizes my testimony on two grounds. First, she disagrees with my statement that the proposed billing timeframes are reasonable. What Ms. Diaz Cortez ignores is that the Arizona Corporation Commission ("Commission) Rules, particularly A.A.C. R14-2-310, are consistent with what the Company proposes. This fact is notably absent from Ms. Diaz Cortez's Surrebuttal Testimony.

Ms. Diaz Cortez then argues that the Company's response to her point that the Company is compensated for the billing lag is "irresponsible at best." Just because customers pay for the billing lag does not mean that it is good public policy to allow for extended payment periods. Taken to its logical conclusion, maybe Ms. Diaz Cortez would argue that the Company should allow a customer six months to pay his or her bill. This encourages poor payment practices and creates situations where multiple bills are due at the same time, making it more difficult for customers to stay current with their balances. Regardless, whether or not the Company is compensated through a billing lag does not address to whether or not the billing timeframe is reasonable or consistent with Commission Rules. The Company's modifications to the Rules and Regulations are appropriate. As stated in my Rebuttal Testimony, the Company will make the allowance that Staff requested for a six-month waiver for customers to become familiar and comfortable with this change.

III. RESPONSE TO MR. MOORE.

Q. In his Surrebuttal Testimony at pages 12 to 14 of his Surrebuttal Testimony, Mr. Moore again urges disallowance of what he argues are "inappropriate and/or unnecessary expenses." Do you have any response?

A. Mr. Moore has not addressed my Rebuttal Testimony on these expenses. While Mr. Moore suggests that the Company has only provided a "trust us and our process" response, I provided an extensive discussion on why these expenses were incurred. Again, review of the proposed disallowances reveals that most are directly related to safety, system integrity and operator training; thus, the expenses are clearly both appropriate and necessary. Mr. Moore makes no effort whatsoever to respond to my explanation of how and why these expenses were incurred, but rather makes a simple list of things he feels are unnecessary, even though these expenses were: (1) incurred performing regulatory-mandated functions such as leak surveys, safety audits, and training; (2) spent on communications in support of all our field communication equipment, and for lease of radio towers that are not only used for normal operations and maintenance but for public emergency situations as well; (3) used for materials, small tools, or personnel protective equipment; and (4) related to our Circle of Safety employee awareness program. My Rebuttal Testimony provides additional details on these expenses.

We continue to believe that these expenses are prudent, and RUCO has not demonstrated otherwise. However, given the small value of the items actually identified by RUCO, it makes little sense to spend further resources disputing these points. Therefore, the Company is proposing an adjustment of $ 27,968 to address the issue raised by RUCO.

Q. In his Surrebuttal Testimony at pages 15 to 16, Mr. Moore urges disallowance of union training as a one time, nonrecurring expense claiming as support a phone conversation he had with you. Do you have response?

A. Yes. As Mr. Dallas J. Dukes pointed out in his Rebuttal Testimony, while the M.A.R.C. Union Training was a one-time training event, training itself is certainly recurring. The Company is highly regulated, growing rapidly and continually adding new employees. Training is an on-going and primarily mandated process for the Company. Training costs will very likely continue to increase for the foreseeable future. In fact, since the end of the test year in this case, another regulatory mandated training program has been directed at all local distribution companies to provide training to both employees and the public. Removing any of these costs from the test year would not be appropriate.

IV. RESPONSE TO MS. SCHEIER.

Q. At page 2 of Ms. Scheier's Surrebuttal Testimony, she argues that the Company's efforts to enroll customers in the CARES program are inadequate. Do you have any response?

A. I am disappointed that Ms. Scheier chooses to be critical of the Company's efforts, especially in light of our increased outreach activities and agreement with her suggestion to automatically enroll LIHEAP recipients who are customers of record in the CARES program, assuming that the Company can acquire the necessary information. Staff recognized the improvement that the Company has made in expanding participation in the CARES program. As pointed out in my Rebuttal Testimony, we are committed to this program and strive to add households by distributing CARES applications to local assistance agencies, public libraries, and town and city halls within our service territory. We also insert CARES applications in all residential customers' bills every calendar quarter, (beginning in February of every year). As customers have discussions with the

Customer Call Center and indicate difficulty in making payments on their accounts, we provide them the information about and/or an application for the CARES program. While Ms. Scheier testifies that additional resources need to be allocated to support an effective outreach and enrollment program, she makes no specific recommendations as to how the Company might make its outreach program more effective, other than the automatic LIHEAP enrollment, which we have already agreed to do. Again, my door is always open to Ms. Scheier to work towards meaningful solutions concerning low income customers.

Q. At page 2 of her Surrebuttal Testimony, Ms. Scheier clarifies that ACAA is concerned that UNS Gas is referring customers to predatory lenders as an option for paying their bills. Do you have any response?

A. I appreciate Ms. Scheier's clarification that ACAA does not suggest that the Company is somehow encouraging customers to enter into agreements with pay day loan operations. We are certainly not. However, as discussed in my Rebuttal Testimony, customers could make the decision to enter into these agreements even if UNS Gas retained all of its branch offices and the customer needed cash to pay his or her gas bill, or even if there were "ATM-like Kiosks" as Ms. Scheier suggests. I am concerned about Ms. Scheier's testimony that low-income clients have reported that upon presenting their bill for payment at pay day loan facilities, customers have been encouraged to take out a loan. This is inconsistent with reports I have received from location managers. I encourage Ms. Scheier to provide the Company with specific information when she receives it so that the Company can inquire at the particular locations.

Again, UNS Gas is trying to keep costs down for all of its customers, including those low-income customers for which Ms. Scheier testifies, while maintaining local payment options for those customers who would like to pay their bills in person.

Q. Finally, at pages 2 to 3 of Ms. Scheier's Surrebuttal Testimony, she takes issue with your statement that CAAs need time to ramp up to support additional funding and the Company commits to work with CAAs prior to its next rate case to discuss opportunities. Do you have any response?

A. As shown in the Company's filing, the Company also proposes an increase in LIW funds in this proceeding. Perhaps what would be most helpful is if Ms. Scheier would provide to the Company and the Commission a breakdown of the funds the CAAs are currently using and what efforts they can support. Then the Commission can make an informed decision about just what increase is appropriate for the LIW program. I would certainly not advocate needy families being "put on hold," as Ms. Scheier suggests but the CAAs have the most relevant information to show the Commission concerning what funds they can effectively utilize.

V. RESPONSE TO MR. MAGRUDER.

Q. In his Surrebuttal Testimony at pages 27 to 31, Mr. Magruder makes several comments with regard to the Company's proposed changes to its Rules and Regulations. Would you please respond?

A. First, Mr. Magruder adopts the criticisms of RUCO and ACAA regarding the changes to the billing timeframe. Contrary to Mr. Magruder's suggestion, the proposed billing timeframe is both reasonable and consistent with Commission Rules. Again, under the Company's proposed rule, customers receive bills approximately two days after a billing period ends. A customer has 10 days to pay before a bill is considered late. Under the proposed changes, after that 10 day period, a customer has another 15 days before a late fee is assessed, for a total of 25 days since the bill was received. Only then would a bill be considered delinquent. The Company would not commence suspension of service procedures unless it did not receive payment for a 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 of shut-off is issued. This is entirely consistent with A.A.C. R14-2-310.C.

Mr. Magruder also disagrees with the Company's modification to Section 11.B.1.d. That modification made absolutely no substantive change to current practice, rather it clarified the Rules and Regulations language. The Company has always been permitted to terminate service without notice to comply with curtailment procedures during supply shortages. Such procedures are not only provided for, but are included in the Commission-mandated curtailment plan in the Company's pricing plans. This change simply refers to the pricing plans for the curtailment procedures.

In response to Mr. Magruder's specific recommendations:

(1) The Company believes that the Rules and Regulations, especially in their modified form, are reader-friendly, accurate and helpful to the customer.

(2) The Company has considered the impact of its changes. To that end, it has agreed with the Staff recommendation that a six-month waiver be implemented with regard to billing timeframe changes.

(3) Again, the proposed change to Section 11.B.1.d is not substantive and was made to make the Rules and Regulations easier to read and understand.

(4) With regard to the recommendation that a Spanish-version of the new Rules and Regulations also be approved by the Commission, the Company would be happy to translate the Rules and Regulations. As they will be the same as the English version, assuming the Commission approves the Rules and Regulations in this proceeding, further approval will not be necessary.

(5) With regard to Mr. Magruder's recommendation that all customers receive a copy of the new Rules and Regulations within 30 days of ACC approval or upon becoming a new customer, to do so would be extremely costly and such costs

would ultimately be borne by the ratepayer. The Rules and Regulations are available publicly on both the Company's and the Commission's websites.

Q. Does this conclude your Rejoinder Testimony?

A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
JEFF HATCH-MILLER- CHAIRMAN
WILLIAM A. MUNDELL
MARC SPITZER
MIKE GLEASON
KRISTIN K. MAYES

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-06-____

Direct Testimony of

Tobin L. Voge

on Behalf of

UNS Gas, Inc.

July 13, 2006

EXHIBIT
tabbies
UNSG-18
admitted

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Tobin L. Voge. My business address is One South Church Avenue, Tucson, Arizona, 85701.

Q. What is your position with UNS Gas, Inc. ("UNS Gas" or the "Company")?

A. I am employed by Tucson Electric Power Company ("TEP") as Manager of Pricing and Economic Forecasting. In this role I am responsible for the cost of service studies and rate design proposals. In this capacity, I also perform these functions for UNS Gas.

Q. Please describe your education and experience.

A. I received a Bachelor of Science Degree in Biochemistry from California Polytechnic State University at San Luis Obispo. I also received a Masters Degree in Business Administration from the University of Arizona. I joined TEP in 1986 and worked as a Financial Planning Analyst until 1991. In 1991, I began working as a Power Contracts Coordinator. From 1991 through 1995, I held positions in Power Contracts and Wholesale Power Marketing. In 1995, I was promoted to Supervisor of Wholesale Power Marketing, and then to Manager in 1999. Since 2001, I have been Manager of Pricing and Economic Forecasting.

Q. What is the purpose of your direct testimony?

A. I am the sponsoring witness for Schedules G and H, which summarize the class cost of service study ("CCOSS"), rate design and proof of revenue for this filing. I also sponsor the Weather Normalization and Year-End Customer Annualization pro-forma adjustments shown in Schedule C-2. My testimony will explain: (i) weather normalization; (ii) customer annualization; (iii) the CCOSS; (iv) proposed rate design changes; and (v) the Company's recommendation for de-coupling.

II. WEATHER NORMALIZATION.

Q. What is the purpose of a weather normalization adjustment?

A. A weather normalization adjustment is performed in order to represent test year sales and revenues under typical weather conditions. Gas consumption for several UNS Gas classes of customers is weather sensitive. The weather normalization adjustment quantifies the change in therm sales and revenue that would have occurred if the weather in the test year had been typical.

Q. How is normal weather determined?

A. For natural gas consumption related to space heating, heating requirements are small when average daily temperatures are greater than 65 degrees Fahrenheit. Therefore, the industry uses the variable known as heating degree days ("HDD") to measure heat load. A HDD is 65 degrees minus the average of the maximum and minimum temperature for the day. UNS Gas records daily temperatures at six locations and this temperature data is used to calculate HDD. To determine normal weather for each calendar month, I averaged the sum of the monthly HDDs recorded over the last ten years.

Q. Please describe your weather normalization calculations.

A. I used historical weather and use-per-customer ("UPC") data to calculate the weather adjustment. I calculated an incremental UPC per HDD above base usage. In most of the weather data locations, the base load month (fewest historic HDD) occurs in July or August. To recognize that customers typically do not use heating equipment anywhere in Arizona in the summer, I limited my weather adjustment calculations to the months of

January through May and October through December of the test year. Monthly heating factors for these months were calculated by dividing the heating load by the recorded HDD. This calculation resulted in a heating factor, or heat load per HDD, for each month in the ten year historical period. The ten-year average monthly heating factor was multiplied by the respective non-summer month's deviation from normal HDD to develop the composite weather adjustment. Although some months were colder than normal, the overall weather for the year was slightly warmer than normal. Therefore sales were slightly lower than normal.

Q. Did you weather normalize all rate classes?

A. No, I weather normalized those rate classes where sales are impacted by heating requirements. I found two classes where there was no strong correlation between monthly consumption and HDDs. These were the industrial and gas light classes.

Q. What was the affect of weather adjustments on test year sales volumes?

A. Because sales were slightly lower than normal, it is necessary to adjust them upward to reflect a "normalized" level of sales. The net result of weather normalization adjustments was an increase in test year sales volumes of 1,832,760 therms or 1.4% of the total actual sales volume for the test year.

III. CUSTOMER ANNUALIZATION.

Q. Please describe the customer annualization adjustment.

A. The customer annualization adjustment restates the number of test year bills and volumes to be consistent with the number of customers on the system at the end of the test year. The customer annualization adjustment also captures the seasonal variation in the number of customers (the comings and goings of seasonal residents). The adjustment distinguishes the effects of the longer-term growth trend in number of customers and seasonal variation. As such, the early months of the test year typically reflect more adjustment in number of customers. The first month of the test year must be adjusted for 11 months of growth to reach adjusted test-year end levels, whereas the eleventh month of the test year only requires one month of adjustment. Adjustments to the monthly volumes were made by multiplying the monthly customer differences by the UPC for the month.

Q. What was the effect of the customer annualization adjustment on test year sales volumes?

A. The net result of the customer annualization adjustment was an increase in test year sales volumes of 1,780,320 therms or 1.4% of the total actual sales volume for the test year.

IV. CLASS COST OF SERVICE STUDY.

Q. Please describe a CCOSS.

A. The purpose of a CCOSS is to allocate each cost component to the respective classes in order to determine an appropriate total cost to serve each class. Allocation should be based upon an equitable method not inconsistent with the cost-causal relationships for the provision of services. The Company's approach follows past approaches that have been approved by the Arizona Corporation Commission ("Commission"). The approach promotes "gradualism"; that is, it helps avoid large percentage differences in class revenue increases, while moving each class towards parity. The term "cost" is used broadly here to cover both expenses, including taxes, and the return on investment. The total cost to serve a class varies depending on its customers' individual and combined consumption characteristics, installed facilities, labor and other capital needed to reliably and safely serve customers in the class.

Q. What is the objective of the CCOSS?

A. Based on allocated costs, the goal is to confirm the extent to which present and proposed rates generate revenue that recovers costs and provides for a reasonable return on investment by class. The CCOSS is designed to clearly present the costs and the allocation factors applied to the costs. The cost model also includes sections summarizing costs, a list of the allocation factors, and a revenue requirements summary. The G Schedules of the filing are assembled using the results of the CCOSS.

Q. Please describe the CCOSS model.

A. The model, created in Microsoft Excel, starts with cost components by function or purpose (functionalized cost). The model presents functionalized costs vertically (i.e., in rows down the spreadsheet) and the allocation of costs to rate classes horizontally (i.e., in columns across the spreadsheet). Exactly 100% - no more, no less – of each functionalized cost is allocated to the customer classes. The percentage of a given cost allocated to a specific class will depend on the allocation factor chosen. The choice of the allocation factor depends on the function of the cost in question. A cost associated with billing customers, for example, should be allocated so as to reasonably approximate the cost of billing the customers, by class. Some allocation factors used are "external" allocation factors. External allocation factors are determined independent of the magnitude of specific costs in the CCOSS. That is, the external allocation factor is developed in an analysis separate from the CCOSS. An example of an external allocation factor is the distribution plant allocation factor ("DISTR"). DISTR is the capacity allocation factor used for the allocation of distribution plant capacity-related costs, such as distribution land and land rights, measuring and regulating station equipment and mains. DISTR is based on the Proportional Responsibility Method. The Proportional Responsibility Method is described in more detail below.

An internal allocation factor is calculated within the CCOSS model and is dependent on the cost components found therein. For example, the Materials and Supplies component of Working Capital (a rate base item) is allocated based on PLANT. PLANT is a composite of different plant categories (e.g., transmission, distribution). To the extent that plant categories allocated differently, the PLANT allocator will vary based on the level of different plant types of net plant. Allocation factors are listed in Schedule G-7. As shown, some factors are "customer-related". Studies on metering, services, meter reading, customer service and billing provide the basis for the customer-related factors. Additionally, there are factors based on labor costs, throughput, or internal factors based on individual or aggregate costs. The overall methodology has been approved in previous filings before this Commission. One example of the use of this methodology is Docket No. G-01032A-02-0598.

Q. Please describe the Proportional Responsibility Method?

A. The Proportional Responsibility Method is based on the respective class' share of total load in each of the twelve months for the test year. The peak load months are more heavily weighted under Proportional Responsibility. A class' share of total load in low load months has only a small impact on the factor. DISTR is the allocation factor used for distribution plant capacity-related costs. DISTR is an external factor because the Proportional Responsibility Method is based on class loads, and is calculated independently of the magnitude of any cost components. The Proportional Responsibility Method drives many significant costs in the CCOSS model.

Q. Has the Proportional Responsibility Method been used in a previous general rate case filing?

A. Yes. This method was used and approved in Docket No. G-01032A-02-0598, Decision No. 66028, when the Commission approved the Citizens Communications Company ("Citizens") Settlement Agreement.

V. <u>RATE DESIGN.</u>

Q. What is the Company's objective in rate design?

A. The primary objective of our rate design proposal is to allow for more equitable collection of the Company's fixed costs. In so doing, we can minimize the cross subsidization that occurs when usage within customer classes varies significantly based on geography and climate. In sum, the Company's proposed rates would more accurately allocate costs to the customers who create the costs.

Q. Please explain the inequities your proposal seeks to address.

A. UNS Gas currently collects the bulk of its fixed costs through a volumetric charge, the Basic Cost of Service. Within the residential class, however, throughput has little impact on the true, non-commodity cost of serving customers (i.e. the costs other than actual natural gas). It costs no more to provide distribution service to high-usage customers than it does to serve low-usage customers. Under UNS Gas' current rates, however, high-usage customers are paying a far greater share of the Company's fixed costs through volumetric charges on their monthly bills.

Q. How has the nature of UNS Gas' service territory exacerbated this inequity?

A. Since natural gas usage is driven largely by weather, the Company's current rates have forced customers in cooler areas (i.e., districts with more HDDs) to subsidize those living in warmer districts. This disparity is exacerbated by the stark geographic differences in UNS Gas' service territory, which includes areas that are either among the coldest (e.g. Flagstaff) or the hottest (e.g. Lake Havasu City) parts of Arizona. So customers in the coldest corners of our service territory – those affected most by rising costs on the commodity portion of their bills during home heating season – have borne the additional burden of subsidizing the fixed cost of serving customers who spend their winters in far more moderate climates.

Q. Have you performed an analysis to illustrate the subsidy of warmer districts by cooler districts?

A. Yes. It is attached as Exhibit TLV-1. The table shows average annual residential consumption and margin revenue for ten locations in the UNS Gas service territory. By "margin", I mean the sum of: (i) customer charge; and (ii) the portion of the volumetric charge not related to the commodity cost of gas. It includes the costs of mains, customer service, and other non-gas costs of serving our customers. The data illustrates the disparity between locations in contribution. For example, the average residential customer in Flagstaff pays an annual margin of $292, $133 more than the $159 paid by the average residential customer in Lake Havasu. The investment in distribution plant that the Company has made to serve the two customers is similar, yet the Flagstaff customer is contributing a larger share of the cost. Indeed, the Flagstaff customer pays about 84% more for the same distribution service.

Q. How might the inequities inherent in UNS Gas' current rates be addressed?

A. Since the true cost of serving individual customers does not vary significantly based on usage, the Company could seek to recover its fixed costs entirely through a monthly Customer Charge. In addition to distributing fixed costs more equitably among customers, this approach would reduce monthly bill fluctuations, send clear price signals on the gas commodity and help customers better understand the charges on their bills. Although gas utilities have traditionally recovered a portion of fixed costs on a volumetric basis, their customers have become increasingly accustomed to paying infrastructure costs on a fixed monthly basis in the bills they receive for cable television, internet access and local telephone service.

For UNS Gas, however, this approach would require a monthly Customer Charge of nearly $26.00, based on the costs documented in this case. Although this fee would be accompanied by a reduction in volumetric charges, it would produce a significant increase to bills in warm weather areas, where customers are unaccustomed to paying their true share of UNS Gas' system costs. It also would somewhat limit customers' ability to influence their bills by moderating usage, since a larger percentage of their monthly costs would be unaffected by the volume of gas they use. For these reasons, UNS Gas has proposed a more moderate increase in its customer charge that would partially mitigate the inequities inherent in current rates.

Q. How would UNS Gas' proposal serve to reduce the inequities you have discussed?

A. 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 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, as described above.

Q. Your proposed average monthly residential customer charge of $17, while lower than the true cost of service, would still produce a significant percentage increase to customer bills in warmer areas. Does your rate design include a way to mitigate the impact to customers?

A. Yes. I recognize that customers in the warmer climates have grown accustomed to having their usage more steeply subsidized by customers in cold weather 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 shift 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 bills pose the largest burden.

Q. What safeguards will you provide for lower income customers who might struggle with higher customer charges?

A. UNS Gas is proposing that monthly customer charges under the Customer Assistance Residential Energy Support ("CARES") R-12 pricing plan be discounted from the Residential Gas Service R-10 pricing plan. Currently, CARES customers pay the standard $7 monthly charge while receiving a discount of $0.15 per therm for the first 100 therms they use during the months November through April. In order to provide year-round assistance for CARES customers, we propose to discount $6.50 from the monthly customer charge applicable under the Residential Gas Service pricing plan. The existing $0.15 per therm winter discount would be eliminated. Given the average monthly CARES customer usage was about 64 therms in the winter period of the test year, the average customer received an annual discount of $58. The proposed annual CARES discount would be $78 for every customer, regardless of usage. This represents a 34 percent increase in annual dollars saved for the average CARES customer.

VI. DE-COUPLING.

Q. What else might be done to make UNS Gas rates fairer to the Company and customers?

A. Although the proposed rate structure described above would mitigate inequities inherent in UNS Gas' current rates, 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 to establish that volumetric rate, customers 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 by providing a greater opportunity for fair and appropriate recovery of the costs allocated in this proceeding.

Q. How has UNS Gas proposed eliminating that uncertainty?

A. UNS Gas has proposed a mechanism that would either reduce or increase the collection of volumetric margin revenues to match anticipated usage levels. This so-called "de-coupling" mechanism, the Throughput Adjustment Mechanism ("TAM"), would weaken the link between UNS Gas revenues and customer usage, achieving greater equity in the Company's cost recovery. Although the increased customer charge discussed above would align rates more closely with actual costs, the proposed TAM is needed to ensure that the remaining volumetric charge allows for equitable cost recovery. UPC can vary significantly due to uncontrollable forces – particularly the weather. A very cold winter could result in a significant UPC increase and related over-recovery by UNS Gas. The mechanism also would allow UNS Gas to actively promote conservation without threatening the volumetric margin revenues needed to serve its customers' growing needs and earn a fair rate of return.

Q. How would this proposed TAM work?

A. Under UNS Gas' proposed TAM, the under-recovery 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. Because the size of those surcharges and credits would be based on anticipated sales, the actual funds collected or refunded might differ slightly from the targeted amount to the extent that actual sales differ from anticipated sales. A final true-up would be made two years from the period in question by incorporating the difference into the next year's credit or surcharge.

Both credits and surcharges would be designed to true-up revenue to a level associated with a constant UPC. Therefore, on a "go-forward" basis, margin revenue would increase (or decrease) as the number of customers increase (or decrease), but would remain unaffected by changes in UPC. This result would be appropriate because it matches cost causation on the system.

The TAM would be independent of UNS Gas' Purchase Gas Adjustor ("PGA"). Therefore, it would be possible for customers to have a PGA surcharge and a TAM credit occur in the same month.

Q. How would the TAM surcharge or credit be calculated?

A. In order to administer the TAM, a base UPC must be established. Our proposal includes a separate base UPC for Residential, Small Volume Commercial, and Small Volume Public Authority customers. The base UPCs will be determined by dividing the 2005 weather adjusted therm sales by the 2005 average number of customers. In subsequent years, actual UPCs will be calculated by dividing calendar year therm sales by average number of customers. The difference between the actual and base UPC will be multiplied by the 2005 base number of customers and the margin rate for the customer class to arrive at the required throughput adjustment stated in dollars. This amount will be divided by projected 12-month therm sales to determine the required throughput adjustment stated in cents per therm.

As an alternative to an annual true-up of the margin rate, establishing a deferred throughput adjustment account is acceptable to UNS Gas. The adjustment calculations would occur as described above, but the dollar amount of the adjustment would be recorded in a regulatory asset/liability account. In the context of the next rate case or in a surcharge or surcredit application, the balance of the account would be reviewed and included in rate base, within an appropriate amortization period to be determined as well.

Q. Have you prepared examples of these calculations?

A. Yes, sample calculations are attached as Exhibit TLV-2.

Q. Have you prepared a proposed TAM Rider?

A. Yes, the proposed Rider RR-2 is attached as Exhibit TLV-3. I have also included revisions to Pricing Plans R-10, R-12, C-20 and PA 40 with references to the Rider.

Q. Why have you chosen to limit the application of the TAM to the Residential, Small Volume Commercial and Small Volume Public Authority customers?

A. These classes of customers are the most weather-sensitive and therefore, are most likely to experience changes in usage due to year-to-year weather variations in HDDs. Furthermore, these customers are the primary participants of energy conservation programs.

Q. Why do you believe this proposed TAM is beneficial to UNS Gas and UNS Gas customers?

A. I believe the TAM would benefit UNS Gas and its customers for the following reasons: (1) the TAM will minimize – over time – the impact of weather on customer bills and the Company's financial condition; and (2) the TAM will allow the Company to implement, fund, and actively promote energy efficiency programs for its customers.

Q. How does this proposal differ from the TAM proposed by Southwest Gas Corporation ("SWG") in its recent rate case?

A. The UNS Gas proposal differs from the SWG proposal in at least three areas:

(i) UNS Gas would include all small volume customers, whereas SWG proposed to limit the adjustment to residential customers;

(ii) UNS Gas provides examples of the calculations required to implement the adjustment, using historical UPC data. This may help the parties to this case gain an appreciation for the potential amount of future adjustments and impact to customers; and

(iii) UNS Gas is willing to consider the creation of a deferred throughput adjustment account.

Q. How will the TAM minimize the impact of weather on customers?

A. The TAM will reduce the volatility in the non-commodity portion of customers' bills over time. As I previously described, in the period following a colder than normal period, customers will receive a credit to the volumetric margin rate. This credit reimburses the customer for the non-commodity portion of the relatively high cold winter gas bill.

Q. How will the TAM minimize the impact of weather on the Company's financial condition?

A. As is the case in this filing, test year costs and revenues are weather normalized. Since the margin the Company collects is based on normal weather, any temperature-sensitive customer usage (primarily space heating) that varies with deviations from normal weather will also cause revenue collection to vary. Therefore, during a period of warmer than normal weather, customer usage will decline and the Company will not collect margin revenues required to recover a portion of its fixed costs. If a TAM is in place, a surcharge will be assessed to customers in order to enable the Company a better opportunity to recover its costs, including capital costs.

Q. Please describe the relationship between the TAM and the Company's motivation to implement and promote energy conservation programs?

A. Energy conservation will have the effect of lowering UPC from the level experienced during the test year. Consequently, if the Company recovers a portion of its fixed costs through a volumetric margin rate, its ability to earn its authorized rate of return is jeopardized upon implementation of post-test year energy conservation programs. This disincentive to introduce energy conservation can be negated by the application of the TAM. Breaking the link between sales volume and revenue collection allows the Company to promote energy efficiency without threatening its financial viability. In this way, the TAM aligns the Company's interests with those of its customers, who clearly benefit from avoiding commodity expenses and other volumetric costs through conservation.

VII. OTHER TARIFF CHANGES.

Q. Are you proposing any other tariff changes?

A. Yes. UNS Gas proposes tariff changes as follows:

(i) Eliminate the Base Cost of Gas in all gas service tariffs. With this modification, all gas commodity and transportation costs will be recovered through the PGA Rate. UNS Gas witness Mr. David G. Hutchens discusses this proposed change in his direct testimony.

(ii) Modify Pricing Plans I-30 Small Volume Industrial and I-32, Large Volume Industrial Service to conform to the North American Industry Classification System ("NAICS") Sector designations. Also, the NAICS Sector for agriculture has been added to the tariff.

(iii) Revise the first sentence of the Applicability section of Pricing Plans Public Authority ("PA")-40 Small Volume Public Authority Service and PA-42 Large Volume Public Authority Service to read " To all facilities *owned or* operated by governmental agencies...".

The four modified Pricing Plans are shown in a red-line format, attached as Exhibit TLV-4.

Q. Why is UNS Gas proposing to change Pricing Plans I-30 and I-32?

A. UNS Gas proposes the replacement of Standard Industrial Classification ("SIC") codes with NAICS designations because SIC codes are no longer used. UNS Gas proposes to add an agriculture designation to the Pricing Plans because the load characteristics of industrial agriculture customers are similar to those of mining and manufacturing.

Q. Why is UNS Gas proposing the change to PA 40 and PA 42?

A. These tariffs are intended to apply to service for governmental agencies. An agency receives the service whether it both owns and operates the facility, or whether it just owns the facility and contracts with another party for the operation of its facility. Adding the words "owned or" enables the governmental agency in the latter case to qualify for one of these Pricing Plans.

Q. Are you proposing an increase in reconnect fees for customers who leave the system and then return?

A. Yes. We have revised the definition of Service Re-Establishment Charge in the UNS Gas Rules and Regulations to include a clause for customers who disconnect and subsequently reconnect at the same premise within a 12-month period. Such customers will be charged the sum of the monthly customer charges that they would have incurred had they remained connected to the system.

Q. Why are you proposing this modification?

A. This modification is intended to discourage customers from disconnecting during the summer months in order to avoid customer charges. Typically, such customers would not use gas during the summer months, so disconnection does not significantly affect their usage. As discussed above, the customer charge is designed to collect fixed costs. It would be unfair to the Company and other customers if some customers were permitted to avoid their fixed cost responsibility by disconnecting service for a portion of the year.

Q. What rate design changes are you proposing for customers not on the general residential rate, including non-residential customers?

A. Schedule H-3 shows a comparison of present and proposed rate components for all UNS Gas Pricing Plans. The rate components in each pricing plan were designed so that the overall revenue increase by class is equal.

VIII. DEMAND SIDE MANAGEMENT COST RECOVERY.

Q. How will UNS Gas recover the costs of the Demand Side Management ("DSM") programs?

A. The Company proposes to implement an annually adjusted charge to provide cost recovery for the approved DSM program portfolio. The DSM charge will be applied to customers' bills as a per therm charge. The charge will be initially set based on total Company adjusted test year therms and expected annual DSM funding (as described in the testimony of Mr. Gary A. Smith). In subsequent years, the required charge will be adjusted based on historic and projected DSM funding and customer collections. Annually, before April 1, the Company will file a request to the Commission with supporting documentation to revise its DSM charge.

Q. What is the projected charge amount if all of the proposed programs are approved?

A. Using adjusted test year therms of 138,233,864 and proposed DSM funding of $1,051,616, the initial DSM surcharge will be $0. 007608 per therm.

Q. What specific DSM programs is UNS Gas proposing?

A. UNS Gas witness Mr. Smith discusses the specific programs and funding levels in his direct testimony.

Q. Does this conclude your testimony?

A. Yes, it does.

EXHIBIT

TVL-1

Residential Use and Margin by Location

Location	Annual Customers Billed	Average Monthly Customers Billed	Billed Usage (Therms) (1)	Average Annual Usage (Therms)	Average Annual Margin Present (2)	Difference from Average	Average Annual Margin Proposed (3)
Flagstaff	333,263	27,381	18,929,161	691	$292	$39	$333
Sedona	73,797	6,063	4,105,548	677	$287	$34	$330
Winslow	32,269	2,651	1,702,099	642	$277	$24	$324
Holbrook	23,224	1,908	1,182,361	620	$270	$17	$319
Prescott	467,420	38,403	22,267,922	580	$258	$5	$312
Show Low	125,393	10,302	5,964,771	579	$258	$5	$312
Kingman	183,190	15,051	7,139,617	474	$226	($26)	$292
Cottonwood	116,995	9,612	4,191,466	436	$215	($38)	$285
Santa Cruz	79,990	6,572	2,772,898	422	$211	($42)	$283
Lake Havasu	74,743	6,141	1,526,258	249	$159	($94)	$250
Total	1,510,284	124,085	69,782,101	562	$253		$309

(1) Does not include unbilled usage.
(2) The residential customer charge is $7.00 per month and margin rate is $0.3004 per therm.
(3) The residential customer charge is $17.00 per month and margin rate is $0.1862 per therm.

EXHIBIT

TVL-2

Example of Throughput Adjustment Calculation

Line	Residential (R-10 and R-12)	
1	Test Year Throughput (Therms)	70,234,286
2	Test Year Average Number of Customers	124,085
3	Test Year Use Per Customer (Line1/Line 2)	566.02
4	Hypothetical 2006 UPC (1)	560.92
5	Difference in UPC (Line 4 - Line 3)	(5.09)
6	Margin Rate (per Therm)	$0.1862
7	Throughput Adjustment (Line 2 x Line 5 x Line 6)	($117,699)
8	Projected 12 month Throughput (Therms) (2)	75,965,404
9	Throughput Adjustment per Therm (Line 7/Line 8)	($0.0015)

	Small Volume Commercial (C-20)	
1	Test Year Throughput (Therms)	28,801,436
2	Test Year Average Number of Customers	10,849
3	Test Year Use Per Customer (Line1/Line 2)	2654.75
4	Hypothetical 2006 UPC (3)	2617.59
5	Difference in UPC (Line 4 - Line 3)	(37.17)
6	Margin Rate (per Therm)	$0.2637
7	Throughput Adjustment (Line 2 x Line 5 x Line 6)	($106,329)
8	Projected 12 month Throughput (Therms) (4)	30,259,509
9	Throughput Adjustment per Therm (Line 7/Line 8)	($0.0035)

	Small Volume Public Authority (PA-40)	
1	Test Year Throughput (Therms)	5,743,485
2	Test Year Average Number of Customers	1,042
3	Test Year Use Per Customer (Line1/Line 2)	5511.98
4	Hypothetical 2006 UPC (5)	5407.25
5	Difference in UPC (Line 4 - Line 3)	(104.73)
6	Margin Rate (per Therm)	$0.2712
7	Throughput Adjustment (Line 2 x Line 5 x Line 6)	($29,595)
8	Projected 12 month Throughput (Therms) (6)	5,858,929
9	Throughput Adjustment per Therm (Line 7/Line 8)	($0.0051)

Notes
(1) Decline of 0.9%, based on the average year over year change in residential UPC years 1996 to 2005.
(2) Based on a 4.0% annual growth rate.
(3) Decline of 1.4%, based on the average year over year change in total commercial UPC years 1996 to 2005.
(4) Based on a 2.5% annual growth rate.
(5) Decline of 1.9%, based on the average year over year change in total public authority UPC years '96 to'05.
(6) Based on a 1.0% annual growth rate.

EXHIBIT

TVL-3

UniSourceEnergy SERVICES

UNS Gas, Inc.
Rider RR-2
Throughput Adjustment Mechanism (TAM)

APPLICABILITY

The Throughput Adjustment Mechanism ("TAM") applies to Company pricing plans R-10 Resiential Gas Service, R-12 Customer Assistance Resiential Energy Support, C-20 Small Volume Commercial Service and PA 40 Small Volume Public Authority Service.

RATE ADJUSTMENT

Each applicable Pricing Plan will be subject to an annual adjustment to the Basic Cost of Service Rate in the form of a credit or surcharge. Such adjustment shall be based on the difference between Use-Per-Customer(UPC) in the Calendar Year and the UPC for the respective Pricing Plans in the Base Year. The Base Year components for number of customers and throughput are those established in Docket No. G-04204A-06-XXX, Decision No. XXXXX. The adjustment to the Basic Cost of Service Rate will be calculated by dividing the end of Calendar Year Throughput Adjustment Bank Balance by the projected twelve month throughput.

THROUGHPUT ADJUSTMENT BANK BALANCE

The Company shall maintain accounting records that accumulate the dollar amounts to be recovered or refunded customers taking service under Pricing Plans R-10, R-12, C-20 and PA-40. The amounts that apply to Pricing Plans R-10 and R-12 will be combined, while the amounts that apply to C-20 and PA-40 will be recorded individually. Each calendar quarter, entries will be made to the three TAM bank balances. Each entry will be calculated by multiplying the difference between the Base Year UPC for the quarter and the UPC in the current quarter by the Base Year average number of customers. This total quarterly throughput volume will be multiplied by the Basic Cost of Service Rate for the respective Pricing Plan to determine the debit or credit entry for the TAM bank balance.

ANNUAL FILINGS

No later than forty-five days after the end of each Calendar Year, the Company shall make a filing with the Commission that shall include each of the four quarterly TAM bank balance entries and supporting documentation. The filing shall also include the Company's calculated adjustment to the respective Basic Cost of Service Rates in the applicable Pricing Plans, including supporting documentation.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan R-10
Residential Gas Service

AVAILABILITY

In all territories served by Company at all points where facilities for gas service are available to the premise served.

APPLICABILITY

Subject to availability, at point of delivery, to residential gas service in individual residences and individually metered apartments when all service is metered through one meter.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

Minimum Customer Charge per month @	$7.00
Basic Cost of Service Rate per therm @	$0.7004

(Base cost of gas of $0.4000 per therm is included in the basic cost of service rate)

Purchased Gas Adjustment: *The basic cost of service rate set forth above shall be increased or decreased by the amount of the purchased gas adjustment for the billing month computed in accordance with the provisions of Rider RR-1. The purchased gas adjustment enables the Company to increase or decrease the basic cost of service rate in order to pass on increases or decreases in the base cost of gas to customers.*

Throughput Adjustment Mechanism: The basic cost of service rate set forth above shall be increased or decreased by the amount of the throughput adjustment surcharge or credit for the billing month computed in accordance with the provisions of Rider RR-2.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan R-12
Customer Assistance Residential Energy Support (C.A.R.E.S.)

AVAILABILITY

In all territories served by Company at all points where facilities for gas service are available to the premise served.

APPLICABILITY

To gas service qualifying for billing under Residential Pricing Plan R-10 where the customer also has qualified for Pricing Plan R-12 as specified in the Company's plan for administration. All provisions of Pricing Plan R-10 will apply except as modified herein.

RATE

The monthly bill shall be in accordance with Pricing Plan R-10 except:

Basic Cost of Service Rate: ~~first 100 therms or less per month will be discounted by $0.1500 per therm for the billing months of November through April.~~ The Customer Charge will be disounted by $6.50 each month.

SPECIAL CONDITIONS

1. Eligibility requirements for C.A.R.E.S. are set forth on the Company's Application and Declaration of Eligibility for Low Income Ratepayer Assistance form. Customers who desire to qualify for this pricing plan must initially make application to the Company for qualification and must provide verification to the Company that the customer's household gross income does not exceed one hundred fifty percent (150%) of the federal poverty level. Qualified customers must have an approved application form on file with the Company. Subsequent to the initial certification, the residential customer seeking to retain eligibility for the C.A.R.E.S. must provide a personal certification that the household gross income of the residential dwelling unit involved does not exceed one hundred fifty percent (150%) of the federal poverty level.

2. Samples of the existing CARES participants will be re-certified every two years prior to October 1 and when a customer changes residence.

3. Eligible customers shall be billed under this pricing plan during the winter season, commencing with the next regularly scheduled billing period after the Company has received the customer's properly completed application form or re-certification.

4. Eligibility information provided by the customer on the application form may be subject to verification by the Company. Refusal or failure of a customer to provide documentation of eligibility acceptable to the Company, upon request of the Company, shall result in removal from or ineligibility for this pricing plan

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan R-12
Customer Assistance Residential Energy Support (C.A.R.E.S.)

PRICING PLAN R-12 (continued)

5. Customers who wrongfully declare eligibility or fail to notify the Company when they no longer meet the eligibility requirements may be rebilled for the period of ineligibility under their otherwise applicable residential pricing plan.

6. It is the responsibility of the customer to notify the Company within thirty (30) days of any changes in the customer's eligibility status.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan C-20
Small Volume Commercial Service

AVAILABILITY

In all territories served by Company at all points where facilities for gas service are available to the premise served.

APPLICABILITY

To all commercial customers whose primary business activity at the location served is not provided for under any other pricing plan, whose usage does not exceed 120,000 therms per year when all service is supplied at one point of delivery, and whose gas is metered through one meter.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

Minimum Customer Charge per month @	$11.00
Basic Cost of Service Rate per therm @	$0.6420

(Base cost of gas of $0.4000 per therm is included in the basic cost of service rate)

Purchased Gas Adjustment: The basic cost of service rate set forth above shall be increased or decreased by the amount of the purchased gas adjustment for the billing month computed in accordance with the provisions of Rider RR-1. The purchased gas adjustment enables the Company to increase or decrease the basic cost of service rate in order to pass on increases or decreases in the base cost of gas to customers.

Throughput Adjustment Mechanism: The basic cost of service rate set forth above shall be increased or decreased by the amount of the throughput adjustment surcharge or credit for the billing month computed in accordance with the provisions of Rider RR-2.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan PA-40
Small Volume Public Authority Service

AVAILABILITY

In all territories served by Company at all points where facilities for gas service are available to the premise served.

APPLICABILITY

To all facilities owned or operated by governmental agencies whose primary business activity at the location served is not provided for under any other pricing plan or special contract, whose usage does not exceed 120,000 therms per year when all service is supplied at one point of delivery and gas is metered through one meter.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

Minimum Customer Charge per month @	$11.00
Basic Cost of Service Rate per therm @	$0.6354

(Base cost of gas of $0.4000 per therm is included in the basic cost of service rate)

Purchased Gas Adjustment: The basic cost of service rate set forth above shall be increased or decreased by the amount of the purchased gas adjustment for the billing month computed in accordance with the provisions of Rider RR-1. The purchased gas adjustment enables the Company to increase or decrease the basic cost of service rate in order to pass on increases or decreases in the base cost of gas to customers.

Throughput Adjustment Mechanism: The basic cost of service rate set forth above shall be increased or decreased by the amount of the throughput adjustment surcharge or credit for the billing month computed in accordance with the provisions of Rider RR-2.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

EXHIBIT

TLV-4

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan I-30
Small Volume Industrial Service

AVAILABILITY

In all territories served by Company at all points where facilities for gas service are available to the premise served.

APPLICABILITY

To all customers whose gas usage does not exceed 120,000 therms per year, who are served through a single meter, and whose primary business activity at the location served is included in one of the following classifications of the North American Classification System, United States:

Sector 11. Agriculture, Forestry, Fishing and Hunting: Subsector 111. Crop Production only;
Sector 21. Mining: All Subsectors
Sector 22. Utilities: Power Generation Subsectors only: and
Sectors 31-33. Manufacturing: All Subsectors

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Deleted: Division B – Mining: All Major Groups

Deleted: Division D – Manufacturing: All Groups; and

Deleted: Division E – Utility: Power Generation only

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

Minimum Customer Charge per month @ $11.00

Basic Cost of Service Rate per therm @ $0.6122
(Base cost of gas of $0.4000 per therm is included in the basic cost of service rate)

Purchased Gas Adjustment: The basic cost of service rate set forth above shall be increased or decreased by the amount of the purchased gas adjustment for the billing month computed in accordance with the provisions of Rider RR-1. The purchased gas adjustment enables the Company to increase or decrease the basic cost of service rate in order to pass on increases or decreases in the base cost of gas to customers.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

Filed By:	Dennis R. Nelson	Tariff No.:	I-30
Title:	Senior Vice President and Chief Operating Officer	Effective:	August 11, 2003
District:	Entire Gas Service Area	Page No.:	1 of 1

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan I-32
Large Volume Industrial Service

AVAILABILITY

In all territories served by Company at all points where facilities for gas service are available to the premise served.

APPLICABILITY

To all customers whose gas usage over the preceding twelve (12) months exceeded 120,000 therms, and whose primary business activity at the location served is included in one of the following classifications of the Northern American Industry Classification System, United States:

Sector 11. Agriculture, Forestry, Fishing and Hunting: Subsector 111. Crop Production only;
Sector 21. Mining: All Subsectors;
Sector 22. Utilities: Power Generation Subsectors only; and
Sectors 31 – 33. Manufacturing: All Subsectors.

Service is supplied at one point of delivery and gas is metered through one meter unless the Company, at its sole discretion, chooses to provide service through multiple meters.

For new customers, their expected usage must exceed 120,000 therms per year.

Any customer transferring from this pricing plan may not return for a period of twelve (12) billing months.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

Minimum Customer Charge per month @ $85.00

Basic Cost of Service Rate per therm @ $0.4864
(Base cost of gas of $0.4000 per therm is included in the basic cost of service rate)

Purchased Gas Adjustment: The basic cost of service rate set forth above shall be increased or decreased by the amount of the purchased gas adjustment for the billing month computed in accordance with the provisions of Rider RR-1. The purchased gas adjustment enables the Company to increase or decrease the basic cost of service rate in order to pass on increases or decreases in the base cost of gas to customers.

PRICING PLAN I-32 (continued)

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan PA-40
Small Volume Public Authority Service

AVAILABILITY

In all territories served by Company at all points where facilities for gas service are available to the premise served.

APPLICABILITY

To all facilities owned or operated by governmental agencies whose primary business activity at the location served is not provided for under any other pricing plan or special contract, whose usage does not exceed 120,000 therms per year when all service is supplied at one point of delivery and gas is metered through one meter.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

Minimum Customer Charge per month @ $11.00

Basic Cost of Service Rate per therm @ $0.6354
(Base cost of gas of $0.4000 per therm is included in the basic cost of service rate)

Purchased Gas Adjustment: The basic cost of service rate set forth above shall be increased or decreased by the amount of the purchased gas adjustment for the billing month computed in accordance with the provisions of Rider RR-1. The purchased gas adjustment enables the Company to increase or decrease the basic cost of service rate in order to pass on increases or decreases in the base cost of gas to customers.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSourceEnergy SERVICES

UNS Gas, Inc.
Pricing Plan PA-42
Large Volume Public Authority Service

AVAILABILITY

In all territories served by Company at all points where facilities for gas service are available to the premise served.

APPLICABILITY

To all facilities owned or operated by governmental agencies whose primary business activity at the location served is not provided for under any other pricing plan or special contract. Under this pricing plan, usage over the preceding twelve (12) months must exceed 120,000 therms when all service is supplied at one point of delivery and gas is metered through one meter unless the Company, at its sole discretion, chooses to provide service through multiple meters.

For new customers, their expected usage must exceed 120,000 therms per year.

Any customer transferring from this pricing plan may not return for a period of twelve (12) billing months.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

Minimum Customer Charge per month @	$85.00
Basic Cost of Service Rate per therm @	$0.5084

(Base cost of gas of $0.4000 per therm is included in the basic cost of service rate)

Purchased Gas Adjustment: The basic cost of service rate set forth above shall be increased or decreased by the amount of the purchased gas adjustment for the billing month computed in accordance with the provisions of Rider RR-1. The purchased gas adjustment enables the Company to increase or decrease the basic cost of service rate in order to pass on increases or decreases in the base cost of gas to customers.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file from time to time with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

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 THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-06-463
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

Rebuttal Testimony of

D. Bentley Erdwurm

on Behalf of

UNS Gas, Inc.

March 16, 2007

EXHIBIT
UNSG-19
admitted

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is D. Bentley Erdwurm. My business address is One South Church Avenue, Tucson, Arizona, 85701.

Q. What is your position with UniSource Energy Corporation?

A. I am employed by Tucson Electric Power Company ("TEP") as a Lead Analyst in the Pricing and Economic Forecasting department. In this role I prepare cost of service studies and rate design proposals. I also perform these functions for UNS Electric, Inc. ("UNS Electric").

Q. Please describe your education and experience.

A. I earned my Master of Science in Economics from Texas A&M University, and my Bachelor of Arts from the University of Dallas. I have 25 years of utility experience in the areas of cost allocation and rate design, forecasting, valuation and fair market value determination, and utility mergers and acquisitions. I have testified before state regulators in Arizona, Texas and Alabama on these issues. I testified on behalf of TEP in general rates cases during the 1990s on issues related to cost allocation, rate design and unbundling.

Q. What is your role in this case?

A. I am adopting the Direct Testimony filed by Tobin L. Voge, and I am filing this Rebuttal Testimony. I functioned as a lead analyst in developing both testimonies and their associated analyses.

Q. What is the purpose of your Rebuttal Testimony?

A The purpose of my Rebuttal Testimony is to respond to the direct testimonies of Steven W. Ruback, Ralph C. Smith, and Julie McNeely-Kirwan on behalf of the Arizona Corporation Commission, Utilities Division Staff ("Staff"), Marylee Diaz Cortez on behalf of the Residential Utility Consumer Office ("RUCO"), and Miquelle Scheier on behalf of the Arizona Community Action Association ("ACAA").

Q. Please summarize your Rebuttal Testimony.

A. My Rebuttal Testimony focuses on four key issues:

1. Customer Annualization;
2. Rate Design issues involving customer charges;
3. Throughput adjustment mechanism ("TAM"); and
4. Customer Assistance Residential Energy Support ("CARES") discount.

These are the issues where there are significant differences between UNS Gas, Inc. ("UNS Gas" or the "Company") positions, and the positions of Staff, RUCO, and ACAA. The differences are discussed in detail below, but a common thread separates the positions. The Company's proposals are innovative and well-supported. They are superior approaches given the circumstances faced by the Company. Unfortunately, Staff and RUCO appear reluctant to chart new ground, and instead resort to an overly cautious approach of rejecting new ideas in favor of previously-used approaches that do not fit the situation at hand. This is unfortunate because the rate design proposals made by the Company were aimed at helping reduce a grossly unfair subsidy to customers in low-use, desert communities from customers in higher use communities like Flagstaff.

Q. Please summarize this issue of geographical inequity.

A. The key problem presented by the Company's current rate design is that *costs are almost independent of volume, yet current rates are driven primarily by volume.* This means that customers who use larger quantities of gas, like 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. Colder weather customers, who already have higher bills than their desert counterparts, are then required to subsidize the customers with the low bills. The problem should be easy to solve. Customer charges need to increase to recognize that much of the cost structure on the distribution system is fixed, not volumetric. Unfortunately, Staff and RUCO have summarily rejected the higher customer charges without considering the impacts on Flagstaff and other high-use customers. They have based their rejection on some bill comparisons showing that smaller customers are receiving higher percentage increases. This is an inadequate reason to reject the higher proposed customer charges. Customer charge increases are cost-based and are exactly the prescription required to deal with the geographical inequity. Dealing with the geographical inequity is the single most important policy implication of the Company's proposed rate design.

II. <u>CUSTOMER ANNUALIZATION ADJUSTMENT</u>.

Q. Have the Staff Witness Smith and the RUCO witness Diaz Cortez recommended rejection of the Company's customer adjustment methodology?

A. Yes. Both Mr. Smith and Ms. Diaz Cortez favor a "traditional" method whereby they 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 per customer for each month, to quantify the additional revenue attributable to the additional customers. Ms. Diaz Cortez calls this the "accepted" method in her Direct Testimony at page 15, line 22 through page 16, line 3.

Q. Is the method just described always the Commission's accepted method?

A. No. In some cases, alternate methods have been proposed and accepted when the traditional method fails to address actual circumstances. The "traditional" method works well when:

i. the number of customers is growing in a stair-step fashion (constant absolute growth each month; linear customers), or the growth rate is constant (and typical of utility customer growth rates) for each month (exponential customer growth); and

ii. new customers to be added after the test year have similar consumption to the average customer in the class (homogeneous customers).

When these criteria are not met, the traditional method can produce erroneous results. An erroneous result could be, for example, that class customers and/or class usage are decreasing when in fact customers and/or usage are increasing. For example, there are cases (e.g., TEP and Arizona Public Service Company) where the largest classes of industrial or commercial customer do no meet either of these criteria. Often there are relatively few industrial customers, and because of the non-homogeneity of class customers, it is unlikely that a new customer will use what the class average customer uses. Consider a hypothetical case where, a huge existing customer will plan to double its size, but at the same time a "borderline" large customer is closing its doors. The impact of the huge customer's expansion may dwarf the loss of the entire borderline large customer. A huge positive customer annualization adjustment may be in order to recognize substantially higher revenue attributable to the huge customer's growth. Yet the simplistic traditional method would result in a negative adjustment simply because the number of customers fell by one – the one being the borderline large customer who is leaving the system. The traditional approach is so easy; unfortunately it is sometimes overly simplistic and wrong.

With the large consumption classes, it is more standard to base a customer adjustment on a "survey approach", where each large customer is studied separately, and the class customer adjustment is calculated on a customer-by-customer basis. The point here is that customer adjustments are not always calculated by some single traditional, accepted method.

Q. Why is the "traditional" method inappropriate in this case?

A. Much of the UNS Gas service area is blessed with the climate and other attributes that make it a favorite destination for seasonal residents. Consequently, the number of gas customers, while growing, follows a recurring cyclical pattern. Residential customers leave the service territory during hot summer months. UNS Gas commercial customers also follow cyclical patterns. As stated above, the "traditional" method works best when customer growth follows a stair step or constant growth pattern. When the number of customers is cyclical, the traditional approach becomes highly sensitive to where the end of the test year falls in the cycle. If the end of the test year falls at September 2005, the end of the trough of the cycle (*i.e.*, if the chosen test year had ended with September, 2005, instead of December, 2005 which was used in this filing), the traditional approach leads to an absurd result – a negative adjustment of 1,181 monthly customers for commercial Rate 20. One cannot explain a negative adjustment – an adjustment that will increase customers' rates – on a growing system. Customers on a system with a positive growth trend in revenue, in customers, and in sales, should never pay more because of some negative customer adjustments calculated using a non-applicable traditional approach. Note that over the 12-month period, the traditional approach yielded negative

Rate 20 adjustments four out of 12 times. In fairness, I must note that one of the 12 adjustments calculated using the Company's approach is negative; the magnitude of the negative adjustment is trivial. The large variation in customer adjustments under the traditional approach renders the results of little use with cyclical customer patterns.

Q. Did you compare the volatility in customer adjustments under the traditional and Company's approach?

A. Yes. I focused my analysis on commercial Rate 20, a class with a cyclical customer pattern. Exhibit DBE-1 (attached) shows that that under the test-year ending December 31, 2005, the Company's approach resulted in a positive adjustment of 844 monthly customers over the test year, while the "traditional" approach resulted in 2,024 monthly customers over the test year. Larger customer adjustments add operating income to the test year and are in the customers' benefit, so the questions is to ask whether the UNS Gas approach consistently favors the Company. The result is that the Company's approach shows no favoritism. Exhibit DBE-1 shows that, for Rate 20, in the 12 different test years (*i.e.*, 12 different overlapping test years comprised of months from 2004 and 2005, with the exception of one last test year which is all from 2005; test years have successive ending months; the first test year being February 2004 through January 2005, the second being March 2004 to February 2005, and so forth -- ending with months January 2005 through December 2005, that six months have "traditional" annualizations exceeding "Company-approach" annualizations. For the other six months, Company's approach annualizations were higher.

The mean annualization for Rate 20 customers was almost the same – with the Company's approach being ever so slightly (in these cases) in the customers' benefit. The results for Rate 20: 1,274 monthly customers for the Company's approach vs. 1,240 for the "traditional" approach. From the standpoint of only the mean of the annualizations, the two approaches produce practically the same result. However, one must be careful about just looking at the mean. For example, San Diego, California and Wichita Falls, Texas have almost the same average annual temperature (64 and 63 degrees Fahrenheit respectively). If one plans to book a vacation, however, be aware that the standard deviation in Wichita Falls' temperature is higher than San Diego's temperature. Wichita Falls' mean monthly temperatures run from 40 to 85 degrees Fahrenheit; San Diego's from 57 to 73 degrees Fahrenheit. This means that if you randomly pick your vacation date, you are more likely to weather closer to the average in San Diego than in Wichita Falls.

The Company's approach to customer adjustments, like San Diego's temperature, has a lower standard deviation than the traditional approach. For the Company's approach, the standard deviation in the adjustment is 673 monthly customers. For the "traditional approach", the standard deviation is 1,746 monthly customers, over 2.5 times as much volatility as the Company-approach. The standard deviation under the traditional approach is even more than the mean. The customer adjustment based on the traditional approach is so volatile its validity with the UNS Gas customer data is questionable. The basic problem here is that one's choice of the start of the test year has a drastic and unintended impact on the customer adjustment under the traditional approach. Using the Company's method is more likely to result in the type of positive customer adjustment one would expect with a growing system. The cyclical behavior in number of customers renders the traditional approach useless. Consequently, I continue to recommend the Company's approach.

III. RATE DESIGN.

Q. On page 27, line 17 of Ms. Diaz Cortez's Direct Testimony, she states that the UNS Gas rate design proposal will "create rate shock for some customers, result in perverted price signals, and stifle conservation." Do you agree with these assertions?

A. No. While some customers would face an adjustment period with the new rates, it is difficult to predict whether customers will be "shocked." Actually, UNS Gas' proposed rate design sends more accurate price signals than the existing structure, because it is more cost-based. Further, since a volumetric rate is still part of the overall structure, and because customers will pay volumetrically for the cost of gas through the purchased gas adjustor ("PGA"), customers will still have ample incentive to conserve. Therefore, I do not agree with any of Ms. Diaz Cortez's assertions.

Q. Are the Company's proposed rates appropriate price signals?

A. Yes. The Company's proposed rates are appropriate signals; however, the Company's current rates are not. The Company has increased customer charges for proposed rates, to recognize the system's substantial fixed costs. Distribution costs are largely fixed. The installed cost of the distribution plant components (*i.e.*, pipe, meters, regulators) as well as expense components (*i.e.*, meter reading and billing) do not vary (over relatively wide ranges represented by a class' customers' usage) with the volume of natural gas flowing through the system. Consequently, the distribution costs for individual customers within the residential class are generally independent of household usage. Higher proposed customer charges recognize this fact, and help bring the non-commodity portions of residential gas bills closer together. This price signal (higher customer charges) under the proposed rates more effectively reflects the reality of usage-insensitive costs.

The key problem presented by the Company's current rate design is that *costs are almost independent of volume, yet current rates are driven primarily by volume.* If there is a perversion in the Company's rate design, it comes from this mismatch in current rates.

In moving to a more cost-based design, the Company's proposed higher customer charges acknowledge higher "fixed" costs that vary little with usage. Higher proposed customer charges enable UNS Gas to cut proposed volumetric charges. Under the Company's proposal, higher use customers will see smaller percentage increases in bills. The current structure, regrettably burdens the average residential customer in Flagstaff with approximately $292 in annual margin, while the average customer in Lake Havasu pays only $159 in annual margin. The margins paid should be closer together. (Flagstaff will still have a higher bill because the Flagstaff customer must pay for more of the natural gas commodity). The current fixed cost recovery predominantly through volumetric rates creates incorrect price signals for our customers. As Ms. Diaz Cortez states in her Direct Testimony at page 28, line 13, the Company collects nearly three quarters of its revenue through commodity rates. (For clarification, the revenue referenced here is distribution margin revenue, and does not include revenue for the recovery of the cost of natural gas.)

That is too much recovery from volumetric charges. The UNS Gas proposal to shift more cost recovery from a volumetric rate to a monthly customer charge is an attempt to send the appropriate price signal and alleviate the disparity that currently exists between our cold and warm climate customers.

Q. Could you further explain why you disagree with the assertion that the Company's rate design proposal will stifle conservation?

A. I disagree because this assertion ignores the impact of the cost of natural gas in encouraging conservation among customers. The current and projected price of natural gas ranges from 60 to 70 cents per therm. This cost of gas provides a strong incentive to reduce consumption. The combination of our proposed distribution rate and the cost of natural gas results in a total rate of approximately 80 to 90 cents per therm for residential customers. The total cost of gas at this level will motivate customers to seek conservation opportunities.

Q. Did Ms. Diaz Cortez provide any evidence in her Direct Testimony supporting her claim that the UNS Gas rate design proposal will stifle conservation?

A. No, she merely states that high users will see a decrease in bills and low users will see an increase as a result of the margin rate going from the current 30 cents per therm to the proposed 18 cents per therm. She then concludes this would all but halt any incentive for conservation. Yet she presents no evidence that a 12-cent decrease in the margin rate will elicit an apathetic response toward conservation among customers while an opportunity to avoid a 60 to 70 cent per therm in natural gas cost exists.

Q. Did any intervenor witnesses 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.

Q. Have any intervenor witnesses disputed the results of the UNS Gas cost of service study which substantiates a monthly charge for residential customers of nearly $26?

A. No. Although UNS Gas has presented evidence that distribution costs are essentially fixed and could be entirely recovered through a monthly customer charge, the rate designs proposed by Staff and RUCO depend considerably on a volumetric rate component for cost recovery. One cannot tell from the Direct Testimony whether any serious cost of service based consideration was given by Staff and intervenors to the Company's customer charge proposals.

Too often, innovative approaches are discarded by simply contending that they violate "gradualism," or will cause "rate shock," or will not gain "public acceptability." I believe that Staff and intervenors often fail to recognize consumer adaptability, and the desire of consumers for cost based rates. The notions of "gradualism" and "public acceptability" should be applied in the context of the current consumer experience. While relatively low gas and electric customer charges for gas and electricity service may be the norm in Arizona, consumers have seen some common products move away from volumetric pricing and toward higher customer charges that establish tiers of service. This is common in the pricing of telephone, cable television, and internet service.

Q. Did you propose the full residential customer charge of $26 that you supported in your analyses?

A. No. The Company-proposed residential customer charge averages $17. That means that substantial levels of fixed costs would still be collected on a volumetric basis under the Company's proposal. Consequently, the intervenors claim that the Company's rate design eliminates revenue volatility and "guarantees return" are a gross exaggeration. The claims are even more exaggerated under the Staff's and RUCO's residential customer charge proposals, whereby the residential customer charge is increased by only $1.50 and $1.13 by Staff and RUCO, respectively.

Q. Mr. Steven W. Ruback for Staff states in his Direct Testimony at page 5, lines 7 through 9 that seasonal customer charges "are also not appropriate because the customer costs included in a customer charge do not change by season." Do you have any comments about that statement?

A. Yes. It is an interesting statement considering Staff's proposed rate design. Mr. Ruback seems to be using a cost-of-service argument against seasonal customer charges. But Staff's proposed rate design gives very little deference to the cost of service study. UNS Gas does seek more certainty that rates will recover costs. This is a natural consequence of cost-based rates. From a policy standpoint, the most important consequence of implementing the Company's cost-based rates is a reduction in the subsidization of customers in low-use desert communities by customers in high-use communities like Flagstaff. The public interest demands an end to this inequity. Cost-based rates dictate higher customer charges. The Company has proposed customer charges that greatly alleviate this degree of subsidization of one town by another and believes the public interest supports such a design. The seasonal customer charge was simply a means to help levelize the total bills over the 12 month period. The seasonal differential was never intended to reflect customer cost by season. What is important is that $204 in customer charges gets collected over the 12 months. UNS Gas would not be averse to levelizing the proposed customer charge over the year, so long as $17 per month for residential customers is collected. UNS Gas's seasonal design was intended to make gas bills easier to budget for over the year.

Q. Why does UNS Gas' proposed rate design not violate any long-standing regulatory principles as Mr. Ruback alleges in his Direct Testimony?

A. Under UNS Gas' proposed rate design, the Company still has to depend on volumetric rates to achieve its authorized rate of return. Moreover, costs must be controlled. When return is calculated, one must consider both revenue and cost. UNS Gas' proposed rate design is hardly a guarantee of the authorized rate of return. Increased revenue stability is a necessary consequence moving toward more cost-based rates for UNG Gas. One cannot be a cheerleader for cost based rates and throw mud on revenue stability in this case. Contrary to Mr. Ruback's Direct Testimony, the Company is not given any guarantee through its proposed rate design. The Company's proposed design violates no long- standing regulatory principles.

Q. Has the Company considered the impact of these higher customer charges on customers?

A. Yes. However, it is important to recognize that with higher customer charges come lower volumetric charges, other things constant. Moreover, the seasonal customer charges discussed above were proposed to help customers budget for their gas bills. Significantly lower winter customer charges will be especially helpful in cool weather areas like Prescott and Flagstaff.

IV. <u>THROUGHPUT ADJUSTMENT MECHANISM ("TAM")</u>.

Q. At page 31, line 2, in her Direct Testimony, Ms. Diaz Cortez asserts that the TAM would entirely remove any risk associated with revenue recovery. Do you concur?

A. No. First, the Company will continue to bear all risk associated with recovery of margin costs from those customers whose Pricing Plans are not subject to adjustment through the TAM. Second, the TAM is intended to true up the revenue requirement of participating customers established in the test year. Therefore, the TAM will not adjust for increases in revenue requirement beyond the test year, such as additional costs associated with labor or plant in service.

Q. On page 32, line 9 in her Direct Testimony, Ms. Diaz Cortez states that minimizing the impact of weather on customers bills is not necessarily a desirable feature for a gas rate design. Do you agree with this statement?

A. No. I believe that breaking the link between recovery of fixed costs and customer usage is appropriate in gas rate design. During a colder than normal winter, customer bills will be higher as a result of increased consumption. When fixed cost recovery occurs through the volumetric margin rate, customers pay more "fixed costs" than they would have under normal weather conditions, even though the Company has not incurred additional fixed costs due to increased throughput. An objective of equitable rate design should be to insulate customers from the burden of additional margin charges in a period of higher than normal consumption.

Q. Would the TAM compromise the Company's willingness and incentive to control costs and afford it a guaranteed return on equity?

A. No. The Company has a strong incentive to control costs with or without the TAM in place. Any cost escalation between rate cases negatively impacts the Company's earnings. The TAM will true up for deviations from the baseline cost recovery established in this case for certain classes of customers. The TAM will not recover increased expenses or plant not already included in rates, so the Company has incentive to keep costs down. Further, because plant will have to be added to meet customer growth, any opportunity to earn its authorized return on equity will likely be eroded. In short, this type of true up does not provide a guarantee that the Company will earn its authorized return on equity.

Q. Do you believe that the implementation of the TAM would adversely impact conservation?

A. No. Ms. Diaz Cortez overstates the customer price response induced by the TAM adjustment. Using historical rates of decline in consumption as shown in Exhibit TLV-2 of my Direct Testimony as an estimate, the 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 a strong incentive for conservation.

Q. Ms. Diaz Cortez and Mr. Ruback cite Commission denial of a decoupling mechanism in the Southwest Gas Corporation rate case in Decision No. 68487 (February 23, 2006) as support for denial in this case. What is your response?

A. Ms. Diaz Cortez and Mr. Ruback failed to note the following paragraph from Decision No. 68487 at page 34, lines 14 through 17:

> We encourage the parties in this proceeding to seek rate design alternatives that will truly encourage conservation efforts, while at the same time providing benefits to all affected stakeholders. To that end, Southwest Gas should coordinate its efforts to pursue implementation of a decoupling mechanism through discussions with Staff, RUCO, SWEEP/NRC and any other interested parties.

It is evident that the Commission supports the continued evaluation of decoupling mechanisms for Southwest Gas and presumably other Arizona gas utilities. The UNS Gas rate design proposal meets the tenets set forth above; it encourages conservation efforts and benefits stakeholders. The expansion of the Demand-Side Management ("DSM") program, as described in Mr. Gary A. Smith's Direct Testimony for UNS Gas, clearly promotes conservation. The symmetrical nature of the TAM benefits stakeholders by minimizing the impact of weather on customer bills and the Company's financial situation.

Q. Has there been support for decoupling mechanisms?

A. Certainly. Attached to my Rebuttal Testimony as Exhibit DBE-2 is a statement from the American Gas Association ("AGA") made on February 12, 2007 before the United States Senate – Energy and Natural Resources Committee. That statement makes the following observations:

- Under the prevailing system of cost recovery, most natural gas utilities are adversely affected when their customers consume less natural gas because they recover a less-than-expected share of the costs of operating their network systems.
- Recent events show that our gas markets are particularly vulnerable to interruptions, with dire consequences for customers.
- Reduced consumption of natural gas tends to have a negative impact upon the bottom line of natural gas utilities, thus giving consumers and natural gas utilities very different perspectives on energy efficiency and conservation.
- The costs of the distribution service – the service to delivering gas to customers – that natural gas utilities provide does not vary much in relation to the amount of gas that utilities' customers consume.
- By disconnecting a utility's revenue stream from the volume of gas actually delivered, utility interests and consumer interests are aligned in promoting energy efficiency. Even slight gains in efficiency have the potential to reduce natural gas prices.

In short, by adopting the TAM, the Commission will help break the dependence of UNS Gas on natural gas consumption as the means to earn its return.

Q. Is there support for decoupling mechanisms other than among the natural gas utility industry?

A. Yes. The Natural Resources Defense Council ("NRDC"), the American Council for an Energy-Efficient Economy ("ACE[3]") and the AGA issued a joint statement in July 2004 to the National Association of Regulatory Utility Commissioners ("NARUC") supporting "mechanisms that use modest automatic rate true-ups to ensure that a utility's opportunity to recover authorized fixed costs is not held hostage to fluctuations in retail gas sales." The NRDC and AGA both recognize that innovative programs are needed to best align the interests of shareholders, customers, and state regulators towards promoting energy conservation and increased efficiencies. Both also noted that natural gas utilities are hurt when promoting energy efficiency when the utilities must also ensure the safe and reliable delivery to homes, schools, hospitals and other customers and ensure that natural gas is available for these customers 24 hours a day and seven days a week. Because volumetric rates link natural gas consumption to meeting its revenue requirements, there is significant financial disincentive for natural gas utilities to encourage customers to use less natural gas. So, the NDRC – which hardly can be considered an industry group – agrees that decoupling mechanisms like the TAM can best align all interests so that all can strive to achieve energy efficiency. This statement is attached to my Rebuttal Testimony as Exhibit DBE-3.

I also note here that this joint statement warns against reducing authorized returns if a decoupling mechanism is adopted. That would "penalize utilities for socially beneficial advocacy and action, including efforts to create mechanisms that minimize the volatility of customer bills."

In addition, NARUC adopted a resolution attached to my Rebuttal Testimony as Exhibit DBE-4 on November 16, 2005, encouraging State commissions to reconsider rate designs and implement innovative rate designs like "decoupling tariffs." This resolution occurred subsequent to the July 14, 2004 resolution cited in Mr. Ruback's Direct Testimony.

Q. Mr. Ruback makes a reference to a terminated "Electric Revenue Adjustment Mechanism" from Maine in support for his position against the TAM. Do you have a response to that?

A. I am skeptical that the mechanism he cites from Maine in effect from the early 1990s has much relevance to what UNS Gas faces now in light of unprecedented natural gas price volatility and the moves it has made toward actively supporting DSM and other energy efficiency programs. In any event, it appears from Mr. Ruback's own Direct Testimony that the problems with Maine's mechanism stem from a $52 million revenue deferrals. The TAM here is designed to recovery any revenue deficiency yearly so such a large deferral is next to impossible.

Q. How many states have adopted decoupling mechanisms?

A. There are at least ten states. Those states are: California, Delaware, Indiana, Maryland, New Jersey, North Carolina, Ohio, Oregon, Utah and Washington. The District of Columbia has also adopted a decoupling mechanism.

V. <u>CUSTOMER ASSISTANCE RESIDENTIAL ENERGY SUPPORT ("CARES")</u>.

Q. Ms. McNeely-Kirwan claims that the proposed changes to the CARES program would have a disproportionate impact on low-usage CARES customers and eliminate the incentive to conserve provided by the current per therm discount. What is your response?

A. I do not agree with either of Ms. McNeely-Kirwan's statements. First, I believe that the UNS Gas' proposed rate design in its entirety – and not just the CARES discount – will have a positive impact for all low-usage residential customers. The objective of the Company's rate design proposal is to correct for the existing subsidy high usage customers in cold climates provide to their counterparts in warm climates. Elimination of this inequity should apply to both non-CARES and CARES customers.

Also, a CARES customer will see less of an annual bill increase than a standard residential customer at a similar level of consumption. For a summer consumption of 35 therms per month, a residential customer will see an increase of $9.00 per month and a CARES customer will see an increase of $2.50 per month (Schedule H-4, pages 1 and 2). Given a winter consumption of 75 therms, a residential customer will see a decrease of $4.56 per month while a CARES customer will see an increase of $0.22 per month. The annual increase for a residential customer at this level of usage is approximately $30 and $21 for the CARES customer.

I also do not agree with the statement that the UNS proposal has eliminated the incentive to conserve provided by the current per therm discount. The current after-discount margin rate for CARES is $0.1504 per therm during the winter months, for the first 100 therms. The UNS Gas proposal is $0.1862 per therm for all therms in all months. It is doubtful that a price difference of $0.0358 per therm during the winter will have a significant influence in a CARES customer's conservation behavior. But the price of gas will still provide a strong incentive for low-income customers to conserve. Further, UNS Gas is committed to the low-income weatherization program to help give these customers the means to conserve. In short, all customers, even low-use low-income customers will have the incentive to conserve.

Q. Does that conclude your Rebuttal Testimony?

A. Yes.

EXHIBIT

DBE-1

UNS Gas
Net Change in Monthly Customers
Attributable to Weather Adjustment

Erdwurm-Rebuttal
Exhibit 1

Rate 20 Results.

Line	Test Year Starts	Test Year Ends	Company's Approach	Traditional Approach
1	Jan-05	Dec-05	844	2,024
2	Dec-04	Nov-05	(120)	(152)
3	Nov-04	Oct-05	256	(1,133)
4	Oct-04	Sep-05	1,610	(1,181)
5	Sep-04	Aug-05	1,872	(558)
6	Aug-04	Jul-05	1,980	228
7	Jul-04	Jun-05	1,860	1,020
8	Jun-04	May-05	1,663	2,244
9	May-04	Apr-05	1,804	3,184
10	Apr-04	Mar-05	1,243	3,547
11	Mar-04	Feb-05	1,000	2,801
12	Feb-04	Jan-05	1,274	2,859
		Mean	1,274	1,240
		Standard Deviation	673	1,746
		Median	1,442	1,522

EXHIBIT

DBE-2

STATEMENT
OF THE AMERICAN GAS ASSOCIATION

ON

ENERGY EFFICIENCY PROGRAMS

BEFORE THE
UNITED STATES SENATE
ENERGY AND NATURAL RESOURCES COMMITTEE

FEBRUARY 12, 2007

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EXECUTIVE SUMMARY

The American Gas Association represents 200 local energy utility companies that deliver natural gas to more than 64 million homes, businesses and industries throughout the United States. Natural gas meets one-fourth of the United States' energy needs and has historically been the fastest growing major energy source. Adequate supplies of competitively priced natural gas are of critical importance to AGA and its member companies. Similarly, ample supplies of reasonably priced natural gas are of critical importance to the more than sixty million consumers that AGA members serve. AGA speaks here for those consumers as well as its member companies.

Natural gas is the cleanest fossil fuel. When combusted it produces less carbon than any other fuel. Importantly, almost all of the natural gas consumed in America is produced in North America. Thus, from the perspective of both its environmental benefits and its contribution to America's energy security, natural gas is nearly the perfect fuel.

Throughout the 1990's natural gas producers, for a variety of reasons, had significant excess production capacity. As a result, gas prices were consistently in the \$2-3 range per million British Thermal Units (MMBtu). In the winter of 2000-2001 natural gas prices rose dramatically. Initially, the general belief was that this spike was an aberration and that new exploration and production efforts spurred by these higher prices would bring additional supply online, and prices would fall concomitantly. To the surprise of almost all involved, this did not occur, and, over time, it became clear that in fact the higher prices were the result of a more systemic underlying problem. New producing areas, which in fact hold prolific supplies of natural gas that could meet America's needs for many decades, were unavailable for exploration and production as a result of a number of federal policies. Accordingly, those in the exploration and production business (which AGA does not represent) have had no choice but to focus on mature areas, where even maintaining current levels of natural gas output requires increasing degrees of effort and financial investment.

As this situation developed, it began to become clear that ameliorating high natural gas prices for consumers would require not only efforts aimed at encouraging more natural gas supply but also efforts aimed at increasing the nation's level of energy efficiency. With the supply-demand situation remaining so narrowly in balance, <u>either</u> modest increases in supply or modest decreases in consumption can have a dramatic effect on the prices consumers pay.

Even prior to the dramatic price increases of 2000-2001, natural gas had achieved a remarkable level of efficiency. The average American home today uses 25% less natural gas than it did in 1980. Similar trends have occurred in the commercial and industrial sectors of the customers served by natural gas utilities. Moreover, data recently compiled by AGA reveal that, since the winter of 2000-2001, Americans have reduced their natural gas consumption at even a more accelerated rate.

Natural gas utilities that deliver natural gas to homeowners generally have two parts to their prices. The first part is the charge for the gas commodity itself. Natural gas utilities essentially act as agents for their customers, buying natural gas for them on an aggregated basis. State public service commissions oversee this process, and they require utilities to sell this gas to their customers without markup or profit. Natural gas is a commodity traded in various wholesale markets that are not unlike those for oil, wheat, corn, and pork bellies.

The second part of the price charged by utilities is the cost of delivering the natural gas to customers. The vast majority of these costs, like those of other network industries, are the capital costs of the delivery network itself. Historically, the cost of providing utility service has been recovered on a "volumetric" basis, subject to oversight and regulation by state public service commissions. In shorthand terms, all of the costs of operating the utility for the year are distributed over the estimated volume of deliveries for the year. If the utility ultimately delivers that exact number of units, then it exactly recovers its costs of delivering gas for the year. If it ultimately delivers fewer units, then it recovers less than all of the costs of operating its system.

Under this prevailing system of cost recovery, most natural gas utilities are adversely affected when their customers consume less natural gas because they recover a less-than-expected share of the costs of operating their network systems. Thus, customers that desire to conserve energy or become more energy efficient and utilities that deliver natural gas have divergent financial interests.

There is a solution, however, to this conundrum. Over the last five years a number of states have "decoupled" natural gas utility rates in order to align the energy-efficiency interests of consumers and natural gas utilities. Although there are many ways to do so, the essence of these programs is to "decouple" the utility's recovery of its system costs from the volume of natural gas delivered through its system, which is also known as "throughput." The result is that the utility recovers the costs of operating its system independent of whether the volume of natural gas it delivers declines as a result of energy efficiency or conservation. Nine states have now embraced some form of decoupling, which breaks the link between utility earnings and customer consumption.

In a "decoupled" environment, the interests of the consumer and the utility are aligned. In a "decoupled" environment the interests of energy efficiency are served because there is no financial disincentive for a utility to promote and encourage efficiency. For these reasons there has been a growing movement in the states to adopt decoupled revenue-recovery mechanisms for natural gas utilities. In a decoupled regulatory regime, natural gas utilities and their customers can work together to implement natural gas efficiency programs.

Natural Gas Prices Are Likely to Remain at Today's High Levels Into the Future

Since the winter of 2000-2001, the natural gas industry has been at a critical crossroads. Natural gas prices were relatively low and very stable for most of the 1980s and 1990s. Wholesale natural gas prices during this period tended to fluctuate around $2-3 per MMBtu. Over the course of the past five years, however, natural gas markets have been supply constrained. Even small changes in weather, economic activity or world energy trends result in significant wholesale natural gas price fluctuations. As a result, our industry walks a supply tightrope, bringing with it unpleasant and undesirable economic and political consequences—most importantly high prices and higher price volatility. These consequences strain natural gas customers—residential, commercial, industrial, and electricity generators.

As this committee well knows, energy is the lifeblood of our economy. Millions of Americans rely upon natural gas to heat their homes, and high prices are a serious drain on their pocketbooks. Small businesses depend on natural gas for space heating, hot water, cooking, clothes drying, cooling and dehumidification, small-scale electricity generation and other applications. The impacts of high, volatile natural gas prices on U.S. industries – including plant closings and unemployment - are well documented. The impacts on small businesses may be less obvious but they are no less significant. Directly or indirectly, natural gas is critical to every American.

The consensus of forecasters is that natural gas demand will increase steadily over the next two decades. The electricity generation market will continue to drive this growth (even more so should we adopt a national climate change policy), as natural gas has been the fuel of choice for over 90 percent of the new generation units constructed over roughly the past decade. In part, the dominance of natural gas in this market is attributable to environmental regulations that promote the clean-burning characteristics of natural gas. The overall growth in gas usage will occur because natural gas is the most environmentally friendly fossil fuel and is an economic, reliable, and homegrown source of energy.

The consensus of forecasters also is that we shall never return to the era of $2-3 natural gas. The more recent era of $6-7 natural gas will characterize the years ahead absent aggressive national policy changes to promote the production of large amounts of the prodigious natural gas resources that North America enjoys.

Moreover, recent events show that our gas markets are particularly vulnerable to interruptions, with dire consequences for consumers. In September 2005 multiple hurricanes in the Gulf of Mexico eliminated nearly 25 percent of our total gas supply for a brief period. The hurricanes resulted in prices that fluctuated between $12.00 and $14.00 per MMBtu, and a brief cold snap in December 2005 produced a price spike to roughly $15.00 per MMBtu. Only a substantially warmer than normal 2005-2006 winter heating season has dampened the impact of these price increases to consumers. Clearly, natural gas markets are higher and more volatile than at any point in history. Moreover, there is no sign that this market volatility will abate in the near future.

It is harmful to small businesses, individual families and to the entire U.S. economy for natural gas prices to remain both high and volatile. Unless we make the proper public policy choices—and quickly—we will face many more difficult years with regard to natural gas prices.

This Committee knows well AGA's position with regard to making more natural gas supply available for America's homes, businesses, and industry. The Committee has received AGA's views on this important topic on a number of occasions over the last five year. AGA will continue to pursue additional land access for the environmentally benign production of natural gas.

The goal, of course, is to provide adequate supplies of reasonably priced energy to Americans. Increasing natural gas supply is only one half of that process. Energy efficiency measures is the other half of providing more reasonably priced natural gas.

Energy Efficiency Can Bring Down The Cost of Natural Gas

The natural gas industry has been a national leader in energy efficiency. Today, the average American home uses about 25% less natural gas than it did a quarter century ago. That reduction in per-capita natural gas use has been driven primarily by energy efficiency. Homeowners have conserved by adding storm windows, insulation, and weather stripping to their homes. Over the past twenty-five years gas appliances have become enormously more efficient. Moreover, new construction, although producing increasingly larger homes, has also produced increasingly energy-efficient homes. These trends have also been seen in both the commercial and industrial sectors of the industry.

Information very recently compiled by AGA suggests that in fact natural gas consumers have increased their energy efficiency efforts since prices increased dramatically in 2000-2001. Over the past five years, homeowners have reduced their natural gas consumption more than the 1% per year that has been the trend over the last twenty-five years. It is uncertain at this point what the exact slope will be of this reduction curve in the years ahead.

Energy efficiency brings gas consumers benefits in terms of lowering their energy bills as well as lowering their carbon emissions. What consumers do not understand, however, is the impact energy efficiency can have upon natural gas prices. An MMBtu of natural gas that is not consumed is no different from a new MMBtu that is produced. Either <u>adds</u> to the gap between productive capacity and demand. Most commentators recognize that increasing natural gas supply or decreasing natural gas demand by only several percent can bring natural gas prices down by 10%, 20%, or more. Thus, the customer that becomes more energy efficient not only saves on its energy bill. It also plays a major role in bringing natural gas prices down for all.

There are, of course, many ways that energy efficiency in the natural gas industry can be continued and indeed improved. AGA will not address those at the moment but will instead address a relatively simple way to promote energy efficiency that has been drawing increasing attention across the United States. The traditional structure of natural gas delivery rates puts natural gas utilities and natural gas consumers at odds in terms of promoting energy efficiency. Reduced consumption of natural gas tends to have a negative impact upon the bottom line of natural gas utilities, thus giving consumers and natural gas utilities very different perspectives on energy efficiency and conservation.

Decoupling Natural Gas Utility Rates Encourages Energy Efficiency

Natural gas utilities are network industries. They typically deliver natural gas from the point where their facilities interconnect with long-line interstate natural gas pipelines to energy consumers—whether they are residential, commercial or industrial. Natural gas utilities essentially provide two different services to their residential customers:

First, natural gas utilities act as merchants in acquiring natural gas for their customers. They aggregate the requirements of all of their customers who desire to purchase natural gas, and they purchase these requirements in various wholesale markets. (In most states industrial customers purchase their own gas. In some states with "retail choice" programs, residential customers also may purchase gas from an entity other than their local utility.) In their "merchant" function natural gas utilities purchase gas in markets that are not unlike markets for oil, corn, wheat, or other commodities. The natural gas utility merchant function is thoroughly regulated by state public service commissions. Utilities are not permitted to mark up the cost of gas or to make a profit on it. Rather, in most states utilities pass these costs on to customers pursuant to state-regulated revolving accounts usually known as Purchased Gas Adjustments, Gas Cost Recovery factor, or something similar.

Second, natural gas utilities deliver gas to their customers. They perform this service whether they have purchased the gas as merchant on behalf of the customer or the customer has purchased the gas itself. The charge for this delivery service is calculated in an entirely different fashion—and entirely separately from—the charge for purchased gas. It is usually calculated under traditional public utility cost-of-service ratemaking principles. As with the purchase of gas for customers, it is determined under the supervision and regulation of the state public service commission.

The charge for natural gas delivery service has traditionally been determined under a form of ratemaking known as "volumetric" rates. Under this methodology, the costs of operating the natural gas delivery service are estimated for a year and then allocated to the projected volumes of gas that will be delivered over that year. Thus, for each unit of gas delivered by the utility the customer pays a small portion of the cost of operating the utility. Should a utility deliver more gas in a year than projected, it will (all other things being equal) earn more than its projected costs. Should a utility deliver less gas in a year than projected, then it will (all other things being equal) earn less than the projected costs of operating its system.

A short example may make this situation more understandable. Assume that the costs of operating utility delivery service are $100 per year. This is composed of operations and maintenance expense of $65, depreciation of assets of $8, taxes of $12, and return on invested debt and equity capital of $15. Assume also that it is projected that the utility will deliver 100 units of gas per year. In this instance, the unit cost of delivering natural gas will be $1. Should consumers install new energy efficient appliances during the year such that actual deliveries are 95 units, then the utility receives delivery revenue of $95. This is less than the actual cost of operating the service. The $5 shortfall drops straight to the bottom line and represents a diminution in the utility's return on equity.

This example makes plain that, under a volumetric form of rate design, energy efficiency and energy conservation can be injurious to the shareholders of the natural gas utility, particularly if it turns out to be more significant than projected in the ratemaking process. The consumer has an interest in minimizing its energy bill. The utility has an interest in providing its expected return on capital to its shareholders (who all ultimately are energy consumers as well).

A fundamental, and probably immutable, fact is that natural gas utilities are fixed-cost businesses. The costs of the distribution service that they provide do not vary much in relation to the amount of gas that the utilities' customers consume.

As noted previously, natural gas consumers have, over the past twenty-five years, reduced their consumption by twenty-five percent, or approximately one percent per year. Over the past five years the most recent data indicate that this trend has accelerated. Although what the exact trend will be in the future is unclear, there is no indication that the trend of natural gas consumers to conserve will stop.

This fact, that traditional utility rate design may discourage energy efficiency, has been recognized on a number of fronts over the past five or more years. Fortunately, it can be corrected relatively easily. The solution is to decouple (*i.e.*, disconnect) a utility's revenue stream from the volume of gas actually delivered. This is not by any means a radical or unsound policy. Most of a utility's costs are fixed—that is, they do not vary with the volume of service delivered. Moreover, most utility's systems are sized to be able to meet deliveries on the peak cold day of the winter. From a ratemaking perspective, therefore, it is by no means irrational to suggest that the revenue should be recovered independent of the volume of gas delivered.

This model has almost universally been adopted in the cable television industry. The customer pays the same amount per month regardless of how many different channels are watched or how many hours the cable box is on. Similarly local telephone service is largely recovered through a fixed monthly charge. Both of these industries are similar to natural gas distribution in that they have large capital costs, most of their costs are fixed, and the network system is sized to meet peak demand.

Many states, as well as federal policy makers, now encourage energy efficiency and conservation. Consequently, several states have put in place rate mechanisms that "decouple" the recovery of distribution system delivery costs from the volume of gas delivered to customers. Doing so frees the utility to promote conservation and energy efficiency actively without a detriment to its shareholders.

There are variety of ratemaking devices that can be implemented to achieve decoupling. One is "straight fixed-variable" rate design. Under that approach, all of the costs of operating the utility system are collected in twelve monthly charges. This is the system used by the Federal Energy Regulatory Commission for interstate natural gas pipelines.

Another somewhat different method is weather normalization. This method takes the effects of differing weather (which is perhaps the largest determinant of volumes in the natural gas delivery business) out of the revenue stream. It does not, however, take into account the effects of energy efficiency or conservation. A related approach might be called "efficiency normalization." Like weather normalization, it takes the effects of efficiency and conservation gains out of the utility's revenue stream. In Oregon, for example, the utility actually compares consumption over time on a customer-by-customer basis to make an adjustment to rates to make the utility whole for the effects of conservation and efficiency.

The essence of revenue decoupling, however, effectuated, is to adjust the actual delivered volumes to the weather-normalized volumes underlying the last rate case of the natural gas utility. When delivered volumes deviate from the level forecasted in the rate case, the true-up mechanism adjusts the distribution charge.

Decoupling is also a fair and efficient means to design utility rates from the customer's perspective. The symmetrical nature of decoupling prevents the utility from increasing its earnings by increasing its delivered volumes because any additional distribution charges collected by the utility in that event are, one way or another, refunded to customers. Moreover, decoupling does not shelter the utility from the impact of increased costs or provide a guarantee that the company will achieve its authorized return on equity. To be clear, decoupling is not "incentive regulation" because there is no reward or bonus for the utility.

An independent evaluation of the Oregon decoupling tariff[1] found the program to be worthwhile and in the public interest. The evaluators found that the mechanism is effective in reducing the variability of utility revenues; removes disincentives to promote energy efficiency; changes the company focus from sales advertising to conservation advertising; does not reduce the incentive for good customer service; and does not shift risk to customers.

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[1] A Review of Distribution Margin Normalization as Approved by the Oregon Public Utility Commission for Northwest Natural, Christensen Associates Energy Consulting, LLC, March 2005.

At present nine states have adopted some form of revenue decoupling, and a number more are considering it.[2] Decoupling has taken a number of forms in these states, depending upon their individual needs, circumstances, and policies. In some of these states, decoupling is linked to public benefit funding that is aimed directly at energy efficiency.

The beneficial nature of decoupling is not simply a view of AGA and the natural gas utility. AGA and the Natural Resources Defense Council have adopted a joint declaration concerning the value of decoupling.[3] Furthermore, the National Association of Regulatory Utility Commissioners, the trade association of state public service commissioners, has adopted a resolution urging the states to review their practices to determine whether innovative rate designs of this sort can assist in bringing natural gas costs down.[4]

Conclusion

Traditional rate design contains a financial disincentive that may inhibit utilities from aggressively promoting energy efficiency and conservation. Revenue decoupling breaks the link between a utility's earnings and energy consumption of its customers. The utility therefore becomes financially indifferent to the declining volumes associated with energy conservation and efficiency. The experience to date with decoupling shows that it has aligned consumer interests with utility interests and made utilities enthusiastic partners in promoting efficiency. Even slight gains in efficiency have the potential to reduce natural gas prices significantly.

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[2] A map of states that have adopted or are considering decoupling is attached.
[3] A copy is attached.
[4] A copy is attached.

EXHIBIT

DBE-3

AGA
American Gas Association

NRDC
THE EARTH'S BEST DEFENSE

ACE3 American Council for an Energy-Efficient Economy

Joint Statement of the American Gas Association, the Natural Resources Defense Council and the American Council for an Energy-Efficient Economy

Submitted to the National Association of Regulatory Utility Commissioners
July 2004

The American Gas Association (AGA) and the Natural Resources Defense Council (NRDC) recognize the many benefits of using clean-burning natural gas efficiently to provide high quality energy services in all sectors of the economy. This statement identifies ways to promote both economic and environmental progress by removing barriers to natural gas distribution companies' investments in urgently needed and cost-effective resources and infrastructure.

NRDC and AGA agree on the importance of state Public Utility Commissions' consideration of innovative programs that encourage increased total energy efficiency and conservation in ways that will align the interests of state regulators, natural gas utility company customers, utility shareholders, and other stakeholders. Cost-effective opportunities abound to improve the efficiency of buildings and equipment in ways that promote the interests of both individual customers and entire utility systems, while improving environmental quality. For example, when energy supply and delivery systems are under stress, even relatively modest reductions in use can yield significant additional cost savings for all customers by relieving strong upward pressures on short-term prices.

NRDC and AGA also encourage state Commissions to support gas distribution company efforts to manage volatility in energy prices and reduce volatility risks for customers.

The Energy Efficiency Problem: Regulated Natural Gas Utilities are Penalized for Aggressively Promoting Energy Efficiency

Local natural gas distribution companies (gas utilities) have very high fixed costs. These fixed costs include the costs of maintaining system safety and reliability throughout the year, staffing customer service telephone lines 24 hours a day and doing what it takes each day of the year to ensure the safe and reliable delivery of natural gas to homes, schools, hospitals, retailers, factories and other customers.

Natural gas utilities typically purchase natural gas on behalf of their customers, and pass through the cost without markup. This means that natural gas utilities do not profit from their acquisitions of natural gas to serve customer needs. The profit (authorized level of rate of return) comes from the rates utilities charge for transporting the natural gas to customers' homes and businesses.

The vast majority of the non-commodity costs of running a gas distribution utility are fixed and do not vary significantly from month to month. However, traditional utility rates do not reflect this reality. Traditional utility rates are designed to capture most of approved revenue requirements for fixed costs through volumetric retail sales of natural gas, so that a utility can recover these costs fully only if its customers consume a certain minimum amount of natural gas (these amounts are normally calculated in rate cases and generally are based on what customers consumed in the past). Thus, many states' rate structures offer – quite unintentionally – a significant financial disincentive for natural gas utilities to aggressively encourage their customers to use less natural gas, such as by providing financial incentives and education to promote energy-efficiency and conservation techniques.

When customers use less natural gas, utility profitability almost always suffers, because recovery of fixed costs is reduced in proportion to the reduction in sales. Thus, conservation may prevent the utility from recovering its authorized fixed costs and earning its state-allowed rate of return. In this important respect, traditional utility rate practices fail to align the interests of utility shareholders with those of utility customers and society as a whole. This need not be the case. Public utility commissions should consider utility rate proposals and other innovative programs that reward utilities for encouraging conservation and managing customer bills to avoid certain negative impacts associated with colder-than-normal weather. There are a number of ways to do this, and NRDC and AGA join in supporting mechanisms that use modest automatic rate true-ups to ensure that a utility's opportunity to recover authorized fixed costs is not held hostage to fluctuations in retail gas sales.[1] We also support performance-based incentives designed to allow utilities to share in independently verified savings associated with cost-effective energy efficiency programs.

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[1]For example, in 2003 the Oregon Public Utility Commission approved a "conservation tariff" for Northwest Natural Gas Company (NW Natural) "to break the link between an energy utility's sales and its profitability, so that the utility can assist its customers with energy efficiency without conflict." The conservation tariff seeks to do that by using modest periodic rate adjustments to "decouple" recovery of the utility's authorized fixed costs from unexpected fluctuations in retail sales. *See* Oregon PUC Order No. 02-634, *Stipulation Adopting Northwest Natural Gas Company Application for Public Purpose Funding and Distribution Margin Normalization* (Sept. 12, 2003). In California, PG&E and other gas utilities have a long tradition of investment in energy efficiency services, including those targeting low-income households, and the PUC is now considering further expansion of these investments along with the creation of performance-based incentives tied to verified net savings. California also pioneered the use of modest periodic true-ups in rates to break the linkage between utilities' financial health and their retail gas sales, and has now restored this policy in the aftermath of an ill-fated industry restructuring experiment. Thus, in March 2004, Southwest Gas Company received an order that authorizes it to establish a margin tracker that will balance actual margin revenues to authorized levels.

Many states' rate structures also place utilities at risk for variations in customer usage based on variations in weather from a normal pattern. This variation can be both positive and negative. Utilities' allowed rate of return is premised on the expectation that weather will be normal, on average, and that customer use of gas will maintain a predictable pattern going forward. Proposals by utilities to decouple revenues from both conservation-induced usage changes and variations in weather from normal have sometimes been characterized as attempts to reduce utilities' risk of earning their authorized return. The result of these rate reforms, in this regulatory view, should be a lowered authorized return. But reducing authorized returns would penalize utilities for socially beneficial advocacy and action, including efforts to create mechanisms that minimize the volatility of customer bills.

Our shared objective is to give utilities real incentives to encourage conservation and energy efficiency. With properly designed programs, the benefits could be significant and widespread:

- Customers could save money by using less natural gas;
- Reduced overall use will help push down short-term prices at times when markets are under stress, reducing costs for all customers (whether or not they participate in the utility programs);
- Utilities would recover their costs and have a fair opportunity to earn their allowed return;
- State policies to encourage economic development could be enhanced by increased energy efficiency and lower business energy costs;
- State PUCs would be able to support larger state policy objectives as well as programs that reflect the public's desire to use energy efficiently and wisely.

In today's climate of rapidly changing natural gas prices, such reforms make good sense for consumers, shareholders, state governments, and the environment.

Natural Gas Consumers, Price Volatility and Resource Portfolio Management. Another area of concern shared by NRDC and AGA is the impact of natural gas price volatility on natural gas consumers, which can be exacerbated by limited diversification of utilities' resource portfolios. Today many of the nation's natural gas utilities find themselves relying on short-term markets for most of their gas needs, with either the encouragement or the acquiescence of their regulators. During much of the 1990's this approach was typically advantageous to consumers, as the market price of natural gas was generally low and did not fluctuate dramatically. As wholesale natural gas prices have risen since 2000 and become more volatile, however, many utilities and commissions are reconsidering this emphasis on short-term market purchases.

While purchasing practices based on short-term supply contracts may offer consumers relatively low-cost natural gas, those consumers are also exposed to more volatile prices and natural gas bills that may rise and fall unpredictably. Public Utility Commissions should favorably consider gas distribution company proposals to manage volatility, such as through hedging, fixed-price contracts of various durations, energy-efficiency improvements in customers' buildings and equipment, and other measures designed to provide greater certainty about both supply adequacy and price stability. Achieving these goals will sometimes require paying a premium over prevailing spot market prices. Like diversified investment portfolios that are designed to mitigate risk, prudent hedging plans should be encouraged as a way to help stabilize gas prices and ensure long-term access to affordable natural gas services.

L:NRDC-AGA Statement – FINAL-June, 2004

EXHIBIT

DBE-4

Resolution on Energy Efficiency and Innovative Rate Design

WHEREAS, The National Association of Regulatory Utility Commissioners (NARUC), at its July 2003 Summer Meetings, adopted a *Resolution on State Commission Responses to the Natural Gas Supply Situation* that encouraged State and Federal regulatory commissions to review the incentives for existing gas and electric utility programs designed to promote and aggressively implement cost-effective conservation, energy efficiency, weatherization, and demand response; *and*

WHEREAS, The NARUC at its November 2003 annual convention, adopted a *Resolution Adopting Natural Gas Information "Toolkit,"* which encouraged the NARUC Natural Gas Task Force to review the findings and recommendations of the September 23, 2003 report by the National Petroleum Council on *Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy* and its recommendations for improving and promoting energy efficiency and conservation initiatives; *and*

WHEREAS, The NARUC at its 2004 Summer Meetings, adopted a *Resolution on Gas and Electric Energy Efficiency* encouraging State commissions and other policy makers to support expansion of energy efficiency programs, including consumer education, weatherization, and energy efficiency and to address regulatory incentives to inefficient use of gas and electricity; *and*

WHEREAS, These NARUC initiatives were prompted by the substantial increases in the price of natural gas in wholesale markets during the 2000-2003 period when compared to the more moderate prices that prevailed throughout the 1990s; *and*

WHEREAS, The wholesale natural gas prices of the last five years largely reflect the fact that the demand by consumers for natural gas has been growing steadily while, for a variety of reasons, the supply of natural gas has had difficulty keeping pace, leading to a situation where natural gas demand and supply are narrowly in balance and where even modest increases in demand produce sharp increases in price; *and*

WHEREAS, Hurricanes Katrina and Rita, in addition to damaging the States of Alabama, Mississippi, Louisiana, and Texas, significantly damaged the nation's onshore and offshore energy infrastructure, resulting in significant interruption in the production and delivery of both oil and natural gas in the Gulf Coast area; *and*

WHEREAS, The confluence of a tight balance of natural gas supply and demand and these natural disasters has driven natural gas prices in wholesale markets to unprecedented levels; *and*

WHEREAS, The present high and unprecedented level of natural gas prices are imposing significant burdens on the nation's natural gas consumers, whether residential, commercial, or industrial, and will likely be injurious to the nation's economy as a whole; *and*

WHEREAS, The recently enacted Energy Policy Act of 2005 contains a number of provisions aimed at encouraging further natural gas production in order to bring down prices for consumers, but these actions, together with any further action on energy issues by Congress, are unlikely to bring forth additional supplies of natural gas in the short term; *and*

WHEREAS, Energy conservation and energy efficiency are, in the short term, the actions most likely to reduce upward pressure on natural gas prices and to assist in bringing energy prices down, to the benefit of all natural gas consumers; *and*

WHEREAS, Innovative rate designs including "energy efficient tariffs" and "decoupling tariffs" (such as those employed by Northwest Natural Gas in Oregon, Baltimore Gas & Electric and Washington Gas in Maryland, Southwest Gas in California, and Piedmont Natural Gas in North Carolina), "fixed-variable" rates (such as that employed by Northern States Power in North Dakota, and Atlanta Gas Light in Georgia), other options (such as that approved in Oklahoma for Oklahoma Natural Gas), and other innovative proposals and programs may assist, especially in the short term, in promoting energy efficiency and energy conservation and slowing the rate of demand growth of natural gas; *and*

WHEREAS, Current forms of rate design may tend to create a misalignment between the interests of natural gas utilities and their customers; *now therefore be it*

RESOLVED, That the National Association of Regulatory Utility Commissioners (NARUC), convened in its November 2005 Annual Convention in Indian Wells, California, encourages State commissions and other policy makers to review the rate designs they have previously approved to determine whether they should be reconsidered in order to implement innovative rate designs that will encourage energy conservation and energy efficiency that will assist in moderating natural gas demand and reducing upward pressure on natural gas prices; *and be it further*

RESOLVED, That NARUC recognizes that the best approach toward promoting energy efficiency programs for any utility, State, or region may likely depend on local issues, preferences, and conditions.

Sponsored by the Committee on Gas
Recommended by the NARUC Board of Directors November 15, 2005
Adopted by the NARUC November 16, 2005

BEFORE THE ARIZONA CORPORATION COMMISSION

<u>COMMISSIONERS</u>
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 THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-06-0463
IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. TO REVIEW AND REVISE ITS PURCHASE 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

Rejoinder Testimony of

D. Bentley Erdwurm

on Behalf of

UNS Gas, Inc.

April 11, 2007

EXHIBIT
UNSG-2D
admitted

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is D. Bentley Erdwurm. My business address is One South Church Avenue, Tucson, Arizona 85701.

Q. Are you the same D. Bentley Erdwurm who filed Rebuttal Testimony in this proceeding?

A. Yes, I am.

Q. Mr. Erdwurm, have you reviewed the Surrebuttal Testimonies filed by the Commission Staff and Intervenors in this case?

A. Yes, I have.

Q. What is the purpose of your Rejoinder Testimony?

A. My Rejoinder Testimony responds to the Surrebuttal Testimonies of Steven W. Ruback, Ralph C. Smith, and Julie McNeely-Kirwan on behalf of the Arizona Corporation Commission, Utilities Division Staff ("Staff"), Marylee Diaz Cortez on behalf of the Residential Utility Consumer Office ("RUCO"), and Mr. Marshall Magruder, a customer.

II. CUSTOMER ADJUSTMENT / ANNUALIZATION.

Q. Mr. Ralph Smith in his Surrebuttal testimony at page 22, line 7 through page 23, line 4 states that you used a hypothetical in your Rebuttal Testimony that was not related to the circumstances faced by the Company. Please comment.

A. The sole purpose of this hypothetical was to show that customer adjustment methods other than the "traditional" approach have been proposed by utilities and approved by this

Commission. The hypothetical was not meant to match the specific circumstance arising for UNS Gas, which is cyclical growth attributable to the comings and goings of seasonal residents. However, both the cyclical and hypothetical growth are instances where the traditional method fails to generate consistently reliable results.

Under the traditional approach, one compares the customer counts in each month of the test year to the test year-end level of customers. Then one multiplies the additional customers attributable to each month by the average revenue per customer for each month to obtain the additional revenue attributable to the additional customers. This method works well when growth is steady and additional customers are similar in size to existing customers. The traditional approach starts breaking down when the assumptions are not met, and that is the case with cyclical growth as experienced by the Company.

My hypothetical involved a "huge" customer – a customer much larger than other customers in the class – who joins the system. The traditional approach is put aside in such a circumstance because it produces spurious results. When the Commission has approved non-traditional customer adjustments, larger commercial and industrial customers have often been involved. It is typical across utilities for the largest industrial or commercial customer classes to be composed of customers with significant variation in size. As mentioned, this composition is ill-suited for the traditional approach.

Q. Has the Commission ever accepted a customer adjustment based on the specific methodology you proposed in UNS Gas?

A. Not to my knowledge. But I believe that the method represents a substantial improvement for cyclical growth situations and should be adopted in this case.

Q. Mr. Ralph Smith states, in his Surrebuttal Testimony at page 24, lines 15 to 22, that a method should be "straight-forward" and "transparent" enough for other parties to follow the results. He does not think your method meets that criterion. Please comment.

A. The method I used is not as simple as the "traditional" approach. However, the monthly growth rate is calculated by the standard method where one is given the number of periods (in this case, months), beginning customers, and ending customers. It is a standard exponential growth model. The topic is mathematically simpler than regression models commonly used in forecasting. While most analysts, myself included, may need to sometimes check some formulas to apply the techniques, doing so is not overly burdensome. The benefit of an improved result justifies a little extra effort on the part of analysts preparing and reviewing customer adjustments.

Q. Mr. Ralph Smith claims that your approach uses percentage "growth factors" instead of customer bill counts. Moreover, he claims that the technique was difficult to follow in terms of verifying the percentages used, and appears to understate growth. Do you agree?

A. No. The growth factors are based on customer bill counts, so his claim that the approach is not based on customer bill counts is not correct. The percentages are based on the constant growth model that assumes beginning and ending results.

Q. In his Surrebuttal Testimony at page 23, line 6 through page 24, line 14, Mr. Ralph Smith states that you made a mistake when you said that "one cannot explain a negative adjustment – an adjustment that will increase customers' rates – on a growing system. Customers on a system with a positive growth trend in revenue, in customers, and in sales, should never pay more because of some negative customer adjustments calculated using a non-applicable traditional approach." Please comment.

A. Mr. Smith spoke at length on this topic. When I referred to a "negative" customer adjustment for a growing system, I was referring to the overall customer adjustment (*i.e.*, the sum of all class adjustments). I agree with Mr. Smith that some classes may have positive adjustments while others have negative adjustments. The fact that positive and negative adjustments can exist simultaneously for different classes is irrelevant to the discussion of whether the traditional approach or the Company approach is preferred.

My point was a simpler one. If a class has positive growth, the customer adjustment should be positive. If the adjustment for this growing class is negative, the analyst should *strongly* consider another approach. A negative adjustment here would effectively increase rates, even though the positive growth in the class supports decreased rates. A negative adjustment for a growing class is nonsense. My primary gripe with the traditional approach when applied to the commercial customers is that depending on when the test year starts, the traditional approach leads to negative customer adjustments on four occasions. Mr. Smith states that these alternate test years are irrelevant because they were not used. I disagree. There is a problem here. The failure of the traditional technique to give a reasonable result on four of twelve occasions shows a weakness in the method. Regardless of when the test year starts, the class is still growing, and the adjustment should be positive.

Q. Ms. Diaz Cortez claims that there is "hardly the extreme seasonality" in the customer count to justify moving away from the traditional approach. Please comment.

A. Exhibit DBE-5 shows otherwise. The Rate 20 Commercial customer count is shown in Exhibit DBE-5, Page 1. The 2004 and 2005 customer counts are graphed for the calendar year January through December. This is a textbook case of cyclicality; the annual shapes match. Total customers are shown on Page 2 of the DBE-5. Again, textbook cyclicality.

When Ms. Diaz Cortez states – on page 12, lines 17 to 23 in her Surrebuttal Testimony – that there are month over month decreases only in the months of April, May, and July, and that the decreases range between "9/100th" of a percent and "1/3rd" of a percent, she attempts to trivialize the cyclicality that is clearly demonstrated in the Exhibit DBE-5, Page 1.

What Ms. Diaz Cortez failed to mention is that the January through December 2005 commercial customer count data reflects annualized growth of around 1.4%, and equivalent monthly growth of around 0.12% (12/100th of a percent). Twelve one hundredths of a percent is in the same ballpark as the 9/100th of a percent Ms. Diaz-Cortez quotes. Relatively speaking, a decrease of 9/100th of a percent is substantial when compared to the monthly growth of 12/100th of a percent. The decrease of 1/3rd of a percent is the same as a decrease of 33/100th of a percent, which is substantially different from the monthly growth of 12/100th of a percent. So, Ms. Diaz Cortez's simple approach does not comport with the relevant data.

Q. Is your method of customer adjustment for a cyclical class the only workable approach?

A. No. However, the approach is preferable to the traditional approach. I am hopeful that the parties will have an opportunity to discuss workable alternatives for customer adjustments for classes with cyclical growth or other atypical characteristics.

III. THROUGHPUT ADJUSTMENT MECHANISM ("TAM").

Q. Staff witness Mr. Steven W. Ruback, at page 1, line 12 of his Surrebuttal Testimony claims that the Company's TAM will "seriously dilute" the incentive of the Company to control cost. Do you agree?

A. I disagree with Mr. Ruback's claim for reasons I discussed in my Rebuttal Testimony. Specifically, the TAM affects revenue. It does not compensate for income shortfalls due to cost discrepancies. If the Company fails to control cost, net income will fall. The Company seeks to maximize income, so a strong incentive to control cost remains.

Q. Mr. Ruback states in his Surrebuttal Testimony at page 2, lines 14 to 25, that you claimed that Southwest Gas Corporation's TAM adjustment was not denied by the Commission. Please comment.

A. I believe that Mr. Ruback knows that I am not disputing the rejection of Southwest Gas' TAM. My point was that the Commission left the door open for additional discussion of the concept.

IV. RATE DESIGN / CUSTOMER CHARGES.

Q. In his Surrebuttal Testimony at page 4, line 22 through page 5, line 19, Mr. Ruback agrees that gas distribution costs are fixed costs and that are largely supported by volumetric rates. But he goes on to say that you "fail to understand that, according to rate design practice that fixed costs do not have to be recovered with fixed charges." Please comment.

A. I am well aware that fixed costs can be recovered through volumetric rates. In fact, the Company's own proportional responsibility allocation method is based on volumetric data. The Company's distribution fixed costs are primarily allocated to classes based on this proportional responsibility data. The result is that the distribution unit costs by class (in $/therm) are brought closer together.

Rate design determines how revenue is recovered from customers within a class. The recovery of more fixed cost though fixed charges (customer charges) is the Company's rate design goal. This helps eliminate the subsidy of low-use warm weather customers by high-use customers. The Company seeks to rectify a problem: Flagstaff customers are paying too much relative to warm weather customers. The Company is unconcerned with practices used in other jurisdictions when the application to our system results in gross geographical inequities. The Company's higher customer charges are an appropriate means of matching revenue to costs within a class.

Q. In her Surrebuttal Testimony, Ms. Diaz-Cortez of RUCO states on page 17, line 2 that low-use customers will see higher percentage increase in bills than high-use customers. She sees that as a negative in the Company's Rate design. Is there a problem with the Company's proposed rate design in this regard?

A. No. Customer charge increases will result in larger percentage increases for low-use customers. This is a result of fixing a geographical inequity. Ms. Diaz-Cortez should keep in mind that customers tend to be "high-use" on the UNS Gas system because they live in colder climate zones. There are significant differences in climate on the system. It is unfair to view the high-use customer as necessarily wasteful or unconcerned about conservation. Similarly, many low-use customers may be unconcerned about conservation. A Flagstaff customer struggling to conserve may still use twice as much gas as a low-use customer. Also, low-income customers are not necessarily low-use customers as they may occupy sub-standard housing. In light of the above, the "fairest" approach to rate design is to tie it to cost causation. That is what the Company has done in its proposal. On the UNS Gas system, it is not so easy to identify the conservation conscious customers. Therefore, lowering the customer charges will not necessarily reward the conservation conscious.

Q. **In his Surrebuttal Testimony, Mr. Marshall Magruder states on line 28, page 15 that the Company transferred some of "the "volumetric" charges from the cost of gas" to the customer charge. Do you agree?**

A. No. No charges related to the cost of gas were transferred to the customer charge.

Q. **In his Surrebuttal Testimony, Mr. Marshall Magruder states on line 19, page 15 that the Company's proposed rate design rewards high users by penalizing low users. Do you agree?**

A. No. Currently, low-use customers are being subsidized. Customers in colder climates like Flagstaff are paying more than their fair share. The Company's proposal merely helps eliminate this inequity. The Company could have justified even higher customer charges, but moderated them in the interest of "gradualism."

Q. In his Surrebuttal Testimony, Mr. Marshall Magruder on line 13, page 22 has a title that reads "Gas Usage Charged with TAM When Not Using Gas." Please comment.

A. The title is wrong. Customers are never charged gas costs under the TAM.

Q. In his Surrebuttal Testimony, Mr. Ruback states on page 5, line 22 that he takes "umbrage with [Mr. Erdwurm's] comment that Staff did not consider cost of service principles in arriving at a recommendation." Please comment.

A. I did not mean to imply that the Staff did not do a thorough job. I know based on Staff testimony that the rates were extensively reviewed. The problem is that Staff is so concerned about "rate shock" and "gradualism" that substantial changes in rates are almost impossible to implement, even when socially desirable. Subsidies are perpetuated and inequities compounded. The process is frustrating because substantial work is completed, but few changes affecting customers are implemented.

V. <u>CARES POLICY</u>.

Q. Staff witness Julie McNeely-Kirwan states that the Company's CARES proposal lessens the incentive to conserve. Do you agree?

A. No. CARES customers all receive the same CARES discount under the Company's proposal. There is no need to use more gas to increase CARES benefits. That design is as pro-conservation as possible. The Company disagrees with Ms. McNeely-Kirwan's proposal to exempt CARES customer from general rate design provisions, as she advocates for in her Surrebuttal Testimony starting at page 3, line 18. The Company's design is based on cost and designed to eliminate geographic inequities.

VI. <u>CARES RECOVERY.</u>

Q. Do you have a concern about the Company's ability to recover of the cost of CARES based on the rate calculations in the in Mr. Ralph Smith's Surrebuttal Testimony at Attachment RCS-S1R, Schedule RD-1, Page 2 of 2?

A. Yes. Attachment RCS-S1R, Schedule RD-1, Page 2 of 2, shows Mr. Smith's proposed rates and the resulting revenue calculation. The Company's concern is that the distribution rate per therm is shown at the same level – $0.3177 per therm – for both Rate 10 (the regular residential rate) and for Rate 12 (the CARES residential rate.) However, a portion of the Rate 12 therms will be sold at a discounted rate under the Staff's proposal. Mr. Smith's calculation of the impact of those discounts is shown on Attachment RCS-S1R, Schedule RD-2. Under Staff's CARES proposal, the Company will collect less per therm under the distribution rate for Rate 12 than for Rate 10. Mr. Smith has made no upward adjustment to the total revenue requirement target that would recognize the absence of a stated discount; therefore Rate 12 must be adjusted downward to reflect the anticipated revenues to be collected based on Staff's proposed rate structure including their proposed CARES discount.

Q. Please explain your last statement about adjusting the revenue requirement to recognize the absence of a stated discount.

A. One may state the Rate 12 rates at the full Rate 10 levels and not show the rate discount in the proof of revenue. However, the revenue requirement would accordingly need to be increased to reflect the recovery of the CARES discount as an expense. To correct Mr. Smith's attachment, one would increase the total revenue requirement by $320,006.

Q. Did the Company show rate components without a discount, and recognize this in the revenue requirement?

A. Yes. The Company booked the discount as revenues, and recorded an equivalent expense. There is no impact on operating income.

Q. Did Mr. Smith recognize the discount with his ($320,006) entry on line 5, column F of his attachment?

A. This number stands alone in column F, but does not appear to be used in any calculation. Column F would also been an appropriate place to show the revenue increases by class that would cover the CARES cost. All the non-CARES revenue increases would total to positive $320,006, exactly offsetting the negative CARES discount of ($320,006). So, Column F would net to zero.

Q. How should this issue be handled?

A. The Company hopes that Mr. Smith's failure to provide recovery for CARES was an inadvertent error. If this is the case, the Company would appreciate revisions to his schedule at the earliest opportunity.

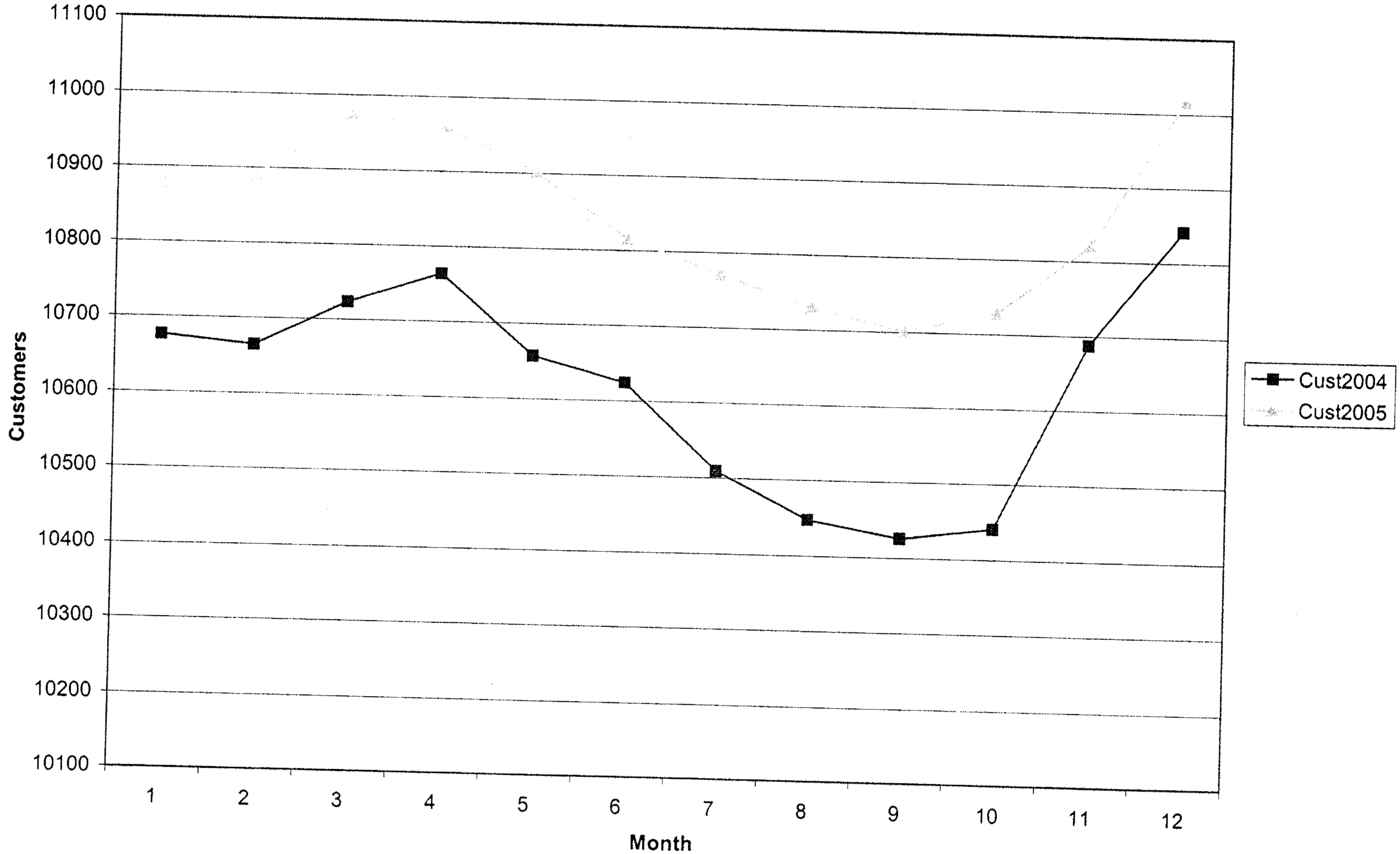
Q. Does this conclude your Rejoinder Testimony?

A. Yes.

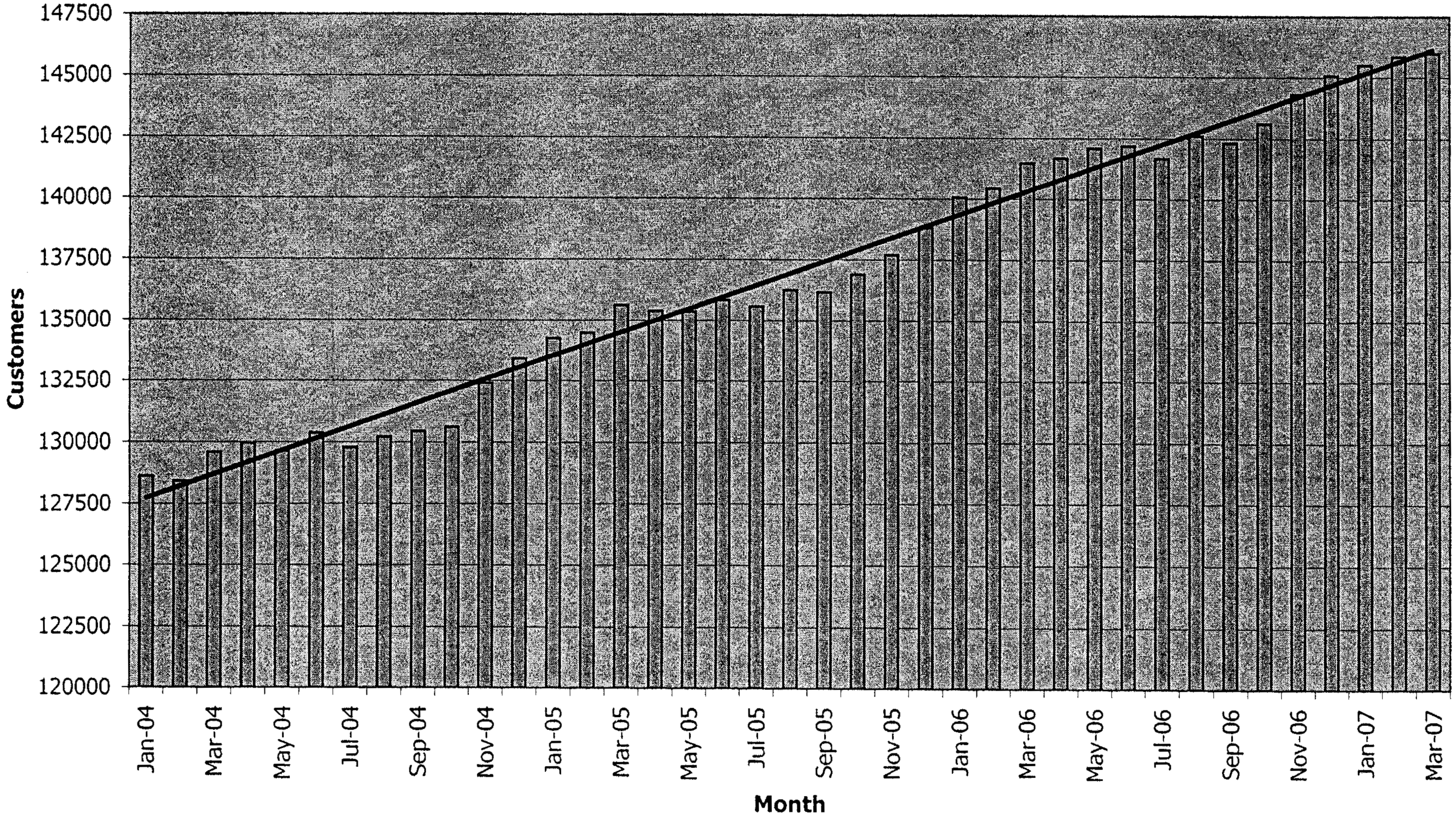
EXHIBIT

DBE-5

Cyclicality in Commercial Customers



Cyclicality in Total Customers



BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
MIKE GLEASON- CHAIRMAN
WILLIAM A. MUNDELL
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IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-06-0463
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IN THE MATTER OF THE INQUIRY INTO THE PRUDENCE OF THE GAS PROCUREMENT PRACTICES OF UNS GAS, INC.	DOCKET NO. G-04204A-05-0831

Rebuttal Testimony of

Denise A. Smith

on Behalf of

UNS Gas, Inc.

March 16, 2007

EXHIBIT
UNSG-21
admitted

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Denise A. Smith. My business address is 4350 E. Irvington Road, Tucson, Arizona.

Q. What is your employment position?

A. I am the Director of Conservation and Renewable Programs at Tucson Electric Power Company, UNS Gas, Inc. ("UNS Gas" or the "Company") and UNS Electric, Inc ("UNS Electric") (collectively the "UniSource Energy Companies").

Q. Please describe your education and professional background.

A. I graduated from Northern Arizona University ("NAU") in 1991 earning a Bachelor of Science degree in Mathematics with an extended major in Statistics and then completed graduate work in Statistics at NAU. During my tenure at TEP, I completed a Masters of Business Administration at the University of Phoenix. After leaving NAU, I was hired by Pima Association of Governments in 1992 in the Travel Reduction Program, which reduces vehicle emissions by targeting major employers to reduce employee's travel to and from work.

I was hired in 1996 by TEP as a Demand-Side Management ("DSM") Analyst, developing, analyzing and researching new DSM and energy-related market programs. In addition, I implemented and reported progress of existing DSM programs and then transitioned them into market-transformation programs. In 1999, I moved into the Pricing and Rates Department, developing cost of service and revenue requirement models. In 2002, I was promoted to the Director of the Pricing and Rates Department. I then accepted the position of Director of Conservation Services. Most recently my position was expanded to include

Renewable Programs. I manage the successful TEP Guarantee Home Program and, for the past year, have been researching and developing new DSM programs for all three UniSource Energy Companies.

Q. On whose behalf are you filing your Rebuttal Testimony in this proceeding?

A. My Testimony is filed on behalf of UNS Gas.

Q. What is the purpose of your Rebuttal Testimony in this proceeding?

A. The purpose of my Rebuttal Testimony is to respond to certain recommendations made by Ms. Julie McNeely-Kirwan on behalf of Commission Staff with regard to DSM matters.

Q. Did you file Direct Testimony in this proceeding?

A. No, I did not. However, due to my close involvement in the proposal, analysis, monitoring and reporting of DSM programs for the Company, I was asked to respond to Ms. McNeely-Kirwan's Direct Testimony.

Q. Will you also be responding to Ms. McNeely-Kirwan's Direct Testimony on topics other than DSM?

A. No. Mr. D. Bentley Erdwurm responds to certain comments made by Ms. McNeely-Kirwan with regard to the customer service charge and its impact on the Customer Assistance Residential Energy Support ("CARES") program and can answer questions regarding the functioning of the DSM Adjustor Mechanism. Mr. Gary Smith responds to her Direct Testimony on Warm Spirits.

Q. Please summarize your Rebuttal Testimony.

A. My Rebuttal Testimony focuses on Ms. McNeely-Kirwan's recommendations about the DSM programs themselves and for ease of review, tracks Ms. McNeely-Kirwan's Direct

Testimony on these issues. In general, UNS Gas agrees with the majority of Staff's recommendations about DSM. However, as discussed in more detail below, there are a few recommendations from Ms. McNeely-Kirwan that we are requesting be modified.

II. DEMAND SIDE MANAGEMENT.

A. Benefits and Costs of DSM

Q. In her Direct Testimony – at page 9, lines 18-21 – Ms. McNeely-Kirwan urges the consideration of the benefits and costs of DSM to society and states that the Commission has adopted the use of the Societal Cost Test. Do you have any response?

A. Yes. I believe that Ms. McNeely-Kirwan's description of Decision No. 57589 (October 29, 1991) merits clarification. Ms. McNeely-Kirwan is correct that the Commission expressed a preference for the Societal Cost Test back in 1991. As an initial matter, however, it is not clear that Decision No. 57589 applies the Societal Cost Test to DSM. Specifically, on page 25 of Decision No. 57589, the Commission summarized its order and stated that one of its objectives is to adopt the Societal Cost Test "for all new power plants."

Even assuming that the Societal Cost Test was intended to be applied to all resource planning, including DSM, the Commission was careful to note that the Societal Cost Test must be tempered with economic concerns, such as ratepayer concerns, utility financial stability and economic growth within the service areas. While Ms. McNeely-Kirwan is correct that the Commission directed that environmental concerns be considered in resource planning, the Commission was clear in its objective that such concerns must be balanced with other important considerations:

> This Commission wants to state loudly and clearly that it has <u>a goal to have financially sound utilities and reasonable rates for consumers, while at the same</u>

time minimizing the effect on our fragile environment. Even though the primary focus of this docket was on resource planning and environmental concerns, it is our firm commitment to strive for the proper balancing of all three of the above listed concerns.

See Decision No. 57589 at 24. (Emphasis in original).

In order to strike the right balance, the Commission ordered that a task force be formed to "identify and quantify the various environmental costs and other externalities such as resource diversity, land use, or economic development." Decision No. 57589 at 10. The task force was directed to identify costs to be included in the Societal Costs and outline how costs are to be quantified and/or monetized. It was also to address the suitability of evaluating costs on a qualitative basis when they could not be quantified or monetized. I am not aware of the Commission adopting any recommendations of the task force. Thus, questions still remain about the Societal Cost Test as to (1) what costs are to be included in the Societal Cost Test, and (2) how these costs are to be treated in evaluation. No determination has ever been made as to how these benefits and costs are to be measured. UNS Gas believes the test it has applied in this case – namely the Total Resource Cost Test ("TRC") - is a more concrete, quantitative analysis that should be used in order to understand the costs and benefits of DSM measures.

In several places throughout her Direct Testimony, Ms. McNeely-Kirwan makes reference to societal costs and benefits (*See e.g.* page 23, line 15; page 24, line 4; page 30, line 10). I would point out again, such costs and benefits have not been formally adopted by this Commission.

Q. **On page 10, Ms. McNeely-Kirwan goes on to describe the societal costs of a DSM program. Do you have any comments about her description?**

A. Again, I am unaware that the Commission has adopted any formal definition of societal costs with regard to DSM programs.

B. <u>Current DSM Programs.</u>

Q. At page 11, at lines 2-4 in her Direct Testimony, Ms. McNeely-Kirwan recommends that the Company submit detailed program proposals to the Commission as soon as possible, rather than waiting for the conclusion of the UNS Electric rate case. Do you have any response to this recommendation?

A. UNS Gas will file detailed program proposals as soon as possible. However, I would note that our cost benefit analyses were conducted assuming some economies of scope and scale through joint program implementation of some measures with UNS Electric. Because we believe that taking advantage of such economies are appropriate, the program proposals that we will file will assume some joint program implementation and administration.

Q. What information will be included in the detailed program proposals?

A. UNS Gas is working to refine the previous analysis and program descriptions based on Staff's recommendations. We have updated the avoided costs numbers to be consistent through-out the UniSource Energy Companies for all DSM evaluations. In addition, we corrected a few errors in the efficiency calculations and provided greater detail in the documentation for the cost benefit calculations. An analysis of the low income weatherization ("LIW") program was also completed to identify energy savings associated with measures installed through that program. UNS Gas is also updating the program descriptions with the information requested by Ms. McNeely-Kirwan as well as including information requested on the overall DSM portfolio. UNS Gas has combined the Commercial Cooking Program and the Commercial HVAC Retrofit into one program to allow customers to choose the measures that serve their needs while achieving economies of scale to minimize administrative and overhead costs.

Q. Also in her Direct Testimony, at page 14, lines 11-13, Ms. McNeely-Kirwan recommends that the therm savings and cost-effectiveness of the LIW program should be determined. Do you have any response to this recommendation?

A. It is difficult to determine the therm savings and cost-effectiveness of the existing LIW program with precision, given the wide variety of weatherization activities that can occur and the differing degrees to which they are installed and the limited records provided to UNS Gas. Even so, we have asked the Northern Arizona Council of Government ("NACOG") to provide some information to help assess the savings resulting from the LIW program. Attached as Exhibit DRS-1 is a letter received from Ms. Margaret Keener, NACOG's LIW Program Manager. She provides information regarding the weatherization measures implemented on the homes.

Ms. Keener estimates that weatherization efforts result in a 20 percent reduction in household energy use at a minimum. In addition, UNS Gas provides funds that are leveraged to acquire additional funds from government agencies. Numbers provided by NACOG suggest that for every dollar supplied by UNS Gas, NACOG is able to leverage about $1.32 from government sources. In other words, customers receive $2.32 worth of energy efficiency improvements for every $1.00 UNS Gas applies.

Q. Can you provide an estimate of the annual therm savings per LIW participant?

A. Yes, through an analysis of customer data through 2006 and confirming through test-year data (Schedule H-2, page 1). A customer qualifying for the LIW program also qualifies for CARES participation. A general review of all CARES customer annual gas consumption indicates that a typical 2006 CARES customer consumes about 500 therms per year. Using NACOG's statement that a LIW project must achieve at least a 20 percent annual energy consumption reduction, I estimate that annual gas consumption reductions of at least 100 therms for each LIW participant under a cursory analysis of the existing program.

However, as described below, UNS Gas is taking steps to better determine savings for the LIW program on a going forward basis.

Q. Ms. McNeely Kirwan describes – at page 15 at lines 16-26 in her Direct Testimony – several cost-effectiveness tests and concludes that UNS should include data required to calculate each of its proposed programs on a Societal Cost Test basis. Do you have response to her description or her suggestion?

A. UNS Gas believes that proper DSM evaluation involves the use of several DSM cost-effectiveness tests. This is consistent with the Commission's objective in Decision No. 57589 to carefully balance environmental concerns with economic concerns. In addition, the October 2001 California Standard Practice Manual "Economic Analysis of Demand Side Management Programs and Projects," attached hereto as Exhibit DRS-2, recognizes the importance and limitations of the Participant test, Ratepayer Impact Measure ("RIM"), TRC test and Program Administrator Cost Test. The Societal Cost Test is defined as a subset of the TRC test in that manual. Given the advances in DSM program evaluation testing described in the October 2001 California Standard Practice Manual, the Commission should now encourage utilities to use a wider spectrum of the cost effectiveness evaluation tools available when reviewing possible DSM programs for submittal to the Commission for approval.

In addition and as I discussed above, the manner in which the Societal Cost Test was to be calculated was to be determined by the task force per Decision No. 57589, assuming the Societal Cost Test applied to DSM programs. Again, the Commission does not appear to have adopted any particular calculation. In the interest of coöperation, however, we will include a form of the Societal Cost Test. In order to reach Societal Cost Test results, TEP replaced the utility capital discount rate with a societal discount rate and quantified the environmental benefits that are expected to result from DSM measures installed in terms of pounds of Carbon Dioxide.

C. Proposed New Programs.

Q. Do you have any response to Ms. McNeely-Kirwan's recommendation at page 20, lines 1-2, that UNS Gas provide information regarding verification and inspection of the LIW program in its program proposals?

A. UNS Gas intends to set up a database to better track the installations made through the LIW program. Proposed modifications to the LIW program design provide UNS Gas the ability to better determine therm savings from weatherization measures in future years. A defined list of weatherization measures and equipment replacement has been identified for use by the agencies who deliver the LIW program for UNS Gas. Engineering simulations determine the deemed therm reduction from installation of each measure. The new process will require weatherization agencies to collect and report more detailed information about the work completed in each household. With an appropriate amount of detail about products or equipment removed and products or equipment installed, UNS Gas can apply deemed savings calculations to determine therm savings and cost effectiveness of the program. This should address Ms. McNeely-Kirwan's concerns regarding verification and inspection of the LIW program.

D. Program Administration and Implementation.

Q. Do you have any response to Ms. McNeely-Kirwan's recommendations on pages 21 to 23 concerning the Company's filing of a portfolio plan?

A. The Company will file a portfolio plan and individual DSM program proposals for those programs it recommends be implemented for UNS Gas customers. The Company will endeavor to include all of the information requested by Ms. McNeely-Kirwan and will file this information as soon as possible. I would note, however, that her requested information includes societal costs and benefits of each measure or program and, as I discuss earlier in my Testimony, the Commission has not defined these societal costs and benefits.

E. <u>Monitoring and Evaluation</u>.

Q. On pages 23 to 25 of her Direct Testimony, Ms. McNeely-Kirwan makes some recommendations with regard to monitoring DSM programs. As an initial matter, do you agree that monitoring DSM is a productive activity?

A. Yes. I agree with Ms. McNeely-Kirwan that it is important to periodically analyze DSM programs to make sure that they are operating effectively, to determine if improvements should be made, and to discontinue those programs that no longer make sense for our customers. In order to do so, we propose a baseline study. This baseline study is necessary to establish the current level of deployment and saturation of energy efficiency technologies in the market, assess the level of market penetration that each program may be able to realize over time, identify opportunities for additional energy efficiency improvements and collect data for market and technology characteristics to support future program planning and evaluation and measurement activities. Examples of the kind of information collected in a baseline study include:

- Non-residential and residential facility types and characteristics (e.g., square footage, vintage);
- Equipment types and characteristics;
- Saturation of energy system technologies;
- Energy system operational characteristics; and
- Current practices of energy system specifics and designers.

UNS Gas seeks approval to begin the process of selecting a contractor and conducting the baseline study. Since the baseline study performance characteristics for most of the efficiency measures included in the plan are already well known and the cost-effectiveness of most measures has been confirmed, UNS Gas seeks approval to launch selected programs concurrently with the execution of the baseline study.

Q. Do you object to creating a monitoring plan for each program and describing such in the program proposals?

A. No, the Company will draft and submit monitoring plans for each of its DSM programs.

Q. Do you agree with the information requested to be filed in semi-annual reports?

A. While the Company is willing to provide the Commission with the information requested by Ms. McNeely-Kirwan, the Company requests that such reporting be done annually, as opposed to semi-annually. If the Company is permitted to report the information annually, it believes that it will be able to do a more comprehensive report within 90 days after the end of each year. In addition, since gas consumption in the UNS Gas territory tends to be winter seasonal, a one-year reporting interval is far more meaningful in providing program results information than a six-month interval.

F. <u>Marketing and Advertisement of the UNS Gas DSM Programs</u>.

Q. Do you agree with the Staff's recommendation on page 26 of Ms. McNeely-Kirwan's Direct Testimony that UNS Gas provide more detailed information regarding the marketing of LIW in its program proposal?

A. Yes. The marketing of the LIW program is conducted by the outside agencies currently administering the program. However, I would be happy to contact those agencies and ask them to provide additional information regarding their marketing efforts.

G. Cost Recovery of DSM Programs.

Q. Do you agree with the Staff's analysis of the appropriate cost recovery mechanism for DSM programs that Ms. McNeely-Kirwan describes in her Direct Testimony at pages 27 to 28?

A. Yes. Ms. McNeely-Kirwan is correct that DSM costs should be timely recovered, cost recovery should be flexible, and these costs are not appropriately placed in the purchase gas adjustor. I further agree with her that DSM costs should be transparent to ratepayers. Thus, we are in agreement that a DSM adjustor mechanism is the most appropriate way to recover DSM costs.

Q. Ms. McNeely-Kirwan recommends that by January 31 of each year, UNS should file information to set the DSM adjustor charge. Do you have any response to this recommendation?

A. The Company would not have the necessary data by January 31 to file for the next year. We would request that the filing be made on April 1 of each year. This would move an annual adjustment back to May 15 or June 1, given Ms. McNeely-Kirwan's proposed timing that she describes in her Direct Testimony. UNS Gas is happy to provide the information requested by Ms. McNeely-Kirwan.

Q. In her Direct Testimony at pages 29 to 30, Ms. McNeely-Kirwan states that initially only funding for LIW should be placed in the DSM Adjustor Mechanism. Do you have any comments?

A. While I believe the intent of Ms. McNeely-Kirwan's recommendation is to eliminate funding for those programs not yet in operation, the Company is close to implementing several programs and her recommendation would preclude the Company from recovering start-up costs for those programs for several months. In order to begin to timely recover start-up costs, I would propose that LIW funds ($113,400), as well as 50 percent of the funds estimated for the new DSM programs ($460,000) be included in the DSM Adjustor Mechanism immediately upon the Commission rendering a decision in this case.

Q. Are there any other costs that should be included in the DSM Adjustor Mechanism right away?

A. Yes. As mentioned above, consistent with Ms. McNeely-Kirwan's recommendation that the Company implement meaningful monitoring and evaluation of DSM programs, the Company seeks cost recovery to commission a baseline study. The costs associated with the baseline study are properly recovered through the DSM Adjustor Mechanism.

Q. What would the initial DSM charge be, if the Commission approves your recommendations to recover 50 percent of the other DSM programs plus the costs to commission a baseline study?

A. The initial charge would be $0.004148 per therm, resulting in a $0.20 monthly charge for the average residential customer using 48 therms per month.

Q. Does this conclude your Rebuttal Testimony?

A. Yes.

EXHIBIT

DAS-1

Northern Arizona Council of Governments

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KENNETH J. SWEET
EXECUTIVE DIRECTOR

February 28, 2007

Tom Hansen
Vice President
Tucson Electric Power
P.O. Box 457
St. Johns, AZ. 85936

Dear Mr. Hansen:

Northern Arizona Council of Governments (NACOG) Weatherization Program's low-income recipients have hugely benefited from Unisource contributions.

Households who receive Weatherization assistance live with poverty level incomes ($10,210 for a household of one; $20,650 for a household of four). Large utility bills impact low-income families. Utilities consume a larger portion of the low-income family's income than they consume of the higher income family's income. About 20% of a low income family's income is used for utilities compared to 5% for a higher income family. Low-income persons must often make monthly decisions as to whether to pay rent or mortgage, pay utilities, or buy food.

The Weatherization Program performs diagnostic tests and installs energy saving measures on homes in order to reduce the family's energy burden and make the home more energy efficient. First, the Weatherization program performs a computerized energy audit on the home. The audit results define the measures that will save energy and make the home more energy efficient. Only those measures that will contribute to a minimum 20% energy savings are accomplished. Second, the Weatherization crews install those elements which make the home more energy efficient and reduce the family's energy burden.

Last year NACOG received $39,000 from Unisource and assisted twenty-one families in the Unisource gas service areas in Navajo, Coconino, and Yavapai counties. The Unisource investments were partnered with the federal Department of Energy (DOE) and Low Income Home Energy Assistance Program (LIHEAP) funds. The maximum Unisource investment was $2,000. Sample measures taken were the installation of attic insulation, replacement of non-operating doors, and replacement of leaky, broken windows with dual-pane windows.

By combining limited resources with Unisource, there were energy savings of 20% to 40% in each home.

About eighty percent of the home that the NACOG Weatherization program assists are older mobile homes. The difference for the lives of the low income participants is in warmth, health, safety, and less income depletion. There is an advantage to the neighborhood as Weatherization helps stabilize the affordable housing stock. There is a saving to society also as the cumulative energy demand is reduced.

Please contact me if you wish any further information.

Thank you for your concern for the less fortunate customers of Unisource.

Sincerely,

Margaret Keener

Margaret Keener
Division Chief

EXHIBIT

DAS-2

CALIFORNIA STANDARD PRACTICE MANUAL

ECONOMIC ANALYSIS OF DEMAND-SIDE PROGRAMS AND PROJECTS

OCTOBER 2001

Table of Contents

Page

Chapter 1

Basic Methodology

Background

Since the 1970s, conservation and load management programs have been promoted by the California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) as alternatives to power plant construction and gas supply options. Conservation and load management (C&LM) programs have been implemented in California by the major utilities through the use of ratepayer money and by the CEC pursuant to the CEC legislative mandate to establish energy efficiency standards for new buildings and appliances.

While cost-effectiveness procedures for the CEC standards are outlined in the Public Resources Code, no such official guidelines existed for utility-sponsored programs. With the publication of the *Standard Practice for Cost-Benefit Analysis of Conservation and Load Management Programs* in February 1983, this void was substantially filled. With the informal "adoption" one year later of an appendix that identified cost-effectiveness procedures for an "All Ratepayers" test, C&LM program cost effectiveness consisted of the application of a series of tests representing a variety of perspectives-participants, non-participants, all ratepayers, society, and the utility.

The Standard Practice Manual was revised again in 1987-88. The primary changes (relative to the 1983 version), were: (1) the renaming of the "Non-Participant Test" to the "Ratepayer Impact Test"; (2) renaming the All-Ratepayer Test" to the "Total Resource Cost Test."; (3) treating the "Societal Test" as a variant of the "Total Resource Cost Test;" and, (4) an expanded explanation of "demand-side" activities that should be subjected to standard procedures of benefit-cost analysis.

Further changes to the manual captured in this (2001) version were prompted by the cumulative effects of changes in the electric and natural gas industries and a variety of changes in California statute related to these changes. As part of the major electric industry restructuring legislation of 1996 (AB1890), for example, a public goods charge was established that ensured minimum funding levels for "cost effective conservation and energy efficiency" for the 1998-2002 period, and then (in 2000) extended through the year 2011. Additional legislation in 2000 (AB1002) established a natural gas surcharge for similar purposes. Later in that year, the Energy Security and Reliability Act of 2000 (AB970) directed the California Public Utilities Commission to establish, by the Spring of 2001, a distribution charge to provide revenues for a self generation program and a directive to consider changes to cost-effectiveness methods to better account for reliability concerns.

In the Spring of 2001, a new state agency — the Consumer Power and Conservation Financing Authority — was created. This agency is expected to provide additional revenues in the form of state revenue bonds that could supplement the amount and type of public financial resources to finance energy efficiency and self generation activities.

The modifications to the Standard Practice Manual reflect these more recent developments in several ways. First, the "Utility Cost Test" is renamed the "Program Administrator Test" to include the assessment of programs managed by other agencies. Second, a definition of self generation as a type of "demand-side" activity is included. Third, the description of the various potential elements of "externalities" in the Societal version of the TRC test is expanded. Finally the limitations section outlines the scope of this manual and elaborates upon the processes traditionally instituted by implementing agencies to adopt values for these externalities and to adopt the the policy rules that accompany this manual.

Demand-Side Management Categories and Program Definitions

One important aspect of establishing standardized procedures for cost-effectiveness evaluations is the development and use of consistent definitions of categories, programs, and program elements.

This manual employs the use of general program categories that distinguish between different types of demand-side management programs, conservation, load management, fuel substitution, load building and self-generation. Conservation programs reduce electricity and/or natural gas consumption during all or significant portions of the year. 'Conservation' in this context includes all 'energy efficiency improvements'. An energy efficiency improvement can be defined as reduced energy use for a comparable level of service, resulting from the installation of an energy efficiency measure or the adoption of an energy efficiency practice. Level of service may be expressed in such ways as the volume of a refrigerator, temperature levels, production output of a manufacturing facility, or lighting level per square foot. Load management programs may either reduce electricity peak demand or shift demand from on peak to non-peak periods.

Fuel substitution and load building programs share the common feature of increasing annual consumption of either electricity or natural gas relative to what would have happened in the absence of the program. This effect is accomplished in significantly different ways, by inducing the choice of one fuel over another (fuel substitution), or by increasing sales of electricity, gas, or electricity and gas (load building). Self generation refers to distributed generation (DG) installed on the customer's side of the electric utility meter, which serves some or all of the customer's electric load, that otherwise would have been provided by the central electric grid.

In some cases, self generation products are applied in a combined heat and power manner, in which case the heat produced by the self generation product is used on site to provide some or all of the customer's thermal needs. Self generation technologies include, but are not limited to, photovoltaics, wind turbines, fuel cells, microturbines, small gas-fired turbines, and gas-fired internal combustion engines.

Fuel substitution and load building programs were relatively new to demand-side management in California in the late 1980s, born out of the convergence of several factors that translated into average rates that substantially exceeded marginal costs. Proposals by utilities to implement programs that increase sales had prompted the need for additional procedures for estimating program cost effectiveness. These procedures maybe applicable in a new context. AB 970 amended the Public Utilities Code and provided the motivation to develop a cost-effectiveness method that can be used on a common basis to evaluate all programs that will remove electric load from the centralized grid, including energy efficiency, load control/demand-responsiveness programs and self-generation. Hence, self-generation was also added to the list of demand side management programs for cost-effectiveness evaluation. In some cases, self-generation programs installed with incremental load are also included since the definition of self-generation is not necessarily confined to projects that reduce electric load on the grid. For example, suppose an industrial customer installs a new facility with a peak consumption of 1.5 MW, with an integrated on-site 1.0 MW gas fired DG unit. The combined impact of the new facility is *load building* since the new facility can draw up to 0.5 MW from the grid, even when the DG unit is running. The proper characterization of each type of demand-side management program is essential to ensure the proper treatment of inputs and the appropriate interpretation of cost-effectiveness results.

Categorizing programs is important because in many cases the same specific device can be and should be evaluated in more than one category. For example, the promotion of an electric heat pump can and should be treated as part of a conservation program if the device is installed in lieu of a less efficient electric resistance heater. If the incentive induces the installation of an electric heat pump instead of gas space heating, however, the program needs to be considered and evaluated as a fuel substitution program. Similarly, natural gas-fired self-generation, as well as self-generation units using other non-renewable fossil fuels, must be treated as fuel-substitution. In common with other types of fuel-substitution, any costs of gas transmission and distribution, and environmental externalities, must be accounted for. In addition, cost-effectiveness analyses of self-generation should account for utility interconnection costs. Similarly, a thermal energy storage device should be treated as a load management program when the predominant effect is to shift load. If the acceptance of a utility incentive by the customer to, install the energy storage device is a decisive aspect of the customer's decision to remain an electric utility customer (i.e., to reject or defer the option of installing a gas-fired cogeneration system), then the predominant effect of the thermal energy storage device has been to substitute electricity service for the natural gas service that would have occurred in the absence of the program.

In addition to Fuel Substitution and Load Building Programs, recent utility program proposals have included reference to "load retention," "sales retention," "market retention," or "customer retention" programs. In most cases, the effect of such programs is identical to either a Fuel Substitution or a Load Building program — sales of one fuel are increased relative to sales without the program. A case may be made, however, for defining a separate category of program called "load retention." One unambiguous example of a load retention program is the situation where a program keeps a customer from relocating to another utility service area. However, computationally the equations and guidelines included in this manual to accommodate Fuel Substitution and Load Building programs can also handle this special situation as well.

Basic Methods

This manual identifies the cost and benefit components and cost-effectiveness calculation procedures from four major perspectives: Participant, Ratepayer Impact Measure (RIM), Program Administrator Cost (PAC), and Total Resource Cost (TRC). A fifth perspective, the Societal, is treated as a variation on the Total Resource Cost test. The results of each perspective can be expressed in a variety of ways, but in all cases it is necessary to calculate the net present value of program impacts over the lifecycle of those impacts.

Table I summarizes the cost-effectiveness tests addressed in this manual. For each of the perspectives, the table shows the appropriate means of expressing test results. The primary unit of measurement refers to the way of expressing test results that are considered by the staffs of the two Commissions as the most useful for summarizing and comparing demand-side management (DSM) program cost-effectiveness. Secondary indicators of cost-effectiveness represent supplemental means of expressing test results that are likely to be of particular value for certain types of proceedings, reports, or programs.

This manual does not specify how the cost-effectiveness test results are to be displayed or the level at which cost-effectiveness is to be calculated (e.g., groups of programs, individual programs, and program elements for all or some programs). It is reasonable to expect different levels and types of results for different regulatory proceedings or for different phases of the process used to establish proposed program-funding levels. For example, for summary tables in general rate case proceedings at the CPUC, the most appropriate tests may be the RIM lifecycle revenue impact, Total Resource Cost, and Program Administrator Cost test results for programs or groups of programs. The analysis and review of program proposals for the same proceeding may include Participant test results and various additional indicators of cost-effectiveness from all tests for each individual program element. In the case of cost-effectiveness evaluations conducted in the context of integrated long-term resource planning activities, such detailed examination of multiple indications of costs and benefits may be impractical.

Table I
Cost-Effectiveness Tests

Participant	
Primary	Secondary
Net present value (all participants)	Discounted payback (years) Benefit-cost ratio Net present value (average participant)
Ratepayer Impact Measure	
Lifecycle revenue impact per Unit of energy (kWh or therm) or demand customer (kW) Net present value	Lifecycle revenue impact per unit Annual revenue impact (by year, per kWh, kW, therm, or customer) First-year revenue impact (per kWh, kW, therm, or customer) Benefit-cost ratio
Total Resource Cost	
Net present value (NPV)	Benefit-cost ratio (BCR) Levelized cost (cents or dollars per unit of energy or demand) Societal (NPV, BCR)
Program Administrator Cost	
Net present value	Benefit-cost ratio Levelized cost (cents or dollars per unit of energy or demand)

Rather than identify the precise requirements for reporting cost-effectiveness results for all types of proceedings or reports, the approach taken in this manual is to (a) specify the components of benefits and costs for each of the major tests, (b) identify the equations to be used to express the results in acceptable ways; and (c) indicate the relative value of the different units of measurement by designating primary and secondary test results for each test.

It should be noted that for some types of demand-side management programs, meaningful cost-effectiveness analyses cannot be performed using the tests in this manual. The following guidelines are offered to clarify the appropriated "match" of different types of programs and tests:

1. For generalized information programs (e.g., when customers are provided generic information on means of reducing utility bills without the benefit of on-site evaluations or customer billing data), cost-effectiveness tests are not expected because of the extreme difficulty in establishing meaningful estimates of load impacts.

2. For any program where more than one fuel is affected, the preferred unit of measurement for the RIM test is the lifecycle revenue impacts per customer, with gas and electric components reported separately for each fuel type and for combined fuels.

3. For load building programs, only the RIM tests are expected to be applied. The Total Resource Cost and Program Administrator Cost tests are intended to identify cost-effectiveness relative to other resource options. It is inappropriate to consider increased load as an alternative to other supply options.

4. Levelized costs may be appropriate as a supplementary indicator of cost per unit for electric conservation and load management programs relative to generation options and gas conservation programs relative to gas supply options, but the levelized cost test is not applicable to fuel substitution programs (since they combine gas and electric effects) or load building programs (which increase sales).

The delineation of the various means of expressing test results in **Table 1** is not meant to discourage the continued development of additional variations for expressing cost-effectiveness. Of particular interest is the development of indicators of program cost effectiveness that can be used to assess the appropriateness of program scope (i.e. level of funding) for General Rate Case proceedings. Additional tests, if constructed from the net present worth in conformance with the equations designated in this manual, could prove useful as a means of developing methodologies that will address issues such as the optimal timing and scope of demand-side management programs in the context of overall resource planning.

Balancing the Tests

The tests set forth in this manual are not intended to be used individually or in isolation. The results of tests that measure efficiency, such as the Total Resource Cost Test, the Societal Test, and the Program Administrator Cost Test, must be compared not only to each other but also to the Ratepayer Impact Measure Test. This multi-perspective approach will require program administrators and state agencies to consider tradeoffs between the various tests. Issues related to the precise weighting of each test relative to other tests and to developing formulas for the definitive balancing of perspectives are outside the scope of this manual. The manual, however, does provide a brief description of the strengths and weaknesses of each test (Chapters 2, 3, 4, and 5) to assist users in qualitatively weighing test results.

Limitations: Externality Values and Policy Rules

The list of externalities identified in Chapter 4, page 27, in the discussion on the Societal version of the Total Resource Cost test is broad, illustrative and by no means exhaustive. Traditionally, implementing agencies have independently determined the details such as the components of the externalities, the externality values and the policy rules which specify the contexts in which the externalities and the tests are used.

Externality Values

The values for the externalities have not been provided in the manual. There are separate studies and methodologies to arrive at these values. There are also separate processes instituted by implementing agencies before such values can be adopted formally.

Policy Rules

The appropriate choice of inputs and input components vary by program area and project. For instance, low income programs are evaluated using a broader set of non-energy benefits that have not been provided in detail in this manual. Implementing agencies traditionally have had the discretion to use or to not use these inputs and/or benefits on a project- or program-specific basis. The policy rules that specify the contexts in which it is appropriate to use the externalities, their components, and tests mentioned in this manual are an integral part of any cost-effectiveness evaluation. These policy rules are not a part of this manual.

To summarize, the manual provides the methodology and the cost-benefit calculations only. The implementing agencies (such as the California Public Utilities Commission and the California Energy Commission) have traditionally utilized open public processes to incorporate the diverse views of stakeholders before adopting externality values and policy rules which are an integral part of the cost-effectiveness evaluation.

Chapter 2

Participant Test

Definition

The Participants Test is the measure of the quantifiable benefits and costs to the customer due to participation in a program. Since many customers do not base their decision to participate in a program entirely on quantifiable variables, this test cannot be a complete measure of the benefits and costs of a program to a customer.

Benefits and Costs

The benefits of participation in a demand-side program include the reduction in the customer's utility bill(s), any incentive paid by the utility or other third parties, and any federal, state, or local tax credit received. The reductions to the utility bill(s) should be calculated using the actual retail rates that would have been charged for the energy service provided (electric demand or energy or gas). Savings estimates should be based on gross savings, as opposed to net energy savings[1].

In the case of fuel substitution programs, benefits to the participant also include the avoided capital and operating costs of the equipment/appliance not chosen. For load building programs, participant benefits include an increase in productivity and/or service, which is presumably equal to or greater than the productivity/ service without participating. The inclusion of these benefits is not required for this test, but if they are included then the societal test should also be performed.

The costs to a customer of program participation are all out-of-pocket expenses incurred as a result of participating in a program, plus any increases in the customer's utility bill(s). The out-of-pocket expenses include the cost of any equipment or materials purchased, including sales tax and installation; any ongoing operation and maintenance costs; any removal costs (less salvage value); and the value of the customer's time in arranging for the installation of the measure, if significant.

[1] Gross energy savings are considered to be the savings in energy and demand seen by the participant at the meter. These are the appropriate program impacts to calculate bill reductions for the Participant Test. Net savings are assumed to be the savings that are attributable to the program. That is, net savings are gross savings minus those changes in energy use and demand that would have happened even in the absence of the program. For fuel substitution and load building programs, gross-to-net considerations account for the impacts that would have occurred in the absence of the program.

How the Results can be Expressed

The results of this test can be expressed in four ways: through a net present value per average participant, a net present value for the total program, a benefit-cost ratio or discounted payback. The primary means of expressing test results is net present value for the total program; discounted payback, benefit-cost ratio, and per participant net present value are secondary tests.

The discounted payback is the number of years it takes until the cumulative discounted benefits equal or exceed the cumulative discounted costs. The shorter the discounted payback, the more attractive or beneficial the program is to the participants. Although "payback period" is often defined as undiscounted in the textbooks, a discounted payback period is used here to approximate more closely the consumer's perception of future benefits and costs.[2]

Net present value (NPVp) gives the net dollar benefit of the program to an average participant or to all participants discounted over some specified time period. A net present value above zero indicates that the program is beneficial to the participants under this test.

The benefit-cost ratio (BCRp) is the ratio of the total benefits of a program to the total costs discounted over some specified time period. The benefit-cost ratio gives a measure of a rough rate of return for the program to the participants and is also an indication of risk. A benefit-cost ratio above one indicates a beneficial program.

Strengths of the Participant Test

The Participants Test gives a good "first cut" of the benefit or desirability of the program to customers. This information is especially useful for voluntary programs as an indication of potential participation rates.

For programs that involve a utility incentive, the Participant Test can be used for program design considerations such as the minimum incentive level, whether incentives are really needed to induce participation, and whether changes in incentive levels will induce the desired amount of participation.

These test results can be useful for program penetration analyses and developing program participation goals, which will minimize adverse ratepayer impacts and maximize benefits.

For fuel substitution programs, the Participant Test can be used to determine whether program participation (i.e. choosing one fuel over another) will be in the long-run best interest of the customer. The primary means of establishing such assurances is the net present value, which looks at the costs and benefits of the fuel choice over the life of the equipment.

[2] It should be noted that if a demand-side program is beneficial to its participants ($NPVp \geq 0$ and $BCRp \geq 1.0$) using a particular discount rate, the program has an internal rate of return (IRR) of at least the value of the discount rate.

Weaknesses of the Participant Test

None of the Participant Test results (discounted payback, net present value, or benefit-cost ratio) accurately capture the complexities and diversity of customer decision-making processes for demand-side management investments. Until or unless more is known about customer attitudes and behavior, interpretations of Participant Test results continue to require considerable judgment. Participant Test results play only a supportive role in any assessment of conservation and load management programs as alternatives to supply projects.

Formulae

The following are the formulas for discounted payback, the net present value (NPVp) and the benefit-cost ratio (BCRp) for the Participant Test.

NPV_P	=	Bp - Cp
NPVavp	=	(Bp - Cp) / P
BCRp	=	Bp / Cp
DPp	=	Min j such that Bj > Cj

Where:

NPVp	=	Net present value to all participants
NPVavp	=	Net present value to the average participant
BCRp	=	Benefit-cost ratio to participants
DPp	=	Discounted payback in years
Bp	=	NPV of benefit to participants
Cp	=	NPV of costs to participants
Bj	=	Cumulative benefits to participants in year j
Cj	=	Cumulative costs to participants in year j
P	=	Number of program participants
J	=	First year in which cumulative benefits are cumulative costs.
d	=	Interest rate (discount)

The Benefit (Bp) and Cost (Cp) terms are further defined as follows:

$$BP = \sum_{t=1}^{N} \frac{BR_t + TC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{AB_{at} + PA_{at}}{(1+d)^{t-1}}$$

$$C = \sum_{t=1}^{N} \frac{PC_t + BI_t}{(1+d)^{t-1}}$$

Where:

BRt	=	Bill reductions in year t
Bit	=	Bill increases in year t

TCt	=	Tax credits in year t
INCt	=	Incentives paid to the participant by the sponsoring utility in year t[3]
PCt	=	Participant costs in year t to include: • Initial capital costs, including sales tax[4] • Ongoing operation and maintenance costs include fuel cost • Removal costs, less salvage value • Value of the customer's time in arranging for installation, if significant
PACat	=	Participant avoided costs in year t for alternate fuel devices (costs of devices not chosen)
Abat	=	Avoided bill from alternate fuel in year t

The first summation in the Bp equation should be used for conservation and load management programs. For fuel substitution programs, both the first and second summations should be used for Bp.

Note that in most cases, the customer bill impact terms (BRt, BIt, and AB_{at}) are further determined by costing period to reflect load impacts and/or rate schedules, which vary substantially by time of day and season. The formulas for these variables are as follows:

$$BR_t = \sum_{i=1}^{I} (\Delta EG_{it} \times AC:E_{it} \times K_{it}) + \sum_{i=1}^{I} (\Delta DG_{it} \times AC:D_{it} \times K_{it}) + OBR_t$$

AB_{at} = (Use BRt formula, but with rates and costing periods appropriate for the alternate fuel utility)

$$BI_t = \sum_{i=1}^{I} (\Delta EG_{it} \times AC:E_{it} \times (K_{it} - 1)) + \sum_{i=1}^{I} (\Delta DG_{it} \times AC:D_{it} \times (K_{it} - 1)) + OBI_t$$

Where:

ΔEG_{it}	=	Reduction in gross energy use in costing period i in year t
ΔDG_{it}	=	Reduction in gross billing demand in costing period i in year t
$AC:E_{it}$	=	Rate charged for energy in costing period i in year t

[3] Some difference of opinion exists as to what should be called an incentive. The term can be interpreted broadly to include almost anything. Direct rebates, interest payment subsidies, and even energy audits can be called incentives. Operationally, it is necessary to restrict the term to include only dollar benefits such as rebates or rate incentives (monthly bill credits). Information and services such as audits are not considered incentives for the purposes of these tests. If the incentive is to offset a specific participant cost, as in a rebate-type incentive, the full customer cost (before the rebate must be included in the PC_t term

[4] If money is borrowed by the customer to cover this cost, it may not be necessary to calculate the annual mortgage and discount this amount if the present worth of the mortgage payments equals the initial cost. This occurs when the discount rate used is equal to the interest rate of the mortgage. If the two rates differ (e.g., a loan offered by the utility), then the stream of mortgage payments should be discounted by the discount rate chosen.

$AC{:}D_{it}$	=	Rate charged for demand in costing period i in year t
K_{it}	=	1 when ΔEGit or ΔDGit is positive (a reduction) in costing period i in year t, and zero otherwise
OBR_t	=	Other bill reductions or avoided bill payments (e.g.,, customer charges, standby rates).
OBI_t	=	Other bill increases (i.e. customer charges, standby rates).
I	=	Number of periods of participant's participation

In load management programs such as TOU rates and air-conditioning cycling, there are often no direct customer hardware costs. However, attempts should be made to quantify indirect costs customers may incur that enable them to take advantage of TOU rates and similar programs.

If no customer hardware costs are expected or estimates of indirect costs and value of service are unavailable, it may not be possible to calculate the benefit-cost ratio and discounted payback period.

Chapter 3

The Ratepayer Impact Measure Test[5]

Definition

The Ratepayer Impact Measure (RIM) test measures what happens to customer bills or rates due to changes in utility revenues and operating costs caused by the program. Rates will go down if the change in revenues from the program is greater than the change in utility costs. Conversely, rates or bills will go up if revenues collected after program implementation are less than the total costs incurred by the utility in implementing the program. This test indicates the direction and magnitude of the expected change in customer bills or rate levels.

Benefits and Costs

The benefits calculated in the RIM test are the savings from avoided supply costs. These avoided costs include the reduction in transmission, distribution, generation, and capacity costs for periods when load has been reduced and the increase in revenues for any periods in which load has been increased. The avoided supply costs are a reduction in total costs or revenue requirements and are included for both fuels for a fuel substitution program. The increase in revenues are also included for both fuels for fuel substitution programs. Both the reductions in supply costs and the revenue increases should be calculated using net energy savings.

The costs for this test are the program costs incurred by the utility, *and/or other entities incurring costs and creating or administering the program,* the incentives paid to the participant, decreased revenues for any periods in which load has been decreased and increased supply costs for any periods when load has been increased. The utility program costs include initial and annual costs, such as the cost of equipment, operation and maintenance, installation, program administration, and customer dropout and removal of equipment (less salvage value). The decreases in revenues and the increases in the supply costs should be calculated for both fuels for fuel substitution programs using net savings.

How the Results can be Expressed

The results of this test can be presented in several forms: the lifecycle revenue impact (cents or dollars) per kWh, kW, therm, or customer; annual or first-year revenue impacts (cents or dollars per kWh, kW, therms, or customer); benefit-cost ratio; and net present value. The primary units of measurement are the lifecycle revenue impact, expressed as the change in rates (cents per kWh for electric energy, dollars per kW for electric capacity, cents per therm for natural gas) and the net present value. Secondary test results are the lifecycle revenue

[5] The Ratepayer Impact Measure Test has previously been described under what was called the "Non-Participant Test." The Non-Participant Test has also been called the "Impact on Rate Levels Test."

impact per customer, first-year and annual revenue impacts, and the benefit-cost ratio. LRI_{RIM} values for programs affecting electricity and gas should be calculated for each fuel individually (cents per kWh or dollars per kW and cents per therm) and on a combined gas and electric basis (cents per customer).

The lifecycle revenue impact (LRI) is the one-time change in rates or the bill change over the life of the program needed to bring total revenues in line with revenue requirements over the life of the program. The rate increase or decrease is expected to be put into effect in the first year of the program. Any successive rate changes such as for cost escalation are made from there. The first-year revenue impact (FRI) is the change in rates in the first year of the program or the bill change needed to get total revenues to match revenue requirements only for that year. The annual revenue impact (ARI) is the series of differences between revenues and revenue requirements in each year of the program. This series shows the cumulative rate change or bill change in a year needed to match revenues to revenue requirements. Thus, the ARIRIM for year six per kWh is the estimate of the difference between present rates and the rate that would be in effect in year six due to the program. For results expressed as lifecycle, annual, or first-year revenue impacts, negative results indicate favorable effects on the bills of ratepayers or reductions in rates. Positive test result values indicate adverse bill impacts or rate increases.

Net present value (NPV_{RIM}) gives the discounted dollar net benefit of the program from the perspective of rate levels or bills over some specified time period. A net present value above zero indicates that the program will benefit (lower) rates and bills.

The benefit-cost ratio (BCR RIM) is the ratio of the total benefits of a program to the total costs discounted over some specified time period. A benefit-cost ratio above one indicates that the program will lower rates and bills.

Strengths of the Ratepayer Impact Measure (RIM) Test

In contrast to most supply options, demand-side management programs cause a direct shift in revenues. Under many conditions, revenues lost from DSM programs have to be made up by ratepayers. The RIM test is the only test that reflects this revenue shift along with the other costs and benefits associated with the program.

An additional strength of the RIM test is that the test can be used for all demand-side management programs (conservation, load management, fuel substitution, and load building). This makes the RIM test particularly useful for comparing impacts among demand-side management options.

Some of the units of measurement for the RIM test are of greater value than others, depending upon the purpose or type of evaluation. The lifecycle revenue impact per customer is the most useful unit of measurement when comparing the merits of programs with highly variable scopes (e.g.,, funding levels) and when analyzing a wide range of programs that include both electric and natural gas impacts. Benefit-cost ratios can also be very useful for program design evaluations to identify the most attractive programs or program elements.

If comparisons are being made between a program or group of conservation/load management programs and a specific resource project, lifecycle cost per unit of energy and annual and first-year net costs per unit of energy are the most useful way to express test results. Of course, this requires developing lifecycle, annual, and first-year revenue impact estimates for the supply-side project.

Weaknesses of the Ratepayer Impact Measure (RIM) Test

Results of the RIM test are probably less certain than those of other tests because the test is sensitive to the differences between long-term projections of marginal costs and long-term projections of rates, two cost streams that are difficult to quantify with certainty.

RIM test results are also sensitive to assumptions regarding the financing of program costs. Sensitivity analyses and interactive analyses that capture feedback effects between system changes, rate design options, and alternative means of financing generation and non-generation options can help overcome these limitations. However, these types of analyses may be difficult to implement.

An additional caution must be exercised in using the RIM test to evaluate a fuel substitution program with multiple end use efficiency options. For example, under conditions where marginal costs are less than average costs, a program that promotes an inefficient appliance may give a more favorable test result than a program that promotes an efficient appliance. Though the results of the RIM test accurately reflect rate impacts, the implications for long-term conservation efforts need to be considered.

Formulae: The formulae for the lifecycle revenue impact (LRI RIM)' net present value (NPV RIM), benefit-cost ratio (BCR RIM)' the first-year revenue impacts and annual revenue impacts are presented below:

LRIRIM	=	(CRIM - BRIM) / E	
FRIRIM	=	(CRIM - BRIM) / E	for t = I
ARIRIMt	=	FRIRIM	for t = I
	=	(CRIMt - BRIMt)/Et	for t=2, ..., N
NPVRIM	=	BRIM-CRIM	

BCRRIM` = BRIM/CRIM where:

LRIRIM = Lifecycle revenue impact of the program per unit of energy (kWh or therm) or demand (kW) (the one-time change in rates) or per customer (the change in customer bills over the life of the program). (Note: An appropriate choice of kWh, therm, kW, and customer should be made)

FRIRIM = First-year revenue impact of the program per unit of energy, demand, or per customer.

ARIRIM = Stream of cumulative annual revenue impacts of the program per unit of energy, demand, or per customer. (Note: The terms in the ARI formula are not discounted; thus they are the nominal cumulative revenue impacts. Discounted cumulative revenue impacts may be calculated and submitted if they are indicated as such. Note also that the sum of the discounted stream of cumulative revenue impacts does not equal the LRI RIM')

NPVRIM = Net present value levels

BCRRIM = Benefit-cost ratio for rate levels

BRIM = Benefits to rate levels or customer bills
CRIM = Costs to rate levels or customer bills
E = Discounted stream of system energy sales (kWh or therms) or demand sales (kW) or first-year customers. (See Appendix D for a description of the derivation and use of this term in the LRIRIM test.)

The B_{RIM} and C_{RIM} terms are further defined as follows:

$$B_{RIM} \sum_{t=1}^{N} \frac{UAC_t + RG_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

$$C_{RIM} \sum_{t=1}^{N} \frac{UIC_t + RL_t + PRC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{RL_{at}}{(1+d)^{t-1}}$$

$$E = \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$

Where:

UACt = Utility avoided supply costs in year t
UICt = Utility increased supply costs in year t
RGt = Revenue gain from increased sales in year t
RLt = Revenue loss from reduced sales in year t
PRCt = Program Administrator program costs in year t
Et = System sales in kWh, kW or therms in year t or first year customers
UACat = Utility avoided supply costs for the alternate fuel in year t
Rlat = Revenue loss from avoided bill payments for alternate fuel in year t (i.e., device not chosen in a fuel substitution program)

For fuel substitution programs, the first term in the B RIM and C RIM equations represents the sponsoring utility (electric or gas), and the second term represents the alternate utility. The RIM test should be calculated separately for electric and gas and combined electric and gas.

The utility avoided cost terms (UAC_t, UIC_t, and UAC_{at}) are further determined by costing period to reflect time-variant costs of supply:

$$UCA_t = \sum_{i=1}^{I} (\Delta EN_{it} \times MC:E_{it} \times K_{it}) + \sum_{i=1}^{I} (\Delta DN_{it} \times MC:D_{it} \times K_{it})$$

UAC_{at} = (Use UACt formula, but with marginal costs and costing periods appropriate for the alternate fuel utility.)

$$UIC_t \sum_{i=1}^{I} (\Delta EN_{it} \times MC:E_{it} \times (K_{it} - 1)) + \sum_{i=1}^{I} (\Delta DN_{it} \times MC:D \times (K_{it} - 1))$$

Where:

[Only terms not previously defined are included here.]

ΔENit	=	Reduction in net energy use in costing period i in year t
ΔDNit	=	Reduction in net demand in costing period i in year t
MC:Eit	=	Marginal cost of energy in costing period i in year t
MC:Dit	=	Marginal cost of demand in costing period i in year t

The revenue impact terms (RG_t, RL_t, and RL_{at}) are parallel to the bill impact terms in the Participant Test. The terms are calculated exactly the same way with the exception that the net impacts are used rather than gross impacts. If a net-to-gross ratio is used to differentiate gross savings from net savings, the revenue terms and the participant's bill terms will be related as follows:

RGt	=	BIt	* (net-to-gross ratio)
RLt	=	BRt	* (net-to-gross ratio)
Rlat	=	Abat	* (net-to-gross ratio)

Chapter 4

Total Resource Cost Test[6]

Definition

The Total Resource Cost Test measures the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs.

The test is applicable to conservation, load management, and fuel substitution programs. For fuel substitution programs, the test measures the net effect of the impacts from the fuel not chosen versus the impacts from the fuel that is chosen as a result of the program. TRC test results for fuel substitution programs should be viewed as a measure of the economic efficiency implications of the total energy supply system (gas and electric).

A variant on the TRC test is the Societal Test. The Societal Test differs from the TRC test in that it includes the effects of externalities (e.g.,, environmental, national security), excludes tax credit benefits, and uses a different (societal) discount rate.

Benefits and Costs: This test represents the combination of the effects of a program on both the customers participating and those not participating in a program. In a sense, it is the summation of the benefit and cost terms in the Participant and the Ratepayer Impact Measure tests, where the revenue (bill) change and the incentive terms intuitively cancel (except for the differences in net and gross savings).

The benefits calculated in the Total Resource Cost Test are the avoided supply costs, the reduction in transmission, distribution, generation, and capacity costs valued at marginal cost for the periods when there is a load reduction. The avoided supply costs should be calculated using net program savings, savings net of changes in energy use that would have happened in the absence of the program. For fuel substitution programs, benefits include the avoided device costs and avoided supply costs for the energy, using equipment not chosen by the program participant.

The costs in this test are the program costs paid by both the utility and the participants plus the increase in supply costs for the periods in which load is increased. Thus all equipment costs, installation, operation and maintenance, cost of removal (less salvage value), and administration costs, no matter who pays for them, are included in this test. Any tax credits are considered a reduction to costs in this test. For fuel substitution programs, the costs also include the increase in supply costs for the utility providing the fuel that is chosen as a result of the program.

[6] This test was previously called the All Ratepayers Test

How the Results Can be Expressed

The results of the Total Resource Cost Test can be expressed in several forms: as a net present value, a benefit-cost ratio, or as a levelized cost. The net present value is the primary unit of measurement for this test. Secondary means of expressing TRC test results are a benefit-cost ratio and levelized costs. The Societal Test expressed in terms of net present value, a benefit-cost ratio, or levelized costs is also considered a secondary means of expressing results. Levelized costs as a unit of measurement are inapplicable for fuel substitution programs, since these programs represent the net change of alternative fuels which are measured in different physical units (e.g.,, kWh or therms). Levelized costs are also not applicable for load building programs.

Net present value (NPVTRC) is the discounted value of the net benefits to this test over a specified period of time. NPVTRC is a measure of the change in the total resource costs due to the program. A net present value above zero indicates that the program is a less expensive resource than the supply option upon which the marginal costs are based.

The benefit-cost ratio (BCRTRC) is the ratio of the discounted total benefits of the program to the discounted total costs over some specified time period. It gives an indication of the rate of return of this program to the utility and its ratepayers. A benefit-cost ratio above one indicates that the program is beneficial to the utility and its ratepayers on a total resource cost basis.

The levelized cost is a measure of the total costs of the program in a form that is sometimes used to estimate costs of utility-owned supply additions. It presents the total costs of the program to the utility and its ratepayers on a per kilowatt, per kilowatt hour, or per therm basis levelized over the life of the program.

The Societal Test is structurally similar to the Total Resource Cost Test. It goes beyond the TRC test in that it attempts to quantify the change in the total resource costs to society as a whole rather than to only the service territory (the utility and its ratepayers). In taking society's perspective, the Societal Test utilizes essentially the same input variables as the TRC Test, but they are defined with a broader societal point of view. More specifically, the Societal Test differs from the TRC Test in at least one of five ways. First, the Societal Test may use higher marginal costs than the TRC test if a utility faces marginal costs that are lower than other utilities in the state or than its out-of-state suppliers. Marginal costs used in the Societal Test would reflect the cost to society of the more expensive alternative resources. Second, tax credits are treated as a transfer payment in the Societal Test, and thus are left out. Third, in the case of capital expenditures, interest payments are considered a transfer payment since society actually expends the resources in the first year. Therefore, capital costs enter the calculations in the year in which they occur. Fourth, a societal discount rate should be used[7]. Finally, Marginal costs used in the Societal Test would also contain externality costs of power generation not captured by the market system. An illustrative and

7 Many economists have pointed out that use of a market discount rate in social cost-benefit analysis undervalues the interests of future generations. Yet if a market discount rate is not used, comparisons with alternative investments are difficult to make.

by no means exhaustive list of 'externalities and their components' is given below (Refer to the Limitations section for elaboration.) These values are also referred to as 'adders' designed to capture or internalize such externalities. The list of potential adders would include for example:

1. The benefit of avoided environmental damage: The CPUC policy specifies two 'adders' to internalize environmental externalities, one for electricity use and one for natural gas use. Both are statewide average values. These adders are intended to help distinguish between cost-effective and non cost-effective energy-efficiency programs. They apply to an average supply mix and would not be useful in distinguishing among competing supply options. The CPUC electricity environmental adder is intended to account for the environmental damage from air pollutant emissions from power plants. The CPUC-adopted adder is intended to cover the human and material damage from sulfur oxides (SOX), nitrogen oxides (NOX), volatile organic compounds (VOC, sometimes called reactive organic gases or ROG), particulate matter at or below 10 micron diameter (PM10), and carbon. The adder for natural gas is intended to account for air pollutant emissions from the direct combustion of the gas. In the CPUC policy guidance, the adders are included in the tabulation of the benefits of energy efficiency programs. They represent reduced environmental damage from displaced electricity generation and avoided gas combustion. The environmental damage is the result of the net change in pollutant emissions in the air basins, or regions, in which there is an impact. This change is the result of direct changes in powerplant or natural gas combustion emission resulting from the efficiency measures, and changes in emissions from other sources, that result from those direct changes in emissions.

2. The benefit of avoided transmission and distribution costs – energy efficiency measures that reduce the growth in peak demand would decrease the required rate of expansion to the transmission and distribution network, eliminating costs of constructing and maintaining new or upgraded lines.

3. The benefit of avoided generation costs – energy efficiency measures reduce consumption and hence avoid the need for generation. This would include avoided energy costs, capacity costs and T&D line

4. The benefit of increased system reliability: The reductions in demand and peak loads from customers opting for self generation, provide reliability benefits to the distribution system in the forms of:
   a. Avoided costs of supply disruptions
   b. Benefits to the economy of damage and control costs avoided by customers and industries in the digital economy that need greater than 99.9 level of reliable electricity service from the central grid
   c. Marginally decreased System Operator's costs to maintain a percentage reserve of electricity supply above the instantaneous demand
   d. Benefits to customers and the public of avoiding blackouts.

5. Non-energy benefits: Non-energy benefits might include a range of program-specific benefits such as saved water in energy-efficient washing machines or self generation units, reduced waste streams from an energy-efficient industrial process, etc.

6. Non-energy benefits for low income programs: The low income programs are social programs which have a separate list of benefits included in what is known as the 'low income public purpose test'. This test and the sepcific benefits associated with this test are outside the scope of this manual.

7. Benefits of fuel diversity include considerations of the risks of supply disruption, the effects of price volatility, and the avoided costs of risk exposure and risk management.

Strengths of the Total Resource Cost Test

The primary strength of the Total Resource Cost (TRC) test is its scope. The test includes total costs (participant plus program administrator) and also has the potential for capturing total benefits (avoided supply costs plus, in the case of the societal test variation, externalities). To the extent supply-side project evaluations also include total costs of generation and/or transmission, the TRC test provides a useful basis for comparing demand- and supply-side options.

Since this test treats incentives paid to participants and revenue shifts as transfer payments (from all ratepayers to participants through increased revenue requirements), the test results are unaffected by the uncertainties of projected average rates, thus reducing the uncertainty of the test results. Average rates and assumptions associated with how other options are financed (analogous to the issue of incentives for DSM programs) are also excluded from most supply-side cost determinations, again making the TRC test useful for comparing demand-side and supply-side options.

Weakness of the Total Resource Cost Test

The treatment of revenue shifts and incentive payments as transfer payments, identified previously as a strength, can also be considered a weakness of the TRC test. While it is true that most supply-side cost analyses do not include such financial issues, it can be argued that DSM programs should include these effects since, in contrast to most supply options, DSM programs do result in lost revenues.

In addition, the costs of the DSM "resource" in the TRC test are based on the total costs of the program, including costs incurred by the participant. Supply-side resource options are typically based only on the costs incurred by the power suppliers.

Finally, the TRC test cannot be applied meaningfully to load building programs, thereby limiting the ability to use this test to compare the full range of demand-side management options.

Formulas

The formulas for the net present value (NPV_{TRC})' the benefit-cost ratio (BCR_{TRC} and levelized costs are presented below:

NPVTRC = BTRC - CTRC
BCRTRC = BTRC /CTRC
LCTRC = LCRC / IMP

Where:

NPVTRC	=	Net present value of total costs of the resource
BCRTRC	=	Benefit-cost ratio of total costs of the resource
LCTRC	=	Levelized cost per unit of the total cost of the resource (cents per kWh for conservation programs; dollars per kW for load management programs)
BTRC	=	Benefits of the program
CTRC	=	Costs of the program
LCRC	=	Total resource costs used for levelizing
IMP	=	Total discounted load impacts of the program
PCN	=	Net Participant Costs

The B_{TRC} C_{TRC} LCRC, and IMP terms are further defined as follows:

$$BTRC = \sum_{t=1}^{N} \frac{UAC_t + TC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at} + PAC_{at}}{(1+d)^{t-1}}$$

$$CTRC = \sum_{t=1}^{N} \frac{PRC_t + PCN_t + UIC_t}{(1+d)^{t-1}}$$

$$LCRC = \sum_{t=1}^{N} \frac{PRC_t + PCN_t - TC_t}{(1+d)^{t-1}}$$

$$IMP = \frac{\sum_{t=1}^{n} \left[\left(\sum_{i=1}^{n} \Delta EN_{it}\right) or \left(\Delta DN_{it} \ where \ I = peak \ period\right) \right]}{(1+d)^{t-1}}$$

[All terms have been defined in previous chapters.]

The first summation in the BTRC equation should be used for conservation and load management programs. For fuel substitution programs, both the first and second summations should be used.

Chapter 5

Program Administrator Cost Test

Definition

The Program Administrator Cost Test measures the net costs of a demand-side management program as a resource option based on the costs incurred by the program administrator (including incentive costs) and excluding any net costs incurred by the participant. The benefits are similar to the TRC benefits. Costs are defined more narrowly.

Benefits and Costs

The benefits for the Program Administrator Cost Test are the avoided supply costs of energy and demand, the reduction in transmission, distribution, generation, and capacity valued at marginal costs for the periods when there is a load reduction. The avoided supply costs should be calculated using net program savings, savings net of changes in energy use that would have happened in the absence of the program. For fuel substitution programs, benefits include the avoided supply costs for the energy-using equipment not chosen by the program participant only in the case of a combination utility where the utility provides both fuels.

The costs for the Program Administrator Cost Test are the program costs incurred by the administrator, the incentives paid to the customers, and the increased supply costs for the periods in which load is increased. Administrator program costs include initial and annual costs, such as the cost of utility equipment, operation and maintenance, installation, program administration, and customer dropout and removal of equipment (less salvage value). For fuel substitution programs, costs include the increased supply costs for the energy-using equipment chosen by the program participant only in the case of a combination utility, as above.

In this test, revenue shifts are viewed as a transfer payment between participants and all ratepayers. Though a shift in revenue affects rates, it does not affect revenue requirements, which are defined as the difference between the net marginal energy and capacity costs avoided and program costs. Thus, if $NPV_{pa} > 0$ and $NPV_{RIM} < 0$, the administrator's overall total costs will decrease, although rates may increase because the sales base over which revenue requirements are spread has decreased.

How the Results Can be Expressed

The results of this test can be expressed either as a net present value, benefit-cost ratio, or levelized costs. The net present value is the primary test, and the benefit-cost ratio and levelized cost are the secondary tests.

Net present value (NPVpa) is the benefit of the program minus the administrator's costs, discounted over some specified period of time. A net present value above zero indicates that this demand-side program would decrease costs to the administrator and the utility.

The benefit-cost ratio (BCRpa) is the ratio of the total discounted benefits of a program to the total discounted costs for a specified time period. A benefit-cost ratio above one indicates that the program would benefit the combined administrator and utility's total cost situation.

The levelized cost is a measure of the costs of the program to the administrator in a form that is sometimes used to estimate costs of utility-owned supply additions. It presents the costs of the program to the administrator and the utility on per kilowatt, per kilowatt-hour, or per therm basis levelized over the life of the program.

Strengths of the Program Administrator Cost Test

As with the Total Resource Cost test, the Program Administrator Cost test treats revenue shifts as transfer payments, meaning that test results are not complicated by the uncertainties associated with long-term rate projections and associated rate design assumptions. In contrast to the Total Resource Cost test, the Program Administrator Test includes only the portion of the participant's equipment costs that is paid for by the administrator in the form of an incentive. Therefore, for purposes of comparison, costs in the Program Administrator Cost Test are defined similarly to those supply-side projects which also do not include direct customer costs.

Weaknesses of the Program Administrator Cost Test

By defining device costs exclusively in terms of costs incurred by the administrator, the Program Administrator Cost test results reflect only a portion of the full costs of the resource.

The Program Administrator Cost Test shares two limitations noted previously for the Total Resource Cost test: (1) by treating revenue shifts as transfer payments, the rate impacts are not captured, and (2) the test cannot be used to evaluate load building programs.

Formulas

The formulas for the net present value, the benefit-cost ratio and levelized cost are presented below:

$$NPVpa = Bpa - Cpa$$
$$BCRpa = Bpa/Cpa$$
$$LCpa = LCpa/IMP$$

Where:

NPVpa	Net present value of Program Administrator costs
BCRpa	Benefit-cost ratio of Program Administrator costs

LCpa	Levelized cost per unit of Program Administrator cost of the resource
Bpa	Benefits of the program
Cpa	Costs of the program
LCpc	Total Program Administrator costs used for levelizing

$$B_{pa} = \sum_{t=1}^{N} \frac{UAC_t}{(1+d)^{t-1}} + \sum_{t+1}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

$$C_{pa} = \sum_{t=1}^{N} \frac{PRC_t + INC_t + UIC_t}{(1+d)^{t-1}}$$

$$LCpc = \sum_{t=1}^{N} \frac{PRC_t + INC_t}{(1+d)^{t-1}}$$

[All variables are defined in previous chapters.]

The first summation in the Bpa equation should be used for conservation and load management programs. For fuel substitution programs, both the first and second summations should be used.

Appendix A

Inputs to Equations and Documentation

A comprehensive review of procedures and sources for developing inputs is beyond the scope of this manual. It would also be inappropriate to attempt a complete standardization of techniques and procedures for developing inputs for such parameters as load impacts, marginal costs, or average rates. Nevertheless, a series of guidelines can help to establish acceptable procedures and improve the chances of obtaining reasonable levels of consistent and meaningful cost-effectiveness results. The following "rules" should be viewed as appropriate guidelines for developing the primary inputs for the cost-effectiveness equations contained in this manual:

1. In the past, Marginal costs for electricity were based on production cost model simulations that clearly identify key assumptions and characteristics of the existing generation system as well as the timing and nature of any generation additions and/or power purchase agreements in the future. With a deregulated market for wholesale electricity, marginal costs for electric generation energy should be based on forecast market prices, which are derived from recent transactions in California energy markets. Such transactions could include spot market purchases as well as longer term bilateral contracts and the marginal costs should be estimated based on components for energy as well as demand and/or capacity costs as is typical for these contracts.

2. In the case of submittals in conjunction with a utility rate proceeding, average rates used in DSM program cost-effectiveness evaluations should be based on proposed rates. Otherwise, average rates should be based on current rate schedules. Evaluations based on alternative rate designs are encouraged.

3. Time-differentiated inputs for electric marginal energy and capacity costs, average energy rates, and demand charges, and electric load impacts should be used for (a) load management programs, (b) any conservation program that involves a financial incentive to the customer, and (c) any Fuel Substitution or Load Building program. Costing periods used should include, at a minimum, summer and winter, on-, and off-peak; further disaggregation is encouraged.

4. When program participation includes customers with different rate schedules, the average rate inputs should represent an average weighted by the estimated mix of participation or impacts. For General Rate Case proceedings it is likely that each major rate class within each program will be considered as program elements requiring separate cost-effectiveness analyses for each measure and each rate class within each program.

5. Program administration cost estimates used in program cost-effectiveness analyses should exclude costs associated with the measurement and evaluation of program impacts unless the costs are a necessary component to administer the program.

6. For DSM programs or program elements that reduce electricity and natural gas consumption, costs and benefits from both fuels should be included.

7. The development and treatment of load impact estimates should distinguish between gross (i.e., impacts expected from the installation of a particular device, measure, appliance) and net (impacts adjusted to account for what would have happened anyway, and therefore not attributable to the program). Load impacts for the Participants test should be based on gross, whereas for all other tests the use of net is appropriate. Gross and net program impact considerations should be applied to all types of demand-side management programs, although in some instances there may be no difference between gross and net.

8. The use of sensitivity analysis, i.e. the calculation of cost-effectiveness test results using alternative input assumptions, is encouraged, particularly for the following programs: new programs, programs for which authorization to substantially change direction is being sought (e.g.,, termination, significant expansion), major programs which show marginal cost-effectiveness and/or particular sensitivity to highly uncertain input(s).

The use of many of these guidelines is illustrated with examples of program cost effectiveness contained in Appendix B.

Appendix B

Summary of Equations and Glossary of Symbols

Basic Equations

Participant Test

NPVP	=	BP - CP
NPVavp	=	(BP - CP) / P
BCRP	=	BP/CP
DPP	=	min j such that Bj > Cj

Ratepayer Impact Measure Test

LRIRIM	=	(CRIM - BRIM) / E	
FRIRIM	=	(CRIM - BRIM) / E	for t = 1
ARIRIMt	=	FRIRIM	for t = 1
	=	(CRIMt- BRIMt)/Et	for t=2,... ,N
NPVRIM	=	BRIM — CRIM	
BCRRIM	=	BRIM /CRIM	

Total Resource Cost Test

NPVTRC	=	BTRC - CTRC
BCRTRC	=	BTRC / CTRC
LCTRC	=	LCRC / IMP

Program Administrator Cost Test

NPVpa	=	Bpa - Cpa
BCRpa	=	Bpa / Cpa
LCpa	=	LCpa / IMP

Benefits and Costs

Participant Test

$$Bp = \sum_{t=1}^{N} \frac{BR_t + TC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{AB_{at} + PAC_{at}}{(1+d)^{t-1}}$$

$$Cp \sum_{t=1}^{N} \frac{PC_t + BI_t}{(1+d)^{t-1}}$$

Ratepayer Impact Measure Test

$$B_{RIM} = \sum_{t=1}^{N} \frac{UAC_t + RG_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

$$C_{RIM} = \sum_{t=1}^{N} \frac{UIC_t + RL_t + PRC_t + INC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{RL_{at}}{(1+d)^{t-1}}$$

$$E = \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$

Total Resource Cost Test

$$B_{TRC} = \sum_{t=1}^{N} \frac{UAC_t + TC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at} + PAC_{at}}{(1+d)^{t-1}}$$

$$C_{TRC} = \sum_{t=1}^{N} \frac{PRC_t + PCN_t + UIC_t}{(1+d)^{t-1}}$$

$$L_{TRC} = \sum_{t=1}^{N} \frac{PRC_t + PCN_t - TC_t}{(1+d)^{t-1}}$$

$$IMP = \frac{\sum_{t=1}^{n}\left[(\sum_{t=1}^{n} \Delta EN_{it})\ or\ (\Delta DN_{it}\ where\ I = peak\ period)\right]}{(1+d)^{t-1}}$$

Program Administrator Cost Test

$$B_{pa} = \sum_{t=1}^{N} \frac{UAC_t}{(1+d)^{t-1}} + \sum_{t=1}^{N} \frac{UAC_{at}}{(1+d)^{t-1}}$$

$$C_{pa} = \sum_{t=1}^{N} \frac{PRC_t + INC_t + UIC_t}{(1+d)^{t-1}}$$

$$LCPA = \sum_{t=1}^{N} \frac{PRC_t + INC_t}{(1+d)^{t-1}}$$

Glossary of Symbols

Abat	=	Avoided bill reductions on bill from alternate fuel in year t
AC:Dit	=	Rate charged for demand in costing period i in year t
AC:Eit	=	Rate charged for energy in costing period i in year t
ARIRIM	=	Stream of cumulative annual revenue impacts of the program per unit of energy, demand, or per customer. Note that the terms in the ARI formula are not discounted, thus they are the nominal cumulative revenue impacts. Discounted cumulative revenue impacts may be calculated and submitted if they are indicated as such. Note also that the sum of the discounted stream of cumulative revenue impacts does not equal the LRIRIM*
BCRp	=	Benefit-cost ratio to participants
BCRRIM	=	Benefit-cost ratio for rate levels
BCRTRC	=	Benefit-cost ratio of total costs of the resource
BCRpa	=	Benefit-cost ratio of program administrator and utility costs
BIt	=	Bill increases in year t
Bj	=	Cumulative benefits to participants in year j
Bp	=	Benefit to participants
BRIM	=	Benefits to rate levels or customer bills
BRt	=	Bill reductions in year t
BTRC	=	Benefits of the program
Bpa	=	Benefits of the program
Cj	=	Cumulative costs to participants in year i

Cp	=	Costs to participants
CRIM	=	Costs to rate levels or customer bills
CTRC	=	Costs of the program
Cpa	=	Costs of the program
D	=	discount rate
ΔDgit	=	Reduction in gross billing demand in costing period i in year t
ΔDnit	=	Reduction in net demand in costing period i in year t
DPp	=	Discounted payback in years
E	=	Discounted stream of system energy sales-(kWh or therms) or demand sales (kW) or first-year customers
ΔEgit	=	Reduction in gross energy use in costing period i in year t
ΔEnit	=	Reduction in net energy use in costing period i in year t
Et	=	System sales in kWh, kW or therms in year t or first year customers
FRIRIM	=	First-year revenue impact of the program per unit of energy, demand, or per customer.
IMP	=	Total discounted load impacts of the program
INCt	=	Incentives paid to the participant by the sponsoring utility in year t First year in which cumulative benefits are > cumulative costs.
Kit	=	1 when ΔEGit or ΔDGit is positive (a reduction) in costing period i in year t, and zero otherwise
LCRC	=	Total resource costs used for levelizing
LCTRC	=	Levelized cost per unit of the total cost of the resource
LCPA	=	Total Program Administrator costs used for levelizing
Lcpa	=	Levelized cost per unit of program administrator cost of the resource
LRIRIM	=	Lifecycle revenue impact of the program per unit of energy (kWh or therm) or demand (kW)-the one-time change in rates-or per customer-the change in customer bills over the life of the program.
MC:Dit	=	Marginal cost of demand in costing period i in year t
MC:Eit	=	Marginal cost of energy in costing period i in year t
NPVavp	=	Net present value to the average participant
NPVP	=	Net present value to all participants
NPVRIM	=	Net present value levels
NPVTRC	=	Net present value of total costs of the resource
NPVpa	=	Net present value of program administrator costs
OBIt	=	Other bill increases (i.e., customer charges, standby rates)
OBRt	=	Other bill reductions or avoided bill payments (e.g., customer charges, standby rates).
P	=	Number of program participants
PACat	=	Participant avoided costs in year t for alternate fuel devices

PCt	=	Participant costs in year t to include: • Initial capital costs, including sales tax • Ongoing operation and maintenance costs • Removal costs, less salvage value • Value of the customer's time in arranging for installation, if significant
PRCt	=	Program Administrator program costs in year t
PCN	=	Net Participant Costs
RGt	=	Revenue gain from increased sales in year t
RLat	=	Revenue loss from avoided bill payments for alternate fuel in year t (i.e., device not chosen in a fuel substitution program)
RLt	=	Revenue loss from reduced sales in year t
TCt	=	Tax credits in year t
UACat	=	Utility avoided supply costs for the alternate fuel in year t
UACt	=	Utility avoided supply costs in year t
PAt	=	Program Administrator costs in year t
UICt	=	Utility increased supply costs in year t

Appendix C.

Derivation of Rim Lifecycle Revenue Impact Formula

Most of the formulas in the manual are either self-explanatory or are explained in the text. This appendix provides additional explanation for a few specific areas where the algebra was considered to be too cumbersome to include in the text.

Rate Impact Measure

The Ratepayer Impact Measure lifecycle revenue impact test (LRIRIM) is assumed to be the one-time increase or decrease in rates that will re-equate the present valued stream of revenues and stream of revenue requirements over the life of the program.

Rates are designed to equate long-term revenues with long-term costs or revenue requirements. The implementation of a demand-side program can disrupt this equality by changing one of the assumptions upon which it is based: the sales forecast. Demand-side programs by definition change sales. This expected difference between the long-term revenues and revenue requirements is calculated in the NPVRIM The amount which present valued revenues are below present valued revenue requirements equals NPVRIM

The LRIRIM is the change in rates that creates a change in the revenue stream that, when present valued, equals the NPVRIM* If the utility raises (or lowers) its rates in the base year by the amount of the LRIRIM' revenues over the term of the program will again equal revenue requirements. (The other assumed changes in rates, implied in the escalation of the rate values, are considered to remain in effect.)

Thus, the formula for the LRIRIM is derived from the following equality where the present value change in revenues due to the rate increase or decrease is set equal to the NPVRIM or the revenue change caused by the program.

$$-NPV_{RIM} = \sum_{t=1}^{N} \frac{LRI_{RIM} \times E_t}{(1+d)^{t-1}}$$

Since the LRI_{RIM} term does not have a time subscript, it can be removed from the summation, and the formula is then:

$$-NPV_{RIM} = LRI_{RIM} \times \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$

Rearranging terms, we then get:

$$LRI_{RIM} = -NPV_{RIM} \Big/ \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$

Thus,

$$E = \sum_{t=1}^{N} \frac{E_t}{(1+d)^{t-1}}$$

BEFORE THE ARIZONA CORPORATION COMMISSION

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IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-06-0463
IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. TO REVIEW AND REVISE ITS PURCHASE 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

Rejoinder Testimony of

Denise A. Smith

on Behalf of

UNS Gas, Inc.

April 11, 2007

EXHIBIT
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TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Denise A. Smith. My business address is 4350 E. Irvington Road, Tucson, Arizona.

Q. Are you the same Denise Smith who filed Rebuttal Testimony in this proceeding?

A. Yes, I am.

Q. What is the purpose of your Rejoinder Testimony in this proceeding?

A. The purpose of my Rejoinder Testimony is to respond to certain comments made in the Surrebuttal Testimonies of Ms. Julie McNeely-Kirwan on behalf of Arizona Corporation Commission ("Commission") Staff regarding Demand Side Management ("DSM") and Ms. Miquelle Scheier on behalf of Arizona Community Action Association ("ACAA") regarding the marketing of the Low Income Weatherization ("LIW") Program.

II. RESPONSE TO MS. MCNEELY-KIRWAN.

A. Baseline Study.

Q. In her Surrebuttal Testimony at pages 1 to 2, Ms. McNeely-Kirwan agrees with the concept of a baseline study and the recovery of the study through the DSM Adjustor Mechanism but testifies that the cost of the baseline study should not be included in the DSM Adjustor immediately. Do you have any response?

A. Ms. McNeely-Kirwan indicates that, at the time she was drafting her Surrebuttal Testimony, she did not have UNS Gas, Inc.'s ("UNS Gas" or the "Company") response to her data request concerning the costs of the baseline study. We have since provided that information to Staff. As we explained in the response to JMK 23-1, the need for a baseline study is not limited to the UNS Gas service territory. UniSource Energy Corporation recognizes that conducting one study to cover the needs for UNS Gas, UNS Electric, Inc. and Tucson Electric Power Company provides efficiencies. The total estimated cost for a statewide baseline study was $370,000. A proportionate amount was assigned to each utility based on the percentage of customers in each service territory to the total number of customers served in the state. This baseline study includes reviewing existing data, model specifications, and data collection with field audits and inspections. This level of funding includes minimal metering and measurement activity. The resulting estimated proportionate cost for a baseline study for UNS Gas is $82,000. With this information, UNS Gas proposes that the baseline study be approved in this docket and recovered through the DSM Adjustor Mechanism.

B. Cost-Effectiveness Tests.

Q. In her Surrebuttal Testimony at page 7, lines 3 to 8, Ms. McNeely-Kirwan testifies that, while she does not disagree with the Company's internal use of other cost-effectiveness tests, the Commission Staff only utilizes the Societal Cost Test to evaluate the cost-effectiveness of DSM programs. Do you have any response?

A. Yes, I have two comments. First, I want to point out that the Company did provide the Commission Staff with information it requested on the Societal Cost Test. Second, I want to clarify that the Company believes that the other cost-effectiveness tests are not only important for the Company's internal review, but also to provide the Commission with a full and complete analysis of the DSM programs. Each test provides different information that may be considered in determining whether or not a DSM measure is right for UNS Gas' ratepayers. While the Company appreciates and supports Staff's DSM cost-effectiveness preference, it is UNS Gas' hope that the Commission might look at each of the tests when considering DSM programs.

Q. In her Surrebuttal Testimony at page 7, lines 12 to 14, Ms. McNeely-Kirwan states that cost-effective DSM is less expensive than acquiring energy supplies. Do you have any response?

A. Yes, only to say that "cost-effective" is the operative word. The Company believes that DSM is only less expense when it is cost-effective under all of the DSM cost-effectiveness tests, especially the Rate Impact Measure test which shows the impact on all customers' rates that will result from adoption of a DSM measure.

C. <u>DSM Adjustor Mechanism</u>.

Q. In order to balance the need to avoid over-collecting and the Company's need to recover costs on a timely basis, Ms. McNeely-Kirwan proposes that the DSM Adjustor Mechanism initially include the LIW funding and one quarter of the proposed budget for the remaining DSM programs. Is this position acceptable to the Company?

A. While the Company believes that its proposal to initially recover LIW and 50% of the proposed budget for remaining DSM programs, it is willing to accept recover of LIW and 25% of the proposed budget, as Ms. McNeely-Kirwan recommends. In addition, because Ms. McNeely-Kirwan agrees with the approval of a baseline study and the inclusion of its cost in the DSM Adjustor Mechanism, the $82,000 cost associated with that baseline study (as discussed above), should also be included. This would change the adjustor recommended by Ms. McNeely-Kirwan slightly to $0.0031. This is accomplished by adding the LIW funding of $113,400 plus 25% of the proposed budget for the remaining DSM programs ($230,000) plus the $82,000 for the baseline study divided by the test year therms of 138,223,864.

D. DSM Reports.

Q. Ms. McNeely-Kirwan disagrees, on pages 9 to 10 of her Surrebuttal Testimony, with the Company's recommendation to move to annual DSM reporting. Do you have any response?

A. I understand Ms. McNeely-Kirwan's point about the Company proposing many new programs and the need to track those programs in their infancy. I also appreciate her suggestion that the question of moving to annual reports could be revisited once the programs have been established and are meeting goals in a cost-effective manner. The Company will therefore continue to report on a semi-annual basis on the dates recommended by Ms. McNeely-Kirwan until its programs are established, at which time, it will approach the Commission to reconsider moving to annual reporting. I note that the dates proposed by Ms. McNeely-Kirwan are acceptable to the Company so long as the Commission understands that some financial data may not be final. This is due to the fact that financial books often do not close until after the March date.

IV. RESPONSE TO MS. SCHEIER.

Q. On page 3 of her Surrebuttal Testimony, Ms. Scheier argues that if the Community Action Agencies ("CAAs") were provided funding to conduct meaningful marketing and if UNS Gas was involved in the marketing of the LIW program, more families could be served and there would be increased awareness. Do you have any response?

A. UNS Gas will ensure that information regarding the LIW program is placed on its website so that customers know of its availability. Again, UNS Gas has proposed an increase in LIW funding in this proceeding. The Commission certainly has the discretion to instruct UNS Gas to spend a greater percentage of the LIW funds on marketing. Should the

Commission think it appropriate, UNS Gas would utilize a portion of the LIW funding to prepare a brochure for the CAAs or UNS Gas to use to market to customers.. In addition, the CAAs may also want to use a portion of the allocated funding to market the program if necessary. Some of the CAAs have experienced a backlog of potential LIW participants. Therefore, the decision on whether or not to promote and/or market the LIW programs – and to what extent to market those programs – should be left up to the CAAs depending upon their resources.

Q. Does this conclude your Rejoinder Testimony?

A. Yes.

What is the typical process?

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IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-06-0463
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IN THE MATTER OF THE INQUIRY INTO THE PRUDENCE OF THE GAS PROCUREMENT PRACTICES OF UNS GAS, INC.	DOCKET NO. G-04204A-05-0831 **NOTICE OF FILING OF SUPPLEMENTAL EXHIBIT TO THE REBUTTAL TESTIMONY OF DENISE A. SMITH**

UNS Gas, Inc. ("UNS Gas"), through undersigned counsel, hereby files Exhibit DAS-3 to Denise A. Smith's UNS Gas Rebuttal Testimony, filed on March 16, 2007. This supplemental exhibit contains UNS Gas' proposed Demand-Side Management ("DSM") portfolio and is being filed for informational purposes so that Staff and others may better evaluate UNS Gas' DSM programs in detail. UNS Gas will also file this portfolio as part of a separate application for approval.

EXHIBIT
UNSG 23
admitted

RESPECTFULLY SUBMITTED this 23rd day of March 2007.

UNS Gas, Inc.

By ______________________
Michael W. Patten
ROSHKA DEWULF & PATTEN, PLC.
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EXHIBIT

DAS-3

UNS Gas
Demand Side Management
Program Portfolio Plan
2008-2012

TABLE OF CONTENTS

Attachments:

1. Introduction

UNS Gas ("UNSG") is requesting approval of the portfolio of DSM programs presented in this plan. This portfolio plan provides an overview of DSM programs that UNSG proposes to implement to provide savings and net benefits for UNSG customers.

2. DSM Portfolio Performance Costs, Savings and Net Benefits

UNSG proposes to implement a portfolio of DSM programs designed to reduce the use of energy by encouraging its customers to implement certain energy-efficiency products, services or practices. The proposed programs are designed to influence residential and non-residential customers to adopt energy efficiency measures through a combination of rebates, technical assistance and training, and consumer education. While the focus of the programs is on reducing the use of natural gas, some of the programs will likely result in electric energy savings as well and those savings have also been estimated and included in the analysis of the programs.

Exhibit 1 summarizes the proposed budget and expected energy savings as a result of program activities from 2008-2012. Exhibit 2 summarizes program net benefits of the programs from 2008-2012 from the perspectives of the Total Resource Cost ("TRC") and the Societal Cost ("SC") tests. These tests are described in more detail below.

Exhibit 1
DSM Portfolio Budgets and Estimated Savings 2008-2012

Program Budget 2008-2012	Annual Therm Savings	Non-coincident Peak Demand Savings (MW)	Coincident Peak Demand Savings (MW)	Annual MWH Savings
$5,486,461	5,966,502	5.2	4.4	3,109

Exhibit 2
DSM Portfolio Net Benefits 2008-2012

Total Resource Cost Test Portfolio Benefits	$39,579,987
Total Resource Cost Portfolio Costs	$24,747,206
Total Resource Cost Portfolio Net Benefits	$14,832,781
Societal Cost Test Portfolio Benefits	$49,955,589
Societal Cost Test Portfolio Costs	$24,747,206
Societal Cost Test Portfolio Net Benefits	$25,208,383
Total Resource Cost Test – Portfolio Level	1.60
Total Societal Cost Test – Portfolio Level	2.02

Total Net Benefits are equal to Total Societal Benefits minus Total Societal Costs. Total Societal Benefits are equal to the avoided costs of demand and energy savings over the life of the efficiency measures, and Total Societal Costs include all program costs including the cost of program administration, and measurement, evaluation and research.

3. Description of Proposed Programs

The program portfolio includes a range of programs designed to provide all of UNSG's customer segments with opportunities to reduce demand, save energy and reduce energy costs. The programs are designed to provide options for improving the energy efficiency of existing residential homes, residential new construction projects, residential low-income homes, commercial and industrial ("C&I") Gas Efficiency, and non-residential new construction and renovation projects.

This section includes a brief description of each proposed DSM program. Detailed program descriptions are provided in the Attachments hereto including information about (1) program concepts; (2) target markets; (3) baseline conditions; (4) customer eligibility; (5) program rationales; (6) program objectives; (7) products and services provided; (8) delivery strategy and administration; (9) marketing and communications; (10) implementation schedules; (11) monitoring and evaluation plans; (12) program costs; (13) estimated energy savings; and (14) program cost effectiveness. Exhibit 3 shows the list of programs included in this plan:

Exhibit 3
Listing of Programs Included in the Portfolio Plan

Residential Efficiency Programs
Low Income Weatherization
Energy Smart Homes Program
Efficient Home Heating Program
Commercial & Industrial Efficiency Programs
C&I Facilities Gas Efficiency Program

3.1 Residential Efficiency Programs

Proposed residential efficiency programs included in the DSM portfolio are described below.

Low Income Weatherization Program
This portfolio plan proposes an expansion and modification of the current Low Income Weatherization ("LIW") program. The LIW program will continue to provide qualifying residential low income customers with funding assistance for the installation of measures that improve the energy-efficiency of their homes. However, the new program will offer an expanded set of efficiency measures and services. The primary goal of the LIW program is to provide financial assistance to install measures that improve comfort and reduce overall energy consumption for eligible customers. Steps taken through this program will reduce electric and gas bills and provide eligible customers with more disposable income for other needs.

The LIW Program is fuel neutral in that weatherization measures approved for the homes will result in a reduction of both electric and gas consumption. Most homes in this program have either no cooling because of climate conditions or they have evaporative cooling and gas or electric space heating; therefore, the program is not expected to significantly reduce summer peak load but it will be an effective program in reducing consumption of natural gas. The main social benefits of the program will be the reduction of gas and electric heating bills for low-income customers. UNSG has not formally tracked program activities in the past but will develop a tracking system for the new program to quantify measures installed, energy savings realized, and report on program achievements.

Changes to the LIW program include: (1) increased funding to weatherization agencies; (2) an expanded list of weatherization measures allowed in each home; (3) an increased spending limit on each home; (4) inclusion of compact fluorescent lighting ("CFL") and low-flow shower and faucet aerators to be installed in every low-income home that also qualifies for emergency repair funding; and (5) an increase in the reporting functions so agencies must report each measure installed in the homes. The new program will allow UNSG to calculate and verify energy and demand savings from the LIW program and report those savings in future years. However, this analysis does not include the positive and unquantifiable effects of leveraging federal and state funding for other improvements to the homes which further reduce energy consumption and improve occupant comfort and safety. For a detailed program description, see Attachment 1.

Energy Smart Home Program

The UNSG Energy Smart Homes ("ESH") program will emphasize the whole-house approach to improving health, safety, comfort, durability and energy efficiency. The program will promote homes that meet the 2006 Environmental Protection Agency /Department Of Energy ("EPA/DOE") Energy Star Home® performance requirements. To encourage program participation by builders, the program will provide incentives to home builders for each qualifying Energy Star Home®. Required on-site inspections and field testing of a random sample of homes to meet Energy Star Home® performance requirements will be conducted by third-party RESNET certified energy raters selected by each builder

Savings are based on heating, cooling and hot water energy use and are achieved through a combination of (1) building envelope upgrades; (2) high performance windows; (3) controlled air filtration; (4) upgraded heating and cooling systems; (5) tight duct systems; and (6) upgraded water heating equipment. New homes constructed through the program will be eligible to display the Energy Star Home® seal. The ESH program will also encourage builders to install Energy Star® labeled dishwashers, clothes washers and refrigerators.

Builders will sign on as an EPA/DOE Energy Star Home® partner and agree to adhere to all requirements of that program. UNSG will provide training and education about building science and the whole-house approach to building homes, marketing and builder incentives. The training and education will be offered to homebuyers, builders, sub-contractors and realtors/builder sales agents. Training is aimed at increasing the applied knowledge of building science and energy efficient building practices to transform the market and improve construction practices in the UNSG service territories. Educational and promotional pieces and design tools will assist builders and associated trade allies (architects and engineers, sub-contractors, etc.) with the construction standards that meet or exceed the ESH program standards. For a detailed program description, see Attachment 2.

Efficient Home Heating Program

The proposed Efficient Home Heating Program provides prescriptive incentives to encourage residential and multi-family homeowners to invest in energy-efficient gas-fueled furnaces with a 90 percent or greater Annual Fuel Utilization Efficiency ("AFUE") rating. UNSG will provide training, qualification and promotion for HVAC contractors who are knowledgeable and meet UNSG standards for the installation and operation of high-efficiency residential gas furnace systems. The program will be promoted to UNSG's residential customers, and will provide education for homeowners on the benefits of high-efficiency heating systems, and information on how to participate in the program. For a detailed program description, see Attachment 3.

3.2 Commercial & Industrial Efficiency Programs

The DSM Portfolio Plan will encourage the installation of energy efficient gas-fueled equipment in existing C&I facilities in UNSG's service region. The proposed program is described below.

C&I Gas Efficiency Program

The C&I Gas Efficiency Program provides prescriptive incentives to owners and operators of non-residential facilities for energy-efficiency improvements in gas-fueled systems and equipment. Specifically, the program provides incentives for high-efficiency space heating, service water heating, and commercial cooking equipment and systems. The program will be available to UNSG's existing non-residential gas customers, including schools and governmental buildings. The program will provide limited technical assistance and education for facility owners and operators on the benefits of high-efficiency equipment and systems, and how to participate in the program. For a detailed program description, see Attachment 4.

4. Budget

UNSG is proposing to spend a total of $5.48 million dollars on energy-efficiency DSM programs collectively from program years 2008-2012.

The proposed budget maximizes the amount of program funds that go directly to customers through rebates and incentives, training and technical assistance, and consumer education. This portfolio plan also takes into account the realities of DSM program start-up costs and funds needed to adequately plan, develop and deliver and evaluate quality programs. It typically takes two years or more to ramp up programs and achieve significant customer participation levels and program savings, and the plan accounts for program ramp-up costs over the 2008-2009 time period. Over the ramp up period through 2009, UNSG expects that on average 55% of the program costs (depending on the program) will benefit customers directly in the form of incentives, training or education. Once the program has reached maturity, UNSG expects that over 60% of total program costs will go directly to customers. The balance of budget expenditures will be applied to program administration. Program administration expenses include all non-incentive expenses, including UNSG internal staff expenses, marketing and communications expenses, implementation contractor fees and expenses, measurement, evaluation and research, and other direct expenses attributable to the programs.

Incentive levels and other program elements will be reviewed and modified as needed during the first year from the approval date of this program, and periodically thereafter. Such modifications will be reported in the mid-year and year-end reports submitted to Staff.

For the purposes of presenting the proposed budgets for this plan, the program budgets have been broken into the following categories:

- **Rebates and Incentives** – Funds that go toward customer rebates and incentives, and installation of measures.
- **Training & Technical Assistance** – Funds that are used for energy-efficiency training and technical assistance.
- **Consumer Education** – Funds that are used to support general consumer education about the benefits of energy-efficient improvements and load management options.

- **Program Implementation** – Program delivery costs associated with implementing the program, including implementation contractor labor and overhead costs as well as other direct program delivery costs.
- **Program Marketing** – All expenses related to marketing the program and increasing DSM consumer awareness and participation.
- **Planning & Administration** – Costs related to planning, developing and administering the programs, including management of program budgets, oversight of implementation contractors, program coordination and general overhead expenses.
- **Measurement, Evaluation, and Research** – Program expenses related to conducting measurement and evaluation of savings attributable to the program and program operational efficiency, as well as related research activities.

Exhibit 4 below shows a summary roll-up of the anticipated budgets for each program by cost category for program years 2008-2012. Exhibit 5 presents the total annual budget for each program over the planning period from 2008 through 2012. Detailed annual budgets for each program year are included in the Attachments. These budgets represent UNSG's best estimate of spending, however, it is inevitable that some programs will achieve greater participation than others, and these budgets may need to be adjusted annually accordingly to maximize the effectiveness of the overall portfolio.

Exhibit 4
2008-2012 DSM Portfolio Budgets by Cost Category

Program	Total Administrative and O&M Cost Allocation	Total Marketing Allocation	Total Direct Implementation	Total EM&V Cost Allocation	Total Cost
Residential Efficiency Programs					
Low Income Weatherization	$90,308	$0	$487,665	$24,082	$602,056
Energy Smart Homes	$336,017	$418,552	$1,413,489	$61,779	$2,229,837
Efficient Home Heating	$360,519	$241,464	$1,441,598	$80,073	$2,123,654
Residential Subtotal	$786,844	$660,016	$3,342,753	$165,934	$4,955,547
Commercial & Industrial Efficiency Programs					
C&I Facilities Gas Efficiency	$100,874	$79,637	$329,166	$21,237	$530,914
Total	$887,718	$739,653	$3,671,919	$187,171	$5,486,461
% of Cost By Category	16.2%	13.5%	66.9%	3.4%	100.0%

Exhibit 5
2008-2012 DSM Portfolio Budgets by Year

Program	2008	2009	2010	2011	2012	Total Cost
Residential Efficiency Programs						
Low Income Weatherization	$113,400	$116,802	$120,306	$123,915	$127,633	$602,056
Energy Smart Homes	$420,000	$432,600	$445,578	$458,945	$472,714	$2,229,837
Efficient Home Heating	$400,000	$412,000	$424,360	$437,091	$450,204	$2,123,654
Residential Subtotal	$933,400	$961,402	$990,244	$1,019,951	$1,050,550	$4,955,547
Commercial & Industrial Efficiency Programs						
C&I Facilities Gas Efficiency	$100,000	$103,000	$106,090	$109,273	$112,551	$530,914
Total	$1,033,400	$1,064,402	$1,096,334	$1,129,224	$1,163,101	$5,486,461

5. Program Energy Savings and Benefits

UNSG has estimated the energy savings, costs, net benefits, and environmental benefits associated with each of the programs included in the proposed DSM portfolio. The following sections describe the energy savings, cost-effectiveness, and environmental benefits that are expected to accrue from the program.

5.1 Portfolio Energy Savings, Costs and Net Benefits

In preparing this plan, UNSG examined energy efficiency measures that are applicable to gas-fueled end use applications (electric and gas efficiency measures were examines for the low income program) and provide a broad set of natural gas savings opportunities in all of UNSG's customer sectors. The analysis included a detailed energy savings and a cost effectiveness analysis of each measure, as well as each program as a whole. In order to complete the analysis, UNSG assembled data on baseline and energy efficient performance of each measure technology as well as a range of other technical and financial data including:

- UNSG avoided cost data;
- Discount rates;
- Effective useful lifetimes ("EULs") for each measure;
- Incremental and installed measure costs for each measure; and
- Projected participation rates for each program over the projected program life presented in this plan.

For the analysis of net program benefits, UNSG has used avoided cost savings that will result from the expected energy savings generated by each DSM program in the proposed portfolio for measures implemented from 2008-2012. Levelized avoided cost data for a 20 year planning horizon was developed for use in the cost effectiveness analysis. UNSG has evaluated the cost effectiveness of each measure and each program as a whole using the Ratepayer Impact Measure ("RIM") test, the TRC test, and the SC test. The SC test is a variant of the TRC test and differs from the TRC test by including the valuation of environmental benefits and using a societal discount rate instead of the market discount rate used for the TRC. A societal discount rate of 5% was used in the computations of the SC test. For the analysis of the portfolio of programs, UNSG quantified the expected environmental benefits resulting from measures installed through the program although they were not monetized for the purposes of cost-effectiveness testing.

Exhibit 6 provides estimates of the expected annual energy savings for each proposed DSM program and a summary of the net benefits (electric demand and energy savings were estimated for the Energy Smart Homes and low income programs only). In addition to the estimated savings and benefits shown in Exhibit 6, the portfolio is anticipated to produce other societal benefits based on the utility cost of capital. Exhibit 7 shows an estimate of the carbon dioxide air emission reductions that are expected as a result of the implementation of the measures promoted by the programs. Significant additional benefits which are expected to accrue to UNSG customers include increased levels of service, non-energy benefits such as increased comfort, and support for low-income households.

Exhibit 6
Electric Savings and Benefits
2008-2012 Programs

Program	Energy Savings (Therms)	Coincident Demand Savings (MW)	Energy Savings (MWh)	Program Budget ($000)	Societal Benefits ($000)	Societal Costs ($000)	Net Benefits ($000)
Residential Efficiency Programs							
Low Income Weatherization	41,207	0.02	245	$602	$442	$602	-$160
Energy Smart Homes	804,881	2.06	126	$2,230	$8,260	$3,965	$4,295
Efficient Home Heating	3,598,733	1.75	2,161	$2,124	$20,022	$13,722	$6,300
Residential Subtotal	4,444,820	3.83	2,532	$4,956	$28,747	$18,289	$10,435
Commercial & Industrial Efficiency Programs							
C&I Facilities Gas Efficiency	1,521,681	0.58	577	$531	$10,855	$6,458	$4,397
Total	5,966,501	4.41	3,109	$5,486	$39,602	$24,747	$14,832

In addition to the gas savings and benefits, additional energy savings resulting from programs in the portfolio include 3.15 MWh of electricity and 4.4 MW of coincident demand, primarily from energy efficient packaged gas heating / air conditioning systems to be installed through the Efficient Home Heating and C&I Facilities Gas Efficiency programs. The Energy Smart Home Program reduces electric energy consumption by 126 MWh and 2.06 MW, and the LIW Program reduces electric energy consumption by 245 MWh and 0.02 MW from 2008 through 2012.

Exhibit 7
DSM Benefit Cost Test
2008-2012 Programs

Program	Total Resource Cost Test	Societal Cost Test	Rate Payer Impact Measure Test
Residential Efficiency Programs			
Low Income Weatherization	0.73	0.90	0.42
Energy Smart Homes	2.08	2.74	0.64
Efficient Home Heating	1.46	1.82	0.37
Commercial & Industrial Efficiency Programs			
C&I Facilities Gas Efficiency	1.68	2.09	0.52

5.2 Environmental Benefits

In preparing this plan, UNSG has estimated the environmental benefits, as avoided CO_2 emissions and avoided water use, expected to result from measures installed as a result of the portfolio of DSM programs. Based on the direction of ACC staff, UNSG is reporting environmental benefits in this plan but has not monetized the benefits for the purposes of cost effectiveness analysis of measures and programs. The environmental reductions are based on the energy savings of all program measures over their expected useful lifetimes.

The factors used to calculate the DSM Environmental Benefits are shown in Exhibit 8. The CO_2 value for natural gas savings is derived from EPA's publication of Emission Factors, AP-42, 5th Edition. Although UNSG's customers utilize various types and sizes of natural gas combustors, conversion of fuel carbon to CO_2 is largely independent of combustion type and size. The CO_2 values for electricity savings and water savings are based on Arizona Public Service Co. estimates as presented in the "APS Demand Side Management Program Portfolio 2005-2007" p. 20.

Exhibit 8
Environmental Benefits Factors

Environmental Factor	Value	Units
CO_2 Emissions Avoided (Natural Gas Savings)	0.0059	Tons CO_2/therm
CO_2 Emissions Avoided (Electricity Savings)	917	Pounds CO_2/MW-hour
Water Saved	233	Gallons/MW-hour

Exhibit 9 shows the estimated CO_2 emissions avoided over the expected lifetime of all measures installed as a result of the proposed DSM portfolio.

Exhibit 9
DSM Estimated Environmental Benefits
2008-2012 Programs

Program	Avoided CO_2 (Tons)	Water Saved (Gal)
Low Income Weatherization	355	56,993
Energy Smart Homes	4,807	29,463
Efficient Home Heating	22,224	503,610
Residential Subtotal	27,386	590,066
C&I Facilities Gas Efficiency	8,978	0
Total	36,364	590,066

6. Program Marketing and Delivery

This section of the portfolio plan presents UNSG's proposed marketing and communications strategy, and implementation/delivery plan.

6.1 Program Marketing and Communications

This plan includes targeted marketing and communication of program offerings and benefits to encourage participation among customers, key market players and trade allies. The objective of the marketing and communications strategy is to make customers and key market actors aware of the program offerings and benefits, and to influence their decision making at the time of purchasing or installing gas-fueled energy systems or equipment in favor of choosing more energy efficient options.

The specifics of the marketing strategy depend on the program, but generally include a mix of internet, print media, radio, direct contact, direct mailings, bill inserts and presentations depending on the market to be reached. The program descriptions in the Attachments describe the proposed approach for each program.

6.2 Program Delivery and Implementation

UNSG proposes that programs be implemented using a mix of both in-house and outsourced resources. UNSG will likely outsource the implementation of the C&I Facilities Gas Efficiency Program as well as field verification inspections of measure installations. The delivery of the LIW program will also be outsourced to community action agencies. This enables UNSG to take advantage of outsourced experts who have implemented similar programs in other areas, while also using in-house resources where appropriate. For all programs, UNSG will retain responsibility for program administration, measurement and evaluation, and reporting activities. UNSG intends to issue Requests for Proposals ("RFP") to qualified firms for all significant activities that will be outsourced.

Exhibit 10 provides a timeline that shows key dates and program implementation activities. For a detailed description of the proposed implementation schedule and implementation models for each individual program, see the program descriptions included in the Attachments.

Tasks	2007				2008				2009			
	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4
Submit Portfolio Plan												
ACC Review & Approval												
Program Marketing & Communication Planning												
Submit RFP for IC and MER												
Select IC and MER Contractor												
Ongoing Low-Income Weatherization Implementatio												
Energy Smart Homes Launch and Implementation												
Efficient Home Heating Progr Launch and Implementation												
C&I Facilities Gas Eff. Progra Launch and Implementation												
Program Impact and Process Evaluation												
Submit Updated Portfolio Plan												

Exhibit 10
Program Development and Implementation Timeline
2008-2012

7. Program Measurement, Evaluation and Research

Measurement, evaluation and research ("MER") is an integral component part of the proposed DSM Portfolio Plan. UNSG will select a MER contractor at the same time as selecting outsourced implementation services. UNSG will develop deemed savings values for all measures promoted by the program. UNSG will develop a database tracking system for monitoring program progress, and use the deemed savings values for tracking and reporting of program savings. UNSG will also adopt an integrated data collection strategy to support program management and MER activities. Integrated data collection requires that the data necessary to support program management and evaluation activities be collected throughout the course of program implementation. The integrated data collection process will provide UNSG with the capacity to assess program progress and savings achievements on an ongoing basis. MER activities are expected to include:

- Verification that energy-efficiency measures are installed as expected;
- Impact analysis to compute the savings that are being achieved;
- Cost-effectiveness analysis; and
- Process evaluation to indicate how well programs are working to achieve objectives.

The MER contractor will work directly with UNSG and implementation contractors to ensure that the program design, database systems, and implementation processes will collect the necessary data for MER.

Attachment 1

Low Income Weatherization Program

Table of Contents

UNSG Low Income Weatherization Program

Program Concept and Description

Customers who receive weatherization assistance live with poverty level incomes ($10,210 for a household of one; $20,650 for a household of four). Utilities typically consume a larger portion of the low-income family's income than they consume of the higher income family's income. Low-income persons must often make monthly decisions as to whether to pay rent or mortgage, pay utilities, or buy food.

UNSG recognizes that many low-income customers live in older homes or mobile homes built when energy prices were low and energy efficient construction methods were not recognized. Many of these homes require significant repair to improve the livability of the structure and to incorporate some level of energy efficiency. The primary goal of the Low-income Weatherization ("LIW") Program is to provide financial assistance to install measures that improve comfort and reduce overall energy consumption for eligible customers. Steps taken through this program will reduce electric and gas bills and provide eligible customers with more disposable income for other needs.

The LIW Program is fuel neutral in that weatherization measures approved for the homes will result in a reduction of both electric and gas consumption. Most homes in this program either have no cooling source due to the weather patterns in the area or they have evaporative cooling and gas or electric space heating; therefore, the program is not expected to significantly reduce summer peak load but it will be an effective program in reducing consumption of natural gas. The main social benefits of the program will be the reduction of gas and electric heating bills for low-income customers.

Target Market

Promotion of the LIW Program is conducted by four agencies in the UNSG service territory: (1) Northern Arizona Council of Governments ("NACOG"); (2) Coconino County Community Services ("CCCS"); (3) Western Arizona Council of Governments ("WACOG") and (4) Southeastern Arizona Community Action Program ("SEACAP"). UNSG is proposing to increase available funding from $71,500 annually to $113,400 annually. Bill payment assistance is also available through the UNSG Warm Spirit program and UNSG provides the CARES pricing plan for low-income customers.

The target housing market is composed primarily of older mobile homes but also includes single family homes constructed of slump block and/or wood frame construction. All homes must receive gas service from UNSG. Income for participants must meet the guidelines established by the Arizona Department of Energy Weatherization. All participants must have household income levels at or below 150% of the poverty level. Eligible customers who are not already on the UNSG CARES Pricing Plan will be encouraged to participate in the CARES Pricing Plan.

Current Baseline Conditions

Customers who meet the income guidelines established by the Arizona Department of Energy Weatherization predominately live in housing projects comprised of older style mobile homes or older style single family residences constructed of wood frame or slump block. Each region in the UNSG service territory may differ in the type and age of construction but one thing in common is that caulking and weather-stripping as well as heating, cooling and water heating equipment will be severely degraded. Many homes will not meet even minimum code requirements for electrical, mechanical, or plumbing.

Program Eligibility

All existing single family homes and mobile homes that receive gas service from UNSG, with household income at or below the guidelines established by the Arizona Department of Energy Weatherization will be eligible for participation. Homes must be owner-occupied or owners who have rental property occupied by low-income participants must sign off to approve any work completed by agencies. All participants must have household income levels at or below 150% of the poverty level.

NACOG, CCCS, WACOG and SEACAP will determine the customer priority based on a number of factors including but not limited to:

- No heat (winter) or no cooling (summer) is high priority;
- Age (80 or above or households with children age 10 or under receive high priority);
- Doctor recommendations due to physical handicap or illness receives high priority; and
- Number of people in household.

NACOS and WACOG also conduct work related to Emergency Home Repair. These homes may not necessarily require weatherization measures, but UNSG believes they present additional opportunities for agencies to include some basic and quick installations of energy saving measures. UNSG will request installation of low-flow shower heads, faucet aerators and CFL's when agencies complete Emergency Home Repair work. UNSG believes that these additions during an Emergency Home Repair visit add value to each customer and bolster energy and demand reductions.

Program Rationale

State and local funding available to non-profit agencies for assistance to low-income customers falls far short of the need that currently exists. Available funding also limits the amount of dollar benefit per household, the type of work it is used for and the amount of dollars allowed for program implementation and administration. Agencies also are limited on the number of homes they can weatherize each year because of a shortage of skilled labor to complete the necessary work, funding to add skilled labor, and the ability to find competent and honest outside contractors to complete the work.

UNSG funding allows agencies the ability to leverage other funds provided by the Federal Department of Energy ("DOE") and the Low Income Home Energy Assistance Program ("LIHEAP"). UNSG funding allows agencies to complete additional home repair, equipment repair or replacement, and nominal weatherization steps that impact energy consumption. Data provided by NACOG indicates that low-income customers that it serves receive $2.32 of energy efficiency improvements for every $1.00 funded by UNSG because of the ability to leverage other funds. As a result, agencies are able to complete more thorough repair or renovation on each home.

Program Objectives

- Allow up to $2,000.00 per residence for weatherization, equipment repair, etc. for low-income customers;
- Increase the number of homes weatherized or the extent of repair completed at each home;
- Lower the average household energy costs for low-income customers; and
- Improve the quality of life for customers in low-income neighborhoods.

Products and Services Provided

Analysis has been completed on a defined list of energy efficiency measures to determine energy and demand impact. This list is included as the measure level energy savings analysis in Appendix 2. Agencies will be allowed to use UNSG funding for any item on the approved list up to the maximum allowance of $2,000 per home. Agency representatives will determine which items should be installed in each home. Some agencies limit measures installed to only those measures that contribute a minimum of 20% energy savings due to LIHEAP requirements. Other agencies are limited to assistance for equipment repair and/or replacement.

Agencies will be asked to install certain energy saving products in any home they enter through the emergency repair and/or flood repair programs. This will support an increase in installation of low-flow shower heads, faucet aerators, or CFLs.

Delivery Strategy and Administration

- Promotion of the LIW Program will occur through NACOG, CCCS, WACOG and SEACAP;
- Funding will be provided to agencies from UNSG upon documentation of work completed;
- NACOG, CCCS, WACOG and SEACAP will determine participant eligibility and priority and will complete all work; and
- NACOG , CCCS, WACOG and SEACAP will provide program administration, marketing, planning, coordination, labor, materials, equipment and entering results into tracking software.

Marketing and Communications

When appropriate, UNSG employees inform customers about the program, local Department of Economic Security ("DES") representatives make referrals, health care service agencies and individual case workers also make referrals. UNSG provides a page on its Web site that directs interested parties to call the NACOG, CCCS, WACOG or SEACAP.

Program Implementation Schedule

UNSG intends to continue the existing LIW Program until the implementation of any new program elements. This will provide time to transition agencies to new program elements following approval by ACC.

The following table shows the estimated timeline for key program activities by quarter assuming program approval by the ACC by the third quarter of 2007:

Table 1. Program Implementation Schedule

Program Activities	2007				2008				2009			
Continue ongoing LIW program												
New program pre-approval submit												
New program approval (estimated)												
Meetings/Notifications to Agencies												
Implementation by Agencies												
Process evaluation												
Savings verification												
Program redesign as needed												

Monitoring and Evaluation Plan

The current LIW Program generated no claims from UNSG of energy savings because individual measures were not tracked. Development of the new program, however, will include calculations for energy savings and therefore work completed at each location will be tracked. UNSG plans to pursue development of an on-line process agencies can use to provide information of each measure installed with appropriate address, dates, and other information.

UNSG will adopt a strategy that calls for integrated data collection that is designed to provide a quality data resource for program tracking, management and evaluation. This approach will entail the following primary activities:

- **Database tracking system development** - As part of detailed program design, UNSG will develop a database tracking system that will be used to collect the necessary data elements and provide the reporting functions needed to track program process and provide a data resource for program evaluation.
- **Integrated implementation data collection** - UNSG will work with the implementation contractor to establish systems to collect the data needed to support effective program management and evaluation through the implementation and customer application processes. The database tracking system will be integrated with implementation data collection processes.
- **Field verification** - UNSG will conduct field verification of the installation of a sample of measures throughout the implementation of the program.
- **Tracking of savings using deemed savings values** - UNSG will develop deemed savings values for each measure and technology promoted by the program and periodically review and revise the savings values to be consistent with program participation and accurately estimate the savings being achieved by the program.

This approach will provide UNSG with ongoing feedback on program progress and enable management to adjust or correct the program measures to be more effective, provide a higher level of service, and be more cost beneficial. Integrated data collection will provide a high quality data resource for evaluation activities.

Program Budget (Future)

The 2008 program year annual budget of approximately $113,400 will be allocated as shown in Table 2, while Table 3 provides the expected program budgets through 2012. Allowing for a 3% annual inflation rate, the average annual budget is approximately $120,411. Appendix 1 provides addition details on the 2008 budget.

Table 2. 2008 Program Budget

Total Program Budget	**$113,400**
Total Administrative and O&M Cost Allocation	
Managerial & Clerical	$15,309
Travel & Direct Expenses	$0
Overhead	$1,701
Total Administrative Cost	***$17,010***
Total Marketing Allocation	
Internal Marketing Expense	$0
Subcontracted Marketing Expense	$0
Total Marketing Cost	***$0***
Total Direct Implementation	
Financial Incentives	$86,343
Support Activity Labor	$2,756
Hardware & Materials	$0
Rebate Processing & Inspection	$2,756
Total Direct Installation Cost	***$91,854***
Total EM&V Cost Allocation	
EM&V / Research Activity	$4,082
EM&V Overhead	$454
Total EM&V Cost	***$4,536***

Table 3. 2008 – 2012 Program Budget

Year	**2008**	**2009**	**2010**	**2011**	**2012**
Total Budget	$113,400	$116,802	$120,306	$123,915	$127,633
Incentives	$86,343	$88,933	$91,601	$94,349	$97,180
Administrative Costs	$27,057	$27,869	$28,705	$29,566	$30,453
Incentives as % of Budget	76%	76%	76%	76%	76%

Estimated Energy Savings

UNSG expects that, on average 42 low income customers will be served annually throughout UNSG service territory through a combination of all four agencies. The energy savings from this activity are presented in Table 5. Appendix 2 provides further information about estimated energy savings for each measure, including the measure and program level benefit cost analysis. The average per site energy savings of approximately 1167 kWh and 196 Therms are expected to reduce customer bills by approximately $388 annually.

Table 4. Low Income Weatherization Program Annual Energy Savings

Year	2008	2009	2010	2011	2012
Number of customers	39	41	42	43	44
Non-coincident peak (kW)	15	15	16	16	17
Coincident peak (kW)	3	3	3	4	4
Energy Savings (kWh)	46,073	47,455	48,879	50,345	51,855
Energy Savings (Therms)	7,761	7,994	8,234	8,481	8,736

As a result of the energy savings shown above, it is estimated that the program will produce environmental benefits through avoided emissions and avoided water use. The estimated additional benefits from 2008 – 2012 are presented in Table 5.

Table 5. Projected Environmental Benefits, 2008 – 2012

CO_2 Emissions Avoided	355	Tons
Water Saved	56,993	Gal

Note: A portion of the CO_2, and all of the water benefits are related to electricity savings and are based on Arizona Public Service Co. estimates as presented in the "APS Demand Side Management Program Portfolio 2005-2007" p. 20.

Program Cost Effectiveness

The cost effectiveness of each measure and the program as a whole was assessed using the Total Resource Cost ("TRC") test, the Societal Cost ("SC") test and the Ratepayer Impact Measure ("RIM") test as defined by the California Standard Practice Manual. Measure analysis worksheets showing all energy savings, cost and cost-effectiveness calculations are included in Appendix 2.

The cost effectiveness analysis requires estimation of:

- net demand and energy savings attributable to the program;
- UNSG program administration costs;
- the present value of program benefits including UNSG avoided costs over the life of the measures; and
- UNSG lost revenues.

Figure 6 provides a summary of the benefit/cost analysis results for this program. A detailed benefit/cost analysis is presented in Appendix 2.

Table 6. Benefit-cost Analysis Results

Cost Effectiveness Tests	TRC	SC	RIM
Benefit/Cost Ratio	0.73	0.90	0.42

Figure 7 provides addition program and financial assumptions, by measure category, used to derive the program level cost-benefits. Additional details for each measure category can be found in Appendix 2.

Table 7. Other Financial Assumptions

PROGRAM DATA	Lighting	Weather	Insulation	HVAC	Hot Water	Appliances	Health and Safety
Conservation Life (yrs):	5	10	20	15	5	10	15
Program Life (yrs):	5	5	5	5	5	5	5
Demand Avoided Costs ($/kW):	55.23	58.74	64.94	61.99	55.23	58.74	61.99
Summer Energy Avoided Costs ($/kWh):	0.0722	0.0707	0.0731	0.0722	0.0722	0.0707	0.0722
Winter Energy Avoided Costs ($/kWh):	0.0701	0.0686	0.0707	0.0694	0.0701	0.0686	0.0694
Levelized Therms:	0.8691	0.8920	0.9451	0.9194	0.8691	0.8920	0.9194
Admin. Costs:	31.34%	31.34%	31.34%	31.34%	31.34%	31.34%	31.34%
TRC Discount Rate:	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%
Social Discount Rate:	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
NTG Ratio:	100%	100%	100%	100%	100%	100%	100%

A detailed benefit/cost analysis is presented in Appendix 4.

Appendix 1 – Program Costs

2008 Program Costs Details

Budget Items	Budget	Allocation Rate (%)
Administrative		
Managerial and Clerical Labor	***$15,309***	
Labor – Clerical	$612	4.0%
Labor - Program Design	$612	4.0%
Labor - Program Development	$612	4.0%
Labor - Program Planning	$2,296	15.0%
Labor - Program/Project Management	$1,531	10.0%
Labor - Staff Management	$765	5.0%
Labor - Staff Supervision	$765	5.0%
Subcontractor Labor - Clerical	$765	5.0%
Subcontractor Labor - Program Design	$4,593	30.0%
Subcontractor Labor - Program Development	$765	5.0%
Subcontractor Labor - Program Planning	$765	5.0%
Subcontractor Labor - Program/Project Management	$1,225	8.0%
Subcontractor Labor - Staff Management	$0	0.0%
Subcontractor Labor - Staff Supervision	$0	0.0%
Subtotal Managerial and Clerical Labor	*$15,309*	*100.0%*
Travel & Direct Expenses	***$0***	
Conference Fees	$0	30.0%
Labor - Conference Attendance	$0	20.0%
Subcontractor - Conference Fees	$0	2.0%
Subcontractor - Travel - Airfare	$0	4.0%
Subcontractor - Travel - Lodging	$0	0.0%
Subcontractor - Travel - Meals	$0	0.0%
Subcontractor - Travel - Mileage	$0	0.0%
Subcontractor - Travel - Parking	$0	0.0%
Subcontractor - Travel - Per Diem for Misc. Expenses	$0	8.0%
Subcontractor Labor - Conference Attendance	$0	2.0%
Travel – Airfare	$0	14.0%
Travel – Lodging	$0	6.0%
Travel – Meals	$0	3.0%
Travel – Mileage	$0	1.0%
Travel – Parking	$0	0.0%
Travel - Per Diem for Misc. Expenses	$0	10.0%
Travel & Direct Expenses	*$0*	*100.0%*
Overhead (General and Administrative) - Labor and Materials	***$1,701***	

Low Income Weatherization Program

Equipment - Communications	$34	2.0%
Equipment - Computing	$34	2.0%
Equipment - Document Reproduction	$34	2.0%
Equipment - General Office	$34	2.0%
Equipment - Transportation	$34	2.0%
Facilities - Lease/Rent Payment	$0	0.0%
Labor - Accounts Payable	$17	1.0%
Labor - Accounts Receivable	$17	1.0%
Labor - Administrative	$17	1.0%
Labor - Automated Systems	$0	0.0%
Labor - Communications	$17	1.0%
Labor - Contract Reporting	$17	1.0%
Labor - Corporate Services	$17	1.0%
Labor - Facilities Maintenance	$17	1.0%
Labor - Information Technology	$17	1.0%
Labor - Materials Management	$17	1.0%
Labor – Procurement	$17	1.0%
Labor - Regulatory Reporting	$680	40.0%
Labor - Shop Services	$17	1.0%
Labor - Telecommunications	$17	1.0%
Labor - Transportation Services	$17	1.0%
Office Supplies	$17	1.0%
Postage	$17	1.0%
Subcontractor - Equipment - Communications	$0	0.0%
Subcontractor - Equipment - Computing	$0	0.0%
Subcontractor - Equipment - Document Reproduction	$0	0.0%
Subcontractor - Equipment - General Office	$0	0.0%
Subcontractor - Equipment - Transportation	$0	0.0%
Subcontractor - Facilities - Lease/Rent Payment	$0	0.0%
Subcontractor - Office Supplies	$0	0.0%
Subcontractor - Postage	$0	0.0%
Subcontractor Labor - Accounts Payable	$0	0.0%
Subcontractor Labor - Accounts Receivable	$0	0.0%
Subcontractor Labor - Administrative	$0	0.0%
Subcontractor Labor - Automated Systems	$0	0.0%
Subcontractor Labor - Communications	$0	0.0%
Subcontractor Labor - Contract Reporting	$0	0.0%
Subcontractor Labor - Corporate Services	$0	0.0%
Subcontractor Labor - Facilities Maintenance	$0	0.0%
Subcontractor Labor - Information Technology	$0	0.0%
Subcontractor Labor - Materials Management	$0	0.0%

Subcontractor Labor - Procurement	$0	0.0%
Subcontractor Labor - Regulatory Reporting	$595	35.0%
Subcontractor Labor - Shop Services	$0	0.0%
Subcontractor Labor - Telecommunications	$0	0.0%
Subcontractor Labor - Transportation Services	$0	0.0%
Subtotal Overhead	*$1,701*	*100.0%*
Total Administrative Costs	**$17,010**	
Marketing/Advertising/Outreach		
Internal Marketing Expense	***$0***	
Advertisements / Media Promotions	$0	25.0%
Bill Inserts	$0	4.0%
Brochures	$0	6.0%
Door Hangers	$0	0.0%
Labor - Business Outreach	$0	5.0%
Labor - Customer Outreach	$0	5.0%
Labor - Customer Relations	$0	5.0%
Labor – Marketing	$0	30.0%
Print Advertisements	$0	15.0%
Radio Spots	$0	5.0%
Subtotal Internal Marketing Expense	*$0*	*100.0%*
Subcontracted Marketing Expense	***$0***	
Subcontractor - Bill Inserts	$0	5.0%
Subcontractor - Brochures	$0	5.0%
Subcontractor – Door Hangers	$0	0.0%
Subcontractor - Print Advertisements	$0	0.0%
Subcontractor – Radio Spots	$0	10.0%
Subcontractor - Television Spots	$0	0.0%
Subcontractor Labor - Business Outreach	$0	5.0%
Subcontractor Labor - Customer Outreach	$0	5.0%
Subcontractor Labor - Customer Relations	$0	5.0%
Subcontractor Labor - Marketing	$0	5.0%
Television Spots	$0	0.0%
Website Development	$0	60.0%
Subtotal Subcontracted Marketing Expense	*$0*	*100.0%*
Total Marketing/Advertising/Outreach	**$0**	
Direct Implementation		
Financial Incentives to Customers	***$86,343***	
Activity – Labor	***$2,756***	
Labor - Curriculum Development	$220	8.0%
Labor - Customer Education and Training	$1,102	40.0%

Labor - Customer Equipment Testing and Diagnostics	$0	0.0%
Labor - Facilities Audits	$827	30.0%
Subcontanctor Labor - Facilities Audits	$276	10.0%
Subcontractor Labor - Curriculum Development	$138	5.0%
Subcontractor Labor - Customer Education and Training	$138	5.0%
Subcontractor Labor - Customer Equipment Testing and Diagnostics	$55	2.0%
Subtotal Activity	*$2,756*	*100.0%*
Hardware and Materials - Installation and Other DI Activity	***$0***	
Audit Applications and Forms	$0	8.0%
Direct Implementation Literature	$0	20.0%
Education Materials	$0	20.0%
Energy Measurement Tools	$0	10.0%
Installation Hardware	$0	10.0%
Subcontractor - Direct Implementation Literature	$0	4.0%
Subcontractor - Education Materials	$0	4.0%
Subcontractor - Energy Measurement Tools	$0	16.0%
Subcontractor - Installation Hardware	$0	6.0%
Subcontractor -Audit Applications and Forms	$0	2.0%
Subtotal Hardware and Materials	*$0*	*100.0%*
Rebate Processing and Inspection - Labor and Materials	***$2,756***	
CARE Billing Assistance	$2,756	100.0%
Labor - Rebate Processing	$0	0.0%
Labor - Site Inspections	$0	0.0%
Rebate Applications	$0	0.0%
Subcontractor - Rebate Applications	$0	0.0%
Subcontractor Labor - Field Verification	$0	0.0%
Subcontractor Labor - Rebate Processing	$0	0.0%
Subcontractor Labor - Site Inspections	$0	0.0%
Subtotal Rebate Processing and Inspection	*$2,756*	*100.0%*
Total Direct Implementation	**$91,854**	
Evaluation, Measurement and Verification		
EM&V Labor and Materials	***$4,082***	
Labor - EM&V	$204	5.0%
Materials - EM&V	$204	5.0%
Subcontractor Labor - EM&V	$3,674	90.0%
Subtotal EM&V Activity - Labor	*$4,082*	*100.0%*
EM&V Overhead	***$454***	
Benefits - EM&V Labor	$0	0.0%
Overhead - EM&V	$227	50.0%
Subcontractor Overhead - EM&V	$0	0.0%
Subcontractor Travel - EM&V	$0	0.0%
Travel - EM&V	$227	50.0%

Subtotal EM&V Overhead	*$454*	*100.0%*
Total EM&V	**$4,536**	
Total Budget	**$113,400**	

Appendix 2 – Benefit/Cost Analysis

Key benefit – cost metrics

Incentive Calculations
LIW100 - LOW INCOME WEATHERIZATION

RATE DATA	
Rate Class: CARES	
$/kW:	0.00
$/kWh, On-Peak:	0.10
$/kWh, Off-Peak:	0.10
$/Therm	1.40

OPERATING DATA	
Average measure life	13.141
Average coincidence	0.22

OTHER FACTORS	
Line Loss Factor:	10.69%
Capacity Reserve Factor:	0.00%
Application:	RET
Cost Basis:	Full Installed

PROGRAM DATA	Ltg.	Weath.	Insul.	HVAC	DHW	Appl.	H&S
Conservation Life (yrs):	5	10	20	15	5	10	15
Program Life (yrs):	5	5	5	5	5	5	5
Demand AC ($/kW):	55.23	58.74	64.94	61.99	55.23	58.74	61.99
Summer Energy AC ($/kWh):	0.0722	0.0707	0.0731	0.0722	0.0722	0.0707	0.0722
Winter Energy AC ($/kWh):	0.0701	0.0686	0.0707	0.0694	0.0701	0.0686	0.0694
Levelized Therms	0.8691	0.8920	0.9451	0.9194	0.8691	0.8920	0.9194
Admin. Costs:	31.34%	31.34%	31.34%	31.34%	31.34%	31.34%	31.34%
IRP Discount Rate*****:	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%	8.50%
Social Discount Rate	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%
NTG Ratio:	100%	100%	100%	100%	100%	100%	100%

DEMAND/ENERGY SAVINGS					INCENTIVE CALCULATIONS						CUSTOMER COST/SAVINGS				TRC
	Non Coin.	Summer	Winter		IRP	Social			PV		Incr.	Cost			
	Demand	Energy	Energy	Energy	PV	PV			Program		Cost	Savings	Payback		
Measure	Savings	Savings	Savings	Savings	Benefit	Benefit	Incentive		Cost	NPV			wo/Inc.	w/Inc.	
Description	(KW)	(KWh)	(KWh)	(Therms)	($)	($)	($)	% PV	($)	($)	($)	($)	(yrs)	(yrs)	BC Ratio
Lighting Total	0.275	143.8	143.8	0.0	$155	$171	$72	$0	$95	$60	$72.40	$28	2.6	0.0	1.63
Weatherization Total	0.000	21.3	21.3	61.6	$382	$449	$241	$1	$316	$66	$240.80	$90	2.7	0.0	1.21
Insulation Total	0.000	127.1	127.1	35.3	$508	$669	$258	$1	$338	$169	$257.66	$74	3.5	0.0	1.50
HVAC Total	0.080	235.6	101.0	62.8	$746	$933	$1,096	$1	$1,439	-$693	$1,096.02	$121	9.1	0.0	0.52
Domestic Hot Water Total	0.000	9.3	9.3	21.7	$80	$88	$226	$3	$297	-$217	$226.39	$32	7.0	0.0	0.27
Appliances Total	0.026	113.8	113.8	2.0	$138	$162	$248	$2	$325	-$187	$247.75	$25	9.9	0.0	0.42
Health and Safety	0.000	0.0	0.0	13.1	$100	$125	$46	$0	$61	$40	$46.25	$18	2.5	0.0	1.65
Total All Projects	0.381	650.881	516.259	196.617	2109.511	2597.111	2187.274	8.152	2872.700	-763.188	2187.274	388.789	37.285	0.000	0.7343

Excel spreadsheet with additional program benefit/cost calculations available upon request.

Unit capacity and energy savings

DEMAND/ENERGY SAVINGS AND COSTS

Measure Description	Cost Unit	Cost Units per Site	Non-Coin. Demand Savings (KW)	Coin. Factor	Coin. Demand Savings (KW)	Energy Savings (KWh)	Energy Savings (Therms)	Incr. Cost ($)	% Incent % Incent per customer (%)
LIGHTING MEASURES									
- Standard CFL	Lamp	1	0.052	10%	0.01	56.94	0	$13.80	60%
- 3-way CFL	Lamp	1	0.070	10%	0.01	60.05	0	$16.20	60%
- R-30 and R-40	Lamp	1	0.067	10%	0.01	57.47	0	$14.50	60%
- 3w and 7w	Lamp	1	0.018	10%	0.00	15.44	0	$7.00	60%
- Torchiere lamp	Lamp	1	0.245	10%	0.02	268.28	0	$65.00	60%
- Nite Lite/Lime Lite	Lamp	1	0.007	10%	0.00	25.45	0	$5.00	50%
Weigheted Average Lighting			0.275		0.027	287.633	0.000	$72.40	
WEATHERIZATION MEASURES									
Interior/Exterior Caulking	per site	1	0.00		0.00	0.64	0.025	$52.00	80%
Aerosol Foam Sealant	per site	1	0.00		0.00	1.14	0.045	$52.00	20%
Door Weatherstrip	per unit	1	0.00		0.00	0.65	0.026	$53.00	100%
Window Weatherstrip	per inch	100	0.00		0.00	15.23	60.482	$10.00	100%
Door Sweep	per unit	2	0.00		0.00	18.17	0.725	$46.00	100%
Replace standard hollow door with insulated door	per door	1	0.00		0.00	15.15	0.570	$93.00	20%
Replace broken single-pane windows with double pane/low e window	per sq ft	9	0.00		0.00	11.79	0.441	$153.00	40%
Weigheted Average Weatherization			0.000		0.000	42.542	61.553	$240.80	460%
INSULATION MEASURES									
Attic Insulation									
-Blown cellulose, unfloored									
R-11	Per Sq.Ft.	1000	0.00		0.00	321.92	44.782	$270.00	4.35%
R-15	Per Sq.Ft.	1000	0.00		0.00	276.69	37.767	$270.00	4.35%
R-19	Per Sq.Ft.	1000	0.00		0.00	274.94	37.325	$270.00	4.35%
R-23	Per Sq.Ft.	1000	0.00		0.00	246.55	33.910	$270.00	4.35%
R-27	Per Sq.Ft.	1000	0.00		0.00	242.14	33.384	$270.00	4.35%
R-30	Per Sq.Ft.	1000	0.00		0.00	241.93	33.396	$270.00	4.35%

Low Income Weatherization Program

R-34	Per Sq.Ft.	1000	0.00	0.00	224.31	30.945	$270.00	4.35%
R-38	Per Sq.Ft.	1000	0.00	0.00	213.41	29.379	$270.00	4.35%
-Blown cellulose, floored								
R-14	Per Sq.Ft.	1000	0.00	0.00	282.46	39.603	$270.00	4.35%
R-18	Per Sq.Ft.	1000	0.00	0.00	277.63	38.345	$270.00	4.35%
R-22	Per Sq.Ft.	1000	0.00	0.00	255.35	34.965	$270.00	4.35%
R-26	Per Sq.Ft.	1000	0.00	0.00	246.16	33.878	$270.00	4.35%
R-30	Per Sq.Ft.	1000	0.00	0.00	241.93	33.396	$270.00	4.35%
-Fiberglass, batts								
-R13	Per Sq.Ft.	1000	0.00	0.00	291.30	41.073	$270.00	4.35%
-R19	Per Sq.Ft.	1000	0.00	0.00	271.20	37.736	$270.00	4.35%
-R30	Per Sq.Ft.	1000	0.00	0.00	241.93	33.396	$270.00	4.35%
-R38	Per Sq.Ft.	1000	0.00	0.00	213.41	29.379	$270.00	4.35%
Floor Insulation Fiberglass								
-R19 - including supports (batt hangers or twine)	Per Sq.Ft.	500	0.00	0.00	146.57	18.272	$135.00	4.35%
-R30 - including supports (batt hangers or twine)	Per Sq.Ft.	500	0.00	0.00	131.18	17.986	$135.00	4.35%
Add R5 duct insulation to gas heat/ elect AC (or coat to similar R value)	Per home	1	0.00	0.00	27.05	38.344	$132.00	10.00%
Add R5 duct insulation to elect heat/ elect AC (or coat to similar R value)	Per home	1	0.00	0.00	278.12	0.000	$132.00	10.00%
Sidewall Insulation (Blown In)								
- Asbestos Shingled	Per Sq.Ft.	500	0.00	0.00	129.37	21.944	$135.00	4.35%
- Asphalt / Wood Siding	Per Sq.Ft.	500	0.00	0.00	129.37	21.944	$135.00	4.35%
- Stucco Siding	Per Sq.Ft.	500	0.00	0.00	129.37	21.944	$135.00	4.35%
Unfinished Wall Insulation								
- R19 Fiberglass	Per Sq.Ft.	200	0.00	0.00	116.37	19.856	$54	4.35%
Weigheted Average Insulation			0.000	0.000	254.233	35.339	$257.66	120%
HVAC MEASURES								
Full tune-ups of Furnace, Central A/C and Heat pumps	Per home	1	0.00	0.00	331.00	15.000	$300.00	40.00%
Central A/C Filter (cleaning or replacement)	Per	1	0.00	0.00	132.34	5.000	$35.00	60.00%

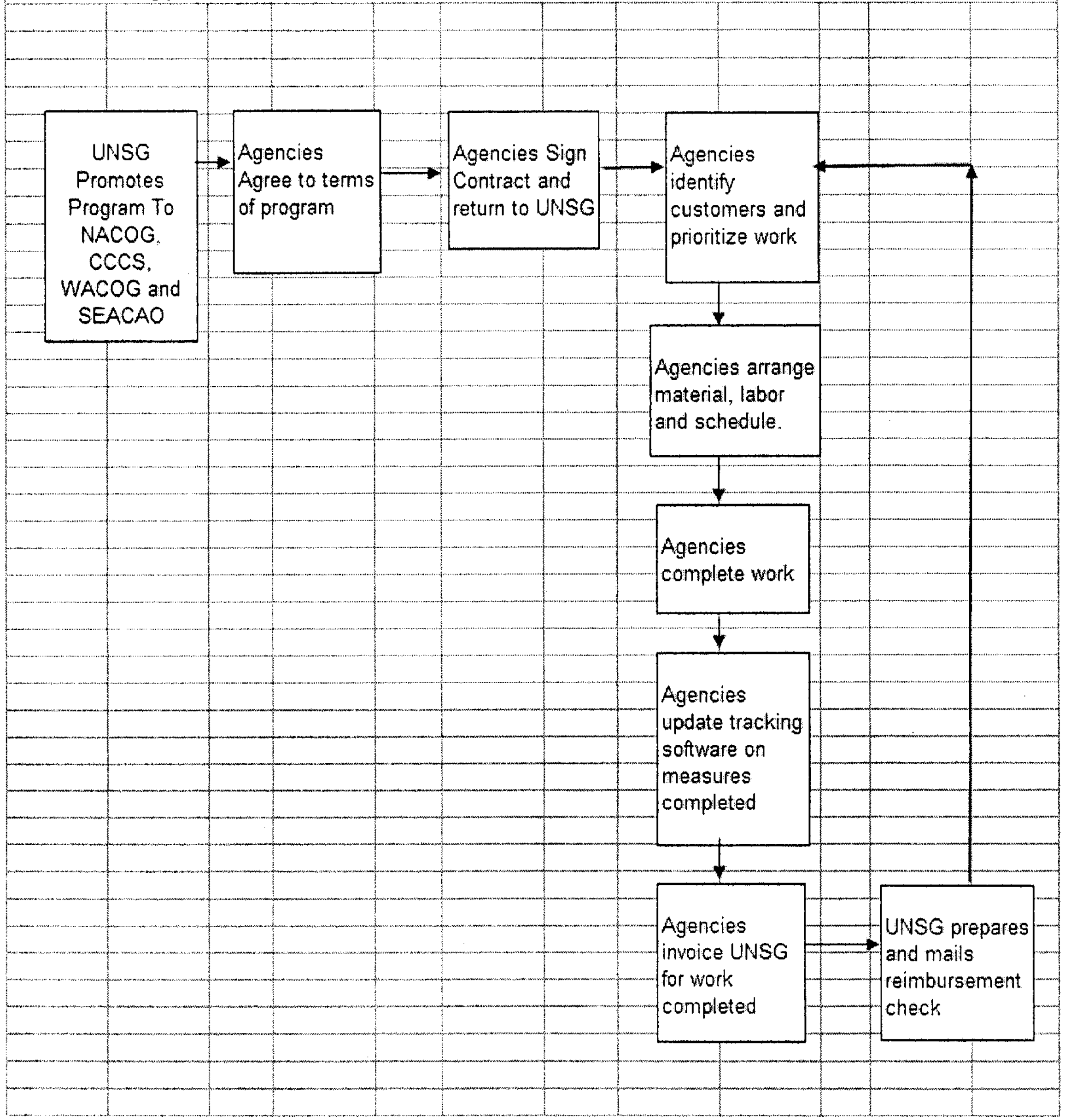
Low Income Weatherization Program

	home								
Central A/C Coil (cleaning)	Per home	1	0.00		0.00	132.34	2.000	$250.00	25.00%
Sealing ducts with mastic	Per home	1	0.00		0.00	24.36	11.425	$282.46	60.00%
Window/wall AC Filter (cleaning or replacement)	Per home	1	0.00		0.00	55.31	0.000	$35.00	20.00%
Electric Heating System Thermostat (digital, line voltage)	Per home	1	0.00		0.00	196.45	0.000	$98.00	20.00%
Gas Heating System Thermostat (digital, line voltage)	Per home	1	0.00		0.00	0.00	43.000	$126.00	50.00%
Install 80 AFUE Furnace, increase AFUE by 15%	Per home	1	0.00		0.00	0.00	99.000	$1,870.00	25.00%
Solar Screen	Per home	1	0.00		0.00	25.00	0.306	$225.00	30.00%
Install attic ventilation (only with AC)	Per home	1	0.10	0	0.00	0.00	0.000	$450.00	10.00%
Replace Single Speed cooler motor with 2-speed motor (1/3 - 1/2)	Per home	1	0.20	0	0.00	0.00	0.000	$210.00	10.00%
Replace Single Speed cooler Motor with 2-speed motor (3/4)	Per home	1	0.20	0	0.00	0.00	0.000	$230.00	10.00%
Plant trees on South and West Exposure (use 0.57 kW and 128 kWh annually per tree)	Per home	1	0.20	1	0.20	128.00	1.000	$63.00	15.00%
Weigheted Average HVAC			0.080		0.030	336.554	62.847	1096.025	29%
DOMESTIC HOT WATER MEASURES									
Water-saving Showerhead w /Massage (with shutoff 2.5 gpm or less)		1	0.00		0.00	0.00	12.460	$25.03	10%
Water-saving Hand Held Showerhead (with shutoff 2.5 gpm or less)		1	0.00		0.00	0.00	12.460	$23.03	50%
Water Heater Insulation Blanket		1	0.00		0.00	0.00	7.000	$32.40	50%
High Efficiency Water Heater - Gas, EF = 0.63		1	0.00		0.00	0.00	18.000	$449.00	20%
High Efficiency Water Heater - Elect, EF = 0.93		1	0.00		0.00	93.00	0.000	$449.00	20%
Faucet Flow restrictor		2	0.00		0.00	0.00	7.690	$15.10	70%
Domestic Hot Water Pipe Insulation (seal all seams and joints; duct tape not permitted)		1	0.00		0.00	0.00	3.560	$12.00	50%
Weighted Average Domestic Hot Water			0.000		0.000	18.600	21.739	226.388	39%
APPLIANCES MEASURES									
15 c.f.		1	0.05	1	0.05	474.50	5.000	$478.00	10%
18 c.f. w/ice		1	0.06	1	0.06	511.00	5.000	$645.00	10%
18 c.f. w/o ice		1	0.06	1	0.06	511.00	5.000	$645.00	5%
21 c.f. w/ice		1	0.08	1	0.08	689.85	5.000	$688.00	10%
21 c.f. w/o ice		1	0.08	1	0.08	689.85	5.000	$688.00	5%
Weighted Average Appliances			0.026		0.026	227.578	2.000	247.750	8%
HEALTH, SAFETY & MISCELLANEOUS MEASURES									
Install CO2 Sensor	Per home	1	0.00	1	0.00	0.00	0.000	$85.00	25%

Low Income Weatherization Program

Repair/replace all connections related to installation and operation of evaporative cooler (no impact)	Per home	1	0.00	1	0.00	0.00	0.000	$150.00	10%
Gas leak repair	Per home	1	0.00	1	0.00	0.00	65.700	$50.00	20%
Weighted Average H&S			0.000		0.000	0.000	13.140	46.250	18%

Appendix 3 - Low Income Weatherization Program Implementation Process



Attachment 2

Residential New Construction Program

Table of Contents

Residential New Construction Program

Program Concept and Description

UniSource Energy Services ("UES") is made up of both UNS Gas ("UNSG") and UNS Electric ("UNSE") utilities. UES is facing a tremendous increase in energy demand stemming from existing developer plans to build more than 200,000 new homes in Mohave County. One developer, Rhodes Homes, has a substantial amount of land and plans to develop more than 130,000 homes. This increased activity is largely the result of a Hoover Dam bypass, scheduled for 2010 completion, which will significantly decrease travel time between Las Vegas, Nevada and Mohave County, especially Kingman. In short, developers' existing plans – and the rapid sale of these lots – mean that Kingman will soon be a suburb of Las Vegas and Clark County, Nevada. This boom in homebuilding presents an enormous challenge for UES, who must meet the increased energy demands these new homes represent. Further, there is no existing energy code in UES territory to help the utility control energy demand.

The Residential New Construction Program for UNSG will be marketed under the name of Energy Smart Homes ("ESH"). All future references to the actual UNSG program will be ESH. The UNSG ESH program will emphasize the whole-house approach to improving health, safety, comfort, durability and energy efficiency. The program will promote homes that meet the 2006 EPA/DOE Energy Star Home® performance requirements. Performance requirements differ by climate zone. Appendix 1 shows climate zones within UNSG service territory and Energy Star Home® performance requirements for each climate zone (from www.energystar.gov). To encourage program participation by builders, the program will provide incentives to home builders for each qualifying ESH. Required on-site inspections and field testing of a random sample of homes to meet Energy Star Home® performance requirements will be conducted by third-party RESNET certified energy raters selected by each builder.

Educational and promotional pieces and design tools will assist builders and associated trade allies (architects and engineers, sub-contractors, etc.) with the construction standards that meet or exceed the ESH program standards.

In 2005, UNSG contracted with ECOS Consulting to complete a comprehensive and updated analysis on the expected savings gained from ESH standards compared to current market conditions and building practices in Mohave and Santa Cruz counties. Results of the 2007 analysis plus the addition of simulation results for Flagstaff completed by Summit Blue Consulting provide the basis for the energy and capacity savings used for the benefit cost analysis. Savings are based on heating, cooling and hot water energy use and are achieved through a combination of 1) building envelope upgrades; 2) high performance windows; 3) controlled air filtration; 4) upgraded heating and cooling systems; 5) tight duct systems; and 6) upgraded water heating equipment.

New homes constructed through the program will be eligible to display the Energy Star Home® seal.

Builders will sign on as an Environmental Protection Agency / Department of Energy ("EPA/DOE") Energy Star Home® partners and agree to adhere to all requirements of that program. UNSG will provide training and education about building science and the whole-house approach to building homes, marketing and builder incentives. The training and education will be offered to homebuyers, builders, sub-contractors and realtors/builder sales agents. Training is aimed at increasing the applied knowledge of building science and energy efficient building practices to transform the market and improve construction practices in the UNSG service territories.

Target Market

The target market is comprised of all individually metered new homes that receive gas service from UNSG. This includes home developments, townhomes and condominium projects where individual units are sold to homeowners and custom home projects. The program will be marketed to all builders within the UNSG service territory.

Current Baseline Conditions

A baseline study was completed by Ecos Consulting in February 2006 for UNSE to determine potential savings from a residential new construction program in Mohave and Santa Cruz counties. The information gathered in this report is also valid for UNSG since both counties surveyed by Ecos are also within the UNSG service territory. The colder climates in UNSG service territory were not included in the Ecos report. However with the absence of adopted energy codes, UNSG believes the baseline construction standards will be similar.

The UNSG service territory includes both rural and metro areas and a variety of baseline housing designs. In metro areas like Kingman and Flagstaff the market may be dominated by production home builders. In the resort areas of Pinetop and Prescott the market may be dominated by custom home builders. In other rural areas the market may be dominated by mobile homes.

We believe builders in Pinetop, Prescott, Sedona and Flagstaff may already practice higher building standards than other builders due to the price-range, the cold climate, and the custom clients they work with. This market may be considered similar to the building standards shown in Lake Havasu. Builders in other UNSG service territories may produce only minimum code compliant homes similar to those found in Kingman.

Climate factors are an important consideration in program design for any residential new construction program. Ecos compared key climatic data for sites throughout UNSG territory. It is important to note that gas savings can be secured through a residential new construction program and is the most important consideration for UNSG.

UNSG contracted with Summit Blue Consulting to expand the simulations to include the same baseline home with Flagstaff weather data. The combination of results from the Ecos evaluation and the Summit Blue evaluation will be used in this report. Kingman weather and construction standards represents the average conditions for warm-weather areas served by UNSG and Flagstaff weather and construction standards represents the average for cold-weather areas served by UNSG.

Throughout UNSG service territories, it is estimated that an average of 5,435 new units per year will be built from 2008 through 2012.

Program Eligibility

- Must be a builder of newly-constructed residential single-family residences (including townhomes, condominiums and duplexes) each served by an individual gas meter.

- New homes must be located within the UNSG certificated service territory.

Program Rationale

The pace of residential new construction in Arizona is one of the biggest drivers of UNSG's system load growth. In December 2004 and 2005 the residential sector of the UNSG customer base made up approximately 91% of total accounts and 67% total therm sales. It is useful to offer this type of energy efficiency program as the load will continue to be present on UNSG's system for 50 plus years after initial construction. It is much easier and more cost effective to work with builders to implement energy efficiency at the time of construction rather than attempt retrofit efficiency after a home has been built. For many new home measures such as building envelope improvements, the benefits of energy efficiency upgrades will be sustained for the life of the home to produce cost effective savings.

Program Objectives

- Reduce peak demand and overall energy consumption (gas and electric) in new homes;
- Incorporate EPA/DOE Energy Star Homes® performance standards into the program;
- Stimulate construction of new homes that are inspected and tested to assure energy performance;
- Stimulate the installation of high SEER (14 or greater) air conditioning units and heat pumps for cooling climates;
- Stimulate the installation of high AFUE (90% or greater) furnaces in heating climates;
- Stimulate the installation of high efficiency water heaters;
- Stimulate the installation of Energy Star® products;
- Achieve an annual participation of between 8% and 12% of new home units, with approximately 402 homes in 2008;
- Assist sales agents with promoting and selling of energy efficient homes;
- Provide information to help explain the benefits of energy efficient features;
- Train builder construction staff and sub-contractors in advanced building science concepts to increase energy efficiency through improved design and installation practices;
- Increase homebuyer awareness and understanding of the benefits they receive from energy efficient building practices; and
- Educate builders who: 1) are not familiar with savings potential; 2) may be uncertain about performance associated with energy efficient construction standards; 3) may be concerned about high first costs for construction measures.

Products and Services

- Promotion of builders and subdivisions that meet or exceed Energy Star® performance standards;
- Builder and sub-contractor education and training;
- Educational and promotional materials for builders and new home buyers; and
- Builder incentives for meeting Energy Star Homes® performance standards.

Figure 1: Energy Smart Homes Program Prescriptive Incentives

UES Energy Smart Home Program Incentives	
Meets ESH and Energy Star Homes® performance standards including testing and inspection protocol.	$400 per home

Delivery Strategy and Administration

UNSG will provide program administration, marketing, planning, coordination of builder and contractor training and consumer education activities. Some program activities, such as training, incentive processing, and other program support may be provided in-house or through specialized vendors.

Key industry relationships will include: (1) EPA/DOE Energy Star Homes® for program branding and certification standards; (2) building Science trainers for training and education; (3) testing and inspection contractors approved by RESNET for third party performance verification and energy ratings; (4) the Arizona Energy Office for support in all areas; and (5) local code officials.

UNSG will develop key trade ally relationships including: (1) builders; (2) energy experts able to provide design assistance and building energy simulation modeling; (3) HVAC Contractors for sizing, installation and start-up of HVAC systems; (4) framing Contractors for framing and blocking detail to enhance insulation performance; and (5) insulation Contractors for insulation installed according to specifications.

Program logic model is included in Appendix 4.

Marketing and Communications

The goal for marketing the ESH is to educate consumers on the benefits of Energy Star Home® performance standards and promote builders who provide Energy Star Home® products. Marketing is necessary to drive the consumers to homebuilders who adhere to these performance standards. As more consumers demand the product, more builders will choose to build to ESH standards. Higher participation by builders results in higher quality and more energy efficient homes being built in the UNSG service territory.

UNSG will provide the following marketing and promotional support:

For Builders:

- Advertisements and article placements in builder trade publications;
- Direct sales through builder account representatives;
- Point-of-Sale materials and sales tools;
- UNSG Web-site; and
- UNSG builder training events.

For Homebuyers:

- Advertisement or articles in targeted homebuyer publications;
- UNSG Web-site;
- Point-of-Sale materials at sales offices and model homes; and

- Brochures or bill-stuffers.

Program Implementation Schedule

The following table shows the estimated timeline for key program activities by quarter assuming program approval by the ACC by the third quarter of 2007:

Figure 2: Implementation Schedule

Program Activities	2007				2008				2009			
New program pre-approval submit												
New program approval (estimated)												
Develop marketing materials & communication												
Program kick-off with Energy Star Home® and builders (On-going)												
Training for builders and partners												
Savings verification												
Program redesign as needed												

Monitoring and Evaluation Plan

UNSG will adopt a strategy that calls for integrated data collection that is designed to provide a quality data resource for program tracking, management and evaluation. This approach will entail the following primary activities:

- **Database tracking system development** - As part of detailed program design, UNSG will develop a database tracking system that will be used to collect the necessary data elements and provide the reporting functions needed to track program process and provide a data resource for program evaluation.
- **Integrated implementation data collection** - UNSG will work with the implementation contractor to establish systems to collect the data needed to support effective program management and evaluation through the implementation and customer application processes. The database tracking system will be integrated with implementation data collection processes.
- **Field verification** - UNSG will conduct field verification of the installation of a sample of measures throughout the implementation of the program.
- **Tracking of savings using deemed savings values** - UNSG will develop deemed savings values for each measure and technology promoted by the program and periodically review and revise the savings values to be consistent with program participation and accurately estimated the savings being achieved by the program.

This approach will provide UNSG with ongoing feedback on program progress and enable program management to adjust or correct the program so as to be more effective, provide a higher level of service, and be more cost beneficial. Integrated data collection will also provide a high quality data resource for evaluation activities.

Program Budget

The average annual ESH annual budget of $446,000 will be allocated as shown in Table 1, while Table 2 provides the expected program budgets through 2012. Appendix 3 provides additional details on the 2008 budget. It is expected that the nature of the construction market in the UNSG service territory and the absence of past energy efficiency initiatives will result in high marketing and administrative costs. On average over the life of the program, incentives are expected to account for 49% of the total budget.

Table 1. 2008 Program Budget

Total Program Budget	$420,000
Total Administrative and O&M Cost Allocation	
Managerial & Clerical	$62,748
Travel & Direct Expenses	$3,780
Overhead	$9,072
Total Administrative Cost	***$75,600***
Total Marketing Allocation	
Internal Marketing Expense	$42,000
Subcontracted Marketing Expense	$42,000
Total Marketing Cost	***$84,000***
Total Direct Implementation	
Financial Incentives	$161,312
Support Activity Labor	$36,540
Hardware & Materials	$33,568
Rebate Processing & Inspection	$12,180
Total Direct Installation Cost	***$243,600***
Total EM&V Cost Allocation	
EM&V / Research Activity	$15,120
EM&V Overhead	$1,680
Total EM&V Cost	***$16,800***

Table 2. 2008 – 2012 Program Budget

Year	2008	2009	2010	2011	2012
Total Budget	$420,000	$432,600	$445,578	$458,945	$472,714
Incentives	$161,312	$195,624	$219,280	$265,144	$249,264
Administrative Costs	$258,688	$236,976	$226,298	$193,801	$223,450
Incentives as % of Budget	38%	45%	49%	58%	53%

Estimated Energy Savings

Total annual participation goals and energy savings are presented in Table 3. The program expects, on average, 545 units annually will participate in the program. Appendix 5 provides further information about estimated energy savings.

Table 3. Residential Air Conditioning Program Annual Energy Savings

Year	2008	2009	2010	2011	2012
Projected Number of Permits	5,041	5,434	5,482	6,026	5,193
Projected ESH Program %	8%	9%	10%	11%	12%
Projected ESH participants	403	489	548	663	623
Coincident peak savings (kW)	304	369	414	500	470
Energy Savings (kWh)	18,703	22,681	25,424	30,742	28,900
Energy Savings (therms)	119,048	144,371	161,829	195,676	183,957

As a result of the energy savings shown above, it is estimated that the program will produce environmental benefits through avoided emissions and avoided water use. The estimated additional benefits from 2008 – 2012 are presented in Table 4.

Table 4. Projected Environmental Benefits, 2008 - 2012

CO_2 Emissions Avoided	4,807	Tons
Water Saved	29,463	Gal

Note: A portion of the CO_2, and all of the water benefits are related to electricity savings and are based on Arizona Public Service Co. estimates as presented in the "APS Demand Side Management Program Portfolio 2005-2007" p. 20.

Program Benefits and Costs

Reports from Ecos Consulting and Summit Blue Consulting include comprehensive and updated analysis on the expected savings gained from ESH standards compared to current market conditions and building practices. The majority of new home activity is expected in UNSG Mohave County which was the focus of the Ecos report. The analysis shows the expected kW demand savings, expected energy savings and therm savings from using higher efficiency heating, cooling and water heating equipment. The analysis also includes the reduction in energy and demand created by performance requirements during construction when homes are inspected and/or tested. Information from the Mohave County results will be applied to the warm weather regions of UNSG service territory. Data collected in this baseline report was then expanded to include energy simulations for Flagstaff climate data to be applied to the cold weather regions of UNSG service territory.

Results of the 2007 analysis provide the basis for the energy and capacity savings used for the benefit cost analysis and the summary table from the ECOS study and the Summit Blue study are included in Appendix 2. UNSG will continue to monitor current conditions and will update the analysis if additional changes are necessary.

Table 5 provides the program costs and benefits, the Total Resource Cost ("TRC") test, the Societal Cost ("SC") test and the Ratepayer Impact Measure ("RIM"). Savings are net based on 0.95 net-to-gross ratio. A detailed benefit/cost analysis is presented in Appendix 5.

Table 5. Benefit-cost analysis results

Cost Effectiveness Tests	TRC	SC	RIM
Benefit/Cost Ratio	2.08	2.74	0.64

In addition to estimating the savings from each measure, this analysis relies on a range of other assumptions and financial data provided in Table 6.

Table 6. Other Financial Assumptions

Conservation Life (yrs)	20
Program Life (yrs)	5
Energy AC ($/Therm)	0.9451
Ratio of Non-inc to Incentive Costs	75.4%
TRC Discount Rate	8.50%
Social Discount Rate	5.00%
NTG Ratio	95%

Appendix 1 - Energy Star Home® Requirements by Climate Zone

Article I. - Builder Option Packages for Arizona

Find Your County and Click on the Corresponding Climate Zone

County	BOPs by Climate Zone	County	BOPs by Climate Zone
Apache	5	Mohave	3
Cochise	3	Navajo	5
Coconino	5	Pima	2
Gila	4	Pinal	2
Graham	3	Santa Cruz	3
Greenlee	3	Yavapai	4
La Paz	2	Yuma	2
Maricopa	2		

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UNS Gas serves Coconino, Mohave, Santa Cruz, and Yavapai Counties.

Continue to next pages for detail

ENERGY STAR Qualified Homes Builder Option Package Notes

2004/2006 IECC Climate Zone[1] – 5	ENERGY STAR Window Zone[10] – Northern

The requirements for the ENERGY STAR Builder Option Package (BOP) are specified in the table below.
To qualify as ENERGY STAR using this BOP, a home must meet the requirements specified, be verified and field-tested in accordance with the HERS Standards by a RESNET-accredited Provider, and meet all applicable codes.

Cooling Equipment (Where Provided)	Right-sized[2] ≥13 SEER/ 11.5 EER ENERGY STAR qualified A/C; OR Right-sized[2] ≥13 SEER/ 11.5 EER/ 8.5 HSPF ENERGY STAR qualified heat pump [3]	
Heating Equipment	≥90 AFUE ENERGY STAR qualified gas furnace; OR ≥13 SEER/ 11.5 EER/ 8.5 HSPF ENERGY STAR qualified heat pump [2, 3]; OR ≥90 AFUE ENERGY STAR qualified boiler; OR ≥85 AFUE ENERGY STAR qualified oil furnace	
Thermostat [3]	ENERGY STAR qualified thermostat (except for zones with mass radiant heat)	
Ductwork	Leakage [4]: ≤ 4 cfm to outdoors / 100 sq. ft.; AND Insulation [5]: ≥ R-6 insulation on ducts in unconditioned spaces	
Envelope	≤ 5 ACH50	Infiltration [6,7]
	≤ Reference UA ≥ 38 R-Value ≥ 30 R-Value ≥ 19 R-Value ≥ 13 + 5 R-Value ≥ 30 R-Value ≥ 10 R-Value ≥ 13 R-Value ≥ 10 R-Value ≥ 13 R-Value ≥ 10 R-Value	UA Alternative Approach [8]; OR Ceiling Insulation [8]; AND (if applicable) Cathedral Ceiling Insulation [8]; AND (if applicable) Wood Frame Wall Insulation [8]; OR Wood Frame Wall Insulation and Sheathing AND (if applicable) Floor Over Unconditioned Space Insulation [8]; AND (if applicable) Crawlspace Wall Insulation Continuous [8]; OR (if applicable) Crawlspace Wall Insulation Framed [8]; AND (if applicable) Basement Wall Insulation Continuous [8]; OR (if applicable) Basement Wall Insulation Framed [8]; AND (if applicable) Slab Insulation at 2 feet Depth [8]; AND
	Completed Thermal Bypass Inspection Checklist [9]	
Windows [10,11,12]	≤ 0.35 U-Value ≤ Any SHGC	
Water Heater [13]	Gas (EF): 40 Gal = 0.61 | 60 Gal = 0.57 | 80 Gal = 0.53 Electric (EF): 40 Gal = 0.93 | 50 Gal = 0.92 | 80 Gal = 0.89 Oil or Gas [14]: Integrated with space heating boiler	
Lighting and Appliances [15,16]	Five or more ENERGY STAR qualified appliances, light fixtures, ceiling fans equipped with lighting fixtures, and/or ventilation fans	

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ENERGY STAR Qualified Homes Builder Option Package Notes

2004/2006 IECC Climate Zone[1] – 5	ENERGY STAR Window Zone[10] – Northern

1. The appropriate climate zone shall be determined by the 2004 International Residential Code (IRC), Figure N1101.2.
2. Cooling equipment shall be sized according to the latest editions of ACCA Manuals J and S, ASHRAE 2001 Handbook of Fundamentals, or an equivalent procedure. Maximum oversizing limit for air conditioners and heat pumps is 15% (with the exception of heat pumps in Climate Zones 5 - 8, where the maximum oversizing limit is 25%). The following operating conditions shall be used in the sizing calculations and verified where reviewed by the rater:

   Outdoor temperatures shall be the 99.0% design temperatures as published in the ASHRAE Handbook of Fundamentals for the home's location or most representative city for which design temperature data are available. Note that a higher outdoor air design temperature may be used if it represents prevailing local practice by the HVAC industry and reflects extreme climate conditions that can be documented with recorded weather data; Indoor temperatures shall be 75 F for cooling; Infiltration rate shall be selected as "tight", or the equivalent term.

   In specifying equipment, the next available size may be used. In addition, indoor and outdoor coils shall be matched in accordance with ARI standards.
3. Homes with heat pumps in Climate Zones 4 and 5 must have an HSPF ≥ 8.5, which exceeds the ENERGY STAR minimum of 8.2 HSPF. Homes with heat pumps in Climate Zones 6, 7, and 8 cannot be qualified using this BOP; but can earn the label using the ENERGY STAR Performance Path requirements. In homes with heat pumps that have programmable thermostats, the thermostat must have "Adaptive Recovery" technology to prevent the excessive use of electric back-up heating.
4. Ducts must be sealed and tested to be ≤ 4 cfm to outdoors / 100 sq. ft. of conditioned floor area, as determined and documented by a RESNET-certified rater using a RESNET-approved testing protocol. If *total* duct leakage is ≤ 4 cfm to outdoors / 100 sq.ft. of conditioned floor area, then leakage to outdoors does not need to be tested. Duct leakage testing can be waived if all ducts and air handling equipment are located in conditioned space (i.e., within the home's air and thermal barriers) AND the envelope leakage has been tested to be ≤ 3 ACH50 OR ≤ 0.25 CFM 50 per sq. ft. of the building envelope. Note that mechanical ventilation will be required in this situation.
5. EPA recommends, but does not require, locating ducts within conditioned space (i.e., inside the air and thermal barriers), and using a minimum of R-4 insulation for ducts inside conditioned space to prevent condensation.
6. Envelope leakage must be determined by a RESNET-certified rater using a RESNET-approved testing protocol.
7. To ensure consistent exchange of indoor air, whole-house mechanical ventilation is recommended, but not required.
8. Insulation levels of a home must meet or exceed Sections N1102.1 and N1102.2 of the 2004 IRC. These sections allow for compliance to be determined by meeting prescriptive insulation requirements, by using U-factor alternatives, or by using a total UA alternative. These sections also provide guidance and exceptions that may be used. However, note that the U-factor for steel-frame envelope assemblies addressed in Section N1102.2.4 shall be calculated using the ASHRAE zone method, or a method providing equivalent results, and not a series-parallel path calculation method as is stated in the code. Additionally, Section N1102.2.2, which allows for the reduction of ceiling insulation in space constrained roof/ceiling assemblies, shall be limited to 500 sq. ft. or 20% of ceiling area, whichever is less. In all cases, insulation shall be inspected to Grade I installation as defined in the RESNET Standards by a RESNET-certified rater. Note that the fenestration requirements of the 2004 IRC do not apply to the fenestration requirements of the National Builder Option Package. Therefore, if UA calculations are performed, they must use the IRC requirements (with the exception of fenestration) plus the fenestration requirements contained in the national BOP. For more information, refer to the "Codes and Standards Information" document.
9. The Thermal Bypass Inspection Checklist must be completed for homes to earn the ENERGY STAR label. The Checklist requires visual inspection of framing areas where air barriers are commonly missed and inspection of insulation to ensure proper alignment with air barriers, thus serving as an extra check that the air and thermal barriers are continuous and complete.
10. All windows and skylights must be ENERGY STAR qualified or meet all specifications for ENERGY STAR qualified windows. Windows in Climate Zones 2 and 4 must exceed ENERGY STAR specifications (CZ 2: U-value ≤ 0.55 and SHGC ≤ 0.35; CZ 4: U-value ≤ 0.40 and SHGC ≤ 0.45). Visit www.energystar.gov/windows for more information on ENERGY STAR qualified windows.

www.energystar.gov

ENERGY STAR Qualified Homes Builder Option Package Notes

2004/2006 IECC Climate Zone[1] – 5	ENERGY STAR Window Zone[10] – Northern

11. All decorative glass and skylight window area counts toward the total window area to above-grade conditioned floor area (WFA) ratio. For homes with a WFA ratio >18%, the following additional requirements apply:
    a. In IRC Climate Zones 1, 2, and 3, an improved window SHGC is required, and is determined by:
    Required SHGC = [0.18 / WFA] x [ENERGY STAR SHGC]
    Where the ENERGY STAR SHGC is the minimum required SHGC of the climate-appropriate window specified in this BOP.
    b. In IRC Climate Zones 4, 5, 6, 7, and 8, an improved window U-Value is required, and is determined by:
    Required U-Value = [0.18 / WFA] x [ENERGY STAR U-Value]
    Where the ENERGY STAR U-Value is the minimum required U-Value of the climate-appropriate window specified in this BOP.
12. Up to 0.75% WFA may be used for decorative glass that does not meet ENERGY STAR requirements. For example, a home with total above-grade conditioned floor area of 2,000 sq. ft. may have up to 15 sq. ft. (0.75% of 2,000) of decorative glass.
13. To determine domestic hot water (DHW) EF requirements for additional tank sizes, use the following equations:
    Gas DHW EF ≥ 0.69 - (0.002 x Tank Gallon Capacity); Electric DHW EF ≥ 0.97 - (0.001 x Tank Gallon Capacity).
14. In homes with gas or oil hydronic space heating, water heating systems must have an efficiency ≥ 0.78 EF. This may be met through the use of an instantaneous water heating system or an indirect storage system with a boiler that has a system efficiency ≥ 85 AFUE. Homes with tankless coil hot water heating systems cannot be qualified using this BOP, but can earn the label using the ENERGY STAR Performance Path requirements.
15. Any combination of ENERGY STAR qualified products listed may be installed to meet this requirement. ENERGY STAR qualified ventilation fans include range hood, bathroom, and inline fans. ENERGY STAR qualified lighting fixtures installed in the following locations shall not be counted: storage rooms (e.g., closets, pantries, sheds), or garages. Eligible appliances include ENERGY STAR qualified refrigerators, dish washers, and washing machines. Further efficiency and savings can be achieved by installing ENERGY STAR qualified products, in addition to those required (e.g., additional lighting, appliances, etc.).
16. Efficient lighting fixtures represent a significant opportunity for persistent energy savings and a meaningful way to differentiate ENERGY STAR qualified homes from those meeting minimum code requirements. In 2008, EPA intends to propose and solicit industry comments on adding the ENERGY STAR Advanced Lighting Package (ALP) as an additional requirement for ENERGY STAR qualified homes in 2009. To learn more about the ALP, refer to www.energystar.gov/homes.

ENERGY STAR Qualified Homes
Builder Option Package Notes

2004/2006 IECC Climate Zone[1] – 4	ENERGY STAR Window Zone[10] – All

The requirements for the ENERGY STAR Builder Option Package (BOP) are specified in the table below.
To qualify as ENERGY STAR using this BOP, a home must meet the requirements specified, be verified and field-tested in accordance with the HERS Standards by a RESNET-accredited Provider, and meet all applicable codes.

Cooling Equipment (Where Provided)	Right-sized[2] ≥13 SEER/ 11.5 EER ENERGY STAR qualified A/C; OR Right-sized[2] ≥13 SEER/ 11.5 EER/ 8.5 HSPF ENERGY STAR qualified heat pump [3]	
Heating Equipment	≥90 AFUE ENERGY STAR qualified gas furnace; OR ≥13 SEER/ 11.5 EER/ 8.5 HSPF ENERGY STAR qualified heat pump [2,3]; OR ≥90 AFUE ENERGY STAR qualified boiler; OR ≥85 AFUE ENERGY STAR qualified oil furnace	
Thermostat [3]	ENERGY STAR qualified thermostat (except for zones with mass radiant heat)	
Ductwork	Leakage [4]: ≤ 4 cfm to outdoors / 100 sq. ft.; AND Insulation [5]: ≥ R-6 insulation on ducts in unconditioned spaces	
Envelope	≤ 6 ACH50	Infiltration [6,7]
	≤ Reference UA ≥ 38 R-Value ≥ 30 R-Value ≥ 13 R-Value ≥ 19 R-Value ≥ 10 R-Value ≥ 13 R-Value ≥ 10 R-Value ≥ 13 R-Value ≥ 10 R-Value	UA Alternative Approach [8], OR Ceiling Insulation [8]; AND (if applicable) Cathedral Ceiling Insulation [8]; AND (if applicable) Wood Frame Wall Insulation [8]; AND (if applicable) Floor Over Unconditioned Space Insulation [8]; AND (if applicable) Crawlspace Wall Insulation Continuous [8]; OR (if applicable) Crawlspace Wall Insulation Framed [8]; AND (if applicable) Basement Wall Insulation Continuous [8]; OR (if applicable) Basement Wall Insulation Framed [8]; AND (if applicable) Slab Insulation at 2 feet Depth [8]; AND
	Completed Thermal Bypass Inspection Checklist [9]	
Windows [10,11,12]	≤ 0.40 U-Value ≤ 0.45 SHGC	
Water Heater [13]	Gas (EF): 40 Gal = 0.61 | 60 Gal = 0.57 | 80 Gal = 0.53 Electric (EF): 40 Gal = 0.93 | 50 Gal = 0.92 | 80 Gal = 0.89 Oil or Gas [14]: Integrated with space heating boiler	
Lighting and Appliances [15,16]	Five or more ENERGY STAR qualified appliances, light fixtures, ceiling fans equipped with lighting fixtures, and/or ventilation fans	

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ENERGY STAR Qualified Homes Builder Option Package Notes

2004/2006 IECC Climate Zone[1] – 4	ENERGY STAR Window Zone[10] – All

1. The appropriate climate zone shall be determined by the 2004 International Residential Code (IRC), Figure N1101.2.
2. Cooling equipment shall be sized according to the latest editions of ACCA Manuals J and S, ASHRAE 2001 Handbook of Fundamentals, or an equivalent procedure. Maximum oversizing limit for air conditioners and heat pumps is 15% (with the exception of heat pumps in Climate Zones 5 - 8, where the maximum oversizing limit is 25%). The following operating conditions shall be used in the sizing calculations and verified where reviewed by the rater:

   Outdoor temperatures shall be the 99.0% design temperatures as published in the ASHRAE Handbook of Fundamentals for the home's location or most representative city for which design temperature data are available. Note that a higher outdoor air design temperature may be used if it represents prevailing local practice by the HVAC industry and reflects extreme climate conditions that can be documented with recorded weather data; Indoor temperatures shall be 75 F for cooling; Infiltration rate shall be selected as "tight", or the equivalent term.

   In specifying equipment, the next available size may be used. In addition, indoor and outdoor coils shall be matched ir accordance with ARI standards.
3. Homes with heat pumps in Climate Zones 4 and 5 must have an HSPF ≥ 8.5, which exceeds the ENERGY STAR minimum of 8.2 HSPF. Homes with heat pumps in Climate Zones 6, 7, and 8 cannot be qualified using this BOP, but can earn the label using the ENERGY STAR Performance Path requirements. In homes with heat pumps that have programmable thermostats, the thermostat must have "Adaptive Recovery" technology to prevent the excessive use of electric back-up heating.
4. Ducts must be sealed and tested to be ≤ 4 cfm to outdoors / 100 sq. ft. of conditioned floor area, as determined and documented by a RESNET-certified rater using a RESNET-approved testing protocol. If *total* duct leakage is ≤ 4 cfm to outdoors / 100 sq.ft. of conditioned floor area, then leakage to outdoors does not need to be tested. Duct leakage testing can be waived if all ducts and air handling equipment are located in conditioned space (i.e., within the home's air and thermal barriers) AND the envelope leakage has been tested to be ≤ 3 ACH50 OR ≤ 0.25 CFM 50 per sq. ft. of the building envelope. Note that mechanical ventilation will be required in this situation.
5. EPA recommends, but does not require, locating ducts within conditioned space (i.e., inside the air and thermal barriers), and using a minimum of R-4 insulation for ducts inside conditioned space to prevent condensation.
6. Envelope leakage must be determined by a RESNET-certified rater using a RESNET-approved testing protocol.
7. To ensure consistent exchange of indoor air, whole-house mechanical ventilation is recommended, but not required.
8. Insulation levels of a home must meet or exceed Sections N1102.1 and N1102.2 of the 2004 IRC. These sections allow for compliance to be determined by meeting prescriptive insulation requirements, by using U-factor alternatives, or by using a total UA alternative. These sections also provide guidance and exceptions that may be used. However, note that the U-factor for steel-frame envelope assemblies addressed in Section N1102.2.4 shall be calculated using the ASHRAE zone method, or a method providing equivalent results, and not a series-parallel path calculation methoc as is stated in the code. Additionally, Section N1102.2.2, which allows for the reduction of ceiling insulation in space constrained roof/ceiling assemblies, shall be limited to 500 sq. ft. or 20% of ceiling area, whichever is less. In all cases, insulation shall be inspected to Grade I installation as defined in the RESNET Standards by a RESNET-certified rater. Note that the fenestration requirements of the 2004 IRC do not apply to the fenestration requirements of the National Builder Option Package. Therefore, if UA calculations are performed, they must use the IRC requirements (with the exception of fenestration) plus the fenestration requirements contained in the national BOP. For more information, refer to the "Codes and Standards Information" document.
9. The Thermal Bypass Inspection Checklist must be completed for homes to earn the ENERGY STAR label. The Checklist requires visual inspection of framing areas where air barriers are commonly missed and inspection of insulation to ensure proper alignment with air barriers, thus serving as an extra check that the air and thermal barriers are continuous and complete.
10. All windows and skylights must be ENERGY STAR qualified or meet all specifications for ENERGY STAR qualified windows. Windows in Climate Zones 2 and 4 must exceed ENERGY STAR specifications (CZ 2: U-value ≤ 0.55 and SHGC ≤ 0.35; CZ 4: U-value ≤ 0.40 and SHGC ≤ 0.45). Visit www.energystar.gov/windows for more information on ENERGY STAR qualified windows.

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ENERGY STAR Qualified Homes Builder Option Package Notes

2004/2006 IECC Climate Zone[1] – 4	ENERGY STAR Window Zone[10] – All

11. All decorative glass and skylight window area counts toward the total window area to above-grade conditioned floor area (WFA) ratio. For homes with a WFA ratio >18%, the following additional requirements apply:
    a. In IRC Climate Zones 1, 2, and 3, an improved window SHGC is required, and is determined by:

       Required SHGC = [0.18 / WFA] x [ENERGY STAR SHGC]

       Where the ENERGY STAR SHGC is the minimum required SHGC of the climate-appropriate window specified in this BOP.

    b. In IRC Climate Zones 4, 5, 6, 7, and 8, an improved window U-Value is required, and is determined by:

       Required U-Value = [0.18 / WFA] x [ENERGY STAR U-Value]

       Where the ENERGY STAR U-Value is the minimum required U-Value of the climate-appropriate window specified in this BOP.

12. Up to 0.75% WFA may be used for decorative glass that does not meet ENERGY STAR requirements. For example, a home with total above-grade conditioned floor area of 2,000 sq. ft. may have up to 15 sq. ft. (0.75% of 2,000) of decorative glass.
13. To determine domestic hot water (DHW) EF requirements for additional tank sizes, use the following equations:

    Gas DHW EF $\geq$ 0.69 - (0.002 x Tank Gallon Capacity); Electric DHW EF $\geq$ 0.97 - (0.001 x Tank Gallon Capacity).
14. In homes with gas or oil hydronic space heating, water heating systems must have an efficiency $\geq$ 0.78 EF. This may be met through the use of an instantaneous water heating system or an indirect storage system with a boiler that has a system efficiency $\geq$ 85 AFUE. Homes with tankless coil hot water heating systems cannot be qualified using this BOP, but can earn the label using the ENERGY STAR Performance Path requirements.
15. Any combination of ENERGY STAR qualified products listed may be installed to meet this requirement. ENERGY STAR qualified ventilation fans include range hood, bathroom, and inline fans. ENERGY STAR qualified lighting fixtures installed in the following locations shall not be counted: storage rooms (e.g., closets, pantries, sheds), or garages. Eligible appliances include ENERGY STAR qualified refrigerators, dish washers, and washing machines. Further efficiency and savings can be achieved by installing ENERGY STAR qualified products, in addition to those required (e.g., additional lighting, appliances, etc.).
16. Efficient lighting fixtures represent a significant opportunity for persistent energy savings and a meaningful way to differentiate ENERGY STAR qualified homes from those meeting minimum code requirements. In 2008, EPA intends to propose and solicit industry comments on adding the ENERGY STAR Advanced Lighting Package (ALP) as an additional requirement for ENERGY STAR qualified homes in 2009. To learn more about the ALP, refer to www.energystar.gov/homes.

ENERGY STAR Qualified Homes Builder Option Package Notes

2004/2006 IECC Climate Zone[1] – 3 | **ENERGY STAR Window Zone[10] – South/Central**

The requirements for the ENERGY STAR Builder Option Package (BOP) are specified in the table below.
To qualify as ENERGY STAR using this BOP, a home must meet the requirements specified, be verified and field-tested in accordance with the HERS Standards by a RESNET-accredited Provider, and meet all applicable codes.

Cooling Equipment (Where Provided)	Right-sized[2] ≥14 SEER/ 11.5 EER ENERGY STAR qualified A/C; OR Right-sized[2] ≥14 SEER/ 11.5 EER/ 8.2 HSPF ENERGY STAR qualified heat pump[3]	
Heating Equipment	≥80 AFUE gas furnace; OR ≥14 SEER/ 11.5 EER/ 8.2 HSPF ENERGY STAR qualified heat pump[2,3]; OR ≥80 AFUE boiler; OR ≥80 AFUE oil furnace	
Thermostat[3]	ENERGY STAR qualified thermostat (except for zones with mass radiant heat)	
Ductwork	Leakage[4]: ≤ 4 cfm to outdoors / 100 sq. ft.; AND Insulation[5]: ≥ R-6 insulation on ducts in unconditioned spaces	
Envelope	≤ 6 ACH50	Infiltration[6,7]
	≤ Reference UA	UA Alternative Approach[8]; OR
	≥ 30 R-Value	Ceiling Insulation[8]; AND (if applicable)
	≥ 30 R-Value	Cathedral Ceiling Insulation[8]; AND (if applicable)
	≥ 13 R-Value	Wood Frame Wall Insulation[8]; AND (if applicable)
	≥ 19 R-Value	Floor Over Unconditioned Space Insulation[8]; AND (if applicable)
	≥ 5 R-Value	Crawlspace Wall Insulation Continuous[8]; OR (if applicable)
	≥ 13 R-Value	Crawlspace Wall Insulation Framed[8]; AND (if applicable)
	None required	Basement Wall Insulation Continuous[8]; OR (if applicable)
	None required	Basement Wall Insulation Framed[8]; AND (if applicable)
	None required	Slab Insulation[8]; AND
	Completed Thermal Bypass Inspection Checklist[9]	
Windows[10,11,12]	≤ 0.40 U-Value ≤ 0.40 SHGC	
Water Heater[13]	Gas (EF): 40 Gal = 0.61 | 60 Gal = 0.57 | 80 Gal = 0.53 Electric (EF): 40 Gal = 0.93 | 50 Gal = 0.92 | 80 Gal = 0.89 Oil or Gas[14]: Integrated with space heating boiler	
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ENERGY STAR Qualified Homes Builder Option Package Notes

2004/2006 IECC Climate Zone[1] – 3	ENERGY STAR Window Zone[10] – South/Central

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   In specifying equipment, the next available size may be used. In addition, indoor and outdoor coils shall be matched in accordance with ARI standards.
3. Homes with heat pumps in Climate Zones 4 and 5 must have an HSPF ≥ 8.5, which exceeds the ENERGY STAR minimum of 8.2 HSPF. Homes with heat pumps in Climate Zones 6, 7, and 8 cannot be qualified using this BOP, but can earn the label using the ENERGY STAR Performance Path requirements. In homes with heat pumps that have programmable thermostats, the thermostat must have "Adaptive Recovery" technology to prevent the excessive use of electric back-up heating.
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ENERGY STAR Qualified Homes Builder Option Package Notes

2004/2006 IECC Climate Zone[1] – 3	ENERGY STAR Window Zone[10] – South/Central

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       Required U-Value = [0.18 / WFA] x [ENERGY STAR U-Value]

       Where the ENERGY STAR U-Value is the minimum required U-Value of the climate-appropriate window specified in this BOP.
12. Up to 0.75% WFA may be used for decorative glass that does not meet ENERGY STAR requirements. For example, a home with total above-grade conditioned floor area of 2,000 sq. ft. may have up to 15 sq. ft. (0.75% of 2,000) of decorative glass.
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    Gas DHW EF ≥ 0.69 - (0.002 x Tank Gallon Capacity); Electric DHW EF ≥ 0.97 - (0.001 x Tank Gallon Capacity).
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Appendix 2 – Energy Simulation Used For Benefit-Cost Analysis – warm weather regions.

Table 5. Estimated Current Construction Practice and Savings Potential with SEER 13 Baseline

Location and Number of Homes		Annual Cooling Usage (MWh)		Annual Cooling Demand (kW)		Annual Heating Usage (Therms)	
Kingman and North Mohave County	# of Homes	Per Home (kWh)	Total	Per Home	Total	Per Home	Total
Current Building Practice	200,000	6,826	1,365,200	5.14	1,028,000	326	65,200,000
UES Efficient Home Specification/ENERGY STAR	200,000	4,271	854,200	3.49	698,000	188	37,600,000
Savings: MWh, kW, Therms		2,555	511,000	1.65	330,000	138	27,600,000
Location and Number of Homes		**Annual Cooling Usage (MWh)**		**Annual Cooling Demand (kW)**		**Annual Heating Usage (Therms)**	
Lake Havasu City area	# of Homes	Per Home (kWh)	Total	Per Home	Total	Per Home	Total
Current Building Practice	10,000	8,974	89,740	5.43	59,500	71	710,000
UES Efficient Home Specification/ENERGY STAR	10,000	5,651	56,510	3.82	38,000	34	340,000
Savings: MWh, kW, Therms		3,323	34,960	2.15	21,500	37	370,000
Location and Number of Homes		**Annual Cooling Usage (MWh)**		**Annual Cooling Demand (kW)**		**Annual Heating Usage (Therms)**	
Totals for all Mohave County	# of Homes	Per Home (kWh)	Total	Per Home	Total	Per Home	Total
Current Building Practice	210,000	n/a	1,454,940	n/a	1,087,500	397	65,910,000
UES Efficient Home Specification/ENERGY STAR	210,000	n/a	910,710	n/a	736,000	222	37,940,000
Savings: MWh, kW, Therms		n/a	544,230	n/a	351,500	175	27,970,000

*Above savings calculations were based upon the following assumptions (see also Appendices E):

- Current Building Practice = SEER 13, 20% duct leakage, .65 U-value and .55 SHGC window (better low-e value in Lake Havasu City), R-13 or R-19 with R-4 foam board wall, R-30 ceiling
- UES Efficient Home Specification = SEER 14 AC, 10% duct leakage, .35 U-value and .40 SHGC window, R-13 or R-19 with R-4 foam board wall, R-38 ceiling, thermal bypass sealing

Summit Blue modeling parameters

S.no	Fixed Parameters	Value	Unit	Model Parameters
1	Location	Kingman,Az	-	
2	Storey	1	-	
3	Slab on grade base	-	-	
4	Exterior wall finish	Stucco	-	
5	Roof	Tile, some asphalt shingles	-	
6	Attic Insulation	R - 30	-	
7	Floor insulation	Slab Floor, no Insulation	-	
8	Wall insulation	R23(R19 batt R4 board)	-	
9	Wall insulation	R17(R13 batt + R4 board)	-	R16 + R4 board
10	Duct insulation	R 4.2	-	
11	Duct insulation Rhodes	R 6	-	
12	Ceiling Insulation	R-12	-	R24
13	Window	Aluminum framed, double paned	-	
14	Window material	metal + vinyl	-	
15	Window U value	0.5 average.	-	0.3
16	Low E Kingman	30 % all homes,average value is 0.6	SHGC	0.45
17	Low E lake H	65 % all homes average 0.48	SHGC	
18	Gas furnace	0.78	AFUE	90 AFUE
19	Split AC	10	SEER	13 SEER
20	Cooling supply air temperature	57	F	
21	**Conditioned Area**	**1941**	**sq. ft.**	
22	Duct leakage	13	%	2
S.no	**Parameters in enovity report**	**Value**	**Unit**	
	(not fixed)			
1	Ceiling height	9	ft	
2	Ceiling construction	Gable	-	
3	Ceiling finish	tile over plywood	-	
4	Floor	Concrete slab	-	
5	Infiltration	0.45	ACH	0.22ACH
6	Perimeter Insulation	None	-	
7	Window area	278 (equal all 4 directions)	sq. ft.	
8	Door construction	Steel/fiberglass insulated	-	
9	Door Area	50	sq. ft.	
10	Door R value	R 2.6	-	
11	Door U value	0.385		
12	rooms	4	-	
13	Outside Air ventilation	60	cfm	
14	Thermostat summer	75	F	
15	Thermostat winter	72	F	
16	Occupancy	4	-	
17	Peak Internal loading	1.7	KW	

18	Domestic hot water heater	Gas	-	
19	Peak flow	7.7	gallons	
20	Energy factor	0.9	-	
21	Natural ventilation	none	-	60 cfm
S.no	**Other Parameters**	**Value**	**Unit**	
	As in calibrated model			
1	Zones	5 (4perimeter + 1 core)	-	
2	Daylight controls	None	-	
3	Building orientation	North	-	
4	Aspect ratio	1	-	
5	Perimeter zone depth	10	ft	
6	Attic above top floor	-	-	
7	Floor construction	6 in. concrete	in.	
8	Interior finish	Carpet with fiber pad	-	
9	Exterior wall	2 X 6 frame, wood	-	
10	Overhangs or fins	None	-	
11	Blinds / drapes	None	-	
12	Skylit rooftop zones	None	-	
13	Occupancy schedule	Typical, daytime unoccupied		
14	Mon - fri	Leave 7, Return 5	-	
15	Weekend, holiday	Leave 9, return 4	-	
16	Activity Area Allocation			
17	Residential (Single family)	85	%	
18	Storage	8	%	
19	Laundry	7	%	
20	Lighting density	1.5	W/sq. ft.	
21	Electric equipment load			
22	Living area	1	W/sq. ft.	
23	Laundry	3	W/sq. ft.	
24	Exterior Lighting Loads			

Appendix 3 – Expected 2008 Program Costs

Budget Items	Budget	Allocation Rate (%)
Administrative		
Managerial and Clerical Labor	***$62,748***	
Labor - Clerical	$3,137	5.0%
Labor - Program Design	$5,020	8.0%
Labor - Program Development	$5,020	8.0%
Labor - Program Planning	$6,275	10.0%
Labor - Program/Project Management	$5,647	9.0%
Labor - Staff Management	$6,275	10.0%
Labor - Staff Supervision	$3,137	5.0%
Subcontractor Labor - Clerical	$3,137	5.0%
Subcontractor Labor - Program Design	$6,275	10.0%
Subcontractor Labor - Program Development	$3,137	5.0%
Subcontractor Labor - Program Planning	$3,137	5.0%
Subcontractor Labor - Program/Project Management	$12,550	20.0%
Subcontractor Labor - Staff Management	$0	0.0%
Subcontractor Labor - Staff Supervision	$0	0.0%
Subtotal Managerial and Clerical Labor	*$62,748*	*100.0%*
Travel & Direct Expenses	***$3,780***	
Conference Fees	$1,134	30.0%
Labor - Conference Attendance	$756	20.0%
Subcontractor - Conference Fees	$76	2.0%
Subcontractor - Travel - Airfare	$151	4.0%
Subcontractor - Travel - Lodging	$0	0.0%
Subcontractor - Travel - Meals	$0	0.0%
Subcontractor - Travel - Mileage	$0	0.0%
Subcontractor - Travel - Parking	$0	0.0%
Subcontractor - Travel - Per Diem for Misc. Expenses	$302	8.0%
Subcontractor Labor - Conference Attendance	$76	2.0%
Travel - Airfare	$529	14.0%
Travel - Lodging	$227	6.0%
Travel - Meals	$113	3.0%
Travel - Mileage	$38	1.0%
Travel - Parking	$0	0.0%
Travel - Per Diem for Misc. Expenses	$378	10.0%
Travel & Direct Expenses	*$3,780*	*100.0%*
Overhead (General and Administrative) - Labor and Materials	***$9,072***	
Equipment - Communications	$181	2.0%
Equipment - Computing	$181	2.0%
Equipment - Document Reproduction	$181	2.0%
Equipment - General Office	$181	2.0%
Equipment - Transportation	$181	2.0%
Facilities - Lease/Rent Payment	$0	0.0%

Residential New Construction Program

Labor - Accounts Payable	$91	1.0%
Labor - Accounts Receivable	$91	1.0%
Labor - Administrative	$91	1.0%
Labor - Automated Systems	$0	0.0%
Labor - Communications	$91	1.0%
Labor - Contract Reporting	$91	1.0%
Labor - Corporate Services	$91	1.0%
Labor - Facilities Maintenance	$91	1.0%
Labor - Information Technology	$91	1.0%
Labor - Materials Management	$91	1.0%
Labor - Procurement	$91	1.0%
Labor - Regulatory Reporting	$3,629	40.0%
Labor - Shop Services	$91	1.0%
Labor - Telecommunications	$91	1.0%
Labor - Transportation Services	$91	1.0%
Office Supplies	$91	1.0%
Postage	$91	1.0%
Subcontractor - Equipment - Communications	$0	0.0%
Subcontractor - Equipment - Computing	$0	0.0%
Subcontractor - Equipment - Document Reproduction	$0	0.0%
Subcontractor - Equipment - General Office	$0	0.0%
Subcontractor - Equipment - Transportation	$0	0.0%
Subcontractor - Facilities - Lease/Rent Payment	$0	0.0%
Subcontractor - Office Supplies	$0	0.0%
Subcontractor - Postage	$0	0.0%
Subcontractor Labor - Accounts Payable	$0	0.0%
Subcontractor Labor - Accounts Receivable	$0	0.0%
Subcontractor Labor - Administrative	$0	0.0%
Subcontractor Labor - Automated Systems	$0	0.0%
Subcontractor Labor - Communications	$0	0.0%
Subcontractor Labor - Contract Reporting	$0	0.0%
Subcontractor Labor - Corporate Services	$0	0.0%
Subcontractor Labor - Facilities Maintenance	$0	0.0%
Subcontractor Labor - Information Technology	$0	0.0%
Subcontractor Labor - Materials Management	$0	0.0%
Subcontractor Labor - Procurement	$0	0.0%
Subcontractor Labor - Regulatory Reporting	$3,175	35.0%
Subcontractor Labor - Shop Services	$0	0.0%
Subcontractor Labor - Telecommunications	$0	0.0%
Subcontractor Labor - Transportation Services	$0	0.0%
Subtotal Overhead	*$9,072*	*100.0%*
Total Administrative Costs	**$75,600**	
Marketing/Advertising/Outreach		
Internal Marketing Expense	***$42,000***	
Advertisements / Media Promotions	$10,500	25.0%
Bill Inserts	$1,680	4.0%
Brochures	$2,520	6.0%
Door Hangers	$0	0.0%
Labor - Business Outreach	$2,100	5.0%
Labor - Customer Outreach	$2,100	5.0%

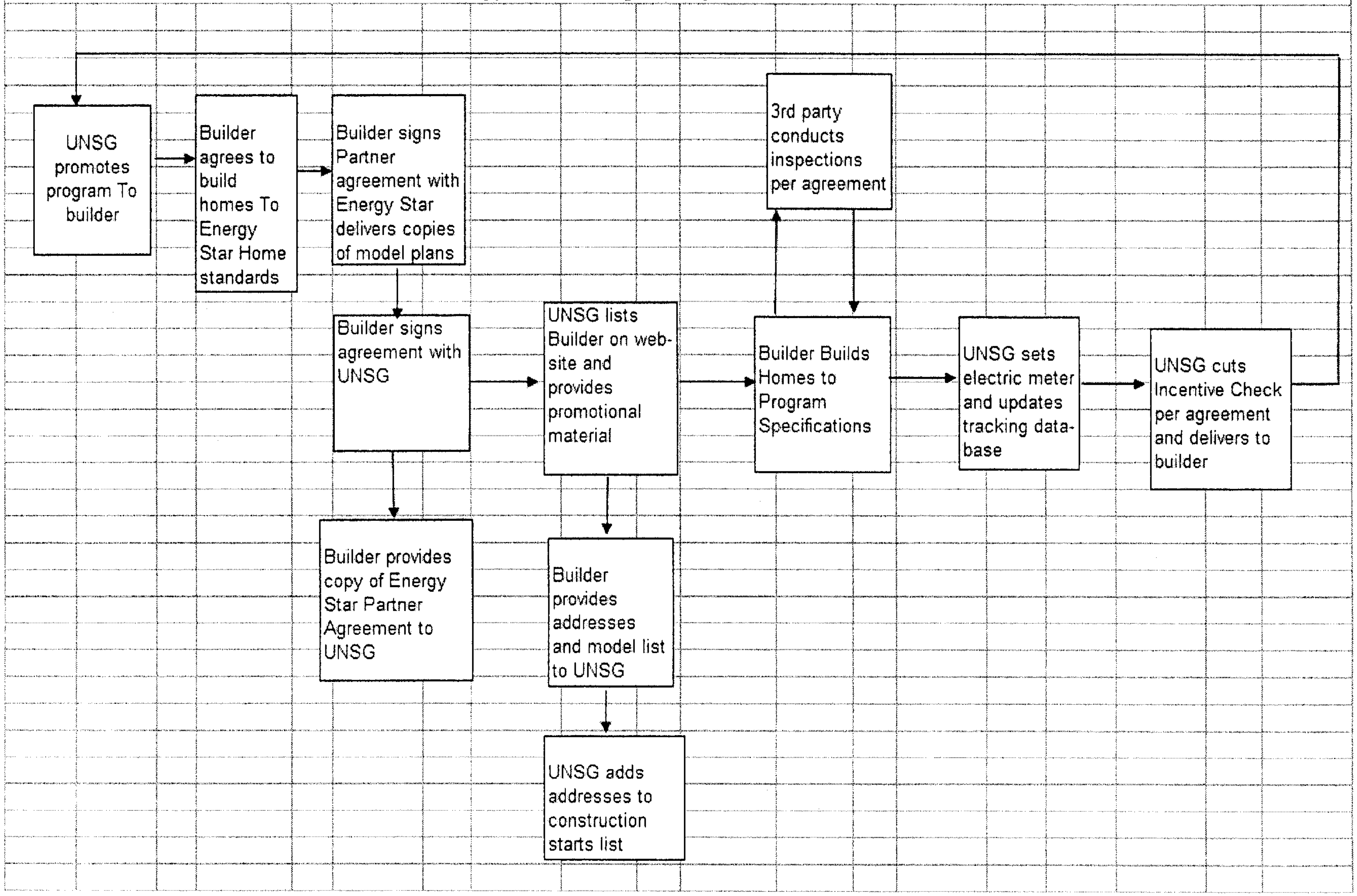
Residential New Construction Program

Labor - Customer Relations	$2,100	5.0%
Labor - Marketing	$12,600	30.0%
Print Advertisements	$6,300	15.0%
Radio Spots	$2,100	5.0%
Subtotal Internal Marketing Expense	*$42,000*	*100.0%*
Subcontracted Marketing Expense	***$42,000***	
Subcontractor - Bill Inserts	$2,100	5.0%
Subcontractor - Brochures	$2,100	5.0%
Subcontractor - Door Hangers	$0	0.0%
Subcontractor - Print Advertisements	$0	0.0%
Subcontractor - Radio Spots	$4,200	10.0%
Subcontractor - Television Spots	$0	0.0%
Subcontractor Labor - Business Outreach	$2,100	5.0%
Subcontractor Labor - Customer Outreach	$2,100	5.0%
Subcontractor Labor - Customer Relations	$2,100	5.0%
Subcontractor Labor - Marketing	$2,100	5.0%
Television Spots	$0	0.0%
Website Development	$25,200	60.0%
Subtotal Subcontracted Marketing Expense	*$42,000*	*100.0%*
Total Marketing/Advertising/Outreach	**$84,000**	
Direct Implementation		
Financial Incentives to Customers	***$161,312***	
Activity - Labor	***$36,540***	
Labor - Curriculum Development	$2,923	8.0%
Labor - Customer Education and Training	$14,616	40.0%
Labor - Customer Equipment Testing and Diagnostics	$0	0.0%
Labor - Facilities Audits	$10,962	30.0%
Subcontanctor Labor - Facilities Audits	$3,654	10.0%
Subcontractor Labor - Curriculum Development	$1,827	5.0%
Subcontractor Labor - Customer Education and Training	$1,827	5.0%
Subcontractor Labor - Customer Equipment Testing and Diagnostics	$731	2.0%
Subtotal Activity	*$36,540*	*100.0%*
Hardware and Materials - Installation and Other DI Activity	***$33,568***	
Audit Applications and Forms	$2,685	8.0%
Direct Implementation Literature	$6,714	20.0%
Education Materials	$6,714	20.0%
Energy Measurement Tools	$3,357	10.0%
Installation Hardware	$3,357	10.0%
Subcontractor - Direct Implementation Literature	$1,343	4.0%
Subcontractor - Education Materials	$1,343	4.0%
Subcontractor - Energy Measurement Tools	$5,371	16.0%
Subcontractor - Installation Hardware	$2,014	6.0%
Subcontractor -Audit Applications and Forms	$671	2.0%
Subtotal Hardware and Materials	*$33,568*	*100.0%*
Rebate Processing and Inspection - Labor and Materials	***$12,180***	
Labor - Field Verification	$1,218	10.0%
Labor - Rebate Processing	$0	0.0%
Labor - Site Inspections	$1,218	10.0%
Rebate Applications	$0	0.0%

Residential New Construction Program

Subcontractor - Rebate Applications	$1,218	10.0%
Subcontractor Labor - Field Verification	$2,436	20.0%
Subcontractor Labor - Rebate Processing	$3,654	30.0%
Subcontractor Labor - Site Inspections	$2,436	20.0%
Subtotal Rebate Processing and Inspection	*$12,180*	*100.0%*
Total Direct Implementation	**$243,600**	
Evaluation, Measurement and Verification		
EM&V Labor and Materials	***$15,120***	
Labor - EM&V	$756	5.0%
Materials - EM&V	$756	5.0%
Subcontractor Labor - EM&V	$13,608	90.0%
Subtotal EM&V Activity - Labor	*$15,120*	*100.0%*
EM&V Overhead	***$1,680***	
Benefits - EM&V Labor	$0	0.0%
Overhead - EM&V	$840	50.0%
Subcontractor Overhead - EM&V	$0	0.0%
Subcontractor Travel - EM&V	$0	0.0%
Travel - EM&V	$840	50.0%
Subtotal EM&V Overhead	*$1,680*	*100.0%*
Total EM&V	**$16,800**	
Total Budget	**$420,000**	

Appendix 4 - Program Implementation Model



Appendix 5 – Home Level Energy Savings and Benefit/Cost Analysis

ESH101 – NEW HOME CONSTRUCTION

Energy Smart Homes Program

PROGRAM DATA	
Conservation Life (yrs):	20
Program Life (yrs):	5
Demand AC ($/kW):	64.94
Summer Energy AC ($/kWh):	0.07314
Winter Energy AC ($/kWh):	0.07075
Levelized Therms	0.94510
Ratio of Non-inc to Incentive Costs	104.46%
IRP Discount Rate*****:	8.50%
Social Discount Rate	5.00%
NTG Ratio:	95%

RATE DATA	
Rate:	
$/kW:	0.00
$/kWh, On-Peak:	0.12277
$/kWh, Off-Peak:	0.09466
$/Therm	1.40080

OPERATING DATA	
Coincidence Factor:	77%

OTHER FACTORS	
Line Loss Factor:	10.69%
Application	New
Cost Basis:	Incremental

	DEMAND/ENERGY SAVINGS												INCENTIVE CALCULATIONS						CUSTOMER COST/SAVINGS				WGT.	% Incent
Measure Type	Current Practices Cooling kWh	Current Practices Heating kWh	Current Practices Demand kW	Current Practices Heating Therms	ESH Cooling kWh	ESH Heating kWh	ESH Demand kW	ESH Heating Therms	Non-Coincident Demand Savings (KW)	Cooling Energy Savings (KWh)	Heating Energy Savings (KWh)	Heating Energy Savings Therms	IRP PV Benefit ($)	Social PV Benefit ($)	Recommended Incentive ($)	Recommended Incentive % PV	PV Program Cost ($)	NPV ($)	Incr. Cost ($)	Cost Savings ($)	Payback wo/Inc. (yrs)	Payback w/Inc. (yrs)	Weighting Factor	(%)
			0				0																	
Gas Heat and DHW @ 13 SEER	872	0	3.18	1007.0	826	0	2.20	711.8	0.980	46	0.00	295	3030	3990	400	13%	1454	1575	1091.00	419	2.6	1.6	1.00	37%
Weighted Average									0.98	46	0	295	$3,030	$3,990	400	13%	1454	1575	1091	419	2.6	1.6	1.00	37%

See worksheet 'Energy Assumptions' for information of E-Quest modelling paprmeters and energy savings data.

See worksheet 'Cost Assumptions' for information of cost data.

Avoided electric costs represent UNSE / TEP simple cycle

Retail electric rates are APS E-12 average revenue/kwh, no BSC, TY Sept 2005

Attachment 3

Efficient Home Heating Program

Table of Contents

UNSG Efficient Home Heating Program

Program Concept and Description

This program promotes the installation of high-efficiency gas-fueled furnaces in existing homes in UNSG's service region. The program promotes the selection of Energy Star qualified high-efficiency equipment that meet or exceed the minimum Energy Star standard of 90% Annual Fuel Utilization Efficiency ("AFUE"). Incentives for the purchase of qualifying high-efficiency equipment are paid directly to homeowners. Any contractor may install or provide qualifying equipment to UNSG customers.

UNSG will provide consumer education on the benefits of qualifying equipment and will promote the program through UNSG promotional events, the UNSG website, and print advertising.

Target Market

The program is targeted at UNSG customers with central gas-fueled air furnace heating systems who are in the market to replace their existing furnace.

Current Baseline Conditions

The average lifetime of residential heating equipment is approximately 15 years, and it is estimated that most of the equipment that will be installed under this program will be in place of a standard 80% efficient furnace.

Program Eligibility

The program is available to all UNSG residential customers with central gas-fueled air furnace heating systems. All brands of equipment that meet the minimum performance standards are eligible for the program. Homeowners are eligible for the incentive for purchasing qualifying high-efficiency equipment.

Program Rationale

Space heating is an important end use in UNSG's high country climate. UNSG's residential customers can realize savings on their energy bills through the installation of high-efficiency furnaces.

Program Objectives

The objective of the program is to promote the purchase of Energy Star qualified high-efficiency furnaces that meet or exceed the minimum Energy Star standard of 90% AFUE.

Products and Services

The products and services provided by the program include:

- Incentives to homeowners for the installation of qualifying high-efficiency furnaces. Incentives and qualifying criteria are summarized in Table 1.

Table 1. Incentives Schedule

Measure	Qualifying Criteria	Average Incentive*
High Efficiency Furnaces	Minimum AFUE of 90%	$382
Packaged Air Conditioners with High-efficiency Furnaces	90 AFUE or better furnace with CEE Tier 1 or 2 AC rating	$516
*Incentives will vary depending on unit heating capacity and efficiency. Note: Consortium for Energy Efficiency ("CEE") **is an independent rating agency.**		

- Education and promotional efforts designed to inform customers about the benefits of high-efficiency heating systems including educational brochures, program promotional material, and UNSG website content.

Delivery Strategy and Administration

The strategy for program delivery and administration is as follows:

- The program will be managed in-house by UNSG staff;
- UNSG will provide overall program management, marketing, planning and coordination of customer and contractor participation tracking and technical support and evaluation;
- Key partnering relationships will include:
  - Heating training professionals;
  - Heating contractors trained in program procedures; and
  - The Arizona Energy Office to provide training, education and awareness.

Program implementation flow chart is included in Appendix 1.

Marketing and Communications

The marketing and communications strategy will include the following components:

- UNSG will provide program marketing and customer awareness-building through a range of strategies including:
    - Promotions on the UNSG website about the benefits of purchasing high-efficiency heating equipment;
    - Advertising in major newspapers and other selected print media in the UNSG service region to raise awareness of the availability of the program;
    - Providing information through UNSG's customer care center;
    - Developing marketing pieces including brochures and other collateral pieces to promote the benefits of qualifying heating equipment; and
    - Assistance with responding to customer inquiries about the program, and how to purchase qualifying heating equipment.
- The advertising campaign will communicate that high-efficiency heating systems will help reduce customer energy bills, provide equal or better comfort conditions, and are beneficial for the environment.

Program Implementation Schedule

Table 2 shows the estimated timeline for key program activities by quarter.

Table 2. Implementation Schedule

Program Activities	2007				2008				2009			
New Program submitted to ACC for approval												
Program approval (estimated)												
Create marketing materials and campaign												
Conduct contractor training												
Conduct program promotions and marketing												
Program implementation and delivery												
Process evaluation												
Measure verification and impact evaluation												
Redesign design program as needed												

Measurement, Evaluation and Research Plan

UNSG will adopt a strategy that calls for integrated data collection that is designed to provide a quality data resource for program tracking, management and evaluation. This approach will entail the following primary activities:

- **Database tracking system development.** As part of detailed program design, UNSG will develop a database tracking system that will be used to collect the necessary data elements and provide the reporting functions needed to track program process and provide a data resource for program evaluation.
- **Integrated implementation data collection.** UNSG will establish systems to collect the data needed to support effective program management and evaluation through the implementation and customer application processes. The database tracking system will be integrated with implementation data collection processes.
- **Field verification.** UNSG will conduct field verification of the installation of a sample of measures throughout the implementation of the program.
- **Tracking of savings using deemed savings values.** UNSG will develop deemed savings values for each measure and technology promoted by the program and

periodically review and revise the savings values to be consistent with program participation and accurately estimated the savings being achieved by the program.

This approach will provide UNSG with ongoing feedback on program progress and enable program management to adjust or correct the program so as to be more effective, provide a higher level of service, and be more cost beneficial. Integrated data collection will also provide a high quality data resource for evaluation activities.

Program Budget

The average annual budget of approximately $425,000 will be allocated as shown in Table 3, while Table 4 provides the expected program budgets through 2012. Appendix 2 provides additional details on the 2008 budget.

Table 3. 2008 Program Budget

Total Program Budget	$400,000
Total Administrative and O&M Cost Allocation	
Managerial & Clerical	$57,600
Travel & Direct Expenses	$8,640
Overhead	$5,760
Total Administrative Cost	***$72,000***
Total Marketing Allocation	
Internal Marketing Expense	$24,000
Subcontracted Marketing Expense	$24,000
Total Marketing Cost	***$48,000***
Total Direct Implementation	
Financial Incentives	$218,400
Support Activity Labor	$10,400
Hardware & Materials	$5,200
Rebate Processing & Inspection	$26,000
Total Direct Installation Cost	***$260,000***
Total EM&V Cost Allocation	
EM&V / Research Activity	$19,000
EM&V Overhead	$1,000
Total EM&V Cost	***$20,000***

Table 4. 2008 – 2012 Program Budget

Year	2008	2009	2010	2011	2012
Total Budget	$400,000	$412,000	$424,360	$437,091	$450,204
Incentives	$218,400	$231,874	$238,830	$253,338	$268,501
Administrative Costs	$181,600	$180,126	$185,530	$183,753	$181,702
Incentives as % of Budget	54.6%	56.3%	56.3%	58.0%	59.6%

Estimated Energy Savings

Total annual participation goals and energy savings are presented in Table 5. The program expects, on average, 3,000 units annually will participate in the program, with approximately

80% of these being furnaces with an AFUE rating of 90% or better, and the balance comprised of packaged units with 90% AFUE furnaces and CEE tier 1 or 2 air conditioning ratings. Appendix 3 provides further information about estimated energy savings, including the measure and program level benefit cost analysis.

Table 5. Residential Air Conditioning Program Annual Energy Savings

Year	2008	2009	2010	2011	2012
Number of Expected Participating Units	3,009	3,099	3,192	3,287	3,386
Coincident peak savings (kW)	330	340	351	361	372
Energy Savings (kWh)	407,113	419,326	431,906	444,863	458,209
Energy Savings (therms)	677,838	698,173	719,118	740,692	762,912

As a result of the energy savings shown above, it is estimated that the program will produce environmental benefits through avoided emissions and avoided water use. The estimated additional benefits from 2008 – 2012 are presented in Table 6.

Table 6. Projected Environmental Benefits, 2008 - 2012

CO_2 Emissions Avoided	22,224	Tons
Water Saved	503,610	Gal

Note: A portion of the CO_2, and all of the water benefits are related to electricity savings and are based on Arizona Public Service Co. estimates as presented in the "APS Demand Side Management Program Portfolio 2005-2007" p. 20.

Program Cost Effectiveness

The cost effectiveness of furnace replacements and the program was assessed using the Total Resource Cost ("TRC") test, the Societal Cost ("SC") test and the Ratepayer Impact Measure ("RIM") test. Measure analysis worksheets showing all energy savings, cost and cost-effectiveness calculations are included in Appendix 3.

The cost effectiveness analysis requires estimation of:

- net energy savings attributable to the program;
- net incremental cost to the customer of purchasing qualifying equipment;
- UNSG's program administration costs;
- the present value of program benefits including UNSG avoided costs over the life of the measures; and
- UNSG lost revenues.

Table 7 provides a summary of the benefit/cost analysis results for this program. A detailed benefit/cost analysis is presented in Appendix 3.

Table 7. Benefit-cost analysis results

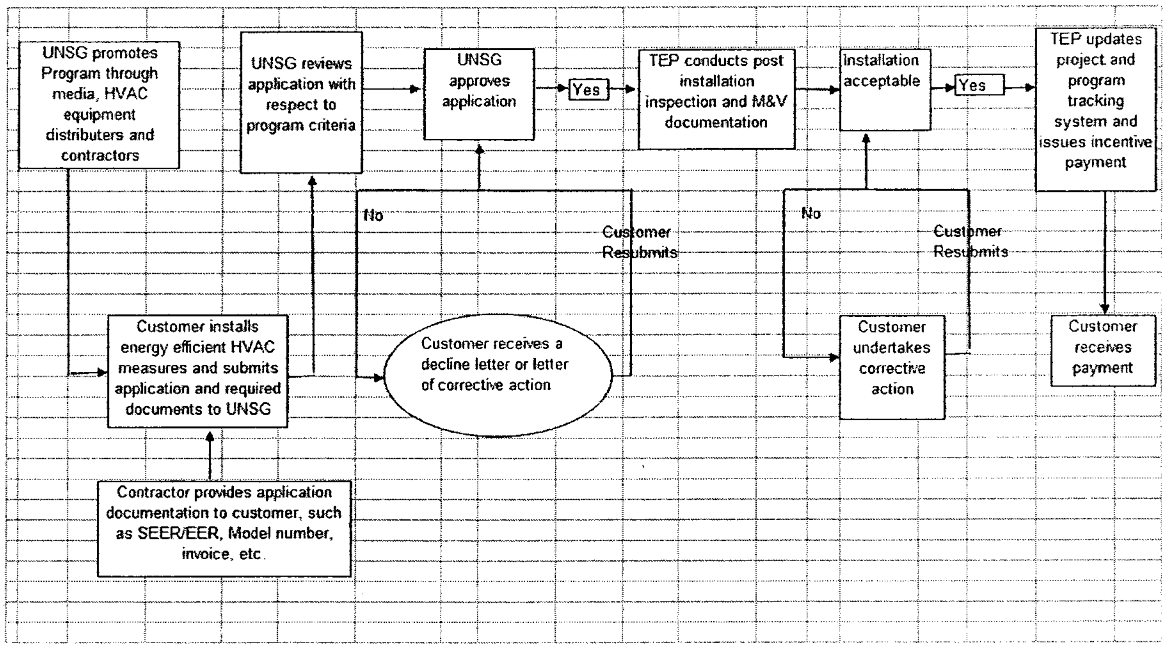
Cost Effectiveness Tests	TRC	SC	RIM
Benefit/Cost Ratio	1.46	1.82	0.37

In addition to estimating the savings from each measure, this analysis relies on a range of other assumptions and financial data provided in Figure 8.

Table 8. Other Financial Assumptions

Conservation Life (yrs):	15
Program Life (yrs):	5
Energy AC ($/Therm):	0.9194
Ratio of Non-inc to Incentive Costs	75.4%
TRC Discount Rate	8.50%
Social Discount Rate	5.00%
NTG Ratio:	64%

Appendix 1 – Efficient Home Heating Program Implementation Plan



Appendix 2 – Expected 2008 Program Costs

Budget Items	Budget	Allocation Rate (%)
Administrative		
Managerial and Clerical Labor	***$57,600***	
Labor - Clerical	$2,880	5.0%
Labor - Program Design	$2,880	5.0%
Labor - Program Development	$2,880	5.0%
Labor - Program Planning	$8,640	15.0%
Labor - Program/Project Management	$5,760	10.0%
Labor - Staff Management	$5,760	10.0%
Labor - Staff Supervision	$2,880	5.0%
Subcontractor Labor - Clerical	$2,880	5.0%
Subcontractor Labor - Program Design	$5,760	10.0%
Subcontractor Labor - Program Development	$2,880	5.0%
Subcontractor Labor - Program Planning	$2,880	5.0%
Subcontractor Labor - Program/Project Management	$11,520	20.0%
Subcontractor Labor - Staff Management	$0	0.0%
Subcontractor Labor - Staff Supervision	$0	0.0%
Subtotal Managerial and Clerical Labor	*$57,600*	*100.0%*
Travel & Direct Expenses	***$8,640***	
Conference Fees	$864	10.0%
Labor - Conference Attendance	$864	10.0%
Subcontractor - Conference Fees	$173	2.0%
Subcontractor - Travel - Airfare	$346	4.0%
Subcontractor - Travel - Lodging	$173	2.0%
Subcontractor - Travel - Meals	$173	2.0%
Subcontractor - Travel - Mileage	$173	2.0%
Subcontractor - Travel - Parking	$173	2.0%
Subcontractor - Travel - Per Diem for Misc. Expenses	$778	9.0%
Subcontractor Labor - Conference Attendance	$173	2.0%
Travel - Airfare	$1,210	14.0%
Travel - Lodging	$864	10.0%
Travel - Meals	$432	5.0%
Travel - Mileage	$432	5.0%
Travel - Parking	$259	3.0%
Travel - Per Diem for Misc. Expenses	$1,555	18.0%
Travel & Direct Expenses	*$8,640*	*100.0%*
Overhead (General and Administrative) - Labor and Materials	***$5,760***	
Equipment - Communications	$115	2.0%
Equipment - Computing	$115	2.0%
Equipment - Document Reproduction	$115	2.0%
Equipment - General Office	$115	2.0%
Equipment - Transportation	$115	2.0%
Facilities - Lease/Rent Payment	$0	0.0%
Labor - Accounts Payable	$58	1.0%
Labor - Accounts Receivable	$58	1.0%
Labor - Administrative	$58	1.0%

Labor - Automated Systems	$0	0.0%
Labor - Communications	$58	1.0%
Labor - Contract Reporting	$58	1.0%
Labor - Corporate Services	$58	1.0%
Labor - Facilities Maintenance	$58	1.0%
Labor - Information Technology	$58	1.0%
Labor - Materials Management	$58	1.0%
Labor - Procurement	$58	1.0%
Labor - Regulatory Reporting	$2,304	40.0%
Labor - Shop Services	$58	1.0%
Labor - Telecommunications	$58	1.0%
Labor - Transportation Services	$58	1.0%
Office Supplies	$58	1.0%
Postage	$58	1.0%
Subcontractor - Equipment - Communications	$0	0.0%
Subcontractor - Equipment - Computing	$0	0.0%
Subcontractor - Equipment - Document Reproduction	$0	0.0%
Subcontractor - Equipment - General Office	$0	0.0%
Subcontractor - Equipment - Transportation	$0	0.0%
Subcontractor - Facilities - Lease/Rent Payment	$0	0.0%
Subcontractor - Office Supplies	$0	0.0%
Subcontractor - Postage	$0	0.0%
Subcontractor Labor - Accounts Payable	$0	0.0%
Subcontractor Labor - Accounts Receivable	$0	0.0%
Subcontractor Labor - Administrative	$0	0.0%
Subcontractor Labor - Automated Systems	$0	0.0%
Subcontractor Labor - Communications	$0	0.0%
Subcontractor Labor - Contract Reporting	$0	0.0%
Subcontractor Labor - Corporate Services	$0	0.0%
Subcontractor Labor - Facilities Maintenance	$0	0.0%
Subcontractor Labor - Information Technology	$0	0.0%
Subcontractor Labor - Materials Management	$0	0.0%
Subcontractor Labor - Procurement	$0	0.0%
Subcontractor Labor - Regulatory Reporting	$2,016	35.0%
Subcontractor Labor - Shop Services	$0	0.0%
Subcontractor Labor - Telecommunications	$0	0.0%
Subcontractor Labor - Transportation Services	$0	0.0%
Subtotal Overhead	*$5,760*	*100.0%*
Total Administrative Costs	**$72,000**	
Marketing/Advertising/Outreach		
Internal Marketing Expense	***$24,000***	
Advertisements / Media Promotions	$6,000	25.0%
Bill Inserts	$960	4.0%
Brochures	$1,440	6.0%
Door Hangers	$0	0.0%
Labor - Business Outreach	$1,200	5.0%
Labor - Customer Outreach	$1,200	5.0%
Labor - Customer Relations	$1,200	5.0%
Labor - Marketing	$7,200	30.0%
Print Advertisements	$3,600	15.0%

Radio Spots	$1,200	5.0%
Subtotal Internal Marketing Expense	*$24,000*	*100.0%*
Subcontracted Marketing Expense	***$24,000***	
Subcontractor - Bill Inserts	$1,200	5.0%
Subcontractor - Brochures	$1,200	5.0%
Subcontractor - Door Hangers	$0	0.0%
Subcontractor - Print Advertisements	$0	0.0%
Subcontractor - Radio Spots	$2,400	10.0%
Subcontractor - Television Spots	$0	0.0%
Subcontractor Labor - Business Outreach	$1,200	5.0%
Subcontractor Labor - Customer Outreach	$1,200	5.0%
Subcontractor Labor - Customer Relations	$1,200	5.0%
Subcontractor Labor - Marketing	$1,200	5.0%
Television Spots	$0	0.0%
Website Development	$14,400	60.0%
Subtotal Subcontracted Marketing Expense	*$24,000*	*100.0%*
Total Marketing/Advertising/Outreach	**$48,000**	
Direct Implementation		
Financial Incentives to Customers	***$218,400***	
Activity - Labor	***$10,400***	
Labor - Curriculum Development	$832	8.0%
Labor - Customer Education and Training	$4,160	40.0%
Labor - Customer Equipment Testing and Diagnostics	$0	0.0%
Labor - Facilities Audits	$3,120	30.0%
Subcontractor Labor - Facilities Audits	$1,040	10.0%
Subcontractor Labor - Curriculum Development	$520	5.0%
Subcontractor Labor - Customer Education and Training	$520	5.0%
Subcontractor Labor - Customer Equipment Testing and Diagnostics	$208	2.0%
Subtotal Activity	*$10,400*	*100.0%*
Hardware and Materials - Installation and Other DI Activity	***$5,200***	
Audit Applications and Forms	$416	8.0%
Direct Implementation Literature	$1,040	20.0%
Education Materials	$1,040	20.0%
Energy Measurement Tools	$520	10.0%
Installation Hardware	$520	10.0%
Subcontractor - Direct Implementation Literature	$208	4.0%
Subcontractor - Education Materials	$208	4.0%
Subcontractor - Energy Measurement Tools	$832	16.0%
Subcontractor - Installation Hardware	$312	6.0%
Subcontractor -Audit Applications and Forms	$104	2.0%
Subtotal Hardware and Materials	*$5,200*	*100.0%*
Rebate Processing and Inspection - Labor and Materials	***$26,000***	
Labor - Field Verification	$2,600	10.0%
Labor - Rebate Processing	$0	0.0%
Labor - Site Inspections	$2,600	10.0%
Rebate Applications	$0	0.0%
Subcontractor - Rebate Applications	$2,600	10.0%
Subcontractor Labor - Field Verification	$5,200	20.0%
Subcontractor Labor - Rebate Processing	$7,800	30.0%

Subcontractor Labor - Site Inspections	$5,200	20.0%
Subtotal Rebate Processing and Inspection	*$26,000*	*100.0%*
Total Direct Implementation	**$260,000**	
Evaluation, Measurement and Verification		
EM&V Labor and Materials	***$19,000***	
Labor - EM&V	$950	5.0%
Materials - EM&V	$950	5.0%
Subcontractor Labor - EM&V	$17,100	90.0%
Subtotal EM&V Activity - Labor	*$19,000*	*100.0%*
EM&V Overhead	***$1,000***	
Benefits - EM&V Labor	$0	0.0%
Overhead - EM&V	$500	50.0%
Subcontractor Overhead - EM&V	$0	0.0%
Subcontractor Travel - EM&V	$0	0.0%
Travel - EM&V	$500	50.0%
Subtotal EM&V Overhead	*$1,000*	*100.0%*
Total EM&V	**$20,000**	
Total Budget	**$400,000**	

See accompanying Excel spreadsheet for 2008-2012 program budgets.

Efficient Home Heating Program

Appendix 3 – Measure Level Energy Savings and Benefit/Cost Analysis

Measure level spreadsheet for program benefit/cost calculations available electronically upon request.

Incentive Calculations
RGHV100 - HIGH-EFFICIENCY FURNACE
RESIDENTIAL PROGRAM

PROGRAM DATA	
Conservation Life (yrs):	15
Program Life (yrs):	5
Levelized Therms	0.91941
Ratio of Non-inc to Incentive Costs	75.4%
IRP Discount Rate*****:	8.50%
Social Discount Rate	5.00%
NTG Ratio:	60%

OPERATING DATA	
Htg. Season Hrs.:	2460
Htg. Season Load Factor:	0.75

RATE DATA	
$/Therm	1.40800

OTHER FACTORS	
Application	R
Cost Basis:	Incremental equipm

DEMAND/ENERGY SAVINGS						INCENTIVE CALCULATIONS						CUSTOMER COST/SAVINGS				WGT.	% Inc
Measure Type	Size	Base Model Capacity (Btuh)	Base Eff.	High Eff.	Annual Savgs. Per Unit (Therms)	IRP PV Benefit ($)	Social PV Benefit ($)	Recommended Incentive ($)	Recommended Incentive % PV	PV Program Cost ($)	NPV ($)	Incr. Cost ($)	Cost Savings ($)	Payback wo/Inc. (yrs)	Payback w/Inc. (yrs)	Weighting Factor	(%)
HI-E FURNACE	0 - 60 MBH	60000	0.80	0.90	154	$704	$880	$300	43%	$585	$119	$598	$216	2.8	1.4	0.25	5
HI-E FURNACE	61 - 120 MBH	90000	0.80	0.90	231	$1,056	$1,320	$350	33%	$676	$381	$686	$325	2.1	1.0	0.30	5
HI-E FURNACE	120+ MBH	135000	0.80	0.90	346	$1,585	$1,981	$400	25%	$794	$791	$820	$487	1.7	0.9	0.07	4
HI-E FURNACE	0 - 60 MBH	60000	0.80	0.92	180	$827	$1,033	$400	48%	$689	$137	$646	$254	2.5	1.0	0.15	6
HI-E FURNACE	61 - 120 MBH	90000	0.80	0.92	271	$1,240	$1,550	$450	36%	$808	$432	$782	$381	2.1	0.9	0.10	5
HI-E FURNACE	120+ MBH	135000	0.80	0.92	406	$1,860	$2,325	$500	27%	$946	$914	$949	$572	1.7	0.8	0.0	5
HI-E FURNACE	0 - 60 MBH	60000	0.80	0.94	206	$944	$1,180	$500	53%	$877	$67	$834	$290	2.9	1.2	0.05	6
HI-E FURNACE	61 - 120 MBH	90000	0.80	0.94	309	$1,416	$1,770	$550	39%	$941	$475	$877	$435	2.0	0.8	0.03	6
HI-E FURNACE	120+ MBH	120000	0.80	0.94	412	$1,888	$2,360	$600	32%	$1,099	$789	$1,078	$580	1.9	0.8	0.02	5
Weighted Average					225.98	$1,035	$1,294	$382	$0	$711	$324	$706	$318	2.32	1.07	1.00	5

Htg Season Hrs based on Kingman at 3212 HDD
**** See worksheet 'Cost Assumptions' for information of cost data.
***** Discount rate is based on TEP estimate 12/31/2006

Efficient Home Heating Program

RGHV200 - ENERGY-EFFICIENT PACKAGED HEAT AND AIR CONDITIONERS -- RESIDENTIAL

POROGRAM DATA	
Conservation Life (yrs):	15
Program Life (yrs):	5
Demand AC ($/kW):	61.99
Summer On-pk Energy AC ($/kWh):	0.07218
Summer Off-pk Energy AC ($/kWh):	0.07218
Winter On-pk Energy AC ($/kWh):	0.06945
Winter Off-pk Energy AC ($/kWh):	0.06945
Levelized Therms	0.91941
Ratio Non-incent to Incent Cost	75.4%
IRP Discount Rate*****:	8.50%
Social Discount Rate	5.00%
NTG Ratio:	80%

RATE DATA	
Rate Class:	Res Ave
$/kW:	0.000
$/kWh, On-Peak:	0.12277
$/kWh, Off-Peak:	0.09466
$/Therm	1.40800

OPERATING DATA	
On-Pk EFLH:	937
Off-Pk EFLH:	234
On-Pk Ratio:	80.0%
Off-Pk Ratio:	20.0%
Summer Ratio:	50%
Winter Ratio:	50%
Coincidence Factor:	0.95
Htg. Season Hrs.:	2460
Htg. Season Load Factor:	0.77

OTHER FACTORS		
Line Loss Factor:		10.69%
Application:		ROB, NEW
Cost Basis:		Incremental
MARKET DISTRIBUTION		
CEE Tier	AFUE	Market %
1	0.907	75%
2	0.907	20%
1	0.921	3%
2	0.921	2%

HEATINTG ENERGY AND COOLING DEMAND / ENERGY SAVINGS												INCENTIVE CALCULATIONS						CUSTOMER COST/SAVINGS				WGT.		
Unit Type	Unit Size (Tons)	Min. Qual. SEER CEE	Min. Qual. EER CEE	BASE EER	Base Furnace Capacity (Btuh)	Base Eff.	High Eff.	Annual Savgs. Per Unit (Therms)	Demand Savings Per Unit (KW)	On-pk Savings Per Unit (KWh)	Off-pk Savings Per Unit (KWh)	PV Benefit Per Unit ($)	Social PV Benefit ($)	Incentive (Per Unit) ($)	Incentive (Per Unit) % PV	PV Cost Per Unit ($)	NPV ($)	Incr. Cost Per Unit ($)	Cost Savings ($)	Payback wo/Inc. (yrs)	Payback w/Inc. (yrs)	Weighting Factor	% Incent	TRC
Less that 5.4 tons	2	13.0	11.3	9.4	60,000	0.80	0.90	152	0	397	99	1371	1714	350	26%	1176	196	1140	272	4.2	2.9	0.167	31%	1.17
90 - 92 AFUE	2.5	13.0	11.3	9.4	70,000	0.80	0.90	178	1	496	124	1637	2046	400	24%	1298	339	1245	323	3.9	2.6	0.167	32%	1.26
CEE Tier 1	3	13.0	11.3	9.4	80,000	0.80	0.90	203	1	595	149	1902	2378	450	24%	1441	462	1377	373	3.7	2.5	0.167	33%	1.32
	3.5	13.0	11.3	9.4	90,000	0.80	0.90	228	1	695	173	2168	2709	500	23%	1581	587	1505	423	3.6	2.4	0.167	33%	1.37
	4	13.0	11.3	9.4	100,000	0.80	0.90	254	1	794	198	2433	3041	550	23%	1656	777	1552	473	3.3	2.1	0.167	35%	1.47
	5.4	13.0	11.3	9.4	120,000	0.80	0.90	304	1	1,072	268	3052	3815	750	25%	2012	1041	1808	586	3.1	1.8	0.167	41%	1.52
Weighted Average		13.00	11.30	9.42	86,707	0.80	0.90	219.9	0.7	675	169	2095	2619	500	24%	1528	567	1438	409	3.6	2.4	1.000	35%	1.37
Less that 5.4 tons	2	14.0	11.6	9.4	60,000	0.80	0.90	152	0	448	112	1429	1786	400	28%	1288	141	1233	280	4.4	3.0	0.167	32%	1.11
90 - 92 AFUE	2.5	14.0	11.6	9.4	70,000	0.80	0.90	178	1	560	140	1708	2135	450	26%	1427	281	1360	332	4.1	2.7	0.167	33%	1.20
CEE Tier 2	3	14.0	11.6	9.4	80,000	0.80	0.90	203	1	673	168	1988	2485	500	25%	1568	420	1489	384	3.9	2.6	0.167	34%	1.27
	3.5	14.0	11.6	9.4	90,000	0.80	0.90	228	1	785	196	2268	2835	550	24%	1714	554	1625	436	3.7	2.5	0.167	34%	1.32
	4	14.0	11.6	9.4	100,000	0.80	0.90	254	1	897	224	2548	3184	600	24%	1796	752	1679	488	3.4	2.2	0.167	36%	1.42
	5.4	14.0	11.6	9.4	120,000	0.80	0.90	304	1	1,211	302	3207	4008	800	25%	2142	1065	1924	606	3.2	1.9	0.167	42%	1.50
Weighted Average		14.00	11.60	9.42	86,667	0.80	0.90	220	1	762	190	2191	2739	550	25%	1656	536	1552	421	3.8	2.5	1.000	35%	1.32
Less that 5.4 tons	2	13.0	11.3	9.4	60,000	0.80	0.92	180	0	397	99	1541	1926	450	29%	1462	79	1404	311	4.5	3.1	0.167	32%	1.05
92+ AFUE	2.5	13.0	11.3	9.4	70,000	0.80	0.92	210	1	496	124	1834	2293	500	27%	1618	216	1552	368	4.2	2.9	0.167	32%	1.13
CEE Tier 1	3	13.0	11.3	9.4	80,000	0.80	0.92	240	1	595	149	2128	2660	550	26%	1797	330	1729	425	4.1	2.8	0.167	32%	1.18
	3.5	13.0	11.3	9.4	90,000	0.80	0.92	270	1	695	173	2421	3027	600	25%	1973	448	1901	482	3.9	2.7	0.167	32%	1.23
	4	13.0	11.3	9.4	100,000	0.80	0.92	300	1	794	198	2715	3394	650	24%	2084	631	1993	538	3.7	2.5	0.167	33%	1.30
	5.4	13.0	11.3	9.4	110,000	0.80	0.92	330	1	1,072	268	3207	4009	850	27%	2523	685	2352	621	3.8	2.4	0.167	36%	1.27
Weighted Average		13.00	11.30	9.42	85,000	0.80	0.92	255	0.7	675	169	2308	2885	600	26%	1910	398	1822	458	4.0	2.7	1.000	33%	1.21
Less that 5.4 tons	2	14.0	11.6	9.4	60,000	0.80	0.92	180	0	448	112	1598	1997	500	31%	1587	11	1512	319	4.7	3.2	0.167	33%	1.01
92+ AFUE	2.5	14.0	11.6	9.4	70,000	0.80	0.92	210	1	560	140	1906	2382	550	29%	1764	142	1687	378	4.5	3.0	0.167	33%	1.08
CEE Tier 2	3	14.0	11.6	9.4	80,000	0.80	0.92	240	1	673	168	2214	2767	600	27%	1941	273	1861	436	4.3	2.9	0.167	32%	1.14
	3.5	14.0	11.6	9.4	90,000	0.80	0.92	270	1	785	196	2522	3152	650	26%	2124	398	2042	495	4.1	2.8	0.167	32%	1.19
	4	14.0	11.6	9.4	100,000	0.80	0.92	300	1	897	224	2830	3537	700	25%	2242	588	2143	553	3.9	2.6	0.167	33%	1.26
	5.4	14.0	11.6	9.4	110,000	0.80	0.92	330	1	1,211	302	3362	4202	900	27%	2669	693	2489	642	3.9	2.5	0.167	36%	1.26
Weighted Average		14.00	11.60	9.42	85,000	0.80	0.92	255	1	762	190	2405	3006	650	27%	2054	351	1956	470	4.2	2.8	1.000	33%	1.17

Attachment 4

C&I Facilities Gas Efficiency Program

Table of Contents

UNSG C&I Facilities Gas Efficiency Program

Program Concept and Description

The C&I Facilities Gas Efficiency Program provides prescriptive incentives for the installation of high-efficiency gas-fueled equipment and systems including space heating, service and domestic water heating, and commercial food service equipment. Prescriptive incentives are offered for a schedule of measures in each of these categories. The schedule of measures and incentives is provided in the following sections.

The viability of each of the prescriptive measures has been assessed through a cost-effectiveness analysis according to the Total Resource Cost ("TRC"), Ratepayer Impact Measure ("RIM") and Societal Cost ("SC") tests. The cost-effectiveness tests account for the energy (therm) savings of each measure, the associated avoided costs and net benefits to UNSG, the customer incremental or installed costs, and the program administration costs.

The program includes consumer educational and promotional pieces designed to assist facility operators and decision makers with the information necessary to improve the energy efficiency of gas-fueled space systems in their facilities. The program includes customer and trade ally education to assist with understanding of what technologies are being promoted, what incentives are offered, and how the program functions.

Appendix 1 provides a program implementation process.

Program Objectives

The primary goal of the program is to encourage UNSG's non-residential customers to install energy efficiency measures in gas-fueled systems in existing facilities. More specifically, the program is designed to:

- Provide incentives to facility operators for the installation of high-efficiency gas fueled space heating, service and domestic water heating, and commercial food service equipment (see Table 1 for the schedule of measures and incentives);
- Overcome market barriers including:
  - Lack of awareness and knowledge about the benefits and cost of energy efficiency improvements;
  - Performance uncertainty associated with energy efficient equipment;
  - Higher first costs for energy efficient equipment;
- Assure that the participation process is clear, easy to understand and simple; and
- Increase the awareness and knowledge of facility operators, managers and decision-makers on the benefits of high-efficiency equipment and systems.

Program Rationale

Certain barriers exist to the adoption of energy efficiency measures including lack of investment capital, competition for funds with other capital improvements, lack of awareness/knowledge about the benefits and costs of energy efficiency measures, high transaction and information search costs, and technology performance uncertainties. This program is designed to help overcome these market barriers and encourage greater adoption of energy efficiency measures in gas-fueled systems in customer facilities.

In addition to helping customers reduce and manage their energy costs, this program provides other societal and customer benefits including reduced greenhouse gas emissions, improved levels of service from energy expenditures, and lower overall rates and energy costs compared to other resource options.

Target Market and Eligibility Requirements

All non-residential customers in the UNSG service region that receive natural gas service from UNSG are eligible to participate in the program. Existing systems that are being replaced on burnout or prior to failure/early retirement and systems installed during new construction projects are all eligible for the program. Applications will be reviewed by UNSG to determine that the facility is within the UNSG service region, the proposed equipment meets energy efficiency standards to qualify for incentive payments and that all necessary specifications are provided to determine the energy impact after installation.

Estimate of Baseline Conditions

UNSG had not conducted a formal baseline study of the existing non-residential market for gas-fueled equipment and systems. However, in preparing the analysis of each of the measures included in this plan, the baseline performance conditions of each technology were estimated based on best available knowledge of current market conditions and technology applications. Resources used for the estimation of both baseline and energy efficiency technology performance and cost included (i) the California Database of Energy Efficiency Resources ("DEER"); (ii) detailed engineering modeling and simulation specific to the region; (iii) data from recognized industry resources such as the Consortium of Energy Efficiency ("CEE") and American Society of Heating Refrigeration and Air Conditioning Engineers ("ASHRAE") ; (iv) manufacturers data; and (v) data accumulated from similar analysis for other regional utilities.

Application and cost basis designators were used to determine which cost elements are used for each measure. The application designation is important because it helps to define what type of cost estimate is needed by identifying the types of projects where the measure is expected to be applied. There are three application codes that have been used:

- **Retrofit ("RET")** – Replacing a working system with a new technology before the end of its useful life, or installing a technology that was not there before. The cost basis for this application is typically installed cost;
- **Replace-on-burnout ("ROB")** – Replacing a technology at the end of its useful life. The cost basis for this application is typically the incremental cost of a more efficient technology compared to a less efficient baseline technology; and
- **New construction ("NEW")** – Installing a technology in a new construction or major renovation project. The cost basis for this application is also typically the incremental cost of a more efficient technology compared to a less efficient baseline technology.

The cost basis designator is used for each measure to determine if the appropriate cost is the incremental or installed cost. The cost basis is determined by: (a) the application (RET, ROB, or NEW) and (b) whether it is displacing an existing technology, installed in the absence of an existing technology, or is an alternative to a competing technology. The cost basis designation is used to define whether the cost is:

- **Incremental** – the differential cost between a base technology and an energy-efficient technology; or
- **Installed** – the full or installed cost of the measure including equipment, labor, overhead & profit ("OH&P").

Products and Services Provided

The C&I Facilities Gas Efficiency Program is a customer incentive program design that provides rebates for the installation of energy efficiency measures in existing non-residential facilities. More specifically, the program offers the following products and services:

- Consumer education and promotion designed to assist facility operators and decision makers with the information necessary to improve the energy efficiency of gas-fueled space heating, service and domestic water heating, and commercial cooking systems;
- Education and promotional efforts for customers and trade allies on how the program functions, what energy efficiency technologies are offered, what incentives are provided and the benefits of the measures; and
- Prescriptive incentives to encourage the adoption energy efficiency measures. Prescriptive measures and incentives provided by the program are included in the tables below.

Table 1 provides average incentives per unit and unit definition. These are expected incentive levels based on market participation. Specific incentive levels for certain items where a variety of configurations are possible can be found in the measure analysis worksheets.

Table 1. Prescriptive Incentives

Measure Description	Average Unit Incentive ($)**	Unit Definition***
Space Heating and Water Heating Measures		
High-efficiency Furnaces	$200	90 AFUE or better furnace
High-efficiency Space Heating or Process Boilers*	$250	85.6% efficient or better boiler
Packaged Air Conditioners with High-efficiency Furnaces	$606	90 AFUE or better furnace with CEE Tier 1 or 2 AC rating
Energy-efficient Storage Water Heaters	$159	64.0% efficient or better tank type water heater
Commercial Food Service Measures		
High-efficiency Fryers	$350	42.0% efficient or better open or pressure fryer
High-efficiency Griddles	$300	45.0% efficient or better griddle
High-efficiency Ovens	$478	45.0% efficient or better combination, deck,

Measure Description	Average Unit Incentive ($)**	Unit Definition***
		convection, or conveyor oven

* The high-efficiency boilers measure applies to both space heating and service water heating applications.
**Incentives will vary depending on unit heating capacity and efficiency
***Efficiencies will vary depending on specific machine type or configuration

Program Delivery Strategy

The C&I Facilities Gas Efficiency Program will be implemented by employing the services of a qualified implementation contractor. The implementation contractor will be sought through a competitive bidding process which will require UNSG to issue an RFP to professional services companies who are active in the field of DSM program implementation. UNSG will assign an in-house program manager to oversee the activities of the implementation contractor, provide guidance on program activities that is consistent with UNSG's goals and customer service requirements, provide an important contact point for customers who are interested in or have concerns about the program, and provide overall quality control and management of the delivery process.

The implementation contractor will provide program administration, application and incentive processing, participation tracking and reporting, project quality control, and technical support. In addition to the implementation contractor, key partnering relationships include: the local architectural and engineering community; electrical, mechanical and building contractors; equipment manufacturers, distributors and vendors; professional and trade service associations; and the Arizona Energy Office. As part of the implementation plan, UNSG will conduct outreach to each of these partner groups, and provide education and training on the benefits and functioning of the program.

Program Marketing and Communications Strategy

The marketing and communications strategy will be designed to inform customers of the availability and benefits of the program and how they can participate in the program. The strategy will include outreach to key partners and trade allies including the architecture/engineering and contractor community, relevant professional and trade associations and other parties of interest in the market. An important part of the marketing plan will be content and functionality on the UNSG website, which will direct customers to information about the program. More specifically, the marketing and communications plan will include:

- Education seminars implemented in each market to provide details about how to participate in the program. The seminars will be tailored to the needs of business owners, building managers, architects, engineers, vendors, and contractors;

- A combination of strategies including major media advertising, outreach and presentations at professional and community forums and events, and through direct outreach to key customers and customer representatives. Marketing activities will include:
    - Brochures that describe the benefits and features of the program including program application forms and worksheets. The brochures will be mailed upon demand and distributed through the call center and the UNSG website and will be available for various public awareness events (school training, presentations, seminars etc);
    - Targeted mailing used to educate customers on the benefits of the program and explain how they can apply;
    - Customer and trade partner outreach and presentations (e.g., school associations, BOMA, ASHRAE) informing interested parties about the benefits of the program and how to participate;
    - Print advertisements to promote the program placed in selected local media including the newspapers and trade publications in the UNSG service territory;
    - Website content providing program information resources, contact information, downloadable application forms and worksheets, and links to other relevant service and information resources;
    - UNSG customer care representatives trained to answer any customer questions regarding the program;
    - Presence at conferences and public events used to increase general awareness of the program and distribute program promotional materials; and
    - Presentations by the program manager to key customers and customer groups to actively solicit their participation in the program.
- The marketing strategy will identify key customer segments and groups for target marketing including the school districts, commercial kitchens and laundromats and prepare specific outreach activities for these customers;
- UNSG will design and develop the content, messaging, branding, and calls to action of all of the marketing and collateral materials used to promote the program; and
- The implementation contractor will be responsible for assisting with program promotion including customer contact, attendance at public presentations and events, and will be the primary contact point from the website and other promotional materials.

Program Implementation Schedule

The program implementation schedule is summarized in Table 2.

Table 2. C&I Facilities Gas Efficiency Program Implementation Schedule

Program Activities	2007				2008				2009			
New program submitted to ACC for approval												
New program approval (estimated)												
Implementation contractor RFPs issued												
Implementation contractors selected												
Marketing and communications plan prepared (including collateral materials)												
Implementation plan prepared												
Program kick-off and marketing campaign												

launched												
Program implementation and delivery												
MER impact and cost-effectiveness analysis												
MER process evaluation												
Program redesign as needed												

Estimated Participation and Demand and Energy Savings

Total annual energy savings goals are presented in Table 3. Appendix 3 provides further information about estimated energy savings for each measure category, including the measure and program level benefit cost analysis. Appendix 3 also provides the expected project technology mix for 2008, which is considered to be the template for all program years.

Table 3. Projected Capacity and Energy Benefits

Annual Incremental Savings	2008	2009	2010	2011	2012
Energy Savings (therms)	286,616	295,214	304,071	313,193	322,588

As a result of the energy savings shown above, it is estimated that the program will produce environmental benefits through avoided emissions of carbon dioxide (CO_2). The estimated avoided emissions from 2008 – 2012 are shown in Table 4:

Table 4. Projected Environmental Benefits, 2008 - 2012

CO2 Emissions Avoided	8,978	Tons

Program Cost Effectiveness

Table 5 provides a summary of the benefit/cost analysis results for this program according to the TRC, SC and RIM tests. A benefit/cost analysis summary of all measures is presented in Appendix 3.

Table 5. Benefit-cost analysis results

Cost Effectiveness Tests	TRC	SC	RIM
Benefit/Cost Ratio	1.68	2.09	0.52

In addition to estimating the savings from each measure, this analysis relies on a range of other assumptions and financial data provided in Table 6. Because the program consists of a variety of measures, each with a unique avoided cost and economic useful life, these metrics are not provided in Table 6 but can be found in the individual measure analysis worksheets.

Table 6. Other Financial Assumptions

Ratio of Non-inc to Incentive Costs	96.7%
TRC Discount Rate	8.50%
Social Discount Rate	5.00%
Weighted Average NTG Ratio:	77%

Program Costs (Budget)

The average annual budget of approximately $106,183 will be allocated as shown in Table 7, while Table 8 provides the expected program budgets through 2012. Appendix 2 provides additional details on the 2008 budget.

Table 7. 2008 Program Budget

Total Program Budget	$100,000
Total Administrative and O&M Cost Allocation	
Managerial & Clerical	$15,200
Travel & Direct Expenses	$2,280
Overhead	$1,520
Total Administrative Cost	***$19,000***
Total Marketing Allocation	
Internal Marketing Expense	$7,500
Subcontracted Marketing Expense	$7,500
Total Marketing Cost	***$15,000***
Total Direct Implementation	
Financial Incentives	$50,840
Support Activity Labor	$3,100
Hardware & Materials	$2,480
Rebate Processing & Inspection	$5,580
Total Direct Installation Cost	***$62,000***
Total EM&V Cost Allocation	
EM&V / Research Activity	$3,800
EM&V Overhead	$200
Total EM&V Cost	***$4,000***

Table 8. 2008 – 2012 Program Budget

Year	2008	2009	2010	2011	2012
Total Budget	$100,000	$103,000	$106,090	$109,273	$112,551
Incentives	$50,840	$52,365	$53,936	$55,554	$57,221
Administrative Costs	$49,160	$50,635	$52,154	$53,718	$55,330
Incentives as % of Budget	50.8%	50.8%	50.8%	50.8%	50.8%

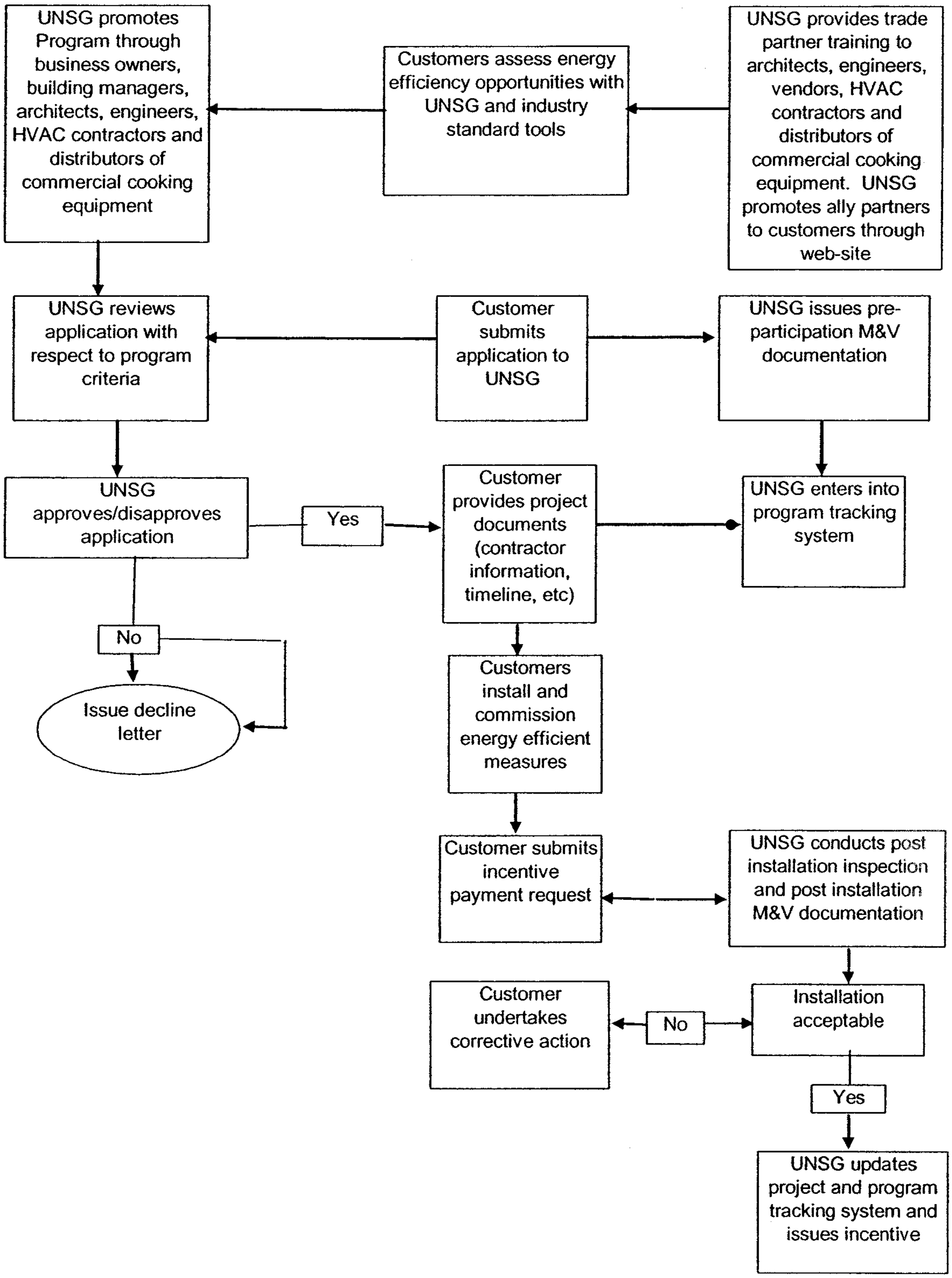
Measurement, Evaluation, and Research

UNSG will adopt a strategy that calls for integrated data collection that is designed to provide a quality data resource for program tracking, management and evaluation. This approach will entail the following primary activities:

- **Database tracking system development.** As part of detailed program design, UNSG will develop a database tracking system that will be used to collect the necessary data elements and provide the reporting functions needed to track program process and provide a data resource for program evaluation.
- **Integrated implementation data collection.** UNSG will work with the implementation contractor to establish systems to collect the data needed to support effective program management and evaluation through the implementation and customer application processes. The database tracking system will be integrated with implementation data collection processes.
- **Field verification.** UNSG will conduct field verification of the installation of a sample of measures throughout the implementation of the program.
- **Tracking of savings using deemed savings values.** UNSG will develop deemed savings values for each measure and technology promoted by the program and periodically review and revise the savings values to be consistent with program participation and accurately estimated the savings being achieved by the program.

This approach will provide UNSG with ongoing feedback on program progress and enable program management to adjust or correct the program so as to be more effective, provide a higher level of service, and be more cost beneficial. Integrated data collection will also provide a high quality data resource for evaluation activities.

Appendix 1 – C&I Facilities Gas Efficiency Implementation Process



Appendix 2 – Expected 2008 Program Costs

Budget Items	Budget	Allocation Rate (%)
Administrative		
Managerial and Clerical Labor	***$15,200***	
Labor - Clerical	$760	5.0%
Labor - Program Design	$760	5.0%
Labor - Program Development	$760	5.0%
Labor - Program Planning	$2,280	15.0%
Labor - Program/Project Management	$1,520	10.0%
Labor - Staff Management	$1,520	10.0%
Labor - Staff Supervision	$760	5.0%
Subcontractor Labor - Clerical	$760	5.0%
Subcontractor Labor - Program Design	$1,520	10.0%
Subcontractor Labor - Program Development	$760	5.0%
Subcontractor Labor - Program Planning	$760	5.0%
Subcontractor Labor - Program/Project Management	$3,040	20.0%
Subcontractor Labor - Staff Management	$0	0.0%
Subcontractor Labor - Staff Supervision	$0	0.0%
Subtotal Managerial and Clerical Labor	*$15,200*	*100.0%*
Travel & Direct Expenses	***$2,280***	
Conference Fees	$228	10.0%
Labor - Conference Attendance	$228	10.0%
Subcontractor - Conference Fees	$46	2.0%
Subcontractor - Travel - Airfare	$91	4.0%
Subcontractor - Travel - Lodging	$46	2.0%
Subcontractor - Travel - Meals	$46	2.0%
Subcontractor - Travel - Mileage	$46	2.0%
Subcontractor - Travel - Parking	$46	2.0%
Subcontractor - Travel - Per Diem for Misc. Expenses	$205	9.0%
Subcontractor Labor - Conference Attendance	$46	2.0%
Travel - Airfare	$319	14.0%
Travel - Lodging	$228	10.0%
Travel - Meals	$114	5.0%
Travel - Mileage	$114	5.0%
Travel - Parking	$68	3.0%
Travel - Per Diem for Misc. Expenses	$410	18.0%
Travel & Direct Expenses	*$2,280*	*100.0%*
Overhead (General and Administrative) - Labor and Materials	***$1,520***	
Equipment - Communications	$30	2.0%
Equipment - Computing	$30	2.0%
Equipment - Document Reproduction	$30	2.0%
Equipment - General Office	$30	2.0%
Equipment - Transportation	$30	2.0%
Facilities - Lease/Rent Payment	$0	0.0%
Labor - Accounts Payable	$15	1.0%
Labor - Accounts Receivable	$15	1.0%

Labor - Administrative	$15	1.0%
Labor - Automated Systems	$0	0.0%
Labor - Communications	$15	1.0%
Labor - Contract Reporting	$15	1.0%
Labor - Corporate Services	$15	1.0%
Labor - Facilities Maintenance	$15	1.0%
Labor - Information Technology	$15	1.0%
Labor - Materials Management	$15	1.0%
Labor - Procurement	$15	1.0%
Labor - Regulatory Reporting	$608	40.0%
Labor - Shop Services	$15	1.0%
Labor - Telecommunications	$15	1.0%
Labor - Transportation Services	$15	1.0%
Office Supplies	$15	1.0%
Postage	$15	1.0%
Subcontractor - Equipment - Communications	$0	0.0%
Subcontractor - Equipment - Computing	$0	0.0%
Subcontractor - Equipment - Document Reproduction	$0	0.0%
Subcontractor - Equipment - General Office	$0	0.0%
Subcontractor - Equipment - Transportation	$0	0.0%
Subcontractor - Facilities - Lease/Rent Payment	$0	0.0%
Subcontractor - Office Supplies	$0	0.0%
Subcontractor - Postage	$0	0.0%
Subcontractor Labor - Accounts Payable	$0	0.0%
Subcontractor Labor - Accounts Receivable	$0	0.0%
Subcontractor Labor - Administrative	$0	0.0%
Subcontractor Labor - Automated Systems	$0	0.0%
Subcontractor Labor - Communications	$0	0.0%
Subcontractor Labor - Contract Reporting	$0	0.0%
Subcontractor Labor - Corporate Services	$0	0.0%
Subcontractor Labor - Facilities Maintenance	$0	0.0%
Subcontractor Labor - Information Technology	$0	0.0%
Subcontractor Labor - Materials Management	$0	0.0%
Subcontractor Labor - Procurement	$0	0.0%
Subcontractor Labor - Regulatory Reporting	$532	35.0%
Subcontractor Labor - Shop Services	$0	0.0%
Subcontractor Labor - Telecommunications	$0	0.0%
Subcontractor Labor - Transportation Services	$0	0.0%
Subtotal Overhead	*$1,520*	*100.0%*
Total Administrative Costs	**$19,000**	
Marketing/Advertising/Outreach		
Internal Marketing Expense	***$7,500***	
Advertisements / Media Promotions	$1,875	25.0%
Bill Inserts	$300	4.0%
Brochures	$450	6.0%
Door Hangers	$0	0.0%
Labor - Business Outreach	$375	5.0%
Labor - Customer Outreach	$375	5.0%

Labor - Customer Relations	$375	5.0%
Labor - Marketing	$2,250	30.0%
Print Advertisements	$1,125	15.0%
Radio Spots	$375	5.0%
Subtotal Internal Marketing Expense	*$7,500*	*100.0%*
Subcontracted Marketing Expense	***$7,500***	
Subcontractor - Bill Inserts	$375	5.0%
Subcontractor - Brochures	$375	5.0%
Subcontractor - Door Hangers	$0	0.0%
Subcontractor - Print Advertisements	$0	0.0%
Subcontractor - Radio Spots	$750	10.0%
Subcontractor - Television Spots	$0	0.0%
Subcontractor Labor - Business Outreach	$375	5.0%
Subcontractor Labor - Customer Outreach	$375	5.0%
Subcontractor Labor - Customer Relations	$375	5.0%
Subcontractor Labor - Marketing	$375	5.0%
Television Spots	$0	0.0%
Website Development	$4,500	60.0%
Subtotal Subcontracted Marketing Expense	*$7,500*	*100.0%*
Total Marketing/Advertising/Outreach	**$15,000**	
Direct Implementation		
Financial Incentives to Customers	***$50,840***	
Activity - Labor	***$3,100***	
Labor - Curriculum Development	$248	8.0%
Labor - Customer Education and Training	$1,240	40.0%
Labor - Customer Equipment Testing and Diagnostics	$0	0.0%
Labor - Facilities Audits	$930	30.0%
Subcontractor Labor - Facilities Audits	$310	10.0%
Subcontractor Labor - Curriculum Development	$155	5.0%
Subcontractor Labor - Customer Education and Training	$155	5.0%
Subcontractor Labor - Customer Equipment Testing and Diagnostics	$62	2.0%
Subtotal Activity	*$3,100*	*100.0%*
Hardware and Materials - Installation and Other DI Activity	***$2,480***	
Audit Applications and Forms	$198	8.0%
Direct Implementation Literature	$496	20.0%
Education Materials	$496	20.0%
Energy Measurement Tools	$248	10.0%
Installation Hardware	$248	10.0%
Subcontractor - Direct Implementation Literature	$99	4.0%
Subcontractor - Education Materials	$99	4.0%
Subcontractor - Energy Measurement Tools	$397	16.0%
Subcontractor - Installation Hardware	$149	6.0%
Subcontractor -Audit Applications and Forms	$50	2.0%
Subtotal Hardware and Materials	*$2,480*	*100.0%*
Rebate Processing and Inspection - Labor and Materials	***$5,580***	
Labor - Field Verification	$558	10.0%
Labor - Rebate Processing	$0	0.0%
Labor - Site Inspections	$558	10.0%

Rebate Applications	$0	0.0%
Subcontractor - Rebate Applications	$558	10.0%
Subcontractor Labor - Field Verification	$1,116	20.0%
Subcontractor Labor - Rebate Processing	$1,674	30.0%
Subcontractor Labor - Site Inspections	$1,116	20.0%
Subtotal Rebate Processing and Inspection	*$5,580*	*100.0%*
Total Direct Implementation	**$62,000**	
Evaluation, Measurement and Verification		
EM&V Labor and Materials	***$3,800***	
Labor - EM&V	$190	5.0%
Materials - EM&V	$190	5.0%
Subcontractor Labor - EM&V	$3,420	90.0%
Subtotal EM&V Activity - Labor	*$3,800*	*100.0%*
EM&V Overhead	***$200***	
Benefits - EM&V Labor	$0	0.0%
Overhead - EM&V	$100	50.0%
Subcontractor Overhead - EM&V	$0	0.0%
Subcontractor Travel - EM&V	$0	0.0%
Travel - EM&V	$100	50.0%
Subtotal EM&V Overhead	*$200*	*100.0%*
Total EM&V	**$4,000**	
Total Budget	**$100,000**	

Appendix 3 – Measure Level Energy Savings and Benefit/Cost Analysis

See accompanying Excel spreadsheet for program additional benefit/cost calculations

GCC100 - HIGH-EFFICIENCY GAS FRYER

Gas C&I

PROGRAM DATA	
Conservation Life (yrs):	12
Program Life (yrs):	5
Levelized Therms	0.90297
Ratio of Non-inc to Incentive Costs	96.7%
IRP Discount Rate*****:	8.50%
Social Discount Rate	5.00%
NTG Ratio:	96%

RATE DATA	
Rate:	
$/Therm	1.29355

OTHER FACTORS	
Application	ROB
Cost Basis:	Incremental equipment

DEMAND/ENERGY SAVINGS						INCENTIVE CALCULATIONS						CUSTOMER COST/SAVINGS				WGT.	% Incent	TRC
Measure Type	Size (lbs oil)	Base Annual Usage (kBtuh)	Base Eff.	High Eff.	Annual Savgs. Per Unit (Therms)	IRP PV Benefit ($)	Social PV Benefit ($)	Recommended Incentive ($)	Recommended Incentive % PV	PV Program Cost ($)	NPV ($)	Incr. Cost ($)	Cost Savings ($)	Payback wo/Inc. (yrs)	Payback w/Inc. (yrs)	Weighting Factor	(%)	BC Ratio
High Efficiency - Open Deep Fat	15 - 39	60,000	0.30	0.57	284	$1,810	$2,184	$300	17%	$740	$1,069	$469	$368	1.3	0.5	0.20	64%	2.45
High Efficiency - Open Deep Fat	40 - 59	100,000	0.30	0.57	474	$3,016	$3,639	$350	12%	$846	$2,169	$529	$613	0.9	0.3	0.50	66%	3.56
High Efficiency - Open Deep Fat	60+	135,000	0.30	0.57	639	$4,071	$4,913	$400	10%	$1,031	$3,040	$671	$827	0.8	0.3	0.20	60%	3.95
High Efficiency - Pressure	15 - 39	45,000	0.30	0.43	132	$843	$1,017	$300	36%	$740	$103	$469	$171	2.7	1.0	0.02	64%	1.14
High Efficiency - Pressure	40 - 59	75,000	0.30	0.43	221	$1,404	$1,695	$350	25%	$846	$558	$529	$285	1.9	0.6	0.07	66%	1.66
High Efficiency - Pressure	60+	125,000	0.30	0.43	368	$2,341	$2,825	$400	17%	$1,031	$1,310	$671	$476	1.4	0.6	0.01	60%	2.27
Weighted Average					443.34	$2,823	$3,406	$350	14%	$862	$1,961	$546	$573	1.0	0.37	1.00	64%	3.28

**** See worksheet 'Cost Assumptions' for information of cost data.

***** Discount rate is based on TEP estimate 12/31/2006

GCC200 - HIGH-EFFICIENCY GAS GRIDDLE

Gas C&I

PROGRAM DATA	
Conservation Life (yrs):	12
Program Life (yrs):	5
Levelized Therms	0.90297
Ratio of Non-inc to Incentive Costs	96.7%
IRP Discount Rate*****:	8.50%
Social Discount Rate	5.00%
NTG Ratio:	96%

RATE DATA	
Rate:	
$/Therm	1.29355

OTHER FACTORS	
Application	ROB
Cost Basis:	Incremental equipment

DEMAND/ENERGY SAVINGS						INCENTIVE CALCULATIONS						CUSTOMER COST/SAVINGS				WGT.	% Incent	TRC
Measure Type	Size (kBtuh)	Base Annual Usage (kBtuh)	Base Eff.	High Eff.	Annual Savgs. Per Unit (Therms)	IRP PV Benefit ($)	Social PV Benefit ($)	Recommended Incentive ($)	Recommended Incentive % PV	PV Program Cost ($)	NPV ($)	Incr. Cost ($)	Cost Savings ($)	Payback wo/Inc. (yrs)	Payback w/Inc. (yrs)	Weighting Factor	(%)	BC Ratio
High Efficiency - Gas Griddle	60 - 80	86,100	0.30	0.45	287	$1,827	$2,205	$300	16%	$714	$1,114	$441	$371	1.2	0.4	1.00	68%	2.56
Weighted Average					287.00	$1,827	$2,205	$300	16%	$714	$1,114	$441	$371	1.19	0.38	1.00	68%	2.56

**** See worksheet 'Cost Assumptions' for information of cost data.

C&I Facilities Gas Efficiency Program

GCC300 - HIGH-EFFICIENCY GAS OVENS

Gas C&I

PROGRAM DATA	
Conservation Life (yrs):	12
Program Life (yrs):	5
Levelized Therms	0.90297
Ratio of Non-inc to Incentive Costs	96.7%
IRP Discount Rate*****:	8.50%
Social Discount Rate	5.00%
NTG Ratio:	96%

RATE DATA	
Rate:	
$/Therm	1.29355

OTHER FACTORS	
Application	ROB
Cost Basis:	Incremental equipment

DEMAND/ENERGY SAVINGS						INCENTIVE CALCULATIONS						CUSTOMER COST/SAVINGS				WGT.	% Incent	TRC
Measure Type	Size (kbtuh)	Base Annual Usage (kBtu)	Base Eff.	High Eff.	Annual Savgs. Per Unit (Therms)	IRP PV Benefit ($)	Social PV Benefit ($)	Recommended Incentive ($)	Recommended Incentive % PV	PV Program Cost ($)	NPV ($)	Incr. Cost ($)	Cost Savings ($)	Payback wo/Inc. (yrs)	Payback w/Inc. (yrs)	Weighting Factor	(%)	BC Ratio
High Efficiency Combination Oven	70	115,000	0.30	0.50	460	$2,929	$3,534	$750	26%	$2,314	$615	$1,655	$595	2.8	1.5	0.05	45%	1.27
High Efficiency Convection Oven	70	60,000	0.25	0.50	300	$1,910	$2,305	$400	21%	$995	$915	$633	$388	1.6	0.6	0.20	63%	1.92
High Efficiency Conveyor Oven	135	210,000	0.15	0.45	1400	$8,913	$10,756	$1,000	11%	$3,247	$5,666	$2,375	$1,811	1.3	0.8	0.10	42%	2.75
High Efficiency Deck Oven	70	65,000	0.25	0.50	325	$2,069	$2,497	$400	19%	$1,122	$947	$766	$420	1.8	0.9	0.65	52%	1.84
Weighted Average					434.25	$2,765	$3,336	$478	19%	$1,369	$1,396	$945	$562	1.78	0.84	1.00	51%	2.02

**** See worksheet 'Cost Assumptions' for information of cost data.

***** Discount rate is based on TEP estimate 12/31/2006

GHV100 - HIGH-EFFICIENCY FURNACE

Gas C&I

PROGRAM DATA	
Conservation Life (yrs):	15
Program Life (yrs):	5
Levelized Therms	0.91941
Ratio of Non-inc to Incentive Costs	96.7%
IRP Discount Rate*****:	8.50%
Social Discount Rate	5.00%
NTG Ratio:	70%

OPERATING DATA	
Htg. Season Hrs.:	2460
Htg. Season Load Factor:	1
Peak Day Load Factor:	0.8

RATE DATA	
Rate:	
$/Therm	1.29355

OTHER FACTORS	
Application	ROB
Cost Basis:	Incremental equipment

DEMAND/ENERGY SAVINGS							INCENTIVE CALCULATIONS						CUSTOMER COST/SAVINGS				WGT.	% Incent	TRC
Measure Type	Size	Base Capacity (Btuh)	Base Eff.	High Eff.	Peak Day Savgs. Per Unit (Therms)	Annual Savgs. Per Unit (Therms)	IRP PV Benefit ($)	Social PV Benefit ($)	Recommended Incentive ($)	Recommended Incentive % PV	PV Program Cost ($)	NPV ($)	Incr. Cost ($)	Cost Savings ($)	Payback wo/Inc. (yrs)	Payback w/Inc. (yrs)	Weighting Factor	(%)	BC Ratio
HI-E FURNACE	0 - 60 MBH	45000	0.78	0.90	1.48	189	$1,011	$1,264	$100	10%	$515	$496	$598	$245	2.4	2.0	0.40	17%	1.96
HI-E FURNACE	61 - 120 MBH	90000	0.78	0.90	2.95	378	$2,023	$2,528	$200	10%	$674	$1,349	$686	$490	1.4	1.0	0.05	29%	3.00
HI-E FURNACE	120+ MBH	135000	0.78	0.90	4.43	568	$3,034	$3,792	$300	10%	$864	$2,170	$820	$734	1.1	0.7	0.05	37%	3.51
HI-E FURNACE	0 - 60 MBH	45000	0.78	0.92	1.69	216	$1,154	$1,443	$150	13%	$598	$557	$646	$279	2.3	1.8	0.35	23%	1.93
HI-E FURNACE	61 - 120 MBH	90000	0.78	0.92	3.37	432	$2,308	$2,885	$300	13%	$837	$1,471	$782	$559	1.4	0.9	0.03	38%	2.76
HI-E FURNACE	120+ MBH	135000	0.78	0.92	5.06	648	$3,463	$4,328	$400	12%	$1,051	$2,411	$949	$838	1.1	0.7	0.03	42%	3.29
HI-E FURNACE	0 - 60 MBH	45000	0.78	0.94	1.89	242	$1,291	$1,614	$100	8%	$681	$610	$834	$312	2.7	2.3	0.06	12%	1.90
HI-E FURNACE	61 - 120 MBH	90000	0.78	0.94	3.77	483	$2,582	$3,227	$400	15%	$1,001	$1,581	$877	$625	1.4	0.8	0.02	46%	2.58
HI-E FURNACE	120+ MBH	135000	0.78	0.94	5.66	725	$3,873	$4,841	$500	13%	$1,238	$2,635	$1,078	$937	1.2	0.6	0.02	46%	3.13
Weighted Average						264.22	$1,412	$1,765	$159	$0	$625	$787	$673	$342	2.19	1.73	1.00	24%	2.26

**** See worksheet 'Cost Assumptions' for information of cost data.

C&I Facilities Gas Efficiency Program

GHV200 - ENERGY-EFFICIENT PACKAGED HEAT AND AIR CONDITIONERS -- NON RESIDENTIAL

POROGRAM DATA	
Conservation Life (yrs):	15
Program Life (yrs):	5
Demand AC ($/kW):	61.99
Summer On-pk Energy AC ($/kWh):	0.07218
Summer Off-pk Energy AC ($/kWh):	0.07218
Winter On-pk Energy AC ($/kWh):	0.06945
Winter Off-pk Energy AC ($/kWh):	0.06945
Levelized Therms	0.91941
Ratio Non-incent to Incent Cost	96.7%
IRP Discount Rate*****:	8.50%
Social Discount Rate	5.00%
NTG Ratio:	80%

RATE DATA	
Rate Class:	Res Ave
$/kW:	0.779
$/kWh, On-Peak:	0.11150
$/kWh, Off-Peak:	0.10036
$/Therm	1.293549

OPERATING DATA	
On-Pk EFLH:	937
Off-Pk EFLH:	234
On-Pk Ratio:	80.0%
Off-Pk Ratio:	20.0%
Summer Ratio:	50%
Winter Ratio:	50%
Coincidence Factor:	0.95
Htg. Season Hrs.:	2460
Htg. Season Load Factor:	1
Peak Day Load Factor:	0.82

OTHER FACTORS		
Line Loss Factor:		9.5%
Capacity Reserve Factor:		0%
Application:		ROB, NEW
Cost Basis:		Incremental
MARKET DISTRIBUTION		
CEE Tier	AFUE	Market %
1	0.907	70%
2	0.907	20%
1	0.921	5%
2	0.921	5%

HEATINTG ENERGY AND COOLING DEMAND / ENERGY SAVINGS												INCENTIVE CALCULATIONS						CUSTOMER COST/SAVINGS				WGT.		
Unit Type	Unit Size (Tons)	Min. Qual. SEER CEE	Min. Qual. EER CEE	BASE EER	Base Furnace Capacity (Btuh)	Base Eff.	High Eff.	Annual Savgs. Per Unit (Therms)	Demand Savings Per Unit (KW)	On-pk Savings Per Unit (KWh)	Off-pk Savings Per Unit (KWh)	PV Benefit Per Unit ($)	Social PV Benefit ($)	Incentive (Per Unit) ($)	Incentive (Per Unit) % PV	PV Cost Per Unit ($)	NPV ($)	Incr. Cost Per Unit ($)	Cost Savings ($)	Payback wo/Inc. (yrs)	Payback w/Inc. (yrs)	Weighting Factor	% Incent	TRC
Less that 5.4 tons	2	13.0	11.3	9.4	50,000	0.80	0.90	171	0	397	99	1480	1850	450	30%	1508	-28	1341	279	4.8	3.2	0.167	34%	0.98
90 - 92 AFUE	2.5	13.0	11.3	9.4	60,000	0.80	0.90	205	1	496	124	1798	2248	500	28%	1656	143	1465	338	4.3	2.9	0.167	34%	1.09
CEE Tier 1	3	13.0	11.3	9.4	80,000	0.80	0.90	273	1	595	149	2325	2906	550	24%	1828	498	1620	441	3.7	2.4	0.167	34%	1.27
	3.5	13.0	11.3	9.4	90,000	0.80	0.90	307	1	695	173	2643	3304	600	23%	1997	646	1771	500	3.5	2.3	0.167	34%	1.32
	4	13.0	11.3	9.4	100,000	0.80	0.90	342	1	794	198	2961	3701	650	22%	2089	872	1826	558	3.3	2.1	0.167	36%	1.42
	5.4	13.0	11.3	9.4	120,000	0.80	0.90	410	1	1,072	268	3684	4605	750	20%	2427	1257	2127	687	3.1	2.0	0.167	35%	1.52
Weighted Average		13.00	11.30	9.42	83,333	0.80	0.900	284.7	0.7	675	169	2482	3102	583	24%	1917	565	1692	467	3.8	2.5	1.000	34%	1.29
Less that 5.4 tons	2	14.0	11.6	9.4	50,000	0.80	0.90	171	0	448	112	1537	1921	500	33%	1644	-106	1450	287	5.1	3.3	0.167	34%	0.94
90 - 92 AFUE	2.5	14.0	11.6	9.4	60,000	0.80	0.90	205	1	560	140	1869	2336	550	29%	1812	57	1600	347	4.6	3.0	0.167	34%	1.03
CEE Tier 2	3	14.0	11.6	9.4	80,000	0.80	0.90	273	1	673	168	2410	3012	600	25%	1981	429	1752	452	3.9	2.5	0.167	34%	1.22
	3.5	14.0	11.6	9.4	90,000	0.80	0.90	307	1	785	196	2742	3427	650	24%	2158	584	1911	513	3.7	2.5	0.167	34%	1.27
	4	14.0	11.6	9.4	100,000	0.80	0.90	342	1	897	224	3074	3843	700	23%	2257	817	1976	573	3.4	2.2	0.167	35%	1.36
	5.4	14.0	11.6	9.4	120,000	0.80	0.90	410	1	1,211	302	3837	4796	800	21%	2584	1253	2263	708	3.2	2.1	0.167	35%	1.48
Weighted Average		14.00	11.60	9.42	83,333	0.80	0.900	285	1	762	190	2578	3223	633	26%	2073	506	1825	480	4.0	2.6	1.000	35%	1.24
Less that 5.4 tons	2	13.0	11.3	9.4	50,000	0.80	0.92	201	0	397	99	1662	2077	550	33%	1737	-75	1507	318	4.7	3.0	0.167	37%	0.96
92+ AFUE	2.5	13.0	11.3	9.4	60,000	0.80	0.92	241	1	496	124	2016	2520	600	30%	1918	99	1672	384	4.4	2.8	0.167	36%	1.05
CEE Tier 1	3	13.0	11.3	9.4	70,000	0.80	0.92	281	1	595	149	2370	2963	650	27%	2123	248	1868	450	4.1	2.7	0.167	35%	1.12
	3.5	13.0	11.3	9.4	80,000	0.80	0.92	321	1	695	173	2725	3406	700	26%	2325	400	2060	517	4.0	2.6	0.167	34%	1.17
	4	13.0	11.3	9.4	90,000	0.80	0.92	361	1	794	198	3079	3848	750	24%	2450	629	2156	583	3.7	2.4	0.167	35%	1.26
	5.4	13.0	11.3	9.4	110,000	0.80	0.92	441	1	1,072	268	3875	4843	850	22%	2854	1021	2540	728	3.5	2.3	0.167	33%	1.36
Weighted Average		13.00	11.30	9.42	76,667	0.80	0.920	307	0.7	675	169	2621	3276	683	27%	2234	387	1967	497	4.1	2.6	1.000	35%	1.17
Less that 5.4 tons	2	14.0	11.6	9.4	50,000	0.80	0.92	206	0	448	112	1754	2192	600	34%	1873	-119	1615	333	4.9	3.1	0.167	37%	0.94
92+ AFUE	2.5	14.0	11.6	9.4	60,000	0.80	0.92	241	1	560	140	2087	2609	650	31%	2074	13	1807	393	4.6	2.9	0.167	36%	1.01
CEE Tier 2	3	14.0	11.6	9.4	70,000	0.80	0.92	281	1	673	168	2455	3069	700	29%	2276	179	1999	462	4.3	2.8	0.167	35%	1.08
	3.5	14.0	11.6	9.4	80,000	0.80	0.92	321	1	785	196	2824	3530	750	27%	2486	338	2201	530	4.2	2.7	0.167	34%	1.14
	4	14.0	11.6	9.4	90,000	0.80	0.92	361	1	897	224	3192	3990	800	25%	2619	574	2306	598	3.9	2.5	0.167	35%	1.22
	5.4	14.0	11.6	9.4	110,000	0.80	0.92	441	1	1,211	302	4028	5034	900	22%	3011	1016	2676	748	3.6	2.4	0.167	34%	1.34
Weighted Average		14.00	11.60	9.42	76,667	0.80	0.921	308	1	762	190	2723	3404	733	28%	2390	334	2101	511	4.2	2.7	1.000	35%	1.14
Market Weighted Average		13.25	11.38	9.42	82,667	0.80	0.902	287.0	0.7	697	174	2520	3150	606	25%	1988	532	1753	473	3.9	2.5	1.000	35%	1.27

C&I Facilities Gas Efficiency Program

GHV300 - HIGH-EFFICIENCY SPACE HEATING/ PROCESS HOT WATER BOILERS

Gas C&I

PROGRAM DATA	
Conservation Life (yrs):	20
Program Life (yrs):	5
Levelized Therms	0.94510
Ratio of Non-inc to Incentive Costs	96.7%
IRP Discount Rate*****:	8.50%
Social Discount Rate	5.00%
NTG Ratio:	70%

OPERATING DATA	
Htg. Season Hrs.:	2460
Htg. Season Load Factor:	1

RATE DATA	
Rate:	
$/Therm	1.29355

OTHER FACTORS	
Application	ROB
Cost Basis:	Incremental equipment

DEMAND/ENERGY SAVINGS						INCENTIVE CALCULATIONS						CUSTOMER COST/SAVINGS				WGT.	% Incent	
Measure Type	ASHRAE Size (kBtuh input)	ASHRAE Base Eff.	Sample Planning Eff.	Base Load (Btuh)	Annual Savgs. Per Unit (Therms)	IRP PV Benefit ($)	Social PV Benefit ($)	Recommended Incentive ($)	Recommended Incentive % PV	PV Program Cost ($)	NPV ($)	Incr. Cost ($)	Cost Savings ($)	Payback wo/Inc. (yrs)	Payback w/Inc. (yrs)	Weighting Factor	(%)	BC Ratio
Small condensing boiler	<300	0.80	0.856	100,000	201.4	$1,261	$1,660	$250	20%	$836	$425	$849	$260	3.3	2.3	0.50	29%	1.51
Medium - Large condensing boiler	>300	0.80	0.857	100,000	206.0	$1,290	$1,698	$250	19%	$491	$798	$357	$266	1.3	0.4	0.50	70%	2.62
Weighted Average					203.67	$1,275	$1,679	$250	$0	$664	$611	$603	$263	2.30	1.35	1.00	41%	1.92

Htg Season Hrs based on Kingman at 3212 HDD

**** See worksheet 'Cost Assumptions' for information of cost data.

***** Discount rate is based on TEP estimate 12/31/2006

C&I Facilities Gas Efficiency Program

GHV400 - HIGH-EFFICIENCY SERVICE WATER HOT WATER HEATERS

Gas C&I

PROGRAM DATA	
Conservation Life (yrs):	15
Program Life (yrs):	5
Levelized Therms	0.91941
Ratio of Non-inc to Incentive Costs	96.7%
IRP Discount Rate*****:	8.50%
Social Discount Rate	5.00%
NTG Ratio:	70%

RATE DATA	
Rate:	
$/Therm	1.29355

OPERATING DATA	
Op. Days/Year:	
Office	255
School	200
Hotel	365
Health	365
Food Service	312
Temp. Rise (F):	100

OTHER FACTORS	
Application	ROB
Cost Basis:	Incremental equipment

DEMAND/ENERGY SAVINGS							INCENTIVE CALCULATIONS						CUSTOMER COST/SAVINGS				WGT.	% Incent	TRC
Measure Type	Building Size	Common Unit (Sq Ft)	Savings/ Common Unit (KBtu)	Savings/ Common Unit (Therms)	Number Common Unit	Annual Savings (Therms)	IRP PV Benefit ($)	Social PV Benefit ($)	Recommended Incentive ($)	Recommended Incentive % PV	PV Program Cost ($)	NPV ($)	Incr. Cost ($)	Cost Savings ($)	Payback wo/Inc. (yrs)	Payback w/Inc. (yrs)	Weighting Factor	(%)	BC Ratio
Education – Primary School	50000	1,000	234	2.3	50	117	$626	$783	$200	32%	$410	$216	$310	$152	2.0	0.7	0.14	65%	1.53
Education – Secondary School	150000	1,000	109	1.1	150	164	$877	$1,096	$200	23%	$410	$466	$310	$212	1.5	0.5	0.14	65%	2.14
Grocery	50000	1,000	70	0.7	50	35	$186	$232	$200	108%	$410	-$224	$310	$45	6.9	2.4	0.14	65%	0.45
Lodging – Motel	30000	1,000	876	8.8	30	263	$1,405	$1,756	$200	14%	$410	$995	$310	$340	0.9	0.3	0.14	65%	3.42
Office – Small	10000	1,000	104	1.0	10	10	$55	$69	$200	361%	$410	-$355	$310	$13	23.1	8.2	0.14	65%	0.14
Restaurant – Fast Food	2000	1,000	6752	67.5	2	135	$722	$902	$200	28%	$410	$311	$310	$175	1.8	0.6	0.14	65%	1.76
Restaurant – Sit Down	4000	1,000	11849	118.5	4	474	$2,533	$3,166	$200	8%	$410	$2,123	$310	$613	0.5	0.2	0.14	65%	6.17
Weighted Average						171	$915	$1,143	$200	$1	$410	$505	$310	$221	5.24	1.86	1.00	65%	2.23

Expected Annual Project Mix

Energy Efficiency Measure	Annual Units	% Therm Savings
High Efficiency Gas Fryer	23	3.6%
High Efficiency Gas Griddle	27	2.7%
High Efficiency Gas Ovens	34	5.1%
Packaged system with 90 AFUE+ furnace	156	15.6%
Energy Efficient Space Heating / Process Hot Water Boiler	32	2.3%
Energy Efficient Service Water Hot Water Heater	135	8.1%
High efficiency furnace 90 AFUE +	679	62.6%

BEFORE THE ARIZONA CORPORATION COMMISSION

<u>**COMMISSIONERS**</u>
JEFF HATCH-MILLER- CHAIRMAN
WILLIAM A. MUNDELL
MARC SPITZER
MIKE GLEASON
KRISTIN K. MAYES

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-06-0463

Direct Testimony of

Dr. Ronald E. White

on Behalf of

UNS Gas, Inc.

July 13, 2006

EXHIBIT
UNSG 24
admitted

Table of Contents

BEFORE THE
ARIZONA CORPORATION COMMISSION

PREPARED DIRECT TESTIMONY OF
DR. RONALD E. WHITE
IN DOCKET NO. G-04204A-06___

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Ronald E. White. My business address is 17595 S. Tamiami Trail, Suite 212, Fort Myers, Florida 33908.

Q. WHAT IS YOUR OCCUPATION?

A. I am an Executive Vice President and Senior Consultant of Foster Associates, Inc.

I. QUALIFICATIONS

Q. WOULD YOU BRIEFLY DESCRIBE YOUR EDUCATIONAL TRAINING AND PROFESSIONAL BACKGROUND?

A. I received a B.S. degree in Engineering Operations and an M.S. degree and Ph.D. (1977) in Engineering Valuation from Iowa State University. I have taught graduate and undergraduate courses in industrial engineering, engineering economics, and engineering valuation at Iowa State University and previously served on the faculty for Depreciation Programs for public utility commissions, companies, and consultants, sponsored by Depreciation Programs, Inc., in cooperation with Western Michigan University. I also conduct courses in depreciation and public utility economics for clients of the firm.

I have prepared and presented a number of papers to professional organizations, committees, and conferences and have published several articles on matters relating to depreciation, valuation and economics. I am a past member of the Board of Directors of the Iowa State Regulatory Conference and an affiliate member of the joint American Gas Association (A.G.A.) – Edison Electric Institute (EEI) Depreciation Accounting Committee, where I previously served as chairman of a standing committee on capital recovery and its effect on corporate economics. I am also a member of the American Economic Association, the Financial Management Association, the

Midwest Finance Association, the Electric Cooperatives Accounting Association (ECAA), and a founding member of the Society of Depreciation Professionals.

Q. WHAT IS YOUR PROFESSIONAL EXPERIENCE?

A. I joined the firm of Foster Associates in 1979, as a specialist in depreciation, the economics of capital investment decisions, and cost of capital studies for ratemaking applications. Before joining Foster Associates, I was employed by Northern States Power Company (1968–1979) in various assignments related to finance and treasury activities. As Manager of the Corporate Economics Department, I was responsible for book depreciation studies, studies involving staff assistance from the Corporate Economics Department in evaluating the economics of capital investment decisions, and the development and execution of innovative forms of project financing. As Assistant Treasurer at Northern States, I was responsible for bank relations, cash requirements planning, and short–term borrowings and investments.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY BODY?

A. Yes. I have testified in numerous proceedings before administrative and judicial bodies in over thirty states, including Arizona. I have also testified before the Federal Energy Regulatory Commission, the Federal Power Commission, the Alberta Energy Board, the Ontario Energy Board, and the Securities and Exchange Commission. I have sponsored position statements before the Federal Communication Commission and numerous local franchising authorities in matters relating to the regulation of telephone and cable television. A more detailed description of my professional qualifications is contained in Attachment REW–1.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Foster Associates was engaged by UNS Gas, Inc. (UNS Gas), an operating subsidiary of UniSource Energy Services, to conduct a 2006 depreciation rate study for gas utility plant owned and operated by UNS Gas. The purpose of my testimony is to sponsor and describe the study conducted by Foster Associates. Depreciation rates currently used by UNS Gas were adopted pursuant to a Settlement Agreement approved in Decision No. 66028 (July 3, 2003).

III. DEVELOPMENT OF DEPRECIATION RATES

Q. WOULD YOU PLEASE EXPLAIN WHY DEPRECIATION STUDIES ARE NEEDED FOR ACCOUNTING AND RATEMAKING PURPOSES?

A. The goal of depreciation accounting is to charge to operations a reasonable estimate of the cost of the service potential of an asset (or group of assets) consumed during an accounting interval. A number of depreciation systems have been developed to achieve this objective, most of which employ time as the apportionment base.

Implementation of a time–based (or age–life system) of depreciation accounting requires the estimation of several parameters or statistics related to a plant account. The average service life of a vintage, for example, is a statistic that will not be known with certainty until all units from the original placement have been retired from service. A vintage average service life, therefore, must be estimated initially and periodically revised as indications of the eventual average service life becomes more certain. Future net salvage rates and projection curves, which describe the expected distribution of retirements over time, are also estimated parameters of a depreciation system that are subject to future revisions. Depreciation studies should be conducted periodically to assess the continuing reasonableness of parameters and accrual rates derived from prior estimates.

The need for periodic depreciation studies is also a derivative of the ratemaking process which establishes prices for utility services based on costs. Absent regulation, deficient or excessive depreciation rates will produce no adverse consequence other than a systematic over or understatement of the accounting measurement of earnings. While a continuance of such practices may not comport with the goals of depreciation accounting, the achievement of capital recovery is not dependent upon either the amount or the timing of depreciation expense for an unregulated firm. In the case of a regulated utility, however, recovery of investor–supplied capital is dependent upon allowed revenues, which are in turn dependent upon approved levels of depreciation expense. Periodic reviews of depreciation rates are, therefore, essential to the achievement of timely capital recovery for a regulated utility.

Q. WHAT ARE THE PRINCIPAL ACTIVITIES INVOLVED IN CONDUCTING A DEPRECIATION STUDY?

A. The first step in conducting a depreciation study is the collection of plant accounting data needed to conduct a statistical analysis of past retirement experience. Data are also collected to permit an analysis of the relationship between retirements and realized gross salvage and removal expense. The data collection phase should include a verification of the accuracy of the plant accounting records and a reconciliation of the assembled data to the official plant records of the company.

The next step in a depreciation study is the estimation of service life statistics from an analysis of past retirement experience. The term *life analysis* is used to describe the activities undertaken in this step to obtain a mathematical description of the forces of retirement acting upon a plant category. The mathematical expressions used to describe these forces are known as survival functions or survivor curves.

Life indications obtained from an analysis of past retirement experience are blended with expectations about the future to obtain an appropriate projection life curve. This step, called *life estimation*, is concerned with predicting the expected remaining life of property units still exposed to the forces of retirement. The amount of weight given to the analysis of historical data will depend upon the extent to which past retirement experience is considered descriptive of the future.

An estimate of the net salvage rate applicable to future retirements is usually obtained from an analysis of the gross salvage and cost of removal realized in the past. An analysis of past experience (including an examination of trends over time) provides a baseline for estimating future salvage and cost of removal. Consideration, however, should be given to events that may cause deviations from the net salvage realized in the past. Among the factors which should be considered are the age of plant retirements; the portion of retirements that will be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the projection life curve; and economic conditions that may warrant greater or lesser weight to be given to the net salvage observed in the past.

A comprehensive depreciation study will also include an analysis of the adequacy of the recorded depreciation reserve. The purpose of such an analysis is to compare the current balance in the recorded reserve with the balance required to achieve the goals and objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized exactly as predicted. The difference between the required (or theoretical) reserve and the recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to extinguish the reserve imbalance.

Although reserve records are typically maintained by various account classifications, the total reserve for a company is the most important measure of the status of the company's depreciation practices and procedures. Differences between the theoretical reserve and the recorded reserve will arise as a normal occurrence when service lives, dispersion patterns and salvage estimates are adjusted in the course of depreciation reviews. Differences will also arise due to plant accounting activity such as transfers and adjustments, which require an identification of reserves at a different level from that maintained in the accounting system. It is appropriate, therefore, and consistent with group depreciation theory, to periodically redistribute recorded reserves among primary accounts based on the most recent estimates of retirement dispersion and salvage. A redistribution of the recorded reserve will provide an initial reserve balance for each primary account consistent with the estimates of retirement dispersion selected to describe mortality characteristics of the accounts and establish a baseline against which future comparisons can be made.

Finally, parameters estimated from service life and net salvage studies are integrated into an appropriate formulation of an accrual rate based upon a selected depreciation system. Three elements are needed to describe a depreciation system. The sub–elements most widely used in constructing a depreciation system are shown in Table 1.

Methods	Procedures	Techniques
Retirement	Total Company	Whole-Life
Compound-Interest	Broad Group	Remaining-Life
Sinking-Fund	Vintage Group	Probable-Life
Straight-Line	Equal-Life Group	
Declining Balance	Unit Summation	
Sum-of-Years'-Digits	Item	
Expensing		
Unit-of-Production		
Net Revenue		

Table 1. Elements of a Depreciation System

These elements (*i.e.*, method, procedure and technique) can be visualized as three dimensions of a cube in which each face describes a variety of sub–elements that can be combined to form a system. A depreciation system is therefore formed by selecting a sub–element from each face such that the system contains one method, one procedure and one technique.

IV. 2006 DEPRECIATION RATE STUDY

Q. DID UNS GAS PROVIDE FOSTER ASSOCIATES PLANT ACCOUNTING DATA FOR CONDUCTING THE 2006 DEPRECIATION STUDY?

A. Yes, they did. The database used in the 2006 study was assembled from three sources. The first source was the database used in conducting a 2002 depreciation study for Citizens Communications Company. The database for the Northern Arizona Gas Division was originally compiled by Citizens and used in its 1993 study. The database had been assembled from a Southern Union Gas Company legacy system that included activity year transactions from inception through December 31, 1991. Foster Associates appended 1992-2001 aged transactions to this database. The 1992–1998 transactions were compiled from annual "CPR Plant Control" reports issued from a Computer Associates plant accounting system. The 1999-2001 transactions were compiled from an SAP system installed in 1999 and populated with age distributions at December 31, 1998.

An unaged database for Santa Cruz Gas Division was compiled by Citizens for all accounts from inception through December 31, 1998. Foster Associates appended unaged transactions for 1999–2001 to this database and initiated an aged transaction database for all accounts beginning in 1999. The resulting database provided age distributions used for accrual computations in the 2002 depreciation study.

The second data source, obtained from Citizens, provided plant and reserve transactions over the period January 1, 2002 through August 31, 2003. This interval is the period of time beyond the end of the database used in conducting the 2002 studies until gas assets were purchased by UNS Gas from Citizens on August 31, 2003. Plant and reserve transactions were coded by Foster Associates and appended to the database used in the 2002 studies.

The third data source was obtained from UNS Gas. Plant and reserve transactions over the period September 1, 2003 through December 31, 2005 were extracted from an Oracle fixed asset system and appended to the database containing transactions through August 31, 2003.

Unlike the 2002 study in which depreciation rates were developed independently for Northern Arizona Gas Division and Santa Cruz Gas Division, the two Citizens divisions were combined in the 2006 study and depreciation rates were developed for the combined plant accounts. Unadjusted Plant History reports produced from the merged database were reconciled to Citizens and UNS Gas ledger reports over the period 1992–2005.

Q. DID FOSTER ASSOCIATES CONDUCT STATISTICAL LIFE STUDIES FOR UNS GAS PLANT AND EQUIPMENT?

A. Yes, we did. As discussed in Attachment REW–2, all plant accounts were analyzed using a technique in which first, second and third degree orthogonal polynomials were fitted to a set of observed retirement ratios. The resulting function can be expressed as a survivorship function, which is numerically integrated to obtain an estimate of the average service life. The smoothed survivorship function is then fitted by a weighted least–squares procedure to the Iowa–curve family to obtain a mathematical description or classification of the dispersion characteristics of the data. Service life indications derived from the statistical analyses were blended with informed judgment and expectations about the future to obtain an appropriate projection life curve for each plant category.

Q. DID FOSTER ASSOCIATES CONDUCT A NET SALVAGE ANALYSIS FOR UNS GAS PLANT AND EQUIPMENT?

A. Yes, we did. A traditional, historical analysis using a five–year moving average of the ratio of realized salvage and removal expense to the associated retirements was used in the study to a) estimate a realized net salvage rate; b) detect the emergence of historical trends; and c) establish a basis for estimating a future net salvage rate.

The average net salvage rate for an account was estimated using direct dollar weighting of historical retirements with the historical net salvage rate, and future retirements (*i.e.*, surviving plant) with the estimated future net salvage rate.

Q. DID FOSTER ASSOCIATES CONDUCT AN ANALYSIS OF RECORDED DEPRECIATION RESERVES?

A. Yes, we did. Statement C of Attachment REW–2 provides a comparison of the computed and recorded reserves for UNS Gas at December 31, 2005. The recorded reserve was $77,127,380 or 26.5 percent of the depreciable plant investment. The corresponding computed reserve is $60,898,596 or 20.9 percent of the depreciable plant investment. A proportionate amount of the measured reserve excess of $16,228,784 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates proposed in the study.

Q. IS FOSTER ASSOCIATES RECOMMENDING A REBALANCING OF DEPRECIATION RESERVES FOR UNS GAS?

A. Yes, we are. Offsetting reserve imbalances attributable to both the passage of time and parameter adjustments recommended in the current study should be realigned among primary accounts to reduce offsetting imbalances and increase depreciation rate stability.

A redistribution of reserves is also needed to eliminate reserve imbalances derived from an initialization of amortization accounting proposed for several general support asset accounts. Amortization periods proposed for these accounts were used to derive theoretical reserves that will replace the recorded reserves and permit a uniform treatment of embedded plant and future additions. Plant older than the proposed amortization periods will be retired from service and future retirements will be posted as each vintage achieves an age equal to the amortization period. Depreciation reserves for the general plant function were redistributed by setting the recorded reserves for the proposed amortization accounts equal to the theoretical reserves derived from the proposed amortization periods and distributing the residual imbalances to the remaining depreciable accounts in the general function.

A redistribution of the recorded reserve for all depreciable plant was achieved by multiplying the calculated reserve for each primary account within a function by the ratio of the function total recorded reserve to the function total calculated reserve. The sum of the redistributed reserves within a function is, therefore, equal to the function total recorded depreciation reserve before the redistribution.

Q. WOULD YOU PLEASE DESCRIBE THE DEPRECIATION SYSTEM CURRENTLY APPROVED BY THE COMMISSION FOR UNS GAS?

A. Current depreciation rates were developed for each primary account in a 2002 study using a depreciation system composed of the straight–line method, vintage group procedure, remaining–life technique. The formulation of an account accrual rate using the currently approved depreciation system is given by:

$$Accrual\ Rate = \frac{1.0 - Reserve\ Ratio - Future\ Net\ Salvage\ Rate}{Remaining\ \ Life}.$$

A remaining–life rate is equivalent to the sum of a whole–life rate and an amortization of any reserve imbalance over the estimated remaining life of a rate category. Stated as an equation, a remaining–life accrual rate is equivalent to

$$Accrual\,Rate = \frac{1.0 - Average\,Net\,Savage\,Rate}{Average\,Life} + \frac{Computed\,Reserve - Recorded\,Reserve}{Remaining\,Life}$$

where both the computed reserve and the recorded reserve are expressed as ratios to the plant in service.

Q. IS FOSTER ASSOCIATES RECOMMENDING A CHANGE IN THE DEPRECIATION SYSTEM FOR UNS GAS?

A. No, we are not. The matching and expense recognition principles of accounting provide that the cost of an asset (or group of assets) should be allocated to operations over an estimate of the economic life of the asset in proportion to the consumption of service potential. It is the opinion of Foster Associates that the objectives of depreciation accounting are adequately achieved using the straight–line method, vintage–group procedure, remaining–life technique.

Q. WOULD YOU PLEASE SUMMARIZE THE DEPRECIATION RATES AND ACCRUALS FOSTER ASSOCIATES RECOMMENDED FOR UNS GAS IN THE 2006 STUDY?

A. Table 2 provides a summary of the changes in annual rates and accruals resulting from adoption of the parameters and depreciation system recommended in the study.

	Accrual Rate			2006 Annualized Accrual		
Function	Present	Proposed	Difference	Present	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Transmission	1.60%	1.54%	-0.06%	$415,845	$400,324	($15,521)
Distribution	2.34%	2.32%	-0.02%	5,764,814	5,718,101	(46,713)
General Plant	12.95%	9.94%	-3.01%	2,362,179	1,813,433	(548,746)
Total	2.94%	2.73%	-0.21%	$8,542,838	$7,931,858	($610,980)

Foster Associates is recommending primary account depreciation rates equivalent to a composite rate of 2.73 percent. Depreciation expense is presently accrued at a composite rate of 2.94 percent. The recommended change in the composite depreciation rate is, therefore, a reduction of 0.21 percentage points.

A continued application of rates currently approved would provide annualized depreciation expense of $8,542,838 compared with an annualized expense of $7,931,858 using the rates developed in the study. The resulting 2006 expense decrease is $610,980. The computed change in the annualized accrual includes a reduction of $728,850 attributable to amortization of a $16,228,784 reserve imbalance.

The remaining portion of the change is attributable to parameter adjustments recommended in the 2006 study.

Of the 35 property accounts included in the 2006 study, Foster Associates is recommending rate reductions for 24 accounts and rate increases for 11 accounts.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

EXHIBIT

REW-1

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Ronald E. White, Ph.D.

Education

1961 - 1964 Valparaiso University
Major: Electrical Engineering

1965 Iowa State University
B.S., Engineering Operations

1968 Iowa State University
M.S., Engineering Valuation
Thesis: The Multivariate Normal Distribution and the Simulated Plant Record Method of Life Analysis

1977 Iowa State University
Ph.D., Engineering Valuation
Minor: Economics
Dissertation: A Comparative Analysis of Various Estimates of the Hazard Rate Associated With the Service Life of Industrial Property

Employment

1996 - Present Foster Associates, Inc.
Executive Vice President

1988 - 1996 Foster Associates, Inc.
Senior Vice President

1979 - 1988 Foster Associates, Inc.
Vice President

1978 - 1979 Northern States Power Company
Assistant Treasurer

1974 - 1978 Northern States Power Company
Manager, Corporate Economics

1972 - 1974 Northern States Power Company
Corporate Economist

1970 - 1972 Iowa State University
Graduate Student and Instructor

1968 - 1970 Northern States Power Company
Valuation Engineer

1965 - 1968 Iowa State University
Graduate Student and Teaching Assistant

Publications

A New Set of Generalized Survivor Tables, Journal of the Society of Depreciation Professionals, October, 1992.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, Journal of the Society of Depreciation Professionals, December, 1989.

Standards for Depreciation Accounting Under Regulated Competition, paper presented at The Institute for Study of Regulation, Rate Symposium, February, 1985.

The Economics of Price-Level Depreciation, paper presented at the Iowa State

University Regulatory Conference, May, 1981.

Depreciation and the Discount Rate for Capital Investment Decisions, paper presented at the National Communications Forum - National Electronics Conference, October 1979.

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Testifying Witness

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Alabama Public Service Commission, Docket No. 20208, General Telephone Company of the South; testimony concerning the equal-life group procedure and remaining-life technique.

Alberta Energy and Utilities Board, Application No. 1250392, Aquila Networks Canada; rebuttal testimony supporting proposed depreciation rates.

Alberta Energy and Utilities Board, Case No. RE95081, Edmonton Power Inc.; rebuttal evidence concerning appropriate depreciation rates.

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Arizona Corporation Commission, Docket No. E–0135A–03–0437, Arizona Public Service Company; rebuttal testimony supporting net salvage rates.

Arizona Corporation Commission, Docket No. E–0135A–05–0816, Arizona Public

Service Company; testimony supporting proposed depreciation rates.

Arizona State Board of Equalization, Docket No. 6302-07-2, Arizona Public Service Company; testimony concerning valuation and assessment of contributions in aid of construction.

California Public Utilities Commission, Case Nos. A.92-06-040, 92-06-042, GTE California Incorporated; rebuttal testimony supporting depreciation study techniques.

California Public Utilities Commission. Docket No. GRC A.05–12–003, Pacific Gas and Electric Company, testimony regarding estimation of net salvage rates.

Public Utilities Commission of the State of Colorado, Application No. 36883-Reopened. U S WEST Communications; testimony concerning equal-life group procedure.

State of Connecticut Department of Public Utility Control, Docket No. 05–03–17, The Southern Connecticut Gas Company; testimony supporting recommended depreciation rates.

Delaware Public Service Commission, Docket No. 81-8, Diamond State Telephone Company; testimony concerning the amortization of inside wiring.

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Idaho Public Utilities Commission, Case No. U-1002-59, General Telephone Company of the Northwest, Inc.; testimony concerning the remaining-life technique and the equal-life group procedure.

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Kentucky Public Service Commission, Case No. 97-224, Jackson Purchase Electric Cooperative Corporation; rebuttal testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 8485, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 7689, Washington Gas Light Company; testimony concerning life analysis and net salvage.

Maryland Public Service Commission, Case No. 8960, Washington Gas Light Company; testimony supporting proposed depreciation rates.

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Michigan Public Service Commission, Case No. U-6587, General Telephone Company of Michigan; testimony concerning use of a theoretical depreciation reserve with the remaining-life technique.

Michigan Public Service Commission, Case No. U-7134, General Telephone Company of Michigan; testimony concerning the equal-life group depreciation procedure.

Minnesota Public Service Commission, Docket No. E-611, Northern States Power Company; testimony concerning rate of return and general financial requirements.

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Public Service Commission of the State of Missouri, Case No. ER-2001-672, Missouri Public Service, a division of Utilicorp United Inc.; surrebuttal testimony regarding computation of income tax expense.

Public Service Commission of the State of Missouri, Case No. TO-82-3, Southwestern Bell Telephone Company; rebuttal testimony concerning the remaining-life technique and the equal-life group procedure.

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Gas Company; rebuttal testimony concerning adequacy of database for conducting depreciation studies.

Public Service Commission of the State of Missouri, Case No. GR-99-315, Laclede Gas Company; rebuttal testimony concerning treatment of net salvage in development of depreciation rates.

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Pennsylvania Public Utility Commission, Docket No. R-80061235, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

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Pennsylvania Public Utility Commission, Docket No. R-811819, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

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Faculty

Depreciation Programs for public utility commissions, companies, and consultants, sponsored by Depreciation Programs, Inc., in cooperation with Western Michigan University. (1980 - 1999)

United States Telephone Association (USTA), Depreciation Training Seminar, November 1999.

Depreciation Advocacy Workshop, a three-day team-training workshop on preparation, presentation, and defense of contested depreciation issues, sponsored by Gilbert Associates, Inc., October, 1979.

Corporate Economics Course, Employee Education Program, Northern States Power Company. (1968 - 1979)

Perspectives of Top Financial Executives, Course No. 5-300, University of Minnesota, September, 1978.

Depreciation Programs for public utility commissions, companies, and consultants, jointly sponsored by Western Michigan University and Michigan Technological University, 1973.

Professional Associations

Advisory Committee to the Institute for Study of Regulation, sponsored by the American University and The University of Missouri-Columbia.

American Economic Association.

American Gas Association - Edison Electric Institute Depreciation Accounting Committee.

Board of Directors, Iowa State Regulatory Conference.

Edison Electric Institute, Energy Analysis Division, Economic Advisory Committee, 1976-1980.

Financial Management Association.

The Institute of Electrical and Electronics Engineers, Inc., Power Engineering Society, Engineering and Planning Economics Working Group.

Midwest Finance Association.

Society of Depreciation Professionals (Founding Member and Chairman, Policy Committee

Moderator

Depreciation Open Forum, Iowa State University Regulatory Conference, May 1991.

The Quantification of Risk and Uncertainty in Engineering Economic Studies, Iowa State University Regulatory Conference, May 1989.

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Speaker

Depreciation Studies for Regulated Utilities, Hydro One Networks, Inc., April 2006.

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Finding the "D" in RCNLD (Valuation Applications of Depreciation), Society of Depreciation Professionals Annual Meeting, September 2001.

Capital Asset and Depreciation Accounting, City of Edmonton Value Engineering Workshop, April 2001.

A Valuation View of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, October 1999.

Capital Recovery in a Changing Regulatory Environment, Pennsylvania Electric Association Financial-Accounting Conference, May 1999.

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Discontinuation of Application of FASB Statement No. 71, Southern Natural Gas Company Accounting Seminar, April 1998.

Forecasting in Depreciation, Society of Depreciation Professionals Annual Meeting, September 1997.

Economic Depreciation In Response to Competitive Market Pricing, 1997 TELUS Depreciation Conference, June 1997.

Valuation of Special Franchise Property, City of New York, Department of Finance Valuation Seminar, March 1997.

Depreciation Implications of FAS Exposure Draft 158-B, 1996 TLG Decommissioning Conference, October 1996.

Why Economic Depreciation?, American Gas Association Depreciation Accounting Committee Meeting, August 1995.

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Annual Meeting, November 1994.

Vintage Depreciation Issues, G & T Accounting and Finance Association Conference, June 1994.

Pricing and Depreciation Strategies for Segmented Markets (Regulated and Competitive), Iowa State Regulatory Conference, May 1990.

Principles and Practices of Depreciation Accounting, Canadian Electrical Association and Nova Scotia Power Electric Utility Regulatory Seminar, December 1989.

Principles and Practices of Depreciation Accounting, Duke Power Accounting Seminar, September 1989.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, GTE Capital Recovery Managers Conference, February 1989.

Valuation Methods for Regulated Utilities, GTE Capital Recovery Managers Conference, January 1988.

Depreciation Principles and Practices for REA Borrowers, NRECA 1985 National Accounting and Finance Conference, September 1985.

Depreciation Principles and Practices for REA Borrowers, Kentucky Association of Electric Cooperatives, Inc., Summer Accountants Association Meeting, June 1985.

Considerations in Conducting a Depreciation Study, NRECA 1984 National Accounting and Finance Conference, October 1984.

Software for Conducting Depreciation Studies on a Personal Computer, United States Independent Telephone Association, September 1984.

Depreciation—An Assessment of Current Practices, NRECA 1983 National Accounting and Finance Conference, September 1983

Depreciation—An Assessment of Current Practices, REA National Field Conference, September 1983.

An Overview of Depreciation Systems, Iowa State Commerce Commission, October 1982.

Depreciation Practices for Gas Utilities, Regulatory Committee of the Canadian Gas Association, September 1981.

Practice, Theory, and Needed Research on Capital Investment Decisions in the Energy Supply Industry, workshop, sponsored by Michigan State University and the Electric Power Research Institute, November 1977.

Depreciation Concepts Under Regulation, Public Utilities Conference, sponsored by The University of Texas at Dallas, July 1976.

Electric Utility Economics, Mid-Continent Area Power Pool, May 1974.

Honors and Awards

The Society of Sigma Xi.

Professional Achievement Citation in Engineering, Iowa State University, 1993.

EXHIBIT

REW-2

Attachment REW–2

2006 Depreciation Rate Study

UNS Gas, Inc.

Prepared by
Foster Associates, Inc.

FOSTER ASSOCIATES INCORPORATED

CONTENTS

General Plant

Account 392.20 – Transportation Equipment C2

May 2006

EXECUTIVE SUMMARY

INTRODUCTION

This report presents findings and recommendations developed in a 2006 Depreciation Rate Study conducted by Foster Associates, Inc. (Foster Associates) for UNS Gas, Inc. (UNS Gas), an operating subsidiary of UniSource Energy Services, Inc. Work on the study commenced in November 2005 and progressed through mid–May 2006, at which time the project was completed.

Foster Associates is a public utility economic consulting firm headquartered in Bethesda, Maryland offering economic research and consulting services on issues and problems arising from governmental regulation of business. Areas of specialization supported by the firm's Fort Myers office include property service–life forecasting, depreciation estimation, and valuation of industrial property.

Foster Associates has undertaken numerous depreciation engagements for both public and privately owned business entities, including detailed statistical life studies, analyses of required net salvage rates, and the selection of depreciation systems that will most nearly achieve the goals of depreciation accounting under the constraints of either government regulation or competitive market pricing. Foster Associates is widely recognized for industry leadership in the development of depreciation systems, life analysis techniques and computer software for conducting depreciation and valuation studies.

Depreciation rates currently used by UNS Gas were adopted pursuant to a Settlement Agreement in Docket No. G–01032A–02–0598 consolidated with Docket Nos. E–01032C–00–0751, E–01933A–02–0914, E–01032C–02–0914 and G–01032A–02–0914 (Order 66028 dated July 3, 2003). The Settlement Agreement between the Joint Applicants and Staff authorized, *inter alia*, UNS Gas to: a) acquire gas assets in Arizona owned and operated by Citizens Communications Company; and b) adopt depreciation rates proposed by Citizens in Docket No. G–01032A–02–0598. Depreciation rates proposed by Citizens were developed in a 2002 depreciation rate study conducted by Foster Associates for Northern Arizona Gas Division and Santa Cruz Gas Division.

The principal findings and recommendations of the 2006 UNS Gas Depreciation Study are summarized in the Statements section of this report. Statement A provides a comparative summary of present and proposed annual depreciation rates for each rate category. Statement B provides a comparison of present and proposed annual depreciation accruals. Statement C provides a comparison of computed, recorded and rebalanced depreciation reserves for each rate category. Statement D provides a summary of the components used to obtain a weighted–average net salvage rate for each plant account. Statement E provides a comparative summary of present and proposed parameters and statistics including projection life, projection curve, average service life, average remaining life, and average and future net salvage rates.

SCOPE OF REVIEW

The principal activities undertaken in conducting the 2006 study included:

- Collection of plant and reserve data;
- Discussions with UNS Gas plant accounting personnel;
- Estimation of projection lives and retirement dispersion patterns;
- Analysis of gross salvage and cost of removal;
- Analysis and redistribution of recorded depreciation reserves; and
- Development of recommended accrual rates for each rate category.

DEPRECIATION SYSTEM

A depreciation rate is formed by combining the elements of a depreciation system. A depreciation system is composed of a method, a procedure and a technique. Depreciation rates currently approved for UNS Gas were developed from a system composed of the straight–line method, vintage group procedure, remaining–life technique.

The matching and expense recognition principles of accounting provide that the cost of an asset (or group of assets) should be allocated to operations over an estimate of the economic life of the asset in proportion to the consumption of service potential. It is the opinion of Foster Associates that the objectives of depreciation accounting are being achieved through the use of the vintage group procedure which distinguishes service lives among vintages, and the remaining–life technique which provides cost apportionment over the estimated weighted–average remaining life of a rate category. Although the emergence of economic factors such as competition and incentive forms of regulation may eventually encourage abandonment of the straight–line method, no attempt was made in the current study to address these concerns.

In addition to revised depreciation rates, amortization accounting is recommended for selected general support asset categories in which the unit cost of equipment is small in relation to the cost of maintaining detailed accounting records. Depreciation accounting would be replaced with amortization accounting for the asset categories summarized in Table 1.

Account Number	Description	Amortization Period
A	B	C
302.00	Office Furniture and Equipment	25 yrs.
303.00	Miscellaneous Intangible Plant	15 yrs.
391.00	Office Furniture and Equipment	22 yrs.
391.20	Computer Equipment - Desktop PCs	5 yrs.
393.00	Stores Equipment	35 yrs.
394.00	Tools, Shop and Garage Equipment	25 yrs.
395.00	Laboratory Equipment	9 yrs.
397.00	Communication Equipment	15 yrs.
398.00	Miscellaneous Equipment	25 yrs.

Table 1. Proposed Amortization Accounts

Recommended amortization periods were used to derive theoretical reserves that will replace recorded reserves and permit a uniform treatment of both embedded plant and future additions. Upon approval of the proposed change in accounting, plant older than the proposed amortization period will be retired from service and future retirements will be posted as each vintage achieves an age equal to the amortization period. Reserve imbalances created by the recommended amortization periods were eliminated by a systematic redistribution of recorded reserves. Reserve imbalances for the proposed amortization accounts were distributed to the remaining depreciable accounts in the General plant function. Net salvage realized in the future would be netted against current–year vintage additions.

RECOMMENDED DEPRECIATION RATES

Table 2 provides a summary of the changes in annual rates and accruals resulting from an application of the parameters and depreciation system recommended for UNS Gas operations.

Function	Accrual Rate			2006 Annualized Accrual		
	Present	Proposed	Difference	Present	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Transmission	1.60%	1.54%	-0.06%	$415,845	$400,324	($15,521)
Distribution	2.34%	2.32%	-0.02%	5,764,814	5,718,101	(46,713)
General Plant	12.95%	9.94%	-3.01%	2,362,179	1,813,433	(548,746)
Total	2.94%	2.73%	-0.21%	$8,542,838	$7,931,858	($610,980)

Table 2. Gas Operations

The composite accrual rate recommended for gas operations is 2.73 percent. The current equivalent rate is 2.94 percent. The recommended change in the composite rate is a reduction of 0.21 percentage points.

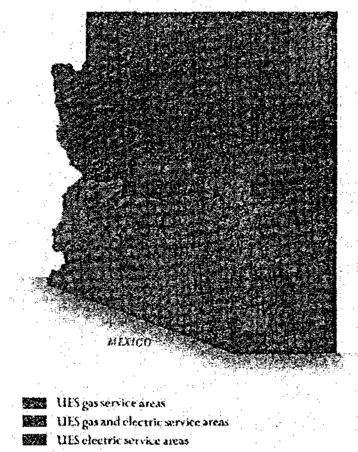
A continued application of current rates would produce annualized depreciation expense of $8,542,838 compared with an annualized expense of $7,931,858 using the proposed rates. The resulting 2006 expense decrease is $610,980. The computed change in the annualized accrual includes a reduction of $728,850 attributable to amortization of a $16,228,784 reserve imbalance. The remaining portion of the change is attributable to parameter adjustments recommended in the 2006 study.

Of the 35 primary accounts included in the 2006 study, Foster Associates is recommending rate reductions for 24 plant accounts and rate increases for 11 accounts.

COMPANY PROFILE

GENERAL

UNS Gas is the second largest and fastest growing gas company in Arizona, serving a large geographic area in Northern Arizona, and a smaller area in the southern part of the state. These counties served comprise approximately 50 percent of Arizona's geographic area. Customer growth in 2005 was 4 percent, which is more than twice the industry average. During 2005, UNS Gas sold or transported over 17.6 billion cubic feet of gas and is one of the lowest cost energy suppliers in the state.



The rates that UNS Gas is allowed to charge for its distribution services are regulated by the Arizona Corporation Commission (ACC).

GAS UTILITY OPERATIONS

UNS Gas has approximately 2,711 miles of distribution main lines and 143,244 service lines in its current distribution system. Since UNS Gas acquired the Citizens system in 2003, the Company has installed approximately 180 miles of distribution main lines and 10,183 service lines.

The distribution system in Arizona is primarily new and well maintained. Approximately 50 percent of the system is steel and the remainder is plastic pipe. UNS Gas has an on-going cathodic protection program for its steel distribution system. As a result, corrosion has all but been eliminated, substantially reducing the replacement of those systems. In addition, UNS Gas has a continual leak survey program and implemented a more stringent classification than prescribed by minimal safety standards. This approach has greatly reduced the risk of hazard and significantly reduced the unaccounted gas, which is reported annually.

The gas distribution system is interconnected with two separate interstate pipeline systems and operates 30 interconnect points. The delivery pressures are set contractually, and range from 200 pounds per square inch gauged ("PSIG") to 1000 PSIG.

CUSTOMER BASE

Ninety percent of UNS Gas customers are residential and nine percent are commercial, with transportation and industrial customers making up the remaining one percent. UNS Gas provides gas to Griffith Energy Plant, a 600-megawatt combined-cycle gas turbine electric generation facility in Mohave County. Griffith is UNS Gas's single largest customer, with annual usage of over 80 MMBtu.

UNS Gas provides natural gas service to 131,493 customers in portions of Coconino, Mohave, Navajo, and Yavapai counties. This service area includes the towns and cities of Flagstaff, Kingman, Prescott, Sedona, Show Low, Cottonwood, Clarkdale, Village of Oak Creek, Verde Village, Pinetop-Lakeside, and Camp Verde.

UNS Gas serves 7,323 customers in Santa Cruz County. Santa Cruz County covers 1,236 square miles and is located near the Mexico border in the southern part of the state. Communities that UNS Gas serves in this area include Nogales, Tubac, Patagonia, Kino Springs, and Rio Rico. Citizens' largest customer in the area is the hospital. Other commercial customers include a sterilizer of medical supplies, hotels, restaurants, and schools.

STUDY PROCEDURE

INTRODUCTION

The purpose of a depreciation study is to analyze the mortality characteristics, net salvage rates and adequacy of the depreciation accrual and recorded depreciation reserve for each rate category. This study provides the foundation and documentation for recommended changes in depreciation rates used by UNS Gas. The proposed rates are subject to approval by the Arizona Corporation Commission.

SCOPE

The steps involved in conducting a depreciation study can be grouped into five major tasks:

- Data Collection;
- Life Analysis and Estimation;
- Net Salvage Analysis;
- Depreciation Reserve Analysis; and
- Development of Accrual Rates.

The scope of the 2006 study undertaken for UNS Gas included a consideration of each of these tasks as described below.

DATA COLLECTION

The minimum database required to conduct a statistical life study consists of a history of vintage year additions and unaged activity year retirements, transfers and adjustments. These data must be appropriately adjusted for transfers, sales and other plant activity that would otherwise bias the measured service life of normal retirements. The age distribution of surviving plant for unaged data can be estimated by distributing the plant in service at the beginning of the study year to prior vintages in proportion to the theoretical amount surviving from a projection or survivor curve identified in the life study. The statistical methods of life analysis used to examine unaged plant data are known as *semi–actuarial techniques*.

A far more extensive database is required to apply statistical methods of life analysis known as *actuarial techniques*. Plant data used in an actuarial life study most often include age distributions of surviving plant at the beginning of a study year and the vintage year, activity year, and dollar amounts associated with normal retirements, reimbursed retirements, sales, abnormal retirements, transfers, corrections, and extraordinary adjustments over a series of prior activity years. An actuarial database may include age distributions of surviving plant at the beginning of the earliest activity year, rather than at the beginning of the study year. Plant additions, however, must be included in a database containing an opening age distribution to derive aged survivors at the beginning of the study year. All activity year transactions with vintage year identification are coded and stored in a data file.

The data are processed by a computer program and transaction summary reports are created in a format reconcilable to the Company's official plant records. The availability of such detailed information is dependent upon an accounting system that supports aged property records. The Continuing Property Record (CPR) system currently used for UNS Gas provides aged transactions over the period August 31, 2003 through December 31, 2005 for all plant accounts.

The database used in the 2006 study was assembled by Foster Associates from three sources. The first source was the database used in conducting a 2002 depreciation study for Citizens Communications Company. The database for the Northern Arizona Gas Division was originally compiled by Citizens and used in its 1993 study. The database had been assembled from a Southern Union Gas Company legacy system that included activity year transactions from inception through December 31, 1991. The database provided aged transactions for all plant accounts with the exception of Account 381.00 (Meters) and Account 383.00 (House Regulators), which were unaged. Foster Associates appended 1992-2001 aged transactions to this database and initiated aged transaction activity for the Meters and House Regulator accounts beginning in 1992. The 1992–1998 transactions were compiled from annual “CPR Plant Control” reports issued from a Computer Associates plant accounting system. The 1999-2001 transactions were compiled from an SAP system installed in 1999 and populated with age distributions at December 31, 1998. Foster Associates reconciled the 1992–2001 activity year total transactions to Citizens’ ledger reports and the age distributions of surviving plant were reconciled to CPR age distributions at December 31, 2001.

An unaged database for Santa Cruz Gas Division was compiled by Citizens for all accounts from inception through December 31, 1998. Foster Associates appended unaged transactions for 1999–2001 to this database and reconciled the 1978–2001 activity year total transactions to Citizens’ ledger reports. The unaged database provided the basis for parameter analysis and estimation in the 2002 study. Additionally, Foster Associates initiated an aged transaction database for all accounts beginning in 1999. The aged database was reconciled to Citizens’ ledger reports for activity years 1999-2001 and to CPR age distributions at December 31, 2001. The resulting database provided age distributions used for accrual computations in the 2002 depreciation study.

The second data source, obtained from Citizens, provided plant and reserve transactions over the period January 1, 2002 through August 31, 2003. This interval is the period of time beyond the end of the database used in conducting the 2002 studies until gas assets were purchased by UNS Gas from Citizens on August 31, 2003. Plant and reserve transactions were coded by Foster Associates and appended to the database used in the 2002 studies.

The third data source was obtained from UNS Gas. Plant and reserve transactions over the period September 1, 2003 through December 31, 2005 were extracted from an Oracle fixed asset system and appended to the database containing transactions through August 31, 2003.

Unlike the 2002 study in which depreciation rates were developed independently for Northern Arizona Gas Division and Santa Cruz Gas Division, the two Citizens divisions were combined in the 2006 study and depreciation rates were developed for the combined plant accounts. Aged plant transactions initiated for the Santa Cruz division in 1999 were merged into the aged history for the Northern Arizona division using a transfer code (Code 33) assigned to the Santa Cruz age distributions of surviving plant at December 31, 1999. Post–1999 Santa Cruz transactions were included with corresponding Northern Arizona transactions in the merged database. Unadjusted Plant History reports produced from the merged database were reconciled to Citizens and UNS Gas ledger reports over the period 1992–2005.

LIFE ANALYSIS AND ESTIMATION

Life analysis and life estimation are terms used to describe a two–step procedure for estimating the mortality characteristics of a plant category. The first step (*i.e.*, life analysis) is largely mechanical and primarily concerned with history. Statistical techniques are used in this step to obtain a mathematical description of the forces of retirement acting upon a plant category and an estimate of a service life known as the *projection life* of the account. Mathematical expressions used to describe these life characteristics are known as *survival functions* or *survivor curves*.

The second step (*i.e.*, life estimation) is concerned with predicting the expected remaining life of property units still exposed to forces of retirement. It is a process of blending the results of a life analysis with informed judgment (including expectations about the future) to obtain an appropriate projection life and curve. The amount of weight given to the life analysis will depend upon the extent to which past retirement experience is considered descriptive of the future.

The analytical methods used in a life analysis are broadly classified as actuarial and semi–actuarial techniques. Actuarial techniques can be applied to plant accounting records that reveal the age of a plant asset at the time of its retirement from service. Stated differently, each property unit must be identifiable by date of installation and age at retirement. Semi–actuarial techniques can be used to derive service life and dispersion estimates when age identification of retirements is not maintained or readily available.

An actuarial life analysis program designed and developed by Foster Associates was used in the 2006 study. The first step in an actuarial analysis involves a systematic treatment of the available data for the purpose of constructing an observed life table. A complete life table contains the life history of a group of property units installed during the same accounting period and various probability relationships derived from the data. A life table is arranged by age–intervals (usually defined as one year) and shows the number of units (or dollars) entering and leaving each age–interval and probability relationships associated with this activity. A life table minimally contains the age of each survivor and the age of each retirement from a group of property units installed in a given accounting year.

A life table can be constructed in any one of at least five alternative methods. The annual–rate or retirement–rate method was used in the 2006 study. The mechanics of the annual–rate method require the calculation of a series of ratios obtained by dividing the number of units (or dollars) surviving at the beginning of an age interval into the number of units (or dollars) retired during the same interval. This ratio (or set of ratios) is commonly referred to as retirement ratios. The cumulative proportion surviving is obtained by multiplying the retirement ratio for each age–interval by the proportion of the original group surviving at the beginning of that interval and subtracting this product from the proportion surviving at the beginning of the same interval. The annual–rate method is applied to multiple groups or vintages by combining the retirements and/or survivors of like ages for each vintage included in the analysis.

The second step in an actuarial analysis involves graduating or smoothing the observed life table and fitting the smoothed series to a family of survival functions. The functions used in the 2006 study are the Iowa–type curves which are mathematically described by the Pearson frequency curve family. Observed life tables were smoothed by a weighted least–squares procedure in which first, second and third degree polynomials were fitted to the observed retirement ratios. The resulting function can be expressed as a survivorship function which is numerically integrated to obtain an estimate of average service life. The smoothed survivorship function is then fitted by a weighted least–squares procedure to the Iowa–curve family to obtain a mathematical description or classification of the dispersion characteristics of the data.

The set of computer programs used in the UNS Gas study provides multiple rolling–band and shrinking–band analyses of an account. Observation bands are defined for a "retirement era" which restricts the analysis to retirement activity of all vintages represented by survivors at the beginning of a selected era. In a rolling–band analysis, a year of retirement experience is added to each successive retirement band and the earliest year from the preceding band is dropped. A shrinking–band analysis begins with the total retirement experience available and the earliest year from the preceding band is dropped for each successive band. Rolling and shrinking band analyses are used to detect the emergence of trends in the behavior of the dispersion and average service life.

Options available in the actuarial life analysis program include the width and location of both placement and observation bands; the interval of years included in a selected rolling or shrinking band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated. The program also provides tabular and graphics output as an aid in the analysis and algorithms for calculating depreciation rates and accruals.

While actuarial and semi–actuarial statistical methods are well–suited to an analysis of plant categories containing a large number of homogeneous units (*e.g.*, poles and services), theses methods are not well–suited to plant categories composed of major items of plant that will most likely be retired as a single unit. Property units retired from an integrated system prior to the retirement of the entire facility are more properly viewed as interim retirements that will be replaced in order to maintain the integrity of the system. Plant facilities may also be added to the existing system (*i.e.*, interim additions) to expand or enhance its productive capacity without extending the service life of the present system. A proper depreciation rate can be developed for an integrated system using a life–span method. All plant accounts were treated as full mortality categories in the UNS Gas study.

NET SALVAGE ANALYSIS

Depreciation rates designed to achieve the goals and objectives of depreciation accounting will normally include a parameter for future net salvage and a variable for average net salvage that reflects both realized and future net salvage rates.

An estimate of the net salvage rate applicable to future retirements is most often obtained from an analysis of gross salvage and removal expense realized in the past. An analysis of past experience (including an examination of trends over time) provides an appropriate basis for estimating future salvage and cost of removal. However, consideration should also be given to events that may cause deviations from net salvage realized in the past. Among the factors that should be considered are the age of plant retirements; the portion of retirements likely to be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the projection life curve; and economic conditions that may warrant greater or lesser weight to be given to the net salvage observed in the past.

Special consideration should also be given to the treatment of insurance proceeds and other forms of third–party reimbursements credited to the depreciation reserve. A properly conducted net salvage study will exclude such activity from the estimate of future parameters and include the activity in the computation of realized and average net salvage rates.

Five–year moving averages of the ratio of realized salvage and cost of removal to the associated retirements were used in the 2006 study to a) estimate a realized net salvage rate; b) detect the emergence of historical trends; and c) establish a basis for estimating a future net salvage rate.

Average net salvage rates were estimated using direct dollar–weighting of historical retirements with the historical net salvage rates, and future retirements (*i.e.*, surviving plant) with the estimated future net salvage rates. The computation of the estimated average net salvage rate for each rate category is shown in Statement D.

DEPRECIATION RESERVE ANALYSIS

The purpose of a depreciation reserve analysis is to compare the current level of the recorded reserve with the level required to achieve the goals or objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized as predicted. The difference between the required depreciation reserve and the recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to gradually extinguish the reserve imbalance.

Unlike a recorded reserve which represents the net amount of depreciation expense charged to previous periods of operations, a theoretical reserve is a measure of the implied reserve requirement at the beginning of a study year if the timing of future retirements and net salvage is in exact conformance with a survivor curve chosen to predict the probable life of plant units still exposed to the forces of retirement. Stated differently, a theoretical depreciation reserve is the difference between the recorded cost of plant presently in service and the sum of the depreciation expense and net salvage that will be charged in the future if retirements are distributed over time according to a specified retirement frequency distribution.

The survivor curve used in the calculation of a theoretical depreciation reserve is intended to describe forces of retirement that will be operative in the future. However, retirements caused by forces such as accidents, physical deterioration and changing technology seldom, if ever, remain stable over time. It is unlikely, therefore, that a probability or retirement frequency distribution can be identified that will accurately describe the age of plant retirements over the complete life cycle of a vintage. It is for this reason that depreciation rates should be reviewed periodically and adjusted for observed or expected changes in the parameters chosen to describe the underlying forces of mortality.

Although reserve records are commonly maintained by various account classifications, the total reserve for a company is the most important measure of the status of the company's depreciation practices. If a company has not previously conducted statistical life studies or considered retirement dispersion in setting depreciation rates, it is likely that some accounts will be over–depreciated and other accounts will be under–depreciated relative to a calculated theoretical reserve. Differences between theoretical reserves and recorded reserves also will arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of depreciation reviews. It is appropriate, therefore, and consistent with group depreciation theory to periodically redistribute or rebalance the total recorded reserve among the various primary accounts based upon the most recent estimates of retirement dispersion and net salvage rates.

A redistribution of recorded reserves is considered appropriate for UNS Gas at this time. Offsetting reserve imbalances attributable to both the passage of time and parameter adjustments recommended in the current study should be realigned among primary accounts to reduce offsetting imbalances and increase depreciation rate stability.

A redistribution of reserves is also needed to eliminate reserve imbalances derived from an initialization of amortization accounting proposed for the general support asset accounts summarized in Table 1. Amortization periods proposed for these accounts were used to derive theoretical reserves that will replace the associated recorded reserves and permit a uniform treatment of embedded plant and future additions. Plant older than the proposed amortization periods will be retired from service and future retirements will be posted as each vintage achieves an age equal to the amortization period. Depreciation reserves for the general plant function were redistributed by setting the recorded reserves for the proposed amortization accounts equal to the theoretical reserves derived from the proposed amortization periods and distributing the residual imbalances to the remaining depreciable accounts in the general function.

A redistribution of the recorded reserve for all depreciable plant was achieved by multiplying the calculated reserve for each primary account within a function by the ratio of the function total recorded reserve to the function total calculated reserve. The sum of the redistributed reserves within a function is, therefore, equal to the function total recorded depreciation reserve before the redistribution.

Statement C provides a comparison of the computed, recorded and rebalanced reserves at December 31, 2005. The recorded reserve was $77,127,380 or 26.5 percent of the depreciable plant investment. The corresponding computed reserve is $60,898,596 or 20.9 percent of the depreciable plant investment. A proportionate amount of the measured reserve excess of $16,228,784 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates proposed in this review.

DEVELOPMENT OF ACCRUAL RATES

The goal or objective of depreciation accounting is cost allocation over the economic life of an asset in proportion to the consumption of service potential. Ideally, the cost of an asset—which represents the cost of obtaining a bundle of service units—should be allocated to future periods of operation in proportion to the amount of service potential expended during an accounting interval. The service potential of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other non–cash expenses) or cash inflows attributable to the use of that asset alone.

Cost allocation in proportion to the consumption of service potential is often approximated by the use of depreciation methods employing time rather than net revenue as the apportionment base. Examples of time–based methods include sinking–fund, straight–line, declining balance, and sum–of–the–years' digits. The advantage of a time–based method is that it does not require an estimate of the remaining amount of service capacity an asset will provide or the amount of capacity actually consumed during an accounting interval. Using a time–based allocation method, however, does not change the goal of depreciation accounting. If it is reasonable to predict that the net revenue pattern of an asset will either decrease or increase over time, then an accelerated or decelerated time–based method should be used to approximate the rate at which service potential is actually consumed.

The time period over which the cost of an asset will be allocated to operations is determined by the combination of a procedure and a technique. A depreciation procedure describes the level of grouping or sub–grouping of assets within a plant category. The broad group, vintage group, equal–life group, and item (or unit) are a few of the more widely used procedures. A depreciation technique describes the life statistic used in a depreciation system. Whole–life and remaining–life (or expectancy) are the most common techniques.

The first step in the development of an accrual rate, therefore, is the selection of an appropriate method, procedure and technique. Depreciation rates recommended in this study were developed using a system composed of the straight–line method, vintage group procedure, remaining–life technique. It is the opinion of Foster Associates that this system will remain appropriate for UNS Gas, provided depreciation studies are conducted periodically and parameters are routinely adjusted to reflect changing operating conditions. Although the emergence of economic factors such as restructuring, bypass and performance based regulation may ultimately encourage abandonment of the straight–line method, no attempt was made in the current study to address this concern.

It is also the opinion of Foster Associates that the adoption of amortization accounting proposed in this study is consistent with the goals and objectives of depreciation accounting derived from the matching and expense recognition principles of accounting. Adoption of amortization accounting for the general plant categories will relieve UNS Gas of the burden to maintain detailed plant records for numerous plant items in which the unit cost is small in relation to the cost of tracking the disposition of the assets.

STATEMENTS

INTRODUCTION

This section provides a comparative summary of depreciation rates, annual depreciation accruals, recorded and computed depreciation reserves, and present and proposed service life and net salvage statistics recommended for UNS Gas. The content of these statements is briefly described below.

- Statement A provides a comparative summary of present and proposed annual depreciation rates using the vintage group procedure, remaining–life technique.
- Statement B provides a comparison of present and proposed annualized 2006 depreciation accruals using the vintage group procedure, remaining–life technique.
- Statement C provides a comparison of recorded, computed and redistributed reserves for each rate category at December 31, 2005.
- Statement D provides a summary of the components used to obtain a weighted average net salvage rate for each rate category.
- Statement E provides a comparative summary of present and proposed parameters including projection life, projection curve, average service life, average remaining life and average and future net salvage rates.

Present depreciation accruals shown on Statement B are the product of the plant investment (Column B) and present depreciation rates (Column D) shown on Statement A. These are the effective rates used by UNS Gas for the mix of investments recorded on December 31, 2005. Proposed depreciation accruals shown on Statement B are the product of the plant investment and proposed depreciation rates (Column H) shown on Statement A. Proposed accrual rates are given by:

$$\textit{Accrual Rate} = \frac{\textit{1.0 – Reserve Ratio – Future Net Salvage Rate}}{\textit{Remaining Life}}.$$

This formulation of the accrual rate is equivalent to

$$\textit{Accrual Rate} = \frac{\textit{1.0 – Average Net Salvage}}{\textit{Average Life}} + \frac{\textit{Computed Reserve – Recorded Reserve}}{\textit{Remaining Life}}$$

where *Average Net Salvage*, *Computed Reserve* and *Recorded Reserve* are expressed in percent.

UNS GAS, INC. Statement A

Comparison of Present and Proposed Accrual Rates
Present: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

	Present			Proposed			
Account Description	Rem. Life	Net Salvage	Accrual Rate	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H
TRANSMISSION PLANT							
365.20 Rights of Way				59.57		17.75%	1.38%
366.00 Structures and Improvements			7.27%	56.50		12.39%	1.55%
367.00 Mains		-10.0%	1.57%	60.21	-10.0%	17.65%	1.53%
369.00 Meas. and Reg. Station Equipment		-5.0%	1.61%	54.10	-5.0%	21.94%	1.54%
371.00 Other Equipment			5.00%	24.50		38.95%	2.49%
Total Transmission Plant			1.60%	58.78	-9.2%	18.38%	1.54%
DISTRIBUTION PLANT							
374.20 Rights of Way				20.74		80.66%	0.93%
374.30 Easements				49.38		13.23%	1.76%
375.00 Structures and Improvements			1.77%	17.21		66.82%	1.93%
376.00 Mains		-20.0%	2.08%	46.64	-20.0%	23.46%	2.07%
378.00 Meas. and Reg. Station Equip. - General		-30.0%	3.03%	34.34	-30.0%	27.99%	2.97%
379.00 Meas. and Reg. Station Equip. - City Gate			2.39%	35.26		16.86%	2.36%
380.00 Services		-50.0%	2.85%	42.82	-50.0%	29.35%	2.82%
381.00 Meters			2.05%	27.49		44.46%	2.02%
382.00 Meter Installations			2.42%	33.80		20.15%	2.36%
383.00 House Regulators			2.63%	25.92		33.67%	2.56%
384.00 House Regulator Installations			2.83%	32.23		9.77%	2.80%
385.00 Industrial Meas. and Reg. Station Equip.		-40.0%	2.61%	33.54	-40.0%	49.32%	2.70%
387.00 Other Work Equipment			3.15%	22.62		31.81%	3.01%
Total Distribution Plant			2.34%	42.85	-26.6%	26.37%	2.32%
GENERAL PLANT							
Depreciable							
389.20 Rights of Way				18.75		7.54%	4.93%
390.00 Structures and Improvements			3.75%	19.00		7.05%	4.89%
392.10 Transportation Equipment - C1			25.00%	5.62	10.0%	7.32%	14.71%
392.20 Transportation Equipment - C2			25.00%	4.78	10.0%	4.56%	17.87%
392.30 Transportation Equipment - C3			25.00%	3.71	10.0%	5.87%	22.68%
392.40 Transportation Equipment - C4			25.00%	6.59	10.0%	4.07%	13.04%
392.50 Transportation Equipment - C5			25.00%	7.48	10.0%	1.50%	11.83%
396.00 Power Operated Equipment		10.0%	5.69%	7.71	10.0%	9.10%	10.49%
Total Depreciable			19.35%	6.25	7.9%	5.54%	13.60%
Amortizable							
302.00 Franchises and Consents			3.95%		← 25 Year Amortization →		
303.00 Miscellaneous Intangible Plant			5.84%		← 15 Year Amortization →		
391.00 Office Furniture and Equipment			4.24%		← 22 Year Amortization →		
391.20 Computer Equipment - Desktop PCs			13.89%		← 5 Year Amortization →		
393.00 Stores Equipment			3.03%		← 35 Year Amortization →		
394.00 Tools, Shop and Garage Equipment			3.64%		← 25 Year Amortization →		
395.00 Laboratory Equipment			9.29%		← 9 Year Amortization →		
397.00 Communication Equipment			6.11%		← 15 Year Amortization →		
398.00 Miscellaneous Equipment			4.01%		← 25 Year Amortization →		
Total Amortizable			9.11%	3.74		60.89%	7.75%
Total General Plant			12.95%	4.68	-23.2%	40.11%	9.94%
TOTAL GAS UTILITY			2.94%	32.35	-23.2%	26.52%	2.73%

UNS GAS, INC. Statement B

Comparison of Present and Proposed Accruals
Present: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/05 Plant Investment	2006 Annualized Accrual Present	Proposed	Difference
A	B	C	D	E=D-C
TRANSMISSION PLANT				
365.20 Rights of Way	$102,606		$1,416	$1,416
366.00 Structures and Improvements	16,853	1,225	261	(964)
367.00 Mains	22,159,137	347,898	339,035	(8,863)
369.00 Meas. and Reg. Station Equipment	3,574,097	57,543	55,041	(2,502)
371.00 Other Equipment	183,581	9,179	4,571	(4,608)
Total Transmission Plant	$26,036,274	$415,845	$400,324	($15,521)
DISTRIBUTION PLANT				
374.20 Rights of Way	$25,111		$234	$234
374.30 Easements	104,951		1,847	1,847
375.00 Structures and Improvements	10,947	194	211	17
376.00 Mains	144,881,931	3,013,544	2,999,056	(14,488)
378.00 Meas. and Reg. Station Equip. - General	2,012,458	60,977	59,770	(1,207)
379.00 Meas. and Reg. Station Equip. - City Gate	2,334,480	55,794	55,094	(700)
380.00 Services	71,193,117	2,029,004	2,007,646	(21,358)
381.00 Meters	12,936,282	265,194	261,313	(3,881)
382.00 Meter Installations	6,624,931	160,323	156,348	(3,975)
383.00 House Regulators	2,565,287	67,467	65,671	(1,796)
384.00 House Regulator Installations	1,135,504	32,135	31,794	(341)
385.00 Industrial Meas. and Reg. Station Equip.	1,212,929	31,657	32,749	1,092
387.00 Other Work Equipment	1,540,463	48,525	46,368	(2,157)
Total Distribution Plant	$246,578,391	$5,764,814	$5,718,101	($46,713)
GENERAL PLANT				
Depreciable				
389.20 Rights of Way	$166,402		$8,204	$8,204
390.00 Structures and Improvements	1,270,787	47,655	62,141	14,486
392.10 Transportation Equipment - C1	1,009,671	252,418	148,523	(103,895)
392.20 Transportation Equipment - C2	1,450,023	362,506	259,119	(103,387)
392.30 Transportation Equipment - C3	906,907	226,727	205,687	(21,040)
392.40 Transportation Equipment - C4	924,281	231,070	120,526	(110,544)
392.50 Transportation Equipment - C5	729,468	182,367	86,296	(96,071)
396.00 Power Operated Equipment	389,812	22,180	40,891	18,711
Total Depreciable	$6,847,351	$1,324,923	$931,387	($393,536)
Amortizable				
302.00 Franchises and Consents	$383,215	$15,137	$13,489	($1,648)
303.00 Miscellaneous Intangible Plant	900,696	52,601	48,187	(4,414)
391.00 Office Furniture and Equipment	1,231,765	52,227	55,429	3,202
391.20 Computer Equipment - Desktop PCs	5,155,361	716,080	557,295	(158,785)
393.00 Stores Equipment	111,289	3,372	2,916	(456)
394.00 Tools, Shop and Garage Equipment	1,628,265	59,269	63,502	4,233
395.00 Laboratory Equipment	730,667	67,879	65,249	(2,630)
397.00 Communication Equipment	985,332	60,204	65,623	5,419
398.00 Miscellaneous Equipment	261,520	10,487	10,356	(131)
Total Amortizable	$11,388,110	$1,037,256	$882,046	($155,210)
Total General Plant	$18,235,461	$2,362,179	$1,813,433	($548,746)
TOTAL GAS UTILITY	$290,850,126	$8,542,838	$7,931,858	($610,980)

UNS GAS, INC.
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2005

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
TRANSMISSION PLANT							
365.20 Rights of Way	$102,606	$0		$8,572	8.35%	$18,211	17.75%
366.00 Structures and Improvements	16,853	4,135	24.54%	983	5.83%	2,089	12.39%
367.00 Mains	22,159,137	4,010,960	18.10%	1,840,773	8.31%	3,910,916	17.65%
369.00 Meas. and Reg. Station Equipment	3,574,097	727,035	20.34%	369,026	10.33%	784,034	21.94%
371.00 Other Equipment	183,581	44,626	24.31%	33,657	18.33%	71,507	38.95%
Total Transmission Plant	$26,036,274	$4,786,757	18.38%	$2,253,010	8.65%	$4,786,757	18.38%
DISTRIBUTION PLANT							
374.20 Rights of Way	$25,111			$15,647	62.31%	$20,255	80.66%
374.30 Easements	104,951	0		10,724	10.22%	13,883	13.23%
375.00 Structures and Improvements	10,947	9,767	89.22%	5,650	51.62%	7,315	66.82%
376.00 Mains	144,881,931	32,928,845	22.73%	26,254,116	18.12%	33,986,611	23.46%
378.00 Meas. and Reg. Station Equip. - General	2,012,458	944,721	46.94%	435,091	21.62%	563,237	27.99%
379.00 Meas. and Reg. Station Equip. - City Gate	2,334,480	821,369	35.18%	304,047	13.02%	393,596	16.86%
380.00 Services	71,193,117	22,263,336	31.27%	16,139,155	22.67%	20,892,541	29.35%
381.00 Meters	12,936,282	4,875,854	37.69%	4,442,888	34.34%	5,751,430	44.46%
382.00 Meter Installations	6,624,931	1,053,528	15.90%	1,031,060	15.56%	1,334,733	20.15%
383.00 House Regulators	2,565,287	1,063,986	41.48%	667,136	26.01%	863,624	33.67%
384.00 House Regulator Installations	1,135,504	94,352	8.31%	85,684	7.55%	110,921	9.77%
385.00 Industrial Meas. and Reg. Station Equip.	1,212,929	598,470	49.34%	462,157	38.10%	598,274	49.32%
387.00 Other Work Equipment	1,540,463	372,256	24.17%	378,567	24.57%	490,064	31.81%
Total Distribution Plant	$246,578,391	$65,026,484	26.37%	$50,231,923	20.37%	$65,026,484	26.37%
GENERAL PLANT							
Depreciable							
389.20 Rights of Way	$166,402			$48,931	29.41%	$12,552	7.54%
390.00 Structures and Improvements	1,270,787	521,758	41.06%	349,006	27.46%	89,531	7.05%
392.10 Transportation Equipment - C1	1,009,671	665,456	65.91%	287,944	28.52%	73,866	7.32%
392.20 Transportation Equipment - C2	1,450,023	452,081	31.18%	257,858	17.78%	66,149	4.56%
392.30 Transportation Equipment - C3	906,907	257,865	28.43%	207,635	22.89%	53,265	5.87%
392.40 Transportation Equipment - C4	924,281	284,002	30.73%	146,614	15.86%	37,611	4.07%
392.50 Transportation Equipment - C5	729,468	101,346	13.89%	42,674	5.85%	10,947	1.50%
396.00 Power Operated Equipment	389,812	289,124	74.17%	138,250	35.47%	35,465	9.10%
Total Depreciable	$6,847,351	$2,571,632	37.56%	$1,478,911	21.60%	$379,387	5.54%

UNS GAS, INC.
Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2005

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
Amortizable							
302.00 Franchises and Consents	$383,215	$197,465	51.53%	$198,464	51.79%	$198,464	51.79%
303.00 Miscellaneous Intangible Plant	900,696	340,154	37.77%	392,962	43.63%	392,962	43.63%
391.00 Office Furniture and Equipment	1,231,765	(102,058)	-8.29%	201,457	16.36%	201,457	16.36%
391.20 Computer Equipment - Desktop PCs	5,155,361	3,349,924	64.98%	4,598,032	89.19%	4,598,032	89.19%
393.00 Stores Equipment	111,289	25,675	23.07%	31,411	28.22%	31,411	28.22%
394.00 Tools, Shop and Garage Equipment	1,628,265	523,919	32.18%	604,885	37.15%	604,885	37.15%
395.00 Laboratory Equipment	730,667	288,256	39.45%	454,766	62.24%	454,766	62.24%
397.00 Communication Equipment	985,332	30,282	3.07%	381,197	38.69%	381,197	38.69%
398.00 Miscellaneous Equipment	261,520	88,888	33.99%	71,579	27.37%	71,579	27.37%
Total Amortizable	$11,388,110	$4,742,508	41.64%	$6,934,753	60.89%	$6,934,753	60.89%
Total General Plant	$18,235,461	$7,314,140	40.11%	$8,413,664	46.14%	$7,314,140	40.11%
TOTAL GAS UTILITY	$290,850,126	$77,127,380	26.52%	$60,898,596	20.94%	$77,127,380	26.52%

UNS GAS, INC.
Average Net Salvage

Statement D

Account Description	Plant Investment Additions	Plant Investment Retirements	Plant Investment Survivors	Salvage Rate Realized	Salvage Rate Future	Net Salvage Realized	Net Salvage Future	Net Salvage Total	Average Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
TRANSMISSION PLANT									
365.20 Rights of Way	$102,606		$102,606						
366.00 Structures and Improvements	16,853		16,853						
367.00 Mains	22,514,429	355,292	22,159,137		-10.0%		(2,215,914)	(2,215,914)	-9.8%
369.00 Meas. and Reg. Station Equipment	3,600,481	26,384	3,574,097	-0.5%	-5.0%	(132)	(178,705)	(178,837)	-5.0%
371.00 Other Equipment	183,581		183,581						
Total Transmission Plant	$26,417,950	$381,676	$26,036,274		-9.2%	($132)	($2,394,619)	($2,394,750)	-9.1%
DISTRIBUTION PLANT									
374.20 Rights of Way	$25,111		$25,111						
374.30 Easements	104,951		104,951						
375.00 Structures and Improvements	10,947		10,947						
376.00 Mains	146,630,613	1,748,682	144,881,931	-15.4%	-20.0%	(269,297)	(28,976,386)	(29,245,683)	-19.9%
378.00 Meas. and Reg. Station Equip. - General	2,164,493	152,035	2,012,458	-13.3%	-30.0%	(20,221)	(603,737)	(623,958)	-28.8%
379.00 Meas. and Reg. Station Equip. - City Gate	2,583,304	248,824	2,334,480						
380.00 Services	73,187,197	1,994,080	71,193,117	-7.0%	-50.0%	(139,586)	(35,596,559)	(35,736,144)	-48.8%
381.00 Meters	13,346,999	410,717	12,936,282	-0.1%		(411)		(411)	
382.00 Meter Installations	6,625,166	235	6,624,931	-597.5%		(1,404)		(1,404)	
383.00 House Regulators	2,727,655	162,368	2,565,287						
384.00 House Regulator Installations	1,135,597	93	1,135,504	-4846.4%		(4,507)		(4,507)	-0.4%
385.00 Industrial Meas. and Reg. Station Equip.	1,380,761	167,832	1,212,929	-16.8%	-40.0%	(28,196)	(485,172)	(513,367)	-37.2%
387.00 Other Work Equipment	1,579,588	39,125	1,540,463						
Total Distribution Plant	$251,502,382	$4,923,991	$246,578,391	-9.4%	-26.6%	($463,621)	($65,661,854)	($66,125,475)	-26.3%
GENERAL PLANT									
Depreciable									
389.20 Rights of Way	$770,032	$603,630	$166,402						
390.00 Structures and Improvements	5,939,521	4,668,734	1,270,787	-0.1%		(4,669)		(4,669)	-0.1%
392.10 Transportation Equipment - C1	1,296,706	287,035	1,009,671	6.2%	10.0%	17,796	100,967	118,763	9.2%
392.20 Transportation Equipment - C2	3,944,715	2,494,692	1,450,023	8.7%	10.0%	217,038	145,002	362,041	9.2%
392.30 Transportation Equipment - C3	1,338,331	431,424	906,907	7.6%	10.0%	32,788	90,691	123,479	9.2%
392.40 Transportation Equipment - C4	939,686	15,405	924,281	9.0%	10.0%	1,386	92,428	93,815	10.0%
392.50 Transportation Equipment - C5	729,468		729,468		10.0%		72,947	72,947	10.0%
396.00 Power Operated Equipment	704,490	314,678	389,812	10.2%	10.0%	32,097	38,981	71,078	10.1%
Total Depreciable	$15,662,949	$8,815,598	$6,847,351	3.4%	7.9%	$296,437	$541,016	$837,454	5.3%

UNS GAS, INC.
Average Net Salvage

Statement D

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
Amortizable									
302.00 Franchises and Consents	$383,215		$383,215						
303.00 Miscellaneous Intangible Plant	900,696		900,696						
391.00 Office Furniture and Equipment	4,963,951	3,732,186	1,231,765						
391.20 Computer Equipment - Desktop PCs	5,252,474	97,113	5,155,361						
393.00 Stores Equipment	124,371	13,082	111,289						
394.00 Tools, Shop and Garage Equipment	2,096,121	467,856	1,628,265						
395.00 Laboratory Equipment	773,310	42,643	730,667						
397.00 Communication Equipment	1,547,910	562,578	985,332						
398.00 Miscellaneous Equipment	284,057	22,537	261,520						
Total Amortizable	$16,326,105	$4,937,995	$11,388,110						
Total General Plant	$31,989,054	$13,753,593	$18,235,461	2.2%	3.0%	$296,437	$541,016	$837,454	2.6%
TOTAL GAS UTILITY	$309,909,386	$19,059,260	$290,850,126	-0.9%	-23.2%	($167,316)	($67,515,456)	($67,682,772)	-21.8%

UNS GAS, INC.
Present and Proposed Parameters
Vintage Group Procedure

Statement E

	Present Parameters						Proposed Parameters					
Account Description	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
TRANSMISSION PLANT												
365.20 Rights of Way							65.00	R3	65.00	59.57		
366.00 Structures and Improvements							60.00	R4	60.00	56.50		
367.00 Mains	65.00	R3				-10.0	65.00	R3	65.01	60.21	-9.8	-10.0
369.00 Meas. and Reg. Station Equipment	60.00	R4				-5.0	60.00	R4	60.00	54.10	-5.0	-5.0
371.00 Other Equipment							30.00	S6	30.00	24.50		
Total Transmission Plant									63.75	58.78	-9.1	-9.2
DISTRIBUTION PLANT												
374.20 Rights of Way							55.00	L5	55.03	20.74		
374.30 Easements	35.00	R4					55.00	L5	55.00	49.38		
375.00 Structures and Improvements	35.00	R4					35.00	R4	35.57	17.21		
376.00 Mains	55.00	L5				-20.0	55.00	L5	54.89	46.64	-19.9	-20.0
378.00 Meas. and Reg. Station Equip. - General	40.00	SC				-30.0	40.00	SC	40.81	34.34	-28.8	-30.0
379.00 Meas. and Reg. Station Equip. - City Gate	40.00	SC					40.00	SC	40.54	35.26		
380.00 Services	50.00	R2.5				-50.0	50.00	R2.5	50.04	42.82	-48.8	-50.0
381.00 Meters	40.00	R5					40.00	R5	41.87	27.49		
382.00 Meter Installations	40.00	R5					40.00	R5	40.03	33.80		
383.00 House Regulators	35.00	R5					35.00	R5	35.03	25.92		
384.00 House Regulator Installations	35.00	R5					35.00	R5	35.00	32.23	-0.4	
385.00 Industrial Meas. and Reg. Station Equip.	45.00	R1.5				-40.0	45.00	R1.5	45.16	33.54	-37.2	-40.0
387.00 Other Work Equipment	30.00	S6					30.00	S6	29.99	22.62		
Total Distribution Plant									51.05	42.85	-26.3	-26.6
GENERAL PLANT												
Depreciable												
389.20 Rights of Way							25.00	SC	26.56	18.75		
390.00 Structures and Improvements	25.00	SC					25.00	SC	26.22	19.00	-0.1	
392.10 Transportation Equipment - C1							8.00	L1.5	8.30	5.62	9.2	10.0
392.20 Transportation Equipment - C2							6.00	L2	6.01	4.78	9.2	10.0
392.30 Transportation Equipment - C3							5.00	S5	5.02	3.71	9.2	10.0
392.40 Transportation Equipment - C4							8.00	S4	8.00	6.59	10.0	10.0
392.50 Transportation Equipment - C5							8.00	S4	8.00	7.48	10.0	10.0
396.00 Power Operated Equipment	12.00	L2				10.0	12.00	L2	12.71	7.71	10.1	10.0
Total Depreciable									8.19	6.25	5.3	7.9

UNS GAS, INC.
Present and Proposed Parameters
Vintage Group Procedure

Statement E

Account Description	Present Parameters P-Life/ AYFR	Present Parameters Curve Shape	Present Parameters VG ASL	Present Parameters Rem. Life	Present Parameters Avg. Sal.	Present Parameters Fut. Sal.	Proposed Parameters P-Life/ AYFR	Proposed Parameters Curve Shape	Proposed Parameters VG ASL	Proposed Parameters Rem. Life	Proposed Parameters Avg. Sal.	Proposed Parameters Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Amortizable												
302.00 Franchises and Consents							25.00	SQ	25.00	13.68		
303.00 Miscellaneous Intangible Plant							15.00	SQ	15.00	10.53		
391.00 Office Furniture and Equipment	22.00	R1.5					22.00	SQ	22.00	18.59		
391.20 Computer Equipment - Desktop PCs	5.00	R4					5.00	SQ	5.00	1.00		
393.00 Stores Equipment	35.00	SC					35.00	SQ	35.00	27.40		
394.00 Tools, Shop and Garage Equipment	25.00	L1					25.00	SQ	25.00	16.12		
395.00 Laboratory Equipment	9.00	S4					9.00	SQ	9.00	4.23		
397.00 Communication Equipment	15.00	L2					15.00	SQ	15.00	9.20		
398.00 Miscellaneous Equipment	25.00	S0					25.00	SQ	25.00	18.32		
Total Amortizable									8.20	3.74		
Total General Plant									8.20	4.68	-21.8	-23.2
TOTAL GAS UTILITY									38.98	32.35	-21.8	-23.2

ANALYSIS

INTRODUCTION

This section provides an explanation of the supporting schedules developed in the UNS Gas depreciation study to estimate appropriate projection curves, projection lives and net salvage statistics for each rate category. The form and content of the schedules developed for an account depend upon the method of analysis adopted for the category.

This section also includes examples of the supporting schedules developed for Account 392.20 (Transportation Equipment C2). Documentation for all other plant accounts is contained in the study work papers. Supporting schedules developed in the UNS Gas study include:

Schedule A – Generation Arrangement;

Schedule B – Age Distribution;

Schedule C – Plant History;

Schedule D – Actuarial Life Analysis;

Schedule E – Graphics Analysis; and

Schedule F – Historical Net Salvage Analysis.

The format and content of these schedules are briefly described below.

SCHEDULE A – GENERATION ARRANGEMENT

The purpose of this schedule is to obtain appropriate weighted–average life statistics for a rate category. The weighted–average remaining–life is the sum of Column H divided by the sum of Column I. The weighted average life is the sum of Column C divided by the sum of Column I.

It should be noted that the generation arrangement does not include parameters for net salvage. Computed Net Plant (Column H) and Accruals (Column I) must be adjusted for net salvage to obtain a correct measurement of theoretical reserves and annualized depreciation accruals.

The following table provides a description of each column in the generation arrangement.

Column	Title	Description
A	Vintage	Vintage or placement year of surviving plant.
B	Age	Age of surviving plant at beginning of study year.
C	Surviving Plant	Actual dollar amount of surviving plant.
D	Average Life	Estimated average life of each vintage. This statistic is the sum of the realized life and the unrealized life, which is the product of the remaining life (Column E) and the theoretical proportion surviving.
E	Remaining Life	Estimated remaining life of each vintage.
F	Net Plant Ratio	Theoretical net plant ratio of each vintage.
G	Allocation Factor	A pivotal ratio which determines the amortization period of the difference between the recorded and computed reserve.
H	Computed Net Plant	Plant in service less theoretical reserve for each vintage.
I	Accrual	Ratio of computed net plant (Column H) and remaining life (Column E).

Table 3. Generation Arrangement

SCHEDULE B – AGE DISTRIBUTION

This schedule provides the age distribution and realized life of surviving plant shown in Column C of the Generation Arrangement (Schedule A). The format of the schedule depends upon the availability of either aged or unaged data. Derived additions for vintage years older than the earliest activity year in an account for unaged data are obtained from the age distribution of surviving plant at the beginning of the earliest activity year. The amount surviving from these vintages is shown in Column D. The realized life (Column G) is derived from the dollar years of service provided by a vintage over the period of years the vintage has been in service. Plant additions for vintages older than the earliest activity year in an account are represented by the opening balances shown in Column D.

The computed proportion surviving (Column D) for unaged is derived from a computed mortality analysis. The average service life displayed in the title block is the life statistic derived for the most recent activity year, given the derived age distribution at the start of the year and the specified retirement dispersion. The realized life (Column F) is obtained by finding the slope of an SC retirement dispersion, which connects the computed survivors of a vintage (Column E) to the recorded vintage addition (Column B). The realized life is the area bounded by the SC dispersion, the computed proportion surviving and the age of the vintage.

SCHEDULE C – PLANT HISTORY

An Unadjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Activity year totals for unaged data are obtained from a transaction file without vintage identification. Information displayed in the unadjusted plant history is consistent with regulated investments reported internally by the Company.

An Adjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company with sales, transfers, and adjustments appropriately aged for depreciation study purposes. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Ageing of adjusting transactions is achieved using transaction codes that identify an adjusting year associated with the dollar amount of a transaction. Adjusting transactions processed in the adjusted plant history are not aged in the Company's records or in the unadjusted plant history.

SCHEDULE D – ACTUARIAL LIFE ANALYSIS

These schedules provide a summary of the dispersion and life indications obtained from an actuarial life analysis for a specified placement band. The observation band (Column A) is specified to produce either a rolling–band or a shrinking–band analysis depending upon the movement of the end points of the band. The degree of censoring (or point of truncation) of the observed life table is shown in Column B for each observation band. The estimated average service life, best fitting Iowa dispersion, and a statistical measure of the goodness of fit are shown for each degree polynomial (First, Second, and Third) fitted to the estimated hazard rates. Options available in the analysis include the width and location of both the placement and observation bands; the interval of years included in a selected rolling or shrinking band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated.

The estimated average service lives (Columns C, F, and I) are flagged with an asterisk if negative hazard rates are indicated by the fitted polynomial. All negative hazard rates are set equal to zero in the calculation of the graduated survivor curve. The Conformance Index (Columns E, H, and K) is the square root of the mean sum–of–squared differences between the graduated survivor curve and the best fitting Iowa curve. A Conformance Index of zero would indicate a perfect fit.

SCHEDULE E – GRAPHICS ANALYSIS

This schedule provides a graphics plot of a) the observed proportion surviving for a selected placement and observation band; b) the statistically best fitting Iowa dispersion and derived average service life; and c) the projection curve and projection life selected to describe future forces of mortality.

The graphics analysis also provides a plot of the observed hazard rates and graduated hazard function for a selected placement and observation band. The estimator of the hazard rates and weighting used in fitting orthogonal polynomials to the observed data are displayed in the title block of the displayed graph.

SCHEDULE F – HISTORICAL NET SALVAGE ANALYSIS

This schedule provides a moving average analysis of the ratio of realized net salvage (Column I) to the associated retirements (Column B). The schedule also provides a moving average analysis of the components of net salvage related to retirements. The ratio of gross salvage to retirements is shown in Column D and the ratio of cost of removal to retirements is shown in Column G.

UNS GAS, INC.
General Plant
Depreciable
Account: 392.20 Transportation Equipment - C2

Dispersion: 6 - L2
Procedure: Vintage Group

Generation Arrangement

Vintage	December 31, 2005 Age	December 31, 2005 Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2005	0.5	311,307	6.00	5.50	0.9173	1.0000	285,552	51,881
2004	1.5	1,141,566	6.01	4.57	0.7614	1.0000	869,239	190,006
2003	2.5	(2,850)	6.04	3.76	0.6223	1.0000	(1,774)	(472)
Total	1.3	$1,450,023	6.01	4.78	0.7952	1.0000	$1,153,018	$241,415

UNS GAS, INC.
General Plant
Depreciable
Account: 392.20 Transportation Equipment - C2

Age Distribution

Vintage	Age as of 12/31/2005	Derived Additions	1949 Opening Balance	Experience to 12/31/2005 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2005	0.5	311,307		311,307	1.0000	0.5000
2004	1.5	1,141,566		1,141,566	1.0000	1.5000
2003	2.5	(2,850)		(2,850)	1.0000	2.5000
2001	4.5	442,902			0.0000	4.0000
2000	5.5	170,859			0.0000	4.6958
1998	7.5	459,468			0.0000	7.0000
1997	8.5	340,424			0.0000	6.3453
1991	14.5	3,499			0.0000	11.0000
1990	15.5	14,956			0.0000	12.0000
1988	17.5	5,175			0.0000	14.0000
1986	19.5	67,507			0.0000	10.7027
1982	23.5	9,529			0.0000	19.0000
1981	24.5	67,781			0.0000	6.7167
1980	25.5	22,229			0.0000	8.0000
1979	26.5	62,138			0.0000	6.2379
1978	27.5	82,482			0.0000	7.4506
1977	28.5	22,285			0.0000	8.8125
1976	29.5	42,556			0.0000	5.9559
1975	30.5	42,524			0.0000	7.4437
1974	31.5	45,220			0.0000	7.1208
1973	32.5	30,658			0.0000	7.1650
1972	33.5	50,257			0.0000	7.0972
1971	34.5	69,175			0.0000	8.8108
1970	35.5	16,802			0.0000	4.9563
1969	36.5	45,261			0.0000	4.4639
1968	37.5	23,873			0.0000	4.7111
1967	38.5	29,721			0.0000	7.4632
1966	39.5	30,795			0.0000	5.0401
1965	40.5	57,816			0.0000	6.0901
1964	41.5	40,896			0.0000	6.5445
1963	42.5	25,356			0.0000	4.8087
1962	43.5	15,780			0.0000	6.2887
1961	44.5	4,879			0.0000	3.5802
1960	45.5	20,885			0.0000	4.5790
1959	46.5	26,535			0.0000	5.8378
1958	47.5	26,043			0.0000	6.2800
1957	48.5	22,779			0.0000	5.4232
1956	49.5	4,215			0.0000	6.4973

UNS GAS, INC.
General Plant
Depreciable
Account: 392.20 Transportation Equipment - C2

Age Distribution

Vintage	Age as of 12/31/2005	Derived Additions	1949 Opening Balance	Experience to 12/31/2005 Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1955	50.5	2,322			0.0000	6.0000
1954	51.5	3,695			0.0000	6.0000
1952	53.5	1,743			0.0000	8.0000
1951	54.5	14,157			0.0000	9.0067
1950	55.5	10,282			0.0000	10.5681
1949	56.5	19,234			0.0000	36.0000
Total		$3,944,715		$1,450,023	0.3676	

UNS GAS, INC.
General Plant
Depreciable
Account: 392.20 Transportation Equipment - C2

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1949		19,234			19,234
1950	19,234	10,282			29,516
1951	29,516	14,157			43,673
1952	43,673	1,743			45,416
1953	45,416				45,416
1954	45,416	3,695			49,111
1955	49,111	2,322			51,433
1956	51,433	4,215			55,648
1957	55,648	22,779			78,427
1958	78,427	26,043			104,470
1959	104,470	26,535	13,983		117,022
1960	117,022	20,885	14,333		123,574
1961	123,574	4,879	4,466		123,987
1962	123,987	15,780	7,849		131,918
1963	131,918	25,356	31,386		125,888
1964	125,888	40,896	20,491		146,293
1965	146,293	57,816	37,867		166,242
1966	166,242	30,795	15,899		181,138
1967	181,138	29,721	16,319		194,540
1968	194,540	23,873	16,816		201,597
1969	201,597	45,261	33,613		213,245
1970	213,245	16,802	16,489		213,558
1971	213,558	69,175	40,869		241,864
1972	241,864	50,257	51,991		240,130
1973	240,130	30,658	31,053		239,735
1974	239,735	45,220	37,565		247,390
1975	247,390	42,524	25,345		264,569
1976	264,569	42,556			307,125
1977	307,125	22,285	30,575		298,835
1978	298,835	82,484	31,884		349,435
1979	349,435	62,138	40,894		370,679
1980	370,679	22,224	16,987		375,916
1981	375,916	67,781	32,639		411,058
1982	411,058		53,897		357,161
1983	357,161		66,449		290,712
1984	290,712		90,653		200,059
1985	200,059		46,534		153,525
1986	153,525	25,275	16,336		162,464
1987	162,464	1,203	27,433		136,234
1988	136,234		79,964		56,270

UNS GAS, INC.
General Plant
Depreciable
Account: 392.20 Transportation Equipment - C2

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1989	56,270	1,187	29,795		27,662
1990	27,662		11,980		15,682
1991	15,682	3,094		(7,242)	11,534
1992	11,534				11,534
1993	11,534		18,777		(7,242)
1994	(7,242)	1,330		7,242	1,330
1995	1,330	10,559			11,889
1996	11,889				11,889
1997	11,889	577,033		19,773	608,696
1998	608,696	520,012			1,128,708
1999	1,128,708	27,211	4,053	99,119	1,250,985
2000	1,250,985	688,746	53,878		1,885,854
2001	1,885,854	823,339	42,227		2,666,966
2002	2,666,966	(27,840)	138,927		2,500,199
2003	2,500,199			(1,255,722)	1,244,477
2004	1,244,477	494,576			1,739,054
2005	1,739,054	955,446	1,244,477		1,450,023

UNS GAS, INC.
General Plant
Depreciable
Account: 392.20 Transportation Equipment - C2

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1949		26,048			26,048
1950	26,048	10,282			36,330
1951	36,330	14,157			50,487
1952	50,487	1,743			52,230
1953	52,230				52,230
1954	52,230	3,695			55,925
1955	55,925	2,322			58,247
1956	58,247	4,215			62,462
1957	62,462	22,779			85,241
1958	85,241	26,043			111,284
1959	111,284	26,535	13,983		123,836
1960	123,836	20,885	14,333		130,388
1961	130,388	4,879	4,466		130,801
1962	130,801	15,780	7,849		138,732
1963	138,732	25,356	31,386		132,702
1964	132,702	40,896	20,491		153,107
1965	153,107	57,816	37,867		173,056
1966	173,056	30,795	15,899		187,952
1967	187,952	29,721	16,319		201,354
1968	201,354	23,873	16,816		208,411
1969	208,411	45,261	33,613		220,059
1970	220,059	16,802	16,489		220,372
1971	220,372	69,175	40,869		248,678
1972	248,678	50,257	51,991		246,944
1973	246,944	30,658	31,053		246,549
1974	246,549	45,220	37,565		254,204
1975	254,204	42,524	25,345		271,383
1976	271,383	42,556			313,939
1977	313,939	27,950	30,575		311,314
1978	311,314	88,264	31,884		367,694
1979	367,694	62,138	40,894		388,938
1980	388,938	22,423	16,987		394,375
1981	394,375	76,330	32,639		438,066
1982	438,066		53,897		384,169
1983	384,169		66,449		317,720
1984	317,720		90,653		227,067
1985	227,067		46,534		180,533
1986	180,533	34,809	16,336		199,007
1987	199,007	1,071	27,433		172,645
1988	172,645		79,964		92,681

UNS GAS, INC.
General Plant
Depreciable
Account: 392.20 Transportation Equipment - C2

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
1989	92,681	(34,581)	29,795		28,305
1990	28,305		11,980		16,325
1991	16,325	3,499		(17,052)	2,772
1992	2,772				2,772
1993	2,772		18,777		(16,005)
1994	(16,005)	21,103		(9,953)	(4,855)
1995	(4,855)	10,559			5,704
1996	5,704				5,704
1997	5,704	577,033			582,738
1998	582,738	520,012			1,102,750
1999	1,102,750	19,660	4,053	99,119	1,217,476
2000	1,217,476	688,746	53,878		1,852,344
2001	1,852,344	823,339	42,227		2,633,456
2002	2,633,456		138,927		2,494,529
2003	2,494,529	(2,850)		(1,250,052)	1,241,627
2004	1,241,627	1,141,566			2,383,193
2005	2,383,193	311,307	1,244,477		1,450,023

UNS GAS, INC.
General Plant
Depreciable
Account: 392.20 Transportation Equipment - C2

T-Cut: None
Placement Band: 1949-2005
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1965-1969	0.0	7.0	O3	17.94	5.4	L2*	3.43	5.2	L2*	3.89
1966-1970	0.0	15.9	O4*	20.51	8.6	L0.5*	4.84	6.9	L1.5*	5.64
1967-1971	9.4	9.6	O4*	13.27	6.9	L2*	6.22	6.4	L2*	5.54
1968-1972	7.6	6.7	O4*	13.19	6.1	L2*	5.61	5.9	L2*	5.37
1969-1973	3.5	5.7	O4*	13.76	5.7	L2*	3.24	5.6	L2*	3.32
1970-1974	3.7	5.7	O3	13.94	5.6	L2*	3.68	5.5	L2*	3.76
1971-1975	1.8	5.5	O3	14.94	5.5	L2*	3.39	5.4	L2*	3.94
1972-1976	2.4	7.7	O3	15.62	6.2	L2*	4.48	6.1	L2*	4.65
1973-1977	4.8	9.7	O3	17.29	7.0	L2*	6.30	7.0	L2*	5.84
1974-1978	0.0	10.0	O3	14.88	7.4	L2*	5.37	7.4	L2*	5.20
1975-1979	0.0	10.6	O3	15.21	8.0	L2*	5.11	8.0	L2*	4.91
1976-1980	0.0	12.3	O3	15.46	9.4	L1.5*	6.74	9.2	L1.5*	6.63
1977-1981	0.0	10.2	O3	13.92	8.3	L2*	5.82	8.3	L2*	5.85
1978-1982	0.0	9.4	O3	14.00	8.0	L2*	3.78	8.0	L2*	3.81
1979-1983	0.0	8.2	O3	14.05	7.6	L2*	3.96	7.6	L2*	4.06
1980-1984	0.0	6.5	O3	15.28	7.1	L3*	4.09	7.0	L3*	4.25
1981-1985	0.1	5.6	O3	15.21	7.0	L3*	4.01	6.9	L3*	4.45
1982-1986	0.0	5.3	O3	16.03	7.1	L3*	4.01	7.0	L3*	4.10
1983-1987	0.0	4.9	O3	15.91	7.2	L2*	3.19	7.2	L2*	3.00
1984-1988	0.0	3.9	O3	19.87	7.0	L3*	2.89	7.0	L3*	2.89
1985-1989	0.0	4.4	O3	18.64	7.4	L3*	2.93	7.4	S1.5*	2.74
1986-1990	0.0	3.0	O4	20.49	7.1	L3*	3.16	7.1	L3*	3.28
1987-1991	2.0	2.0	O4	24.60	5.2	L1*	7.83	6.4	L3*	3.59
1988-1992	0.6	0.9	O4*	30.92	9.1	S6*	16.82	3.8	L0.5*	15.58
1989-1993	-1333.6	0.3	SC*	345.45	8.8	L3*	368.44	6.1	L2*	356.36
1990-1994	-1333.6	30.5	L5*	485.01	11.3	L3*	454.78	8.5	L1.5*	444.24
1991-1995	21.4	31.3	L5*	53.16	12.3	L4*	25.72	14.3	O3*	13.68
1992-1996	100.0				No Retirements					
1993-1997	100.0				No Retirements					
1994-1998	100.0				No Retirements					
1995-1999	89.0	15.3	L1.5*	27.55	18.2	R5*	6.50	18.1	S5*	6.77
1996-2000	81.5	15.6	L0.5	24.20	47.1	O4*	44.90	39.0	O4*	44.34
1997-2001	0.0	9.8	L2*	35.73	11.1	S1.5	28.19	12.2	R2.5	21.28
1998-2002	0.0	8.7	L2*	18.60	9.0	S1*	16.74	9.0	S1*	16.89
1999-2003	0.0	9.6	L2*	18.38	9.9	S1.5	15.40	10.1	S1.5*	14.73
2000-2004	0.0	10.2	L2*	15.85	10.2	R2.5	13.28	10.4	R2.5	12.18
2001-2005	0.0	5.6	S1.5*	6.63	5.6	S1.5*	6.52	5.8	S2*	5.01

UNS GAS, INC.
General Plant
Depreciable
Account: 392.20 Transportation Equipment - C2

Schedule D
Page 1 of 1

T-Cut: None
Placement Band: 1949-2005
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
1965-2005	0.0	6.5	O2	9.30	6.3	L2*	3.65	6.0	L2*	3.65
1967-2005	0.0	6.5	O2	9.29	6.3	L2*	3.61	6.0	L2*	3.68
1969-2005	0.0	6.4	O2	9.21	6.3	L2*	3.52	6.0	L2*	3.67
1971-2005	0.0	6.4	O2	9.14	6.2	L2*	3.49	6.0	L2*	3.72
1973-2005	0.0	6.5	O2	9.07	6.2	L2*	3.49	6.0	L2*	3.75
1975-2005	0.0	6.5	O2	8.92	6.2	L2*	3.49	6.0	L2*	3.79
1977-2005	0.0	6.4	O2	8.63	6.1	L2*	3.41	6.0	L2*	3.71
1979-2005	0.0	6.3	O2	8.31	6.1	L2*	3.44	6.0	L2*	3.76
1981-2005	0.0	6.2	L0	8.06	6.0	L2*	3.62	5.9	L2*	3.91
1983-2005	0.0	6.1	L0	7.44	5.9	L2*	3.67	5.8	L2*	3.93
1985-2005	0.0	6.1	L1	6.27	5.9	L2*	3.77	5.8	L2*	3.94
1987-2005	-0.1	6.6	L1	7.51	6.3	L2*	4.71	6.1	L2*	4.65
1989-2005	-1.2	6.6	L1	7.35	6.2	L2*	5.07	6.1	L2*	5.03
1991-2005	-2.2	6.4	L1.5*	6.36	6.2	L2*	5.10	6.1	L2*	5.12
1993-2005	-2.2	6.3	L2*	5.66	6.1	L2*	4.97	6.0	L2*	5.01
1995-2005	-2.7	6.3	L2*	8.12	6.1	L2*	7.57	6.1	L2*	7.30
1997-2005	-3.2	6.3	L2*	8.21	6.1	L2*	7.65	6.2	L2*	7.40
1999-2005	0.0	5.9	L2*	5.94	5.7	L2*	6.40	5.8	S1.5*	5.26
2001-2005	0.0	5.6	S1.5*	6.63	5.6	S1.5*	6.52	5.8	S2*	5.01
2003-2005	0.0	5.0	S1.5*	13.72	5.1	S1.5	15.72	4.6	L1.5*	15.79
2005-2005	0.0	3.1	S1*	23.09	2.7	S3	29.64	2.5	L4	33.78

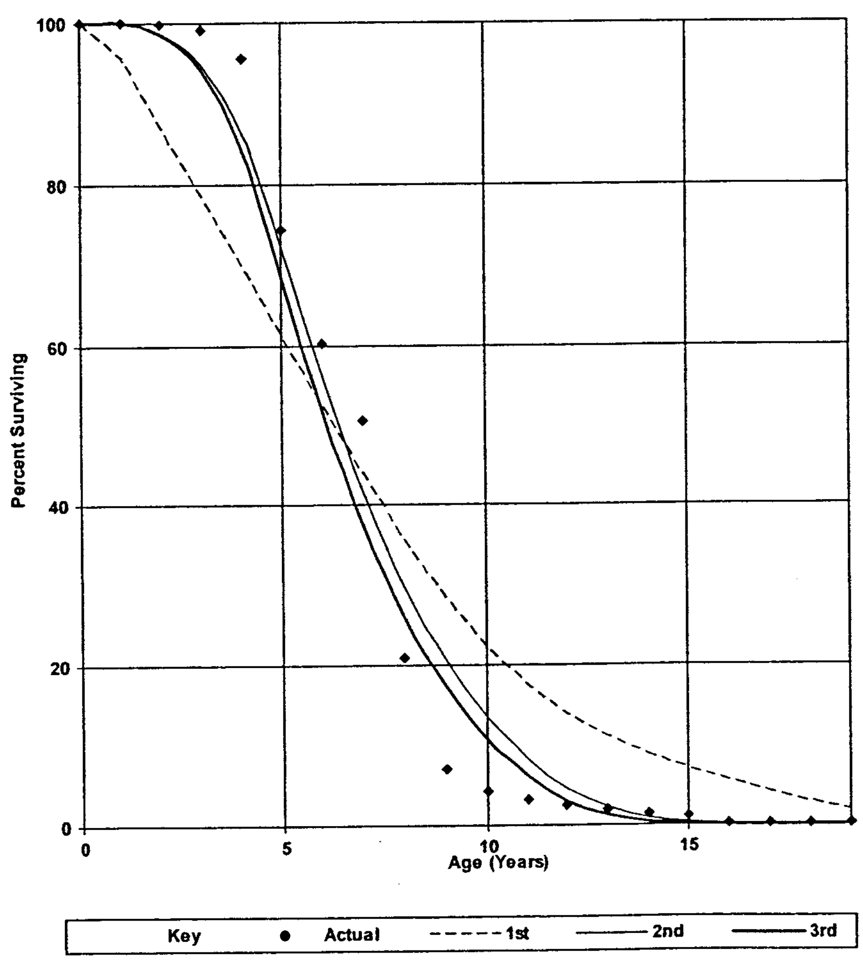
UNS GAS, INC.
General Plant
Depreciable
Account: 392.20 Transportation Equipment - C2

T-Cut: None

Placement Band: 1949-2005 Observation Band: 1965-2005
Hazard Function: Proportion Retired
Weighting: Exposures

Graphics Analysis

1st: 6.5-O2 2nd: 6.3-L2 3rd: 6.0-L2



UNS GAS, INC. Schedule E

General Plant

Depreciable

Account: 392.20 Transportation Equipment - C2

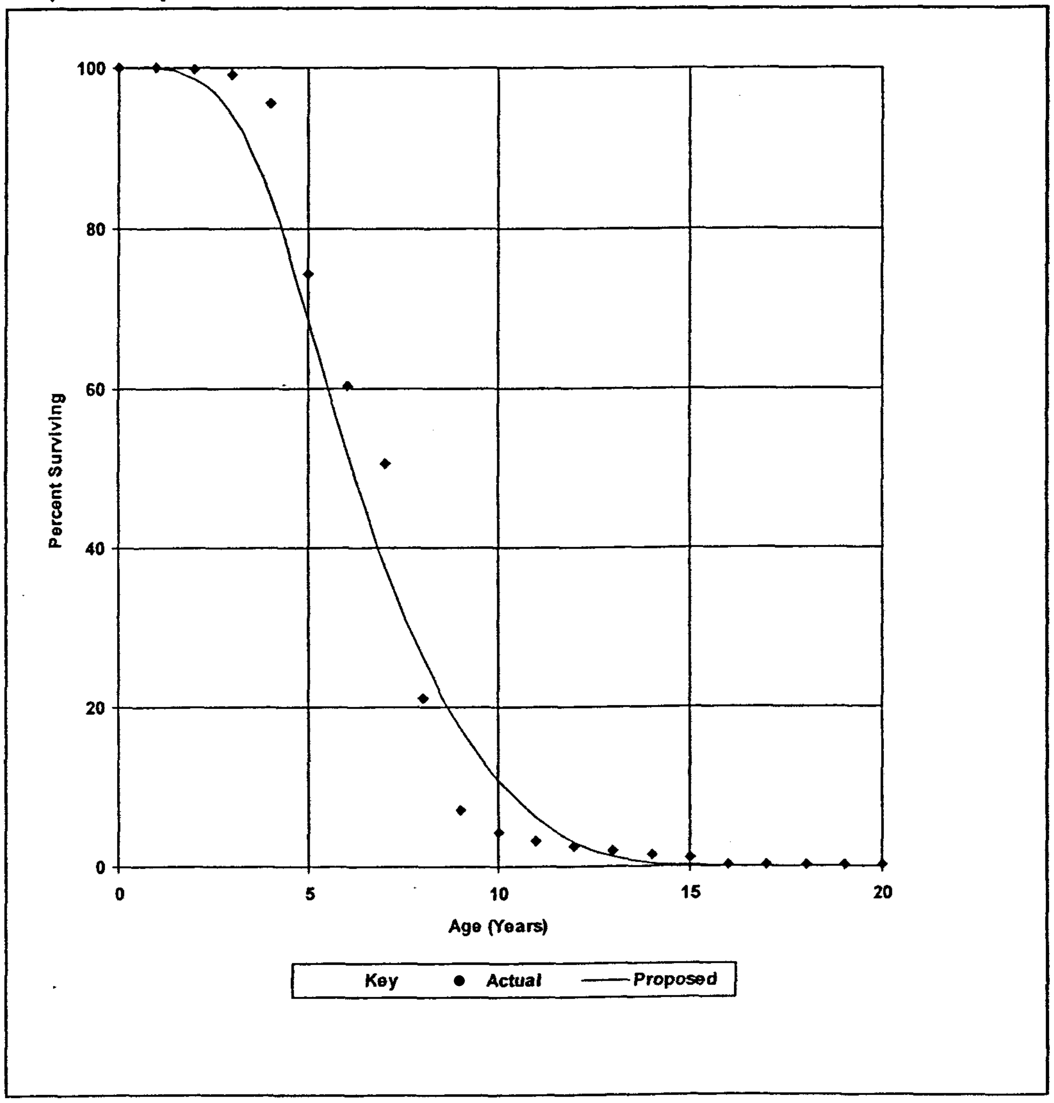
T-Cut: 20

Placement Band: 1949-2005

Observation Band: 1965-2005

6.0-L2

Proposed Projection Life Curve



UNS GAS, INC.
General Plant
Depreciable
Account: 392.20 Transportation Equipment - C2

Unadjusted Net Salvage History

Year	Retirements	Gross Salvage Amount	Gross Salvage Pct.	Gross Salvage 5-Yr Avg.	Cost of Retiring Amount	Cost of Retiring Pct.	Cost of Retiring 5-Yr Avg.	Net Salvage Amount	Net Salvage Pct.	Net Salvage 5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1982	59,684		0.0			0.0			0.0	
1983	66,449		0.0			0.0			0.0	
1984	93,857		0.0			0.0			0.0	
1985	55,284	4,800	8.7			0.0		4,800	8.7	
1986	32,349	7,000	21.6	3.8		0.0	0.0	7,000	21.6	3.8
1987	27,433		0.0	4.3		0.0	0.0		0.0	4.3
1988	82,864	300	0.4	4.1		0.0	0.0	300	0.4	4.1
1989	35,462		0.0	5.2		0.0	0.0		0.0	5.2
1990	19,993	1,675	8.4	4.5		0.0	0.0	1,675	8.4	4.5
1991			0.0	1.2		0.0	0.0		0.0	1.2
1992			0.0	1.4		0.0	0.0		0.0	1.4
1993	18,777		0.0	2.3		0.0	0.0		0.0	2.3
1994	2,673		0.0	4.0		0.0	0.0		0.0	4.0
1995	3,800		0.0	0.0		0.0	0.0		0.0	0.0
1996	9,949		0.0	0.0		0.0	0.0		0.0	0.0
1997	15,450		0.0	0.0		0.0	0.0		0.0	0.0
1998			0.0	0.0		0.0	0.0		0.0	0.0
1999	4,053		0.0	0.0		0.0	0.0		0.0	0.0
2000	53,878		0.0	0.0		0.0	0.0		0.0	0.0
2001	42,227		0.0	0.0		0.0	0.0		0.0	0.0
2002	138,927		0.0	0.0		0.0	0.0		0.0	0.0
2003			0.0	0.0		0.0	0.0		0.0	0.0
2004			0.0	0.0		0.0	0.0		0.0	0.0
2005	1,244,477	161,167	13.0	11.3		0.0	0.0	161,167	13.0	11.3
Total	2,007,585	174,942	8.7			0.0		174,942	8.7	

UNS GAS, INC.
General Plant
Depreciable
Account: 392.20 Transportation Equipment - C2

Adjusted Net Salvage History

		Gross Salvage			Cost of Retiring			Net Salvage		
Year	Retirements	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.	Amount	Pct.	5-Yr Avg.
A	B	C	D=C/B	E	F	G=F/B	H	I=C-F	J=I/B	K
1982	59,684		0.0			0.0			0.0	
1983	66,449		0.0			0.0			0.0	
1984	93,857		0.0			0.0			0.0	
1985	55,284	4,800	8.7			0.0		4,800	8.7	
1986	32,349	7,000	21.6	3.8		0.0	0.0	7,000	21.6	3.8
1987	27,433		0.0	4.3		0.0	0.0		0.0	4.3
1988	82,864	300	0.4	4.1		0.0	0.0	300	0.4	4.1
1989	35,462		0.0	5.2		0.0	0.0		0.0	5.2
1990	19,993	1,675	8.4	4.5		0.0	0.0	1,675	8.4	4.5
1991			0.0	1.2		0.0	0.0		0.0	1.2
1992			0.0	1.4		0.0	0.0		0.0	1.4
1993	18,777		0.0	2.3		0.0	0.0		0.0	2.3
1994	2,673		0.0	4.0		0.0	0.0		0.0	4.0
1995	3,800		0.0	0.0		0.0	0.0		0.0	0.0
1996	9,949		0.0	0.0		0.0	0.0		0.0	0.0
1997	15,450		0.0	0.0		0.0	0.0		0.0	0.0
1998			0.0	0.0		0.0	0.0		0.0	0.0
1999	4,053		0.0	0.0		0.0	0.0		0.0	0.0
2000	53,878		0.0	0.0		0.0	0.0		0.0	0.0
2001	42,227		0.0	0.0		0.0	0.0		0.0	0.0
2002	138,927		0.0	0.0		0.0	0.0		0.0	0.0
2003			0.0	0.0		0.0	0.0		0.0	0.0
2004			0.0	0.0		0.0	0.0		0.0	0.0
2005	1,244,477	161,167	13.0	11.3		0.0	0.0	161,167	13.0	11.3
Total	2,007,585	174,942	8.7			0.0		174,942	8.7	

UNSG-23
25

RUCO'S RESPONSE TO
UNS GAS, INC'S
FIRST SET OF DATA REQUESTS
DOCKET NO. G-04204-06-0463

UNSG 1-30: **<u>Rate Case Expense</u>**: Regarding Adjustments to Rate Case Expense Adjustment No. 8, to reduce the rate case expense recovery requested by UNS Gas.

a. RUCO witness Rodney L. Moore's direct testimony at page 25, line 9, references an amount of $1,742,023 as the deferred rate case cost for UNS Gas as of November 30, 2006. In the supplemental response to RUCO data request 1.06, UNS Gas provided a PDF file named "RUCO 1.06 (Sep 06 thru Nov 06) (5823-5857) – Confidential". The first page of this file shows that the balance of the deferred rate case cost as of November 30, 2006 is $614,907.52 and is clearly marked as such. Given the magnitude of the mis-statement, does RUCO plan to correct this error within the record?

b. RUCO witness Rodney L. Moore's direct testimony at page 25, line 16, uses the term "in-house staff" to compare who prepared the Southwest Gas Corporation ("SWG") most recent rate case to those who prepared the UNS Gas rate case. Can RUCO define in detail who is considered "in-house staff" for SWG and for UNS Gas?

c. Please explain in detail how those individuals identified as "in-house staff" are treated within the revenue requirements (excluding rate case cost) for SWG and for UNS Gas? In other words, for those individuals considered "in-house staff", are their salaries indirectly allocated to the companies, are they directly allocated based on work performed for the direct benefit of the companies or are they actually employees of the companies?

d. Have RUCO compared the expense for the individuals considered "in-house staff" that is included in the revenue requirements (excluding rate case cost) for SWG and for UNS Gas in the two rate filings RUCO is comparing? If RUCO has, please provide the analysis. If RUCO has not, please explain in detail why not.

e. RUCO witness Rodney L. Moore states in his direct testimony at page 26, lines 1 through 3, "Nevertheless, UNS made no attempt to reconcile more than two-fold increase in rate case expenses for processing a comparable filing to SWG's application". Please provide a copy of and reference where UNS Gas was requested to reconcile their rate case expense to SWG's rate case expense.

EXHIBIT
tabbies
UNSG-25
admitted

RUCO'S RESPONSE TO
UNS GAS, INC'S
FIRST SET OF DATA REQUESTS
DOCKET NO. G-04204-06-0463

Response: Rodney Moore

a. RUCO interprets the Company's response to data request 1.06 as a monthly update of rate case expenses and considered the stated "Sum" of $1,742,022.50 as the aggregated amount of actual rate case expenses to date.

b. RUCO considers "in-house staff" as any person employed under the umbrella of the Utility's parent company and/or its affiliates.

c. Both UNS and SWG treat the Corporate-allocated in-house staff expenses similarly by allocating these corporate related costs to their various divisions based on the Massachusetts formula.

d. RUCO's analysis determined SWG's system allocated labor cost was $17,775,000 or 6.38% of the total operating expenses of $278,632,626 (excluding gas costs); while UNS's system allocated labor cost was $679,468 or 1.75% of the total operating expenses of $38,740,547 (excluding gas costs).

e. RUCO is unaware of a request for UNS to reconcile a more than two-fold increase in rate case expenses for processing a comparable filing to SWG's application.

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UNSG-~~29~~ 26

BEFORE THE ARIZONA CORPORATION COMMISSION

MARCIA WEEKS
CHAIRMAN
RENZ D. JENNINGS
COMMISSIONER
DALE H. MORGAN
COMMISSIONER

IN THE MATTER OF THE APPLICATION OF CITIZENS UTILITIES COMPANY (ARIZONA GAS DIVISION) FOR A HEARING (1) TO DETERMINE THE FAIR VALUE OF ITS PROPERTIES FOR RATE-MAKING PURPOSES TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON AND TO APPROVE RATE SCHEDULES DESIGNED TO PROVIDE SUCH RATE OF RETURN AND (2) TO APPROVE THE PROPOSED ACCRUAL METHOD OF ACCOUNTING FOR POST RETIREMENT BENEFITS OTHER THAN PENSIONS, AS REQUIRED BY THE FINANCIAL ACCOUNTING STANDARDS BOARD STATEMENT NO. 106.	DOCKET NO. E-1032-93-111 Arizona Corporation Commission DOCKETED JUN 16 1994 DOCKETED BY C.M.
IN THE MATTER OF THE APPLICATION OF CITIZENS UTILITIES COMPANY, ARIZONA GAS DIVISION, FOR AN ORDER APPROVING ITS PROPOSED BUILD OUT PROGRAM FOR NORTHERN ARIZONA AND AUTHORIZING THE RATEMAKING AND ACCOUNTING PROCEDURES NECESSARY TO IMPLEMENT THE BUILD OUT PROGRAM.	DOCKET NO. E-1032-93-193 DECISION NO. 58664 **OPINION AND ORDER**

DATES OF HEARING: January 12, 13, 14, 18, 19, 20, 21, 24, 25, 26, and 27, 1994

PUBLIC COMMENT: November 29, 1993, January 5 and January 6, 1994

PLACE OF HEARING: Phoenix, Arizona

PRESIDING OFFICERS: Lyn Farmer
Richard N. Blair

IN ATTENDANCE: Marcia Weeks, Chairman
Renz D. Jennings, Commissioner
Dale H. Morgan, Commissioner

APPEARANCES: Ms. Beth Ann Burns, Senior Counsel - Arizona, and Mr. L. Russell Mitten, II, Vice-President, General Counsel, on behalf of Citizens Utilities Company;

EXHIBIT
UNSG-26
admitted

Correction

BEFORE THE ARIZONA CORPORATION COMMISSION

MARCIA WEEKS
CHAIRMAN
RENZ D. JENNINGS
COMMISSIONER
DALE H. MORGAN
COMMISSIONER

IN THE MATTER OF THE APPLICATION OF CITIZENS UTILITIES COMPANY (ARIZONA GAS DIVISION) FOR A HEARING (1) TO DETERMINE THE FAIR VALUE OF ITS PROPERTIES FOR RATE-MAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON AND TO APPROVE RATE SCHEDULES DESIGNED TO PROVIDE SUCH RATE OF RETURN AND (2) TO APPROVE THE PROPOSED ACCRUAL METHOD OF ACCOUNTING FOR POST RETIREMENT BENEFITS OTHER THAN PENSIONS, AS REQUIRED BY THE FINANCIAL ACCOUNTING STANDARDS BOARD STATEMENT NO. 106.

DOCKET NO. E-1032-93-111

Arizona Corporation Commission
DOCKETED
[illegible] 1[illegible] 1994
DOCKETED BY C.M.

IN THE MATTER OF THE APPLICATION OF CITIZENS UTILITIES COMPANY, ARIZONA GAS DIVISION, FOR AN ORDER APPROVING ITS PROPOSED BUILD OUT PROGRAM FOR NORTHERN ARIZONA AND AUTHORIZING THE RATEMAKING AND ACCOUNTING PROCEDURES NECESSARY TO IMPLEMENT THE BUILD OUT PROGRAM.

DOCKET NO. E-1032-93-193

DECISION NO. 58664

OPINION AND ORDER

DATES OF HEARING:	January 12, 13, 14, 18, 19, 20, 21, 24, 25, 26, and 27, 1994
PUBLIC COMMENT:	November 29, 1993, January 5 and January 6, 1994
PLACE OF HEARING:	Phoenix, Arizona
PRESIDING OFFICERS:	Lyn Farmer Richard N. Blair
IN ATTENDANCE:	Marcia Weeks, Chairman Renz D. Jennings, Commissioner Dale H. Morgan, Commissioner
APPEARANCES:	Ms. Beth Ann Burns, Senior Counsel - Arizona, and Mr. L. Russell Mitten, II, Vice-President, General Counsel, on behalf of Citizens Utilities Company;

Correction

045004 0001

BEFORE THE ARIZONA CORPORATION COMMISSION

MARCIA WEEKS
CHAIRMAN
RENZ D. JENNINGS
COMMISSIONER
DALE H. MORGAN
COMMISSIONER

IN THE MATTER OF THE APPLICATION OF CITIZENS UTILITIES COMPANY (ARIZONA GAS DIVISION) FOR A HEARING (1) TO DETERMINE THE FAIR VALUE OF ITS PROPERTIES FOR RATE-MAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON AND TO APPROVE RATE SCHEDULES DESIGNED TO PROVIDE SUCH RATE OF RETURN AND (2) TO APPROVE THE PROPOSED ACCRUAL METHOD OF ACCOUNTING FOR POST RETIREMENT BENEFITS OTHER THAN PENSIONS, AS REQUIRED BY THE FINANCIAL ACCOUNTING STANDARDS BOARD STATEMENT NO. 106.	DOCKET NO. E-1032-93-111 Arizona Corporation Commission DOCKETED JUN 1 6 1994 DOCKETED BY CM
IN THE MATTER OF THE APPLICATION OF CITIZENS UTILITIES COMPANY, ARIZONA GAS DIVISION, FOR AN ORDER APPROVING ITS PROPOSED BUILD OUT PROGRAM FOR NORTHERN ARIZONA AND AUTHORIZING THE RATEMAKING AND ACCOUNTING PROCEDURES NECESSARY TO IMPLEMENT THE BUILD OUT PROGRAM.	DOCKET NO. E-1032-93-193 DECISION NO. 58664 **OPINION AND ORDER**

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PLACE OF HEARING:	Phoenix, Arizona
PRESIDING OFFICERS:	Lyn Farmer Richard N. Blair
IN ATTENDANCE:	Marcia Weeks, Chairman Renz D. Jennings, Commissioner Dale H. Morgan, Commissioner
APPEARANCES:	Ms. Beth Ann Burns, Senior Counsel - Arizona, and Mr. L. Russell Mitten, II, Vice-President, General Counsel, on behalf of Citizens Utilities Company;

Ms. Elaine Williams, Attorney, on behalf of the Residential Utility Consumer Office; and

Ms. Janet F. Wagner, and Mr. Bradford A. Borman, Staff Attorneys, Legal Division, of behalf of the Utilities Division of the Arizona Corporation Commission.

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TABLE OF CONTENTS

BY THE COMMISSION:

On May 3, 1993, Citizens Utilities Company ("Citizens", "Applicant", or "Company") filed with the Arizona Corporation Commission ("Commission") an application requesting that the Commission determine the fair value of Citizens' gas properties that are used and useful in providing utility services to customers, to fix a just and reasonable rate of return thereon, to approve revised rate schedules designed to allow the Company to achieve such return, and for approval of the proposed accrual method of accounting for postretirement benefits other than pensions for all of Citizens' Arizona utility operations.

On July 19, 1993, Citizens filed its application requesting approval of its 1993-1997 Build Out Plan ("Build Out Plan"). On August 24, 1993, Citizens' rate application and its Build Out Plan application were consolidated.

Intervention in these matters was granted to the Residential Utility Consumer Office ("RUCO"); Ms. J. Jenelle Tuttle; and Ms. Ruth E. Siedow.

By Procedural Order issued May 27, 1993 the hearing in this matter was scheduled to commence on November 29, 1993. By Procedural Order dated August 24, 1993, the hearing was rescheduled to commence on January 12, 1994. Public comment sessions were held in Flagstaff, Kingman, Prescott, Sedona, and Show Low, Arizona.

The hearings were held as scheduled and concluded on January 27, 1994. At the hearing, Citizens, RUCO, and Staff presented testimony. Citizens, Staff, and RUCO filed opening briefs on February 22, 1994, and reply briefs on March 4, 1994.

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DISCUSSION

Applicant is a Delaware corporation certificated by the Commission to provide public utility gas service in areas of Apache, Coconino, Mohave, Navajo, and Yavapai counties, Arizona. The total number of customers served in the certificated area is approximately 70,000.

Citizens has requested an increase in operating revenues for gas service of $6,590,294[1] or approximately 20 percent. Staff recommended a total increase of approximately $2.3 million and RUCO recommended an increase of $665,377.

Citizens also requests approval of the proposed accrual method of accounting for postretirement benefits other than pensions for all of its Arizona utility operations.

RATE BASE

Original Cost Rate Base

Applicant, Staff, and RUCO reviewed the account balances at the end of the test year, December 31, 1992, ("TY") and proposed various adjustments in order to determine the fair value of Citizens' property for ratemaking purposes. Applicant proposed an Original Cost Rate Base ("OCRB") of $37,170,176; Staff proposed an OCRB of $30,739,079; and RUCO proposed an OCRB of $29,600,013.

Acquisition Adjustment

Decision No. 57647 (December 2, 1991) approved the joint application of Southern Union Gas Company, a Division of Southern Union Company ("SUG"), and Citizens for transfer of assets and

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[1] The application calculated a revenue deficiency of $6,583,667 in gross annual revenues based upon operating data for the test year ended December 31, 1992. During the proceeding, this figure was revised to $6,590,294.

Certificates of Convenience and Necessity.

Staff and RUCO proposed adjustments to reduce the Company's rate base to exclude amounts which they believe should be included in the acquisition adjustment. At issue is approximately $6,187,274 which the parties have referred to as the "net liabilities assumed"[2]. The calculation of the acquisition adjustment is a relatively simple matter - it is the difference between the total cost to Citizens of the utility plant acquired in excess of the net depreciated original cost value of the plant acquired.[3] The total purchase price of the Arizona Gas Division ("AGD") included $40,411,485 in cash payments, $11,386,307 in liabilities assumed, and $598,759 in acquisition costs, for a total cost of $52,396,551. The net depreciated original cost of the assets acquired was $34,697,771. Accordingly, the acquisition adjustment is $17,698,780.

Citizens states that it is not requesting recovery of an acquisition adjustment[4], but that it should be accorded rate recognition of the "net liabilities assumed". Citizens' attempt to characterize the "net liabilities assumed" as anything other than part of the over $17 million acquisition adjustment is totally without merit. Citizens' argument that if the "net liabilities assumed" are not reflected in rate base, it would be unfairly penalized for proceeding with closing because of its reliance upon a Staff exhibit

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[2] In addition to paying cash, Citizens also assumed liabilities. We find no reason to distinguish between the two methods of consideration, and the use of the term "net liabilities assumed" has caused confusion, and is unnecessary and irrelevant to our determination herein.

[3] See National Association of Regulatory Utility Commissioners ("NARUC") Uniform System of Accounts ("USOA") for Gas Utilities.

[4] See Applicant's Opening Brief, p. 7.

presented during the transfer proceeding, is also without merit. Our Decision No. 57647, Finding of Fact No. 8 specifically stated that "[t]he ratemaking treatment of marketing expenses and any acquisition adjustment will be deferred until a future rate proceeding." Further, we stated that "Citizens must be reminded that Arizona allows for a return on <u>invested plant, not on the sale price paid for the utility.</u>"[5] Consistent with our prior Decision, we are now making that ratemaking treatment. Citizens excluded only $11,511,506 of the $17,698,780 acquisition adjustment, and accordingly, an additional ($6,187,274) adjustment to rate base is necessary.

<u>Acquisition Costs</u>

Citizens' application included $598,759 of acquisition related costs in rate base. Both Staff and RUCO made adjustments to remove these costs from rate base. Staff recommended removing the costs until Citizens can meet the requirement of Decision No. 57647 which requires Citizens to show that the acquisition has resulted in savings due to structural advantages, i.e., savings that Citizens can offer that were not possible under SUG's ownership. RUCO argued that the costs were improperly recorded as plant in service when they should have been included in the acquisition adjustment account.

As we have indicated above, the USOA[6] treats these "acquisition costs" as part of the acquisition adjustment. These costs are included in the $17,698,780 acquisition adjustment and therefore, consistent with our Decision No. 57647, Citizens must make the

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[5] Decision No. 57647 p. 7 (emphasis added).

[6] Plant Accounting Instruction No. 5 specifies that the costs of acquisition, including expenses incidental to the acquisition of the purchased utility plant, are to be recorded as part of the acquisition adjustment.

required showing before these costs are included in rate base.

RUCO raised a second issue concerning these "acquisition costs". RUCO argued that the following costs included by Citizens were improper: $374 for Christmas cards charged by Citizens' President, Daryl Ferguson; $1,444 airfare for Mrs. Ferguson to accompany her husband to Phoenix, Kingman, and Las Vegas; $406 for upgrades to first class air travel for the Ferguson's trip; $18,392 in legal fees paid in connection with an unsuccessful bid to acquire an unidentified natural gas company; a $125,000 fee to Bear Stearns for which the Company has provided no supporting documentation; and $104,594 in legal fees to the law firm headed by Citizens' board and compensation committee member Aaron Fleishman; for a total cost of $250,210.

Citizens agreed that the $18,392 in legal fees and the $374 for Christmas cards, a total of $18,766 should be removed. We find that the travel expenses incurred for Mrs. Ferguson to accompany her husband were for the personal benefit of Mr. Ferguson are not proper acquisition related costs. Citizens failed to document or explain the inclusion of $125,000 in fees to Bear Stearns, and therefore, that amount should be excluded. Although we share RUCO's concern that transactions that are not at arms length lack independence and may result in conflicts of interest, excessive or nonessential payments, we believe that $104,594 in legal fees for such a transaction is not unreasonable.[7] Accordingly, we find that $145,210 of the acquisition adjustment should be removed from that account so that Citizens will not recover that amount from ratepayers should Citizens be allowed recovery of the acquisition adjustment sometime in the future.

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[7] Citizens, SUG, and the law firm agreed to split the fee between Citizens and SUG. The total fee paid to the law firm was approximately $209,000.

Post Test Year Non-Revenue Producing Plant Additions

In its application, Citizens included two items of post TY non-revenue producing plant additions: $128,597 for the Highway 180 project; and $197,400 for the Butler Avenue Project. Citizens' final request included an additional $159,591 for the "total actual construction costs" for the Highway 180 project, and deleted the request for the inclusion of the Butler Avenue project. Accordingly, Citizens' adjustment to post TY non-revenue producing plant is $288,188.

Staff opposed the inclusion of the Highway 180 project because during the TY, the project was Construction Work in Progress ("CWIP") and to include it in rate base and not to include adjustments for expected reductions in cost of service would create a test year that does not properly balance all of the ratemaking components.

RUCO also opposed inclusion of the projects in rate base because it was CWIP and was not providing service at the end of the TY. RUCO believes that recognition of the post TY project completion would provide a return on a twice inflated rate base - inflated once for Allowance for Funds Used During Construction ("AFUDC") during the first seven months of 1993, and again if it is included with plant in service at the end of the TY.

We agree with all the parties that rate base should not be adjusted to include the Butler Avenue project, and with Staff and RUCO that the Highway 180 project should also not be included. Although the project was completed within six months of the TY and is currently providing service to customers, Citizens continued to capitalize AFUDC for six months after the end of the TY, thereby increasing the total amount of plant upon which it will earn a return. Citizens cannot have it both ways, and it has chosen to capitalize AFUDC. Therefore, we will disallow the Butler Avenue and Highway 180 adjustments.

<u>Arizona Gas Division Four-Factor Allocator</u>

The Stamford Administrative Office ("SAO") common plant is allocated to the various Citizens operating divisions using a four-factor formula which includes gross plant in service, operation and maintenance expense ("O&M"), the number of customers, and payroll charged to O&M. In its application, Citizens calculated a 7.33 percent allocator for the AGD, which the Company subsequently updated to 7.15 percent to reflect the actual data for the TY.

RUCO proposed a 6.55 percent allocator, based upon its use of a plant amount which it believes excludes the acquisition adjustment. Citizens and RUCO both presented mathematical evidence to support the level of plant each believes should be used in the calculation. Neither was able to show how the other's calculation was incorrect. Citizens argues that RUCO's plant amount is actually a rate base amount, not a gross plant amount. RUCO believes that the plant amount recorded on the Company's books does include the part of the acquisition adjustment. The central problem is in how Citizens recorded the acquisition. Citizens recorded the transaction on its books in one manner, which benefitted the Company, by including approximately $6.2 million as plant in service instead of including it in the acquisition adjustment account, and yet when it calculated the four-factor allocator, it used a different, unrecorded amount as the gross plant value.[8] The gross plant acquired from SUG was

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[8] Instead of recording the $44,982,509 Citizens says is SUG's gross plant as of 11/30/91 as its own gross plant, Citizens recorded a net amount which was not even the net utility plant (it was inflated by $5,588,515 "net liabilities assumed" which was calculated by netting liabilities against non-plant assets).

 DECISION NO. 58664

$44,982,509 as of November 30, 1991. Since the acquisition, $5,791,528 in plant has been added, for a total gross plant amount of $50,774,037. RUCO's argument that gross plant includes the acquisition adjustment is true in the sense that gross plant includes not only net plant, but accumulated depreciation as well, which may or may not be related to the amount of the acquisition adjustment. We disagree with the manner in which Citizens recorded the acquisition and will require Citizens to record the acquisition using the correct gross plant amount. Citizens' four-factor allocator has consistently used the gross plant amount as one factor to allocate SAO costs and we decline to adopt a different plant amount for that calculation at this time.

RUCO also proposed an adjustment to the AGD's O&M allocation factor. With the Louisiana Gas Service Company ("LGS") division, Citizens uses the "California Method" which omits the purchased gas costs from the computation of the O&M expense factor; but with the AGD, it uses the "Arizona Method" which includes the purchased gas costs in the O&M costs. RUCO believes that the Company should compute the AGD's allocation factor consistently with how it computes the LGS' allocation factor, otherwise, the AGD would unfairly and improperly bear more than its share of SAO costs. We agree that Citizens should use the same method consistently when calculating O&M expense as one of the four factors used to allocate SAO costs. Therefore, it is appropriate to use a factor for the AGD which is based upon consistent

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Citizens' decision to record the transaction in this manner also caused it to respond to data requests using this amount recorded in the general ledger ($34,390,427) as well as the amount Citizens determined was the acquisition adjustment ($11,511,506) in calculating the plant in service amount of $51,352,185 (See exhibit R-1 Schedule 203-B) which it shows it used as the appropriate gross plant figure it used in calculating the four-factor allocator.

treatment of purchased gas costs in the O&M expense allocator. We find that the appropriate SAO four-factor allocator for the AGD, using the "Arizona Method" consistently for all gas divisions is 7.09 percent Accordingly, we will reduce plant in service by $35,821 and adjust accumulated depreciation by ($13,474).

Stamford Administrative Office Common Plant

RUCO recommended disallowance of the AGD's allocated share of $1,688,685 of SAO common plant. The items included: $978,935 of leasehold improvements for a building at 1200 High Ridge Road; $224,305 for an office for retired executive I. Jacobson; and $485,445 for expensive furniture and artwork. These items were disallowed in Citizens' Arizona Electric Division ("AED")[9] rate case, but Citizens is asking the Commission to re-evaluate the issue in this proceeding, based upon the evidence presented herein.

Citizens argues that the only basis for RUCO's position on the furniture and artwork is that it is the opinion of RUCO's consultant, who visited the SAO, that the items are lavish. Citizens presented photographs of some of the offices and conference rooms to support its position that the furnishings are not lavish, the offices are not extravagant, and that there is no art collection. RUCO responded that the photographs did not show Mr. Tow's office or "most of the offensive objects" and that Arizona ratepayers will never see the expensive furnishings or artwork, will not benefit from them, and should not pay for them. In response to Citizens' criticism that the adjustment eliminated the entire item and did not allow any amounts for these items at all, RUCO stated that its adjustment still allowed 85 to 90 percent of the total SAO office costs, which it believes

[9] Decision No. 58360 (July 23, 1993).

would be sufficient to cover appropriate costs for necessary office furnishings. Citizens' photographs lend support to RUCO's recommended adjustment. As was pointed out in our Decision No. 58360, Citizens wanted Arizona ratepayers to pay $4,961 for one item of "4th Floor Pantry Art". The photographs submitted by Citizens show the pantry with a piece of artwork hanging on the wall. Citizens has failed to show why such expensive artwork is necessary to provide utility service to the AGD and why Arizona ratepayers should pay a return on Citizens' investment in this "common plant". We agree with Citizens that a reasonable allowance should be made for furnishings such as desks, conference tables, and chairs, but we also agree with RUCO that the level of plant remaining after these adjustments is sufficient to cover reasonable and appropriate costs for necessary office furnishings.

Citizens offered no new evidence concerning the leasehold improvements at 1200 High Ridge Park and we find nothing to change our previous determination that improvements made for a temporary purpose, which purpose is no longer needed, should not be included in rate base. Citizens has not shown that the investment was necessary or designed for storage and training purposes, or that such cost is reasonable for such uses. Neither has Citizens offered evidence to change our previous decision to eliminate from rate base the amount of an office for Citizens' former President, Chief Executive, and Chief Operating Officer. Accordingly, we will reduce rate base by $119,728 and adjust accumulated depreciation by ($33,919).

<u>Harvey Administrative Office Plant</u>

RUCO also proposed two adjustments to the Harvey Administrative Office ("HAO") allocator similar to its adjustments to the SAO allocator. RUCO reduced rate base to use its gross plant amount in the four-factor allocator, and by $10,447 to eliminate the allocated, depreciated cost of more than $72,000 in paintings and sculptures carried in HAO plant accounts. Consistent with the discussion concerning gross plant above, we will not adjust the allocator. We will also not adopt RUCO's recommendation to disallow all art and sculpture from the HAO plant account. We note that the items listed were acquired between the years 1973 and 1982 and do not appear to rise to the level of the recent, expensive, and extensive acquisitions made for the SAO.

Accumulated Depreciation Reserve

In its application Citizens included $16,664,317 as accumulated depreciation. Staff and the Company agreed that the calculation of the accumulated depreciation reserve should be based upon the depreciation rates in effect during the TY, using the 1992 plant balances, and including the associated cost of removal and retirements.

RUCO proposed several adjustments to the Company's accumulated depreciation reserve, including: an increase to the balance of the reserve to match the proforma TY depreciation expense increase requested; to reduce the balance by the depreciation associated with the acquisition adjustment and the RUCO recommendation to reduce HAO plant allocated to the AGD; and to correct an error in the CIAC amortization calculation.

We agree with the method used by Staff and the Company to determine the accumulated depreciation balance. That method calculates depreciation based on the total depreciable plant as of December 1, 1991 and does include depreciation associated with the

1992 plant additions, but does not include depreciation based upon rates which were not in effect during the TY. Accumulated depreciation associated with the SAO common plant disallowed in plant in service is $478,405, accordingly the total accumulated depreciation should be adjusted by ($33,919). Accumulated depreciation was adjusted hereinabove as a result of changing the AGD allocator, so an additional adjustment to accumulated depreciation of ($13,474) is necessary. A further adjustment of ($3,840) is necessary based on RUCO adjustments accepted by the Company. Accordingly, accumulated depreciation is ($16,613,084).

Accumulated Deferred Income Tax Reserve

The Company agreed with Staff that the accumulated deferred income tax reserve should be based on year-end 1992 plant in service and the depreciation rates in effect during the TY. Consistent with our determination hereinabove to reduce the Company's recorded plant in service by the additional $6.2 million acquisition adjustment, the accumulated deferred income tax reserve should be increased by $215,180, for a total deferred income tax amount of $480,584.

Cash Working Capital

The Company proposed a cash working capital allowance of ($1,073,054)[10] which includes recognition of the rate case expenses of this proceeding as well as deferred Target: Excellence expenses. Citizens believes that shareholders are entitled to be compensated through the cash working capital allowance for the time value of their money spent for these purposes.

Staff and RUCO presented cash working capital allowances of

[10] After adjustments made by the Company during the proceeding, the Company's final cash working capital allowance was ($1,240,689).

($1,442,054) and ($1,810,355), respectively. Staff and RUCO excluded the rate case expenses from their calculations based on their positions that including rate case expense in rate base would provide Citizens with a profit on the expense and would fail to recognize the tax benefits of rate case costs, as well as the belief that by amortizing rate case expense in cost of service but excluding the unamortized amount from rate base, the "cost" of processing a rate proceeding is shared between ratepayers and the Company, and will provide a modest incentive to management to control the level of rate case expense incurred. RUCO and Staff believe that the unamortized Target: Excellence costs should not be included in rate base because Target: Excellence is designed, in part, to achieve certain cost efficiencies which have not been quantified or identified to date. Additionally, these costs should also have tax benefits which the Company's presentation failed to identify.

We agree with Staff and RUCO that the rate case expense and Target: Excellence costs should not be included in the cash working capital calculation for the reasons cited above. Accordingly, we will adopt Staff's cash working capital allowance of ($1,442,054) and will reduce rate base by $369,000.

<u>Miscellaneous</u>

RUCO proposed several adjustments which the Company has accepted, including a $37,542 reduction to Materials and Supplies; an increase to Customer Deposits of $19,923; a decrease of $21,628 for customer-provided capital through the "Warm Spirit" program; an increase to plant in service of $3,750 for appraisal expenses related to a sale of property in Lake Havasu; an increase in plant in service of $1,585 for telephone equipment purchases, along with a corresponding adjustment to accumulated depreciation.

Original Cost Rate Base Summary

Based on the foregoing, the following statement details the adjusted TY original cost rate base ("OCRB") for ratemaking purposes:

	Citizens Adjusted	Commission Adjustments	Adjusted Test Year
Plant in Service	$61,018,638	$(6,663,485)	$54,355,153
Accumulated Depreciation	(16,664,317)	51,233	(16,613,084)
Net Plant	44,354,321	(6,612,252)	37,742,069
PLUS:			
Amortization of CIAC	$ 563,351	-0-	$ 563,351
Materials and Supplies	$ 403,382	$ (37,542)	$ 365,840
LESS:			
Deferred Income Taxes	265,404	215,180	480,584
Contribution in Aid of Construction	3,156,287	-0-	3,156,287
Advances for Construction	2,569,194	-0-	2,569,194
Customer Deposits	399,143	(19,923)	379,220
Allowance for Working Capital	1,073,054	369,000	1,442,054
Other Cost Free Capital	-0-	21,628	21,628
TOTAL	37,857,972	(7,235,679)	30,622,293

Reconstruction Cost New Rate Base

In schedule A-1 to the Company's filing, Citizens presents a jurisdictional reconstruction cost new rate base ("RCNRB") of $70,180,000. All of the adjustments reflected in our determination of the OCRB are equally applicable to the RCNRB. No change in these adjustments is necessary to restate them in terms of reconstruction cost new. Thus, our RCNRB is $62,944,321.

Fair Value Rate Base

The Commission has traditionally determined the "fair value" rate base ("FVRB") by taking the average of OCRB and RCNRB. No party has suggested that a different weighting be used in this proceeding.

Consequently, we find Citizens' adjusted FVRB at December 31, 1992 is $46,783,307.

OPERATING INCOME

Applicant, Staff, and RUCO have analyzed the Company's accounts for the TY and have recommended various adjustments to the actual operating results. The parties reached agreement on: the synchronization of purchased gas expense with the Purchased Gas Adjustment ("PGA") clause revenues; rate recognition of the electronic meter reading and customer information system; correction of the SUG billing error; use of the 35 percent income tax effective January 1, 1993; the exclusion of industry association dues, promotional expenses, donations and social organization dues, and the miscellaneous expenses listed in Exhibit R-2, Schedule 318, lines 1-4, 7, and 10; the reclassification of the appraisal fee on that schedule as a debit to accumulated depreciation; and to the capitalization of the telephone equipment identified on the same schedule. We hereby approve these agreed upon adjustments.

Revenues

Customer Annualization

Citizens calculated revenues based upon recorded sales to customers during the TY. Both RUCO and Staff have proposed customer annualization adjustments. Staff's adjustment would increase revenues by $1,022,515; RUCO's would increase revenues by $1,109,658. Staff's adjustment reflects TY revenues and expenses "as if customers taking service at test year end had taken service throughout the test year". Staff believes that the adjustment is necessary to properly match all major cost of service components to test year end levels. Staff believes that since it used year end rate base components and annualized expenses capable of supporting and servicing the December 1992 levels of customers, it is appropriate that an annualized level of revenues associated with year end customers should also be reflected.

RUCO's annualization adjustment is based upon the TY amounts for customers and usage levels, by geographic area, and upon the application of the AGD's current tariff rates to the year-end customer usage and customer number increases, unadjusted for the impact of weather.

We agree with Staff and RUCO that a customer annualization is appropriate. Consistent with the adjustments herein to plant in service, accumulated depreciation, and other expense-related adjustments, it is appropriate to reflect an annualized level of revenues associated with year end customers. Consistent with our determination concerning weather normalization hereinbelow, we will adopt the customer annualization adjustment proposed by Staff. Accordingly, an adjustment is needed to increase revenues by $1,022,515.[11]

Weather Normalization

Citizens' application did not include a weather normalization adjustment because Citizens believes that the weather conditions during the TY closely approximated the recent 10-year average, and would be considered to be within the normal range. Both Staff and

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[11] A corresponding adjustment is necessary to purchased gas expense in the amount of $663,973, as well as an $8,514 adjustment to customer accounts for postage expense and uncollectible expense.

RUCO proposed weather annualizations.[12]

Staff's adjustment would increase revenues by $148,668, for a net revenue adjustment of $40,051. RUCO's weather normalization adjustment would increase revenues by $953,103, for a net revenue adjustment of $293,308. Staff used a 10-year average as the basis for its adjustment, RUCO used a 30-year average. Citizens opposed use of a 30-year average because such an average would ignore the warming trend it says is occurring in the AGD service territory.

We agree with Staff that use of a 10-year average is an appropriate basis from which to calculate the necessary weather normalization adjustment. We believe that little weight should be given to Citizens' argument that such an adjustment is unnecessary, since Citizens' concerns were what initially prompted Staff to make the calculation. RUCO recommended that the Commission should require Citizens to maintain weather normalized gas sales data, and to reflect weather normalized gas sales in future filings for the AGD. We agree that this information may be helpful to us in future rate proceedings, and we will order Citizens to comply with the recommendations. Accordingly, an adjustment is necessary to increase revenues $148,668.[13]

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[12] Staff proposed its weather normalization adjustment in response to concerns expressed by Citizens regarding Staff's customer annualization adjustment.

[13] A corresponding adjustment is necessary to purchased gas expense in the amount of $108,171, as well as an $446 adjustment to customer accounts.

Expenses

Harvey Administrative Office Expense

Staff recommended that the Commission not adopt the Company's proposed allocation of $545,680 additional HAO expenses to the AGD. Staff believes that Citizens' administrative costs have risen dramatically, and argues that the Company cannot explain why, nor has the Company identified any one-time costs related to the acquisition which may have inflated the administrative costs on a nonrecurring basis. Staff compares the Company's pro forma 1992 TY, which contains adjustments which estimate expenses that were actually incurred, but not recorded, with SUG's actual 1990 recorded expenses, to conclude that Citizens' administrative costs are significantly higher than SUG's. Staff also noted that Citizens' explanation for the $545,680 adjustment has not been consistent. At one time, the adjustment was to reflect an allocation for HAO common plant occurring during the TY, but unrecorded because allocation procedures were not in place. Later, the Company indicated that the amount was related to the Build Out Plan. At hearing, the Company stated that it could not separate out Build Out costs from other costs contained in the adjustment that represented costs for other ongoing activities.

Citizens compared the average per customer direct and allocated charges to the AGD from SUG for 1990 with the average charge per customer of direct and allocated charges by Citizens for SAO, HAO and the Phoenix Administrative Office ("PAO") and concluded that there was a substantial reduction in the actual dollar amount of charges allocated by Citizens. Citizens made a similar comparison using total O&M expense. Citizens admits that although the direct and allocated charges to the AGD during the TY were less than SUG's had been, there is an increase in A&G reflected in the pro forma calculation. Citizens' brief states that the increase is attributable to the increased level of activity of all of the administrative support functions in the design and development of the Build Out Plan.

RUCO also made an adjustment to reduce Citizens' total amount of TY A&G expenses allocated to and incurred directly by the AGD. RUCO's adjustment would decrease A&G by approximately $1.57 million RUCO points out that Citizens' per-customer charge comparison is affected by the change in the number of customers, and notes that Citizens' own evidence shows that projected per-customer charges are increasing under its ownership.

We agree with Staff that Citizens' proposed pro forma $545,680 allocation to the AGD from the HAO should be disallowed. The evidence in the record to substantiate these costs is conflicting.

Stamford Administrative Office Expense

RUCO proposed several adjustments to the SAO four-factor allocator, which have been discussed hereinabove. Consistent with our calculation of the appropriate four-factor allocator for the SAO common plant to be allocated to AGD, we will use the same 7.09 percent allocator to allocate SAO overheads.

RUCO also proposed disallowance of several expenses, totaling approximately $1.3 million. Those expenses include: $225,957 in outside directors fees and expenses; $225,459 in depreciation expense associated with RUCO's specific SAO common plant disallowances; $117,900 in rental payments for the building at 1200 High Ridge Road; $90,066 in legal fees related to a Citizens shareholder; $83,000 in "SAOC Other" expenses; $38,794 in consulting and special corporate communications charges; $38,499 for a video project and brochure design; $87 to $35,825 in individual travel and per-diem executive charges; $33,500 paid to Leonard Tow for directors fees; $29,249 payment to Citizens' General Counsel; $17,500 in consulting and special - executive charges; $3,500 for a Connecticut photographer; compensation paid to Dr. Tow in excess of $500,000; and the salary of Citizens' Executive Chef. RUCO's proposed adjustment results in a disallowance of charges to the AGD of $58,329.

Although we share RUCO's concern about the increased level of Director's fees and expenses, we agree with the Company that due to the changes in the size of the Board, its functions and responsibilities, as well as the number of committees and the frequency of their meetings, it is difficult to compare the Board in 1989 to the Board in 1992. We will, however, caution the Company that we will closely watch the level of Board expenses as well as the necessity of and appropriateness of those expenses in future proceedings.

We also agree with the Company that the lease expense of the 1200 High Ridge Road and the fees incurred related to a Citizens shareholder should be allowed. Citizens is incurring lease expense on the space and it is used for business-related activities. Citizens' cost of responding to shareholder inquiries is a normal business activity, and RUCO did not establish that the costs were related to shareholder litigation.

We agree with RUCO that the payment to the general counsel should be removed as it is a nonrecurring expense; that depreciation needs to be adjusted to reflect the SAO plant disallowances; and that the "SAOC Other" expenses, as well as the consulting, video, photography, executive chef salary, and individual and per diem charges should be disallowed.

Citizens cites the "significant achievements and cost savings that have obtained from Dr. Tow's stewardship" as support for his compensation level. While it may be true that there has been a "change in corporate culture", this would be not be unexpected when there is a change in the upper management of a company. Merely because positions are filled with new personnel who make changes does not mean the compensation for that position should increase so dramatically over the incumbent's salary. We agree with RUCO that an adjustment to Dr. Tow's salary is appropriate. We note that Dr. Tow is receiving compensation in base salary that is substantially more than that of his predecessors; that the compensation study performed by Hay Associates[14] does not support his level of compensation; that he must split his time between Citizens and another corporation; and that Citizens has provided little to support the reasonableness of his employment contract. We also agree with Staff and RUCO that the AGD's share ($183,120) of Dr. Tow's supplemental pension of $3 million is excessive and should be disallowed.

Accordingly, we find that SAO expense should be adjusted by ($230,836).

Payroll Expense Annualization

In its application, Citizens included pro forma payroll expense of $3,492,583, an increase of nearly 12 percent over the TY recorded payroll. RUCO made a three-part adjustment that reduces the pro forma claim by $76,904. The portion allocated to O&M expenses[15] amounts to

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[14] Hay Associates' study indicates that the midpoint base salary for Citizens' CEO position is $360,639.

[15] 85.16 percent

a reduction of $65,837. RUCO's adjustment used an average vacancy rate of 1.1 percent, corrected for an error in the amount of "compression" increases resulting from the Company's Hay Study, and adjusted for four positions filled after the test year end from estimated to actual amounts. The Company has accepted RUCO's adjustment.

Staff proposed an adjustment to eliminate the Company's adjustment to annualize post TY wage increases and post TY budgeted increases in number of employees. Staff recommends that payroll annualization should be limited to test year end wages and number of employees. Staff believes that all the various components of the TY should be annualized and normalized to level and conditions existing at December 31, 1992, the end of the TY. Staff notes that Citizens' level of annualized costs will not occur until 1994, and by that time, Citizens will have experienced a full year's customer growth which will not be reflected and which will therefore distort the TY.

We agree with Staff's adjustment to annualize payroll costs to the level of test year end wages and number of employees. Reflecting an annualized cost of expenses that will not be experienced until over one year after the end of the TY, while not annualizing customer growth during that same period, would result in a mismatching of revenues and expenses. Accordingly, we will reduce payroll expense by $300,201.

<u>Group Medical Insurance Expense</u>

Citizens' application included $742,429 for group medical insurance costs. RUCO proposed an adjustment to this expense which uses current data to recognize the known and measurable increases experienced in 1993. RUCO's adjustment decreases group medical insurance expense by $111,862, to which Citizens has agreed. We agree with RUCO and the Company that it is appropriate to reduce the pro forma group medical expenses to reflect the known and measurable increase, and therefore will adjust this expense by ($111,862).

Postretirement Benefits Other than Pensions

Citizens requests the Commission's approval of the Company's proposed accrual method of accounting for postretirement benefits other than pensions ("PBOPs") in the amount of $114,077. Citizens' witness testified that the accrual method would correctly match the cost of providing service with the charges to customers for the service rendered, and thereby avoid an inter-generational subsidy by future customers of the costs incurred today to serve current customers. Citizens witness testified that it would allow for a structured phase-in of the transition obligation and would result in the lowest overall revenue requirement for customers.

Staff recommended eliminating the PBOP costs because it believes that the Company has not justified the reasonableness of implementing PBOPs. Staff believes that Citizens' failure to address this issue, as well as its failure to update its data responses to Staff concerning PBOPs and to produce its study regarding employee benefits until its rejoinder testimony, and the failure of the study to show or even claim that it will reduce costs for the AGD, all support Staff's adjustment to remove the PBOPs in the TY. Staff believes that if the Commission were to approve PBOPs, it should not approve the Company's request to use accrual accounting because accrual based expenses are too speculative to be known and measurable.

RUCO recommends that the Commission not approve Citizens' request for accrual accounting of PBOP expense. The reasons for RUCO's recommendation include: the Financial Accounting Standards Board Statement No. 106 ("FAS 106") is not mandatory for ratemaking; Citizens has no funding plan; Citizens has made no prefunding contributions to tax-advantaged trusts; the FAS 106 accrual is based on speculative assumptions; the majority of FAS 106 accrual is for costs attributable to past periods; using FAS 106 accrual would unfairly charge current ratepayers with more than one generation of cost; and the Commission has ruled in other recent cases that utilities should remain on the pay-as-you-go ("PAYGO") method for ratemaking purposes.

We agree with RUCO for the reasons cited above, that Citizens should record its PBOP on the PAYGO method. Accordingly, we will reduce PBOP expense by $114,077.

Incentive Deferred Compensation Plan

Citizens included $72,447 in expenses associated with its Incentive Deferred Compensation Plan ("IDCP"). We have previously disallowed these kind of expenses, and Citizens has asked us to re-evaluate the expenses in light of changes made in its plan. Those changes include steps to "shift a portion of its base pay compensation into variable pay" and to extend participation in the program to a greater number of employees.

RUCO and Staff propose that IDCP expense be excluded from rate recognition. RUCO argues that during the TY only 8 percent of the Company's employees were eligible for these payments; that they relate to the recipient's achievement of ordinary job functions and are obtained in addition to pay increases and promotions; and that the Company has shown no past or present relationship between these payments and customer savings.

Staff believes that the expense should be removed because the Company is not meeting the goals of the IDCP, which are to: emphasize customer service and employee satisfaction; lower overall compensation from that which would have been achieved with a traditional system of cost of living and merit increases; and force employees to achieve certain objectives in order to "re-earn" their merit increases of previous periods. Staff points out that in 1991 and 1992, the employees were not adequately informed of their goals until after the plan year had concluded, and that in 1993, individual employees were not informed of any specific goals. Staff concludes that without an understanding of the specific, individual goals, it is difficult to see how employees could meet any specific individual objectives regarding customer service and employee satisfaction. As far as the goal of lowering overall compensation, Staff notes that 20-35 percent of the IDCP awards were given to executives, whose salaries were going up at the same time the IDCP awards were increasing.[16]

We agree with Staff and RUCO that expenditures for IDCP during the TY should not be included in operating expenses. Contrary to Citizens' assertion in its Opening Brief, the record evidence does not establish that "total compensation has been reduced since 1989 as a result of the changes instituted by Citizens' new top management." The evidence indicates that between 1989 and 1992, total payroll increased by almost $13 million, including a total IDCP increase of approximately $1.1 million. The evidence indicates that under the IDCP, no employee received a pay reduction, so the per employee

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[16] Staff cites the cumulative base salary of the two most senior positions increased by more than 75 percent, or in excess of 20 percent annually, for the three years ending 1992, and the IDCP awards for the two positions have increased by nearly 278 percent.

payroll amount decrease has to be an effect of the increased number of employees[17], not a result of the IDCP. Accordingly, we will adjust IDCP expense by ($62,022).

Directors' and Officers' Liability Insurance Expense

Citizens' application includes $17,987 of allocated Directors' and Officers' ("D&O") liability insurance for the TY. RUCO sponsored an adjustment which would share the cost of such insurance equally between ratepayers and shareholders. Consistent with our Decision No. 58360 that ratepayers should not have to pay for an increased insurance premium that will enable Citizens to fight off shareholder suits, we will adopt RUCO's adjustment and adjust insurance by ($8,993). Additionally, consistent with our SAO factor, we will adjust comprehensive insurance by ($3,399).

Target: Excellence Expense

Citizens seeks recovery of $100,000 from the AGD for its Target: Excellence program. Citizens explains that the Target: Excellence program embodies the corporate change in culture taking place at Citizens. "It is the continuous improvement process that directly focuses on training all employees to provide improved customer service, with the achievement of cost savings and curtailment being one aspect of the benefits under the program. The training enhances employee awareness of the meaning of quality, of the relationship between the Company, its employees, and its customers, and of continuous improvement."[18]

RUCO proposed an adjustment to remove the Target: Excellence

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[17] According to Exhibit A-41, Schedule D, the per employee payroll amount was $31,970 in 1989, and $28,002 in 1992, after the 39.40 percent increase in number of employees.

[18] Applicant's Opening Brief, p.38.

expense from operating expenses. RUCO believes that the expenditures have provided no specific, quantifiable, benefits to ratepayers, and that any future benefit is not known and measurable and would not be matched to the present expenditures. Staff made no adjustment to the Target: Excellence expense.

We agree with RUCO that the goals of Target: Excellence and the benefits Citizens believes it will provide are nebulous. We agree with the Company that it should strive to improve its quality of service to its customers. What we cannot agree to is that only one of its "customers" should have to bear the entire cost of such an expensive program which has yet to demonstrate any savings. Accordingly, we believe that the costs of the Target: Excellence program should be shared equally between Citizens' ratepayers and its shareholders, and we will adjust the Target: Excellence expense by ($50,000).

Depreciation Expense

Staff and Citizens disagree on the appropriate depreciation rate for two accounts: Account 376 - Distribution Mains; and Account 380 - Distribution Services.

Account 376 - Distribution Mains

Citizens proposed a 40 year useful life for distribution mains with a depreciation rate of 2.92 percent. Citizens' witness used a two step process to reach his estimate. His first step was a life analysis using both actuarial and semi-actuarial methods, and the second step was a life estimation based upon his evaluation of non-physical factors affecting future retirements.

Staff proposed a 55 year useful life for distribution mains with a depreciation rate of 1.86 percent. Staff's witness relied upon actuarial analyses of the data for Account 376 to establish the appropriate life characteristics. Staff also considered the fact that Citizens is using more plastic pipe than its predecessor did, which has, as a conservative estimate, a 50 year average service life.[19]

The current useful life in effect for distribution mains is 45 years. Based upon all the analyses as well as the other factors cited by the parties which affect the future life of distribution mains, we find that a 45 year useful life continues to be appropriate for this account, with a corresponding depreciation rate of 2.2 percent.

Account 380 - Distribution Services

The other disagreement between Staff and Citizens concerned Account 380 - Distribution Services. Citizens proposed a net salvage value of negative 150 percent, with a corresponding depreciation rate of 6.39 percent. Using the depreciation studies presented in the two most recent SUG rate cases and the rates approved by the Commission in those cases, the Company's witness found that the net salvage rates have increased steadily since 1982. Although the Company's witness found that historic data justifies a current rate of negative 200 percent, he considered other non-physical factors affecting retirements and salvage value.

Staff proposed a net salvage value of negative 75 percent. Staff found that the historical data was not sufficient to permit a reliable analysis.[20] In making its recommendation, Staff considered the level

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[19] Staff's analysis of the Company's historical data indicates that the average life expectancy of steel pipe is 55 years.

[20] Staff found that the dollar level of retirement activity associated with this plant account over the last ten years has been minimal--$16,057 of retirements have occurred for a plant account with an outstanding balance of $11,250,047 at year end 1992.

of activity of the historical data, the types of retirements that have occurred, and the frequency of retirements compared to future anticipated levels.

We find that the current net salvage value of negative 130 percent is appropriate for this account at this time. This is supported by the record. From 1989 to the present, the net salvage value has been maintained at negative 130 percent. While there was conflicting testimony presented at the hearing, none was more persuasive than the current value. Consequently, we decline to alter the net salvage value at this time.

Accordingly, we will adjust depreciation expense by ($563,845).

Rate Case Expense

Citizens proposes rate case expense of $165,000. This includes $360,000 of rate case expense amortized over three years; $120,000 of additional rate case expense "attributable to the initial data development that was necessary" because this is Citizens' first rate case for the AGD, to be amortized over six years at $20,000 per year; and $125,000 of costs associated with the design and development of the Build Out Program, to be amortized over five years at $25,000 per year.

Staff recommends a rate case expense level of $275,000, to be amortized over three years at $91,667 per year. Staff's recommendation is based upon a "liberal 'rounding up'" of the rate case level adopted by the Commission in the Citizens Arizona Electric Division case. Staff rounded up the amount to account for one year's worth of inflation as well as the complexities of the Build Out Program.

RUCO recommended a rate case expense level of $251,000, to be amortized over three years at $83,667. RUCO states that its level is supported by reasoning previously presented to and adopted by the Commission regarding Citizens' rate case expense charges. RUCO cites the Company's behavior during the discovery stage of this proceeding; Citizens' decision to relitigate issues previously decided; and increased costs due to Citizens' use of numerous witnesses and Company personnel as reasons for the excessive rate case expenses.

We agree with Staff and RUCO that Citizens' rate case expenses are higher than necessary. As we noted in our Decision concerning Citizens' AED rate proceeding, the level of rate case expense is largely within the Company's control. Citizens has not convinced us that it is serious about controlling its rate case expenses, and there apparently are no internal incentives to contain or manage the resources expended to seek approval for rate increases. Accordingly, we can continue to give Citizens an incentive to control its costs, through disallowance of excessive rate case expense. We find that an appropriate level of rate case expense for the rate case portion of the proceeding to be $300,000, amortized over a period of three years. This level of rate case expense recognizes the fact that this is Citizens' first AGD rate case, as well as the costs associated with the additional purchased gas cost issues that were incorporated into this proceeding. We also believe that $125,000 of costs associated with the Build Out Plan, amortized over ten years, is appropriate. Accordingly, we will adjust rate case expenses by ($54,439).

<u>Property Tax Expense</u>

Citizens' application includes pro forma property tax expense of $1,545,602 for the AGD. RUCO recommended that the property tax expense be reduced to eliminate the amount of taxes associated with the acquisition costs the Company improperly recorded as plant in service. RUCO recommends a ($166,792) adjustment to the actual TY recorded amount of property tax, $1,389,930.

Staff's proposed property tax expense is synchronized to Staff's proposed level of test year end plant in service, and applies the 1993 property tax assessment rate. We believe that it is appropriate to use the 1993 property tax assessment rate, just as we are using the new Federal income tax rate. Consistent with our plant in service determination to exclude the additional $6.2 million acquisition adjustment from rate base, property tax expense should be adjusted by ($346,254).

Income Tax - Interest Synchronization

Applicant, Staff, and RUCO each proposed an adjustment to synchronize the interest component included in the cost of capital with an interest component in the calculation of income tax expense. Applicant and Staff used the same procedure in their calculations, and RUCO's calculation encompassed its hypothetical capital structure. We find that the appropriate adjustment is $120,311.

Miscellaneous Expenses

As discussed above, the parties have agreed to certain miscellaneous adjustments including: synchronization of purchased gas expense with the PGA clause revenues - ($122,923); rate recognition of the electronic meter reading and customer information system - $341,524; correction of the SUG billing error - ($3,060); the exclusion of industry association dues - ($4,946), promotional expenses - ($9,000), donations and social organization dues - ($8,312)

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and miscellaneous expenses identified on Exhibit R-2 Schedule 318 - ($14,678)[21].

Statement of Net Operating Income

Consistent with the foregoing discussion, the adjusted TY net operating income for the AGD adopted for ratemaking purposes is as follows:

Operating Income Summary

TY Operating Revenues (per Citizens)	$33,470,009
Commission approved adjustments	1,171,183
TY Adjusted Operating Revenues	34,641,192
TY Operating Expenses (per Citizens)[22]	34,383,808
Commission approved adjustments	
Purchased gas	649,221
Customer Accounts	8,960
Meter & Billing System	3[illegible]1,524
HAO	(545,680)
SAO	(230,836)
Payroll	(300,201)
Payroll tax	(22,895)
Group Medical Insurance	(111,862)
PBOP	(114,077)
IDCP	(62,022)
D&O liability insurance	(12,392)
Target: Excellence	(50,000)
Depreciation	(563,845)
Rate Case	(54,439)
Miscellaneous	(39,996)
Property tax	(346,254)
TY Adjusted Operating Expenses	32,929,014
TY Adjusted Operating Income	1,712,178
Income Tax	351,116
Net Income	**1,361,062**

RATE OF RETURN

Witnesses from Staff, RUCO, and Citizens presented cost of capital analyses to be considered as evidence by the Commission in determining a fair value rate of return for the purpose of these proceedings. Citizens' witness found the cost of capital to be 10.16

[21] We also adopt RUCO's proposed disallowance of decals.

[22] Excluding income tax.

percent, Staff's witness concluded that 9.11 percent is a reasonable rate of return for Citizens' AGD, and RUCO's witness presented testimony supporting an 8.88 percent rate of return.

Capital Structure

Citizens actual, consolidated capital structure at the end of the TY and the configurations recommended by the parties are as follows:

	Actual	Citizens	Staff	RUCO
Common Equity	61.57%	61.57%	61.57%	50%
Long-Term Debt	38.43%	38.43%	38.43%	50%

Citizens and Staff agree that Citizens actual consolidated capital structure in existence at the end of the TY should be used in determining the rate of return[23]. RUCO recommended that the Commission adopt a capital structure for Citizens consisting of 50 percent equity and 50 percent debt, on the grounds that this capital structure is more cost effective than the Company's requested capital structure. RUCO argues that the risk profile of the parent does not closely resemble that of the AGD and that the parent's risk includes the higher risk of non-utility subsidiaries. RUCO recommends that if the Commission uses the actual capital structure of Citizens, then a lower equity cost would be fair.

We agree with Staff and Citizens that the actual consolidated capital structure should be used in this proceeding to determine the appropriate rate of return. As noted in our previous Decision concerning the Citizens Arizona Electric Division, the AGD has no stand alone capital structure and as a division of Citizens, obtains all of its capital from Citizens.

[23] Citizens originally used a 60/40 percentage, but its final position was to use the actual percentages.

Cost of Debt

The proposed cost of long-term debt by Citizens, Staff, and RUCO were 7.45 percent; 7.22 percent; and 7.26 percent respectively. The numbers used by Staff and the Company reflect the debt of the parent company, but Staff's cost of debt was the actual embedded cost of debt at the end of 1992. Staff believes that use of the embedded cost of debt is more appropriate, because it is known and measurable. We agree and will adopt a cost of debt of 7.22 percent.

Cost of Common Equity

The proposed equity cost rate by Citizens, Staff, and RUCO were 12[24] percent; 10.3 percent; and 10.5 percent[25], respectively.

Citizens' witness, Dr. Morin conducted a discounted cash flow ("DCF") model as well as other analyses. In his DCF method, Dr. Morin adjusted the dividend yield to reflect the time value of quarterly dividend payments. Dr. Morin also included an allowance for floatation costs. Dr. Morin conducted three risk premium estimates, which in conjunction with the results of his DCF results, lead him to recommend that a just and reasonable return on common equity for the AGD lies within the range of 12.00 to 12.25 percent.

Staff performed several analyses in determining the appropriate cost of equity for Citizens. Staff primarily used a DCF analysis, but also used a capital asset pricing model ("CAPM") and a comparable earnings analysis as a check to insure that the recommendation was reasonable. Staff's DCF analysis showed that, giving more weight to

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[24] Citizens' brief states that Dr. Morin estimated that the current cost of equity for the AGD to be 12.125 percent, but in Applicant's comparison schedules, Citizens uses 12.00%.

[25] RUCO's cost of equity is 10 percent if the Commission adopts Citizens' consolidated capital structure.

the DCF study that reflects dividend growth, the range for the cost of equity established by the DCF method for publicly traded natural gas companies was 8.6 percent to 10.9 percent. Staff's CAPM analysis resulted in a range for the present and future cost of equity of 8.1 percent to 10.9 percent. Staff's comparable earnings analysis was conducted on two groups of utilities. One group was for natural gas distribution companies which showed an average of 11.1 percent on common equity for 1992, and the second group (consisting of the fourteen companies sampled used by Staff in its DCF analysis) have an average end year return on equity for 1992 of 9.9 percent. As of June 30, 1993, the average return on equity of the sampled companies was 11.3 percent. Staff's cost of equity excludes floatation costs. In support of its position, Staff cites the Commission's consistent rejection of adjustments to the DCF model to reflect these costs, as well as Citizens' inability to identify any market price effects or out of pocket issuance costs. Staff also rejected the Company's quarterly compoundings of dividends in its DCF analysis. In support of its position, Staff noted that the Commission has consistently rejected adjustments to the DCF model to reflect quarterly compounding; that there is no increased risk from quarterly dividends which justify a higher expected return; and that there is no reason for ratepayers to provide a higher return associated with quarterly compounding when the value of the stock to the investors is already increased due to the earlier dividend payment. Staff further noted that since the time the Company's witness prepared his testimony, the cost of both equity and long-term debt has declined about 100 basis points, and Staff's recommendation reflects this decline in the cost of capital recommendation for Citizens. Taken altogether, Staff's analyses resulted in overall range of 8.1 percent to 11.3 percent.

RUCO's witness, Mr. Hill, estimated the AGD's cost of equity by analyzing market data of a sample of ten gas distribution companies with risks similar to that of the AGD. Mr. Hill used four different analytical methods, including DCF, earnings-price ratio ("EPR"), market to book ratio ("MTB") and CAPM. His primary DCF analysis for the ten sample gas distribution companies produced an average cost of equity capital of 10.46 percent. Mr. Hill's EPR study computed the mid-point of the earnings price ratio and the expected book equity return of the gas distribution sample group. The results were an estimated cost of equity for 1993 of 9.14 percent, and 9.77 percent for the period 1996 through 1998. Mr. Hill concluded that these results validate the results of his primary DCF method. Mr. Hill's MTB resulted in a cost of equity for the sample group of 10.21 percent using 1993 projected data and 10.17 percent using three to five year projections. Mr. Hill concluded these results also verify his DCF analysis. Mr. Hill's CAPM analysis produced equity costs rate estimates of 8.32 percent to 9.40 percent. RUCO's cost of equity does not include any adjustment for issuance expenses or market pressure on stock prices. RUCO argued that the Company's witness' testimony was based on stock prices from early 1993 and risk premium data that were more than a year old at the time of the hearing. RUCO noted that stock prices have risen and bond yields have declined since that time, and substitution of current information confirms the equity return range recommended by RUCO. In its brief, RUCO noted that the results obtained by using current data show a decline in the "raw end" DCF percentages from 11.60 percent/11.45 percent to 10.72 percent/10.14 percent.

Based upon the record evidence, we find that the appropriate cost of equity for the AGD is 10.5 percent.

Cost of Capital Summary

	Percentage	Cost	Weighted Cost
Common Equity	61.57%	10.5%	6.46%
Long-term Debt	38.43%	7.22%	2.77%
TOTAL			**9.23%**

AUTHORIZED INCREASE

With the adjustments adopted herein, the adjusted TY net income is $1,361,062. Further, the 9.23 percent cost of capital translates into a 6.11 percent rate of return on FVRB as authorized hereinabove. Multiplying the fair value rate base by the fair value rate of return produces a required operating income of $2,858,460. This is $1,497,398 more than the adjusted TY income under existing rates. The required increase in gross annual revenues is $2,530,303, or 7.3 percent.

RATE DESIGN

Cost of Service

Citizens' application included a cost of service study that indicated that current rates for large volume commercial, industrial and public authority service provide returns that are above both the current and requested system average rate of return on rate base.

The class cost of service study sponsored by Staff demonstrates that current revenues are reasonably aligned with the cost of providing service.

The parties disagree on the allocations of main investment, O&M expense, and A&G expense. Staff believes that it is appropriate to allocate no less than forty percent of main investment on the basis of throughput in order to recognize the cause of the costs and to reasonably approximate the pattern of cost recovery in more competitive markets. Citizens states that in the past, commercial and industrial customers could be forced to subsidize residential customers, because the commercial and industrial customers had no alternative source of supply. Citizens argues that this situation no longer exists, and if costs are allocated on an uneconomic basis, gas distribution companies risk the loss of commercial and industrial customers.

Staff believes that this increased competition supports Staff's method of allocating mains because changes in Federal Energy Regulatory Commission ("FERC") policy now permit Citizens to recover, through off-system sales, a significant share of the cost of the pipeline capacity reserved to serve the peak period requirements of the AGD. Staff believes that its recommendation assigns a reasonable share of main-related costs to customers that purchase gas primarily during off-peak periods, and that this is necessary to approximate cost recovery in competitive markets and to prevent cross-subsidies between large and small volume customers. We concur and will adopt Staff's recommended allocation of main investment.

Staff allocated two operating expenses on the basis of throughput. We agree with Staff that it is appropriate to use throughput to assign the daily costs of main and station operations to customer classes. We also concur with Staff's proposal for allocation of A&G expenses. We find that it is a reasonable basis for allocating management overheads, because it includes the cost of plant, labor, and materials needed to provide service.

Rate Design

Citizens requests that most of the increase in revenues be recovered through an increase in residential and other small volume service; that the minimum annual sales volume used to define a large volume customer be lowered from an annual usage of 1,000,000 therms to an annual usage of 120,000 therms, and that the therm rate for customers to be served under large volumes remain unchanged. Citizens proposes that the monthly customer charge for the residential, small commercial, public authority, and irrigation classes be increased from $4.50 to $7.00; and that the monthly customer charge for the large commercial, large industrial, and large public authority classes increase from $25.00 to $50.00.

Staff recommended that the Commission spread the authorized increase in revenues among rate classes in proportion to current revenues and increase the customer and commodity charges for residential service by an equal percentage amount.[26]

Staff accepts the Company's proposed customer charges for non-residential customers, the re-definition of "large volume customer"; as well as Citizens' proposed change to large volume service from a declining block structure to a flat rate. Staff agrees with Citizens' proposed changes to small volume service, but Staff proposes to consolidate the first and second rate blocks. Staff recommends that the rate for transportation service be set equal to the corresponding rate for large volume service less the cost of purchased gas, with a rider to the Rate 32 tariff that provides for a discount of $.025 per therm for transmission level service.[27]

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[26] Staff proposes no increase in the gas light rates.

[27] Staff's cost of service study indicated that the cost of serving two large industrial customers who are served directly from transmission facilities is less than the cost to serve other large industrial customers. With the adoption of this rider, the "excess usage" discount that currently applies to these customers is

RUCO proposes that the residential customer charge increase by a percentage that is commensurate with the increase approved for the residential class as a whole, with a $1.00 ceiling. RUCO recommends that the Commission direct the Company to review the reasonableness of the declining block structure for Rate Residential Air Conditioning in connection with its next filing. RUCO also recommended that the Company reduce its tolerance level of its free balancing service and require transportation customers to settle balances monthly. Although we will not require the Company to change its balancing procedure in this proceeding, we agree that the Company, should, as a part of its next rate filing, address the reasonableness of its balancing procedure and determine whether it is causing any "negative impact" to the AGD or its customers.

Consistent with our agreement with the cost of service analysis performed by Staff, we find that the authorized level of increase in revenues should be spread among rate classes in proportion to current revenues. Likewise, we find that the residential monthly customer charge should increase by the same proportion as the increase to the commodity rate; that the minimum annual sales volume used to define a large volume customer be lowered from an annual usage of 1,000,000 therms to an annual usage of 120,000 therms; that the monthly customer charge for the large commercial, large industrial, and large public authority classes increase from $25.00 to $50.00; that the large volume service be changed from a declining block structure to a flat rate; that the small volume service monthly customer charge increase to $7.00 and the first and second block rates be consolidated; and that the rate for transportation service shall be set equal to the

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eliminated.

corresponding rate for large volume service less the cost of purchased gas, with a rider to the Rate 32 tariff that provides for a discount of $.025 per therm for transmission level service, with the elimination of the "excess usage" discount.

Demand Side Management

Staff recommends that the Commission order Citizens to implement a Demand-Side Management ("DSM") program for the AGD. Staff defines DSM as the cost-effective reduction in the total societal cost of meeting the demand for energy service needs by reducing or shifting, in time, the demand for energy. It involves the planning, implementation, and evaluation of programs which will accomplish this in a cost-effective manner. Citizens currently does not engage any DSM in any of its Arizona gas operations. Staff recommends that Citizens evaluate a wide range of DSM measures for all customer classes. Staff has several recommendations concerning DSM including:

- Citizens should conduct a marginal cost study to determine its avoided costs and the study should reflect both short-run and long-run marginal costs and seasonal variations by customer class. The study should be submitted to Staff by December 31, 1994.

- Citizens should conduct a study of the potential for implementing cost-effective DSM within the AGD, for all customer classes, and submit to Staff the results of the study on DSM potential by June 30, 1995.

- If the evaluation of DSM potential and the marginal cost study demonstrate that the incremental societal benefits of DSM are greater than the incremental societal costs, then Staff recommends Citizens engage in DSM in Arizona and submit a DSM plan for Staff review and preapproval, by December 31, 1995.

- Citizens should obtain prior approval from Staff before implementing any program or project identified in the DSM program plan.

- Staff recommends that Citizens recover the program costs associated with preapproved DSM programs. Recoverable program costs include administrative expenses, monitoring expenses, the value of any incentives, promotional expenses and educational program expenses. This would include the prudent cost incurred in designing, evaluating, and implementing preapproved programs. Additionally, Staff recommends that Citizens should recover lost net revenue resulting from a DSM program once the Company completes its monitoring and evaluation.

- To recover these costs Staff recommends that a conservation account be established, in which the aforementioned costs would be recorded and deferred for recovery in Citizens' next rate case.
- Staff recommends that Citizens submit for preapproval an administrative plan which details how the Company will administer this account prior to entering any monies in the account.
- To help Staff monitor Citizens' DSM efforts, Staff recommends the Company submit semi-annual progress reports due on August 15 and April 15 of each year containing specific information.

Citizens says that it generally supports DSM but is troubled by aspects of Staff's proposal for the AGD. Citizens' concern primarily relates to the probable costs of implementing the proposal and opportunities Staff has suggested for recovering costs through rates. Citizens also questions why Staff believes it is better to implement DSM for Arizona gas utilities on a company-by-company basis instead of through a generic proceeding involving all jurisdictional gas distribution companies. Citizens was not clear whether under Staff's proposal, DSM's startup costs must be borne by Citizens' shareholders or whether Staff would be amenable to allowing the AGD to defer all start-up costs for possible recovery in future rate cases. The Company is also concerned that the benefits Staff expects will result from DSM can not be cost justified. Citizens believes that many of the DSM measures are currently being promoted as part of DSM programs already under way by Arizona electric utilities.

Staff believes that the Company's concerns are ill founded. Staff notes that Section 115 of the Energy Policy Act of 1992 encourages investment in conservation and energy efficiency by gas utilities. Staff believes that there are significant opportunities for cost-effective DSM in Citizens' service territory, because it encompasses some of the colder portions of the state. Staff notes that Citizens relies on Southwest Gas' experience in northern Nevada, but does not know how that state's cost-effective test compares to the one used in Arizona. Staff believes that the Company's concerns regarding cost recovery are adequately addressed by the Staff recommendations. Specifically, Staff recommends that costs to be included in the deferral account would include prudent costs incurred in designing, evaluating, and implementing the programs. Staff believes that should Citizens' prudent research efforts in the marginal cost study and DSM potential study indicate that no DSM programs would be cost-effective, Staff would recommend that Citizens should also be able to recover reasonable research costs, which could be done through the preapproval of the marginal cost study.

We believe that Staff's recommendations for Citizens to begin exploring cost-effective DSM programs in the AGD are appropriate at this time. As there is currently no generic proceeding to guide this DSM process for gas, we will apply the definitions, procedures, cost-recovery including start-up costs, guidelines and theories adopted in Decision No. 58643 in Docket No. U-0000-93-052 for Integrated Resource Planning until such time that a generic proceeding for gas DSM is adopted or until the next rate case.

BUILD OUT PLAN

Decision No. 57647 authorized Citizens to acquire all natural gas distribution facilities owned and operated in Arizona by SUG. The Decision ordered Citizens to "submit a long-term plan of at least 5 years to the Director of the Utilities Division concerning extension of service" in its certificated area. On July 19, 1993, Citizens filed its application which included its "1993-1997 Build Out Plan". Under the Build Out Plan as filed, Citizens proposed to spend approximately $53 million dollars in capital improvements over a five-year period commencing in 1993 and ultimately providing service to more than 20,000 customers.

Citizens believes that its Build Out Plan is unique in many respects including: its scope; the "long-term service ethic it represents"; the investment required to extend service; the financing to be used for significant portion of the required capital investment; and the regulatory innovations it seeks to implement. Citizens believes that the Build Out Plan provides needed additional investment to meet the long-term service requirements of the AGD existing and future customers. The Company plans to refurbish and improve its existing infrastructure to insure that current customers' current and future needs will be met, and also to expand service to new customers in those communities where natural gas utility service is currently available. The Build Out Plan also includes the extension of natural gas utility service to residents in portions of the AGD's service area that do not currently have such service.

As proposed by the Company, the Build Out Plan includes all construction planned for the AGD during the period January 1, 1993 through December 31, 1997. This includes infrastructure refurbishments and improvements; expansion of facilities to serve new customers in new areas within communities currently receiving natural gas; and extension of infrastructure pipeline mains and service lines to and within communities in the AGD service area that are not currently receiving natural gas service. The Company estimates that these construction expenditures will more than double Citizens' current investment in the AGD.

One part of the Build Out Plan is Citizens' promise not to seek general rate relief to become effective before July 1, 1998. The Build Out Plan contemplates that a general rate case will be filed in 1997 as part the proposed "true up" mechanism, but the rates would not take effect prior to July 1, 1998. Citizens believes that this moratorium would benefit the customers because it would provide a significant degree of rate stability during the Plan period; it protects customers from the effects of factors that tends to increase the utility's costs of service over time (i.e., rate case expense); it will prevent the Company from relitigating issues adversely decided in this proceeding until the general rate case to be filed in 1997; and it prohibits Citizens from seeking to increase its authorized rate of return during the period.[28]

Another component to the Build Out Plan is annual step rate increases. Citizens believes that if it invests $53 million contemplated in the Build Out Plan together with a rate case moratorium, the Company will suffer significant and serious reduction in future earnings unless the requested regulatory measures are adopted. In order to mitigate the effect on future earnings of the investment and related costs included in the Build Out Plan, the Company seeks authority for three step rate increases that will apply

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[28] In its Brief, Citizens states that any such rate case moratorium, (as well as all components of the Plan, especially the post-in-service AFUDC to all plant as well as step rate increases) is contingent on the Commission's acceptance of the Company's Build Out Plan in total.

to all customers of the AGD. Citizens proposes that the Commission determine certain levels of revenues, expenses and rate base, as well as fair rate of return, in this rate proceeding. These levels would form the basis for the subsequent step rate increases. Citizens has designed the model, which is actually a computer program, with the purpose of reflecting the inter-relationship of each aspect of the AGD's cost of service. Citizens proposed an annual review process to precede the step rate increases whereby the results of the AGD'S operations for the proceeding calendar year, adjusted for specific findings of the Commission in this proceeding, would be input into the model. If the adjusted results of operation show the Company exceeded the rate of return authorized by the Commission in this proceeding, no step increase would be implemented. However, if the results of operations show the earned rate of return is equal to or less than the authorized rate of return, the review process would begin to determine the amount of step increase based on projections of rate base and earnings. The Company's review proposal also includes a final "true up" procedure that will allow the parties to review the AGD's actual result of operations at the end of the Build Out Plan to make sure earnings did not exceed the Company's authorized rate of return for the entire Plan.

The Company has also requested that it be allowed to accrue post-in-service allowance for funds used during construction ("AFUDC") for all capital expenditures in the AGD.[29] Citizens' post-in-service AFUDC would allow the Company to continue to accrue AFUDC,

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[29] Traditionally, AFUDC is accrued during construction at a rate equal to the actual cost of funds used to finance the construction. When construction is completed the accrued amount of AFUDC is included in utility plant and transferred to plant in service.

even though construction is completed, until new customers are added to the AGD system. As new customers are added, construction expenditures would be transferred to plant in service and then would no longer accrue post-in-service AFUDC.

Another feature of the Build Out Plan is Citizens' request for a "new service area multiple" ("NSAM"). Citizens proposes the NSAM charge in order to mitigate potential subsidy by lower cost current customers on behalf of the higher cost new customers. Citizens proposes a NSAM charge equal to 150 percent of current rates, which would apply to areas not currently being provided with gas service. Citizens believes that if the Commission authorizes the NSAM it will place the burden of increased costs required to provide service to new customers in new areas where it belongs: on the new customers themselves. The Company proposes that the NSAM charge remain in effect at least until rates set in the next general rate case scheduled for 1997 are effective.

Staff generally supports the Company's Build Out Plan. Staff recognizes that there is a strong interest among persons in Citizens' certificated area for natural gas service, and no party to the proceedings has disputed that Citizens' expansion of gas service would be in the public interest. Staff believes that its recommendation is the best balance between the competing interests of the Company and the ratepayers in deciding how to accomplish the expansion in the most equitable manner. Staff has proposed that some of the Company's requested rate and accounting methods be adopted. Staff recognizes the Build Out places a fairly significant short-term drain on the AGD earnings and therefore Staff's recommendations are designed to address this problem.

Staff recommends that the Commission adopt the Company's proposed post-in-service AFUDC treatment, but limit such treatment to plant investment in new service areas. Staff believes that this recommendation would give Citizens sufficient motivation to invest in the new service area, but Staff believes that such treatment is not appropriate for property additions in its existing service territory, as such investment is more "business as usual".[30] Staff recommended that Citizens calculate post-in-service AFUDC consistent with the FERC Accounting Release No. 13. Staff further recommended that Citizens file with the Commission the projected AFUDC rate and total amounts to be capitalized at the beginning of each calendar year, as well as the actual AFUDC rate implemented in total amounts capitalized at the end of each calendar year. The Company has not objected to these recommendations concerning the procedures and methodologies.

Staff recommends that the Commission adopt a 140 percent NSAM to be charged in areas not currently receiving gas service. Staff noted the discussion in the hearing involving determinations of areas to be charged NSAM. The Company proposed two alternatives for the Village area. Under the first option, which Staff has adopted, all customers taking gas service on or before the effective date of this Decision would not be charged a NSAM. Under this option the NSAM would be removed effective the date the new rates go into effect from Citizens' next general rate case or July 1, 1998. The second option presented by the Company is that it would not charge the NSAM to any new

[30] Staff noted that it was especially concerned in light of the items which would be given such treatment under Citizens' request. As proposed by the Company, post-in-service AFUDC would apply to all capital expenditures in the AGD, including desks purchased for Flagstaff, main extensions in Kingman, etc., which have nothing to do with service extension to new territories.

customer in the Verde Village area, and instead would raise the AFUDC rate for the entire Build Out to replace the income lost by not charging the NSAM in the area. Staff believes that the first option is the better option. Staff recognizes that there are fairness concerns involved in instances where neighbors would be paying different rates for gas service, but at the same time Staff realizes that the revenues to be derived from charging the NSAM in Verde Village constitute a significant portion of the Company's total build out revenue.

Staff opposes Citizens' proposal regarding the multi-year step rate increases for several reasons. Staff has problems with the model developed by the Company and believes that the model contains simplified assumptions which were not well documented. Staff also is concerned that in an expedited annual review process, with a track record like Citizens has in responding to discovery deadlines, the parties would be seriously limited in their ability to review all relevant matters that should and would ordinarily be considered. Staff believes that this would greatly undermine the rate making process by preventing Staff or other parties from inquiring into the propriety and reasonableness of the Company's expenditures. Finally, Staff is concerned that the Company's proposal is tantamount to a multi-year rate case based upon forecasted test years, noting that the Commission uses a historical TY.

Staff also recommends that the Commission can and should order Citizens to undertake the Build Out Plan. Staff noted that the Company inferred that if the Commission did not adopt all the alternative ratemaking treatments, the Company would not perform the Build Out Plan. Staff noted the position was softened at hearing, with the Company stating that it would still undertake the Build Out project, but it would simply take longer. Staff suggests that the Commission consider ordering Citizens to complete the projects, regardless of which ratemaking treatment is ultimately adopted. Staff believes that the Commission has such authority and should consider exercising it in this case.

RUCO believes that the Company's Build Out proposal is unacceptable. RUCO has serious reservations regarding the data used by the Company to prepare and/or support its Build Out Program. RUCO cited the lack of an econometric model and the absence of data regarding key variables. RUCO believes that Citizens' future customer requirements may be overstated and that per customer usage may be improperly based and distorted for a variety of reasons. RUCO's greatest concern is that the Build Out Program is based upon projections.

RUCO recognizes and supports the goal of providing natural gas service to communities that are not presently served, but believes that the proposed Build Out Plan goes well beyond such a goal. RUCO defines the true "build out" as the incremental $4.659 million construction expenditure to extend gas service into the communities that presently do not receive gas service. RUCO believes that Citizens' proposal goes well beyond those construction expenditures, however, and demands special ratemaking treatment for all of its planned construction. RUCO believes that the Company has not demonstrated a need for, or any other basis that could justify approval of the requested rate making concessions and innovations contained in the Company's Build Out proposal. RUCO proposes that the Commission approve only limited and modified elements of that proposal. RUCO supports and recommends the adoption of a post-in-service allowance in this "unusual situation" as an incentive to the Company to supply natural gas in response to the demand for its availability in presently unserved areas. RUCO recommends the special post-in-service allowance only on the approximate $4.659 million of additional infrastructure construction.[11] RUCO recommends that the Commission set a ceiling rate on this allowance and proposes that 8 percent is an appropriate level given the availability of industrial development revenue bonds ("IDRB") funding and the approximate 7 percent return for the Company alternative uses of funds. Recovery of the amount of the accrued allowance would begin when the in service plant would be rate based during the Company's next rate case.

RUCO further recommends that the Company be allowed the 150 percent NSAM charge on the condition that Citizens' proposed step rate increases are denied. RUCO believes that the NSAM should be applied only to customers in new service areas based on the recognition that the cost of providing gas service to those customers is significantly greater than the cost of providing service to customers in the AGD's existing service areas.

In our Decision No. 57647, we ordered Citizens to submit a long term plan of at least five years concerning extension of service. In response, Citizens submitted an aggressive Build Out Plan which would provide service to several new areas within five years and would also expend significant funds refurbishing and improving its existing infrastructure. It appears to us that Citizens has taken our

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[11] That infrastructure includes $3.355 million incremental costs for expansion of the Sedona pipeline installation projects to areas that are not presently served and $1.304 million for additional infrastructure necessary to serve Pinetop/Lakeside.

directive and combined it with plans to expend considerable sums on existing infrastructure in its Build Out application. In doing so, the Company has tied all of its investment to the approval of the "special rate making treatment" requested.

We have a number of concerns with the Build Out program as presented by the Company. Although Citizens cites that its investment in the AGD would double during the term of the Build Out, it has not convinced us that special regulatory treatment for all capital expenditures is necessary to allow the Company the opportunity to earn a fair rate of return. We agree with Staff and RUCO that those special regulatory treatments may be appropriate with new service areas, but the other expenditures for existing infrastructure are "business as usual" and Citizens has not provided sufficient rationale to part from traditional ratemaking treatment in those areas. We find no reason to give an incentive to Citizens to improve and refurbish its infrastructure. As a public service corporation certificated to provide service within its certificated service area, Citizens has a responsibility to provide safe and efficient service to its customers.

We agree with RUCO and Staff that the step increase requests should not be approved. It was clear to us from the hearing that there were problems with the Company's model. The model, and the procedures for determining when and if a step increase should go into effect were not understood by the parties. Based on the record evidence, we are not convinced that the computer program developed by Citizens has been studied extensively enough to give it our approval. There are assumptions in the computer model which were not explained and which were not litigated by the parties in the hearing. We decline to accept the computer model, which would conclusively establish whether step rate increases were necessary, based upon data input. We believe that such a model and process limits review by the parties and by the Commission and we are not convinced, based on the experience in this proceeding, that the review procedure would be conducted cooperatively by all the parties. We also agree with Staff's concern that as designed, the model appears to lean towards the result such that the Company would always be more likely entitled to a step rate increase. Although we do not find it necessary to resolve the issue concerning the lawfulness of the step rate increases because our decision is based on other reasons identified hereinabove, we do agree that setting rates without considering all elements, including the appropriate rate of return, at the same time is not appropriate during the time period of the Build Out. For these reasons, we will not approve Citizens' request for step rate increases.

We agree with Staff and RUCO that the NSAM charges are appropriate and will help to prevent the subsidy between old and new customers. We agree with RUCO and the Company that the NSAM should be at 150 percent the current rates. We also find that Verde Village option number one, which would not apply NSAM charges to customers who take gas service prior to the effective date of this Decision, is a more appropriate option.

There was much discussion during the hearing concerning the specific areas that will be charged the NSAM. In order to avoid customer confusion as the Build Out Plan is implemented, we have attached to this Decision Citizens' Exhibit A-53 in order to define the areas that will be assessed the NSAM. The Build Out Plan consists of the following areas: Village of Oak Creek, Verde Village, Pinetop-

Lakeside, Camp Verde and Cornville.

We agree with Staff and RUCO that post-in-service AFUDC should not be allowed for capital expenditures other than those associated with providing service to the new service areas. Consistent with our decision not to approve step rate increases and AFUDC on all plant investment, a moratorium on rates would not be appropriate.

As far as Staff's recommendation that we consider ordering Citizens to proceed with the projects, we agree that we have such authority. Our Decision No. 57647 indicated our desire that Citizens proceed with a plan to provide service to areas within its certificated area which desire gas service. Citizens has demonstrated that this is possible and that the infrastructure needed is approximately five million dollars. The fact that Citizens also has the need for additional infrastructure refurbishment and improvements should not affect its decision to proceed with the extension of its service to new service areas. However, we will note that our decision did not "mandate" a five year Build Out program, it required Citizens to submit a program with <u>at least a five year term</u>.

PURCHASED GAS ADJUSTOR

In Decision No. 58420 (September 30, 1993), we deferred to this rate case a determination regarding the propriety of passing pipeline charges from Transwestern Pipeline Company ("Transwestern") through the PGA mechanism to ratepayers. The predecessor owner of the AGD, SUG, entered into a contract for firm capacity on the Transwestern system in July 1990. The contract provided, in part, for a maximum daily quantity of 25,000 dekatherms of capacity; 10,000 dekatherms for delivery to the Kingman service area and 15,000 dekatherms for the Flagstaff service area. At the time of contracting with Transwestern, SUG had a full requirements contract with El Paso Natural Gas ("El Paso"). In 1991, Citizens acquired the AGD and assumed the contractual relationships of SUG pertaining to the El Paso and Transwestern pipelines. Decision No. 57647 subjected Citizens to those terms and conditions previously imposed upon SUG by the Commission concerning its PGA mechanism.

Transwestern Pipeline Capacity Charges

Citizens' witness, Mr. John Cogan, testified that the Company's firm capacity reservation on the Transwestern pipeline is reasonable and prudent to cover the differential between the demand of AGD's customers under design day conditions[12], and the maximum daily capacity available from El Paso. The Company argues that all Transwestern costs should be recoverable from ratepayers since the underlying decision to enter into a firm capacity contract with Transwestern was reasonable when viewed in conjunction with testimony from Staff's witness, Mr. Lelash, in Docket No. U-1240-90-051, recommending that SUG seek diversified gas supplies. Citizens attributes the following beneficial consequences to the availability of Transwestern capacity: it placed competitive pressure on EL Paso to expend $2 million for expansion of its facilities to AGD's Clarksdale, Cottonwood, and Sedona areas; it provides capacity to allow for AGD's projected future growth; it improves security of gas supply to Flagstaff and Cottonwood; and it precipitated cost reductions from El Paso. Citizens has projected that the construction required to integrate Transwestern supplies into the Flagstaff distribution system will occur in the 1994-1995 heating season.

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[12] Design day conditions represents the demand placed upon the system to deliver gas service to customers in the coldest weather conditions.

Citizens' witness, Mr. Terzic, testified that a time lag of two to three years is not unreasonable since Citizens acted prudently in analyzing SUG's construction plans and then delaying construction to develop its own construction plans for integrating the Transwestern capacity into its service territory. Mr. Terzic also points out that construction was delayed until construction and routing approvals from FERC could be obtained and this was a matter outside the control of the Company.

Mr. Richard Kauffman testified for RUCO that only 1,460 of the 25,000 dekatherms of capacity purchased from Transwestern is necessary to serve current customers in existing design day loads in Flagstaff, exclusive of El Paso displacement, and, therefore, recommends the disallowance of $3,030,200 in Transwestern reservation costs accumulated from March 1992 through October 1993.[33] (Exhibit R-20, Schedule RVK-2) In suggesting that the Commission disallow the net annual pipeline costs of reserving capacity on the Transwestern, Mr. Kauffman concludes that the Transwestern contract was not prudent since the benefits of having Transwestern as a secondary supply source are outweighed by its annual reservation costs of approximately $4 million. Mr. Kauffman recommends that $3,030,200 million be returned to ratepayers through a credit to the Company's PGA bank account. Since pipeline costs are now specifically identifiable, known, and measurable fixed costs, Mr. Kauffman suggests that these costs be

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[33] Ruco's recommended disallowance was computed as follows: $594,694 in capacity releases credited to the PGA account were subtracted from the total capacity reservation charges of $4,008,454 to arrive at net capacity reservation charges of $3,413,760. From the $3,413,760 RUCO subtracted $338,125 to account for the 1,640 dekatherms required for current Flagstaff customers and $45,435 for a variable transportation cost credit to arrive at a net disallowance of $3,030,200.

removed from the fuel adjustor clause and included in base rates. Mr. Kauffman also recommended that Transwestern capacity costs subsequent to October 1993 should be recoverable only to the extent justified by customer growth, so that customer demand, including provision of reasonable reserve for weather variation and other contingencies, matches the need for additional pipeline capacity.

The following reasons were stated to support Mr. Kauffman's findings and conclusions:

- Citizens has displaced available El Paso capacity with more expensive Transwestern capacity without an overall increase in pipeline capacity utilization;
- Citizens' total reserved capacity in the El Paso and Transwestern pipelines exceeds its current customer demand;
- virtually no substantial competitive benefits can be directly attributed to the Transwestern capacity; and
- the cost of reserving excess capacity on the Transwestern pipeline is not justified by the Company's allegations of supply shortage problems and service disruptions since there has been only one incident of service disruption which occurred in December 1990, and affected approximately 665 customers in the Flagstaff vicinity.

Staff's witness, Mr. Steven Andersen, concluded that the prudence of SUG's decision to contract with Transwestern was supported by the evidence, but Citizens' failure to effectively utilize and access the available capacity should preclude full recovery of associated costs through the PGA. Mr. Andersen recommended that the Commission disallow: $1.3 million of capacity reservation charges paid for Transwestern service at Flagstaff between December 1992[34] and October

[34] December 1992 is the date when 15,000 dekatherms of Transwestern capacity became available to Citizens at Flagstaff. The $1.3 million disallowance represents 54.16 percent of the net cost of reserving Transwestern capacity, with 54.16 percent

1993; and 90.27 percent of the cost of reserving Transwestern capacity to serve Flagstaff from November 1993 through the date of completion of the distribution capacity required to access the full 15,000 Dth. The disallowance represents 13,450 Dth of Transwestern capacity that is currently unavailable to ratepayers, not used, and not useful because Citizens has not completed the distribution facilities to access the capacity. Mr. Andersen also concluded that the time lag in completing the required distribution plant exceeds three years even assuming that Citizens could not begin physical construction prior to Transwestern receiving final FERC certification in August 1991. However, Mr. Andersen believes that the time lag for preconstruction planning realistically exceeds four years when measured from the date of executing the contract with Transwestern in 1990. Staff contends that ratepayers should not bear the expense of the cost of the Transwestern capacity that is unavailable, not used, and not useful, notwithstanding whether the delay in constructing facilities resulted from Citizens' decision to reevaluate and revise SUG's construction plans or additional approvals required by FERC for routing modifications. With respect to Transwestern capacity purchased to serve Kingman, Mr. Andersen proposed no adjustment to associated costs. Mr. Andersen concluded that although only 64 percent of the Transwestern capacity at Kingman would be utilized under design day conditions it was not unreasonable to permit the costs associated with the remaining 36 percent of capacity to be allowed in order to serve

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calculated as follows: 13,540 Dth unavailable for use at Flagstaff as the numerator and 25,000 Dth of total reserved Transwestern capacity as the denominator. The disallowance is also referred to as 90.27 percent of the cost of reserving capacity at Flagstaff since only 9.73 percent of the Flagstaff capacity is being utilized by Citizens.

future growth.

We agree with Staff that SUG's initial decision to contract with Transwestern for a second source of supply was prudent under the circumstances, but the record does not support Citizens claim that contract quantity itself of 25,000 Dth was reasonable. On the contrary, the evidence suggests Transwestern capacity is approximately 90 percent more costly than service from El Paso, that Citizens is displacing El Paso capacity with the more expensive Transwestern capacity, and that insufficient distribution systems still exist preventing Citizens from accessing 13,540 Dth of the Transwestern capacity reserved at Flagstaff. Although it is difficult to state a general rule of reasonableness in which to measure the time lag in constructing distribution facilities, the record is clear that distribution facilities to Flagstaff have not yet been completed and approximately 91 percent of the Flagstaff reserved capacity is still not accessible four years after SUG's initial contract with Transwestern. Notwithstanding that the time lag resulted from the Citizens review of SUG's distribution plans, merger delays in the acquisition of the AGD, or time delays in obtaining additional FERC approvals, we do not believe that there is justification to charge ratepayers through the PGA clause for capacity that is unavailable and unaccessible by Citizens. This is true whether the time lag is two years or four years. Citizens, not the ratepayers, should bear the cost of the 13,540 Dth of contracted, but unaccessible, capacity available at Flagstaff, therefore we concur with Staff's recommendation to disallow reservation charges for excess capacity. Therefore, we will disallow $1.26 million of Transwestern capacity reservation charges paid for service at Flagstaff between December

1992 and October 1993. Furthermore, we also concur with Staff that on a prospective basis 90.27 percent of the cost of reserving Transwestern capacity at Flagstaff be disallowed from November 1993 and until such time as Citizens indicates to the Commission that the distribution facilities are installed and that the Company has full access to 15,000 Dth from Transwestern. We will utilize RUCO's recommendation to the extent that the $1.26 million disallowance relating to the period of December 1992 to October 1993 shall be returned to ratepayers as a credit to the PGA bank account. This will provide ratepayers with an immediate benefit by reducing any undercollection in the PGA bank account.

Finally, we agree conceptually with Citizens and Staff that some excess capacity at Kingman should be reserved for future growth, but disagree that 36 percent of the Transwestern capacity is an appropriate amount for future growth. Although Mr. Kauffman opposed current customers paying for capacity charges to benefit new customers in the future, he also recognized that there can be benefits to current users of reserving capacity for future growth. We believe that 20 percent is a more reasonable figure to appropriate for future growth. This is especially true since the 64 percent utilization of Transwestern capacity at Kingman is calculated based upon design day conditions which represent worst-case weather scenarios. Therefore, we will also disallow 16 percent, or $247,351, of the net Transwestern capacity charges at Kingman from June 1992 through October 1993, which the Company will credit to the PGA bank account. Commencing November 1993, 16 percent of the net Transwestern capacity charges at Kingman will also be disallowed as a fixed cost to be included in the PGA.

. . .

Retention of PGA Mechanism

Mr. Kauffman opposes the abolition of the PGA mechanism at this time, but recommends that the mechanism be modified to exclude pipeline capacity costs and restricted to the recovery of deferred gas commodity costs and associated variable transportation costs. The instability of gas prices and the absence of long term contracting are two conditions which weigh against the elimination of some form of PGA for Citizens at this time. Mr. Kauffman recommends that allowable pipeline costs of El Paso and Transwestern should be removed from TY gas costs reported in this rate case. The allowable pipeline capacity charges should be reassigned as a separate item in the cost of service study and allocated among classes on the basis of adjusted TY sales volumes, thus permitting new rates to be derived.

Although we are not persuaded to adopt RUCO's recommendation at this time, we agree that the PGA mechanism should be reviewed in the next Citizens Gas case to determine whether allowable fixed pipeline capacity costs should be eliminated from the PGA and reassigned to base rates, thereby restricting the PGA to recovery of deferred gas commodity costs and associated variable transportation costs.

Staff recommends that the Commission retain Citizens' PGA clause at this time, but suggests that the recoverability of the future cost of El Paso transportation service be reserved as an open issue. Mr. Andersen concurred with Citizens that the existence of the PGA may reduce the frequency of rate cases and that an elimination of the PGA would result in potential volatility of earnings.

Citizens asserts that its purchased gas costs represent a very substantial expense of the Company, therefore without a PGA clause even small fluctuations in the cost of gas would have significant impact upon earnings. Utilization of the PGA reduces rate shock, reduces the frequency of rate cases, permits cost savings to be immediately credited to customers, and reduces business risk by allowing for the timely recovery of gas cost fluctuations. Citizens indicates that the potential volatility of earnings, given the current uncertainty in the natural gas market and industry reforms, justifies the retention of the PGA.

We concur with the recommendation offered by Staff and the Company to retain the PGA clause in its present form at this time. The record indicates that all parties have concurred that the gas cost component is a very substantial expense of the Company. As such, the PGA mechanism permits the Company to react to market fluctuations expediently in the regulatory environment in order to avoid severe impact on the Company's earnings and rate shock to the customers. Elimination of the PGA clause would require the Company to file rate cases on a more frequent basis which could substantially prolong and burden the regulatory process and hinder the Company's ability of responding to volatile market conditions.

Base Cost of Gas

Citizens presented testimony using historical data indicating the base cost of gas was $0.30086 per therm. Staff presented testimony using both projected and actual data that the base cost of gas was $0.2917. We find that the current base cost of gas, $0.3000 per them should remain unchanged.

* * * * * * * * * *

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

FINDINGS OF FACT

1. Citizens is a Delaware corporation engaged in providing public utility gas service, through its Arizona Gas Division ("AGD") to the public in certain portions of Apache, Coconino, Mohave, Navajo, and Yavapai counties, Arizona.

2. On April 2, 1993, Citizens filed an application for approval of a general increase in rates and charges for gas service and for approval of the proposed accrual method of accounting for postretirement benefits other than pensions, as required by the Financial Accounting Standards Board, Statement of Financial Accounting Standards No. 106 ("FAS 106") for all of Citizens' Arizona utility operations.

3. On July 19, 1993, Citizens filed its 1993-1997 Build Out Plan application with the Commission, which was subsequently consolidated with the rate application.

4. In accordance with A.A.C. R14-3-101, a Procedural Order was issued May 27, 1993, which order was subsequently amended by Procedural Orders dated August 24, 1993 and October 6, 1993.

5. In accordance with the Procedural Order, Citizens provided notice of its application for an increase in rates by mailing a copy of the notice to each of its customers.

6. Public hearings were held on the application in Flagstaff, Kingman, Prescott, Sedona, and Show Low, Arizona and at the Commission's offices in Phoenix, Arizona, on the dates indicated hereinabove.

7. For ratemaking purposes, Citizens' adjusted TY revenues were $34,641,192, its TY operating expenses, including income tax expense, were $33,280,130, and its existing rates provided TY net operating

income of $1,361,062.

8. For ratemaking purposes, Citizens' OCRB, RCNRB, and FVRB for the TY ended September 30, 1991 are determined to be $30,622,293, $62,944,321, and $46,783,307.

9. A fair and reasonable rate of return on Citizens' FVRB is 6.11 percent.

10. Operating income of $2,858,460 is necessary to yield a 6.11 percent rate of return on the FVRB.

11. Citizens must increase operating revenues by $2,530,303 to produce operating income of $2,858,460.

12. Citizens' proposed increase of $6,590,294 would produce an excessive return on its FVRB.

13. Based upon the cost of service studies, the level of increase authorized herein, and schedule simplicity, the revenue distribution method described herein is appropriate in this case.

14. Citizens should use the pay-as-you-go accounting method for ratemaking purposes to account for its post retirement benefits other than pensions.

15. Citizens should, as part of its next rate application, address the reasonableness of the balancing procedure it uses for transportation customers.

16. Citizens should maintain weather normalized gas sales data and reflect such weather normalized gas sales in future filings.

17. Staff's recommendations concerning exploring cost-effective DSM programs are reasonable and appropriate.

18. Since we have not established a DSM process for gas, we will use the definitions, procedures, cost-recovery including start-up costs, guidelines and theories adopted in Decision No. 58643 for

Integrated Resource Planning.

19. The previous owner of the AGD, SUG, entered into a contract with Transwestern in July 1990, to provide a maximum daily quantity of 10,000 Dkh of capacity for delivery to the Kingman area and 15,000 Dkh for the Flagstaff service area.

20. SUG had a full requirements contract with El Paso at the time of executing its contract with the Transwestern pipeline.

21. In Decision No. 57647 (December 2, 1991), the Commission authorized Citizens' acquisition of the AGD from SUG and subjected Citizens to the terms and conditions of SUG's existing PGA mechanism.

22. The Commission in Decision No. 58420 (September 30, 1993), deferred until this rate case a determination regarding the propriety of recovering fixed pipeline reservation charges through the PGA mechanism and provided that to the extent that certain reservation charges paid from June 1, 1992 forward, constitute payment for unreasonable excess pipeline capacity, those charges be subject to refund.

23. We find that the SUG's decision to contract with Transwestern for a second source of supply was prudent, but that full recovery of the Transwestern reservation charges is precluded since a portion of the contract quantity of 25,000 Dth represents unreasonable excess capacity.

24. Approximately 90.27 percent, or 13,540 Dth, of the Transwestern capacity reserved at Flagstaff is unavailable and unaccessible by Citizens.

25. The method recommended by Staff for computing the disallowance of Transwestern capacity reservation charges paid for service at Flagstaff is reasonable and should be adopted.

26. We find that $1.26 million of the Transwestern capacity reservation charges for service at Flagstaff for the period December 1992 through October 1993, constitute payment for unreasonable excess pipeline capacity and should be disallowed from the PGA and subject to refund.

27. The method of refunding excess Transwestern pipeline capacity charges to ratepayers as a credit to the PGA bank account recommended by RUCO is reasonable and should be adopted.

28. The Commission agrees with Staff's recommendation to disallow recovery in the PGA for 90.27 percent, 13,540 dth, of Citizens' contracted capacity for Transwestern Capacity charges for service at Flagstaff commencing November 1993, and continuing until Citizens has installed distribution facilities to permit full access to 15,000 Dth of Transwestern capacity at Flagstaff.

29. Based upon design day conditions, Citizens utilizes 64 percent of the 10,000 Dth of Transwestern capacity available at Kingman.

30. We find that 20 percent of the Transwestern pipeline capacity at Kingman is reasonable excess capacity to appropriate for future growth and 16 percent is determined to be unreasonable excess capacity.

31. We find that $247,351 of the Transwestern capacity reservation charges for service at Kingman for the period June 1992 through October 1993, constitute payment for unreasonable excess pipeline capacity and should be disallowed from the PGA and subject to refund.

32. From November 1, 1993 forward, Transwestern reservation charges for daily capacity in excess of 8400 dth at Kingman will be

disallowed as a fixed reservation cost in Citizens' PGA mechanism and will be subject to refund.

33. The PGA mechanism should be retained since it permits the Company to quickly react to market conditions in order to avoid rate shock to customers and severe impact on the Company's financial viability.

34. We find that the authorized base cost of gas shall remain at $0.3000 per therm.

35. Citizens should be allowed to charge a NSAM of 150 percent of current rates only in areas considered part of the proposed build out plan, including the new customers in the Cottonwood-Verde Village area who take gas service after the effective date of this Decision, until new rates go into effect from Citizens' next general rate case or July 1, 1988.

36. Citizens should be allowed post-in-service AFUDC only to plant investment in the build out plan. Post-in-service AFUDC will be allowed only on the plant investment for infrastructure pipelines, distribution feeders and new business distribution estimated to cost $14,224,000 in 1992 dollars and $15,649,400 in current dollars.

37. With the approval of the NSAM charge and the post-in-service AFUDC, Citizens' requested multi-year step rate increases are not necessary for the Company to earn a fair return.

38. Citizens should calculate post-in-service AFUDC consistent with the FERC AR No. 13 and file with the Commission the projected AFUDC rate and total amounts to be capitalized at the beginning of each calendar year, as well as the actual AFUDC rate implemented and capitalized at the end of each calendar year. In calculating post-in service AFUDC, the rate should be calculated based on the actual

sources of financing utilized. However, the rate shall in no instance exceed the weighted average cost of capital approved in this order.

39. With the modifications adopted herein, Citizens' Build Out Plan should be approved.

CONCLUSIONS OF LAW

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

2. The Commission has jurisdiction over Citizens and of the subject matter of the application.

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

4. The rates and charges for gas service proposed by Citizens are not just and reasonable.

5. The Build Out Plan as proposed by Citizens is approved with the modifications discusses herein.

6. The rates and charges established hereinafter are just and reasonable.

7. Citizens should be authorized to file revised tariffs for gas service consistent with the above Findings of Fact and the discussion herein under Authorized Increase and Rate Design.

ORDER

IT IS THEREFORE ORDERED that Citizens Utilities Company (Arizona Gas Division) be, and hereby is authorized and directed to file, on or before June 30, 1994, revised tariffs setting forth the rates and charges for the provision of gas service authorized herein and in accordance with the Discussion, Findings of Fact, and Conclusions of Law herein, and a proof of revenues showing that the revised rates will produce no more than the authorized increase in revenues.

IT IS FURTHER ORDERED that the rates and charges contained in said tariffs shall become effective for service rendered on and after July 1, 1994.

IT IS FURTHER ORDERED that Citizens Utilities Company (Arizona Gas Division) shall notify its customers of the rates and charges authorized herein and the effective date of same by means of an insert in the next regularly scheduled monthly billing.

IT IS FURTHER ORDERED that Citizens is hereby ordered in future gas division rate applications, to remove (by an explicit adjustment) all Purchased Gas Adjustor (PGA) revenues and gas costs from its test year utilized in its filing.

IT IS FURTHER ORDERED that the definitions, procedures, cost-recovery including start-up costs, guidelines and theories as adopted in Docket No. U-0000-93-052 for Integrated Resource Planning, Decision No. 58643 shall be used with Citizens Utilities Company (Arizona Gas Division) demand side management program.

IT IS FURTHER ORDERED that Citizens Utilities Company (Arizona Gas Division) Build Out Plan is hereby approved, with the modifications approved herein.

IT IS FURTHER ORDERED that Citizens Utilities Company (Arizona Gas Division) shall calculate the post-in-service allowance for use of funds during construction in compliance with Accounting Release No. 13 and shall comply with the reporting requirements discussed herein.

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IT IS FURTHER ORDERED that Citizens Utilities Company (Arizona Gas Division) shall credit the PGA bank account with $1.26 million in Transwestern pipeline reservation charges paid for service to Flagstaff, Arizona for the period December 1, 1992 through October 1993.

IT IS FURTHER ORDERED that Citizens Utilities Company (Arizona Gas Division) shall credit the PGA bank account with $247,351 in Transwestern pipeline reservation charges paid for service to Kingman, Arizona for the period June 1, 1992 through October 1993.

IT IS FURTHER ORDERED that commencing July 1, 1994, Citizens Utilities Company (Arizona Gas Division) shall exclude from its PGA as fixed reservations costs all Transwestern reservation charges from daily capacity in excess of 1,460 dth for service to Flagstaff, Arizona and 8,400 dth for service to Kingman, Arizona.

IT IS FURTHER ORDERED that within 30 days from the effective date of this Decision, Citizens Utilities Company (Arizona Gas Division) shall credit to the PGA bank account Transwestern reservation charges for daily capacity in excess of 1,460 dth for service to Flagstaff, Arizona and 8,400 dth for delivery to Kingman, Arizona for the period November 1, 1993 through June 30, 1994. Citizens shall deduct from the above all amounts previously credited to the PGA bank account from capacity releases sold during the period November 1, 1993 through June 30, 1994.

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IT IS FURTHER ORDERED that the authorized base cost of gas is $0.3000 per therm.

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

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

Renz Walker		Dale H. Morgan
CHAIRMAN	COMMISSIONER	COMMISSIONER

IN WITNESS WHEREOF, I, JAMES MATTHEWS, Executive Secretary of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 16 day of June, 1994.

James Matthews
JAMES MATTHEWS
EXECUTIVE SECRETARY

DISSENT ______________
LF

See attached Special Concurrence by Commissioner Dale H. Morgan.

See attached Special Concurrence by Commissioner Renz D. Jennings.

 DECISION NO. 58664

0040004 00001

SERVICE LIST FOR: CITIZENS UTILITIES COMPANY (ARIZONA GAS DIVISION)

DOCKET NOS.: E-1032-93-111 AND E-1032-93-193

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EXHIBIT
admitted
A-53

REVISED

CITIZENS UTILITIES COMPANY

ARIZONA GAS DIVISION BUILD OUT PLAN

AREAS TO BE CHARGED THE SURCHARGE FOR THE BUILD OUT

On all maps referenced in the following proposed area descriptions the streets which currently have gas service available in them have been highlighted in orange.

BUILD OUT TO VILLAGE OF OAK CREEK--MAP # 1

The Company's proposal is to charge the New Service Area Multiple ("NSAM") to new customers to the south of and outside of the Sedona city limits, as the Sedona city limits exist on the date an order is issued in this proceeding. This would include the prospective customers in the Village of Oak Creek.

As shown on MAP # 1, the existing service area where natural gas utility service is provided is in the northern part of Sedona and ends just before the intersection of CMO Rojo and Highway 179. Since the extension of service to the area between the above described existing service area and the southern boundary of the city limits (designated by Little Horse Park on the map) could be served in the normal course of system growth, the Company proposes that all customers within the city limits (as the city limits exist on the date an order is issued in this proceeding) be exempt from the NSAM.

The NSAM would be charged to all customers connecting to the system in the Village of Oak Creek, and nearby areas, which are south of Sedona outside of the

DECISION NO. 58664

Sedona city limits.

BUILD OUT TO VERDE VILLAGE--MAP # 2

The NSAM will not be charged to any customer within the city limits of Cottonwood, as these city limits exist on the date an order is issued in this proceeding. Since there is some existing natural gas utility service outside of the Cottonwood city limits, the Company is presenting two options for charging the NSAM to new customers outside of the city limits of Cottonwood. This would include the prospective gas customers in Verde Village.

OPTION # 1 FOR VERDE VILLAGE

All customers with active gas service on or before the effective date of the order in this proceeding will not be charged the NSAM. All new customers at addresses which receive initial active gas service after the effective date of the order in this proceeding will be charged the NSAM.

The Company is aware that this procedure will create some instances where neighbors could be paying different rates for gas utility service for the next several years. However, the Company believes that this is the preferred procedure, since these new customers would not have received gas service without the additional investment under the Build Out Program.

The Company, under this option, proposes that a date certain be set for the removal of the NSAM. The date proposed by the Company will be the earlier of the effective date of new rates from the next general rate case of the Company on July 1, 1998, which will be approximately four years after the NSAM is authorized. The Build Out Program estimates that the number of effected customers at the end of each year will be:

December 31, 1994	200
December 31, 1995	600
December 31, 1996	1,100
December 31, 1997	1,606

OPTION # 2 FOR VERDE VILLAGE

The Company, under this option, will not charge the NSAM to any new customer. Since this option will substantially reduce revenues from the NSAM, the Company would require an additional revenue source to compensate for this revenue loss. The Company would propose that the rate for the "Post-in-Service AFUDC" under the Build Out Program be increased to provide the Company with replacement income for that lost by not charging the NSAM to any new customer in the Verde Valley area.

The Company's Build Out Program contains NSAM revenues for new customers in Verde Village, at the 50 percent level, in the approximate amounts of $ 18,000 for 1994; $ 83,000 for 1995; $ 182,000 for 1996; $ 295,000 for 1997 and $ 180,000 for the six months before new rates would be effective from the Company's next proposed general rate case.

The Company believes that Option # 1 is the simplest and would be accepted by the new customers since, without significant infrastructure improvements, there would be little, if any, additional gas service in the Verde Village area for the next several years. Furthermore, the new customers will know that the NSAM will be eliminated at a date certain and that after the elimination of the NSAM their rates will be the same as all other customers in the Verde Village.

BUILD OUT TO PINETOP-LAKESIDE--MAP # 3

The Company proposes to charge the NSAM to all customers in the Pinetop-Lakeside area, since this area is separate from any existing service area of the Arizona Gas Division. The area of Pinetop-Lakeside will be served by a new pipeline that does not pass through any current service area of the Company or any area of significant population.

In the Slow Low area, the Company proposes that all customers within the city limits (as the city limits exist on the date of an order in this proceeding) and also those customers outside the Show Low city limits south to include the areas of Wagon Wheel and Show Low Estates, be charged the standard rates without being charged the NSAM. To further define these areas, Wagon Wheel is bounded on the south by Wagon Wheel Road and Forest View Road while Show Low Estates included Deer Trail and Snowshoe Lane. The Company believes that the customers in Show Low, as well as those just south of Show Low including Wagon Wheel and Show Low

Estates, should be served in the normal course of business and, therefore, the NSAM will not be appropriate.

The area south of Wagon Wheel and Show Low Estates and north of Pinetop-Lakeside is not part of the existing Build Out Program and is not considered in this proposal, since this area is not expected to experience development in the next ten years.

BUILD OUT TO CAMP VERDE & CORNVILLE MAP # 4, MAP # 5, AND MAP # 6

As shown on MAP # 6, the northern boundary of Camp Verde (MAP # 4) is approximately 5 miles south of the Verde Village and is not interconnected with any existing Company service area. MAP # 6 illustrates Camp Verde's isolation from the Company's existing service area. Therefore, the Company proposes to charge the NSAM to all new customers in the Camp Verde area.

As also shown on MAP # 6, the area of Cornville (MAP # 5) is approximately 4 1/2 miles east southeast of Cottonwood and the Company's existing service area. Therefore, the Company proposes to charge the NSAM to all customers in the Cornville area.

SPECIAL CONCURRENCE

E-1032-93-111 ET AL

COMMISSIONER JENNINGS,

The vote on this Order was taken only after the Commission was led through nine amendments offered by Commissioner Morgan which, if all adopted, would have resulted in much higher rates.

The Commissioner's arguments weren't persuasive to the Hearing Officer when first made by the Company. Nor were those arguments persuasive when they were presented by Commissioner Morgan. Commissioner Morgan's special concurrence is limited to just three of his nine amendments.

There is one particular issue championed by Commissioner Morgan for Citizens Utilities Co. that I believe needs to be addressed here. That is the issue of post-retirement benefits other than pensions, known by accountants as "PBOPs."

The first and foremost principal that I believe we need to keep in mind is that accounting pronouncements do not, and should not, dictate ratemaking policy. They can be instructive as to the perspective of financial institutions. But these accounting conventions should be adopted only if they further the objective of setting just and reasonable rates.

Commissioner Morgan argues that this case presents us with a "nearly perfect" situation in which to approve accrual accounting, rather than the traditional "pay-as-you-go" method, because the so-called transition obligation is very small. One glaring imperfection with that, however, is the fact that Citizens has yet to begin funding its PBOP obligation.

More importantly, Commissioner Morgan's reasoning begins with the assumption that accrual accounting is the correct method. The truth of that assumption has simply not yet been established.

The accrual accounting method for PBOPs is based on a myriad of assumptions which may or may not prove to be correct. For example, assumptions must be made regarding the inflation rate for health care, the age at which employees retire, their lifespan after retirement, the lifespans of their spouses, and other matters which in any other circumstance would never remotely be considered to be known and measurable changes. Indeed each of the above is attended by large uncertainties.

While prudent long-term planning is to be encouraged, and the welfare of our children's children should be of concern to us today, the certainty of costs to be paid now by consumers to reflect the uncertainty of benefits that may or may not materialize 30, 40 or even 50 years into the future is a step we should take only if a clear superiority of accrual accounting is demonstrated.

SPECIAL CONCURRENCE
COMMISSIONER JENNINGS
E-1032-93-111 ET AL

There may come a time when this Commission determines that accrual accounting for PBOPs should be approved for a given utility. However, no Arizona utility has yet to establish that accrual accounting is more beneficial to ratepayers today than traditional pay-as-you-go accounting, where ratepayers rightfully bear the costs of dollars expended today rather than imaginary dollars that may or may not be spent at unknown levels at some indeterminate date in the future.

In conclusion, the Order treats the issue of PBOPs in the correct manner. I concur.

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CITIZENS UTILITIES COMPANY (AGD) DOCKET NOS. E-1032-93-111
E-1032-93-193

SPECIAL CONCURRENCE

COMMISSIONER MORGAN,

While I concur with today's Order granting rate relief to Citizens Utilities Company, Arizona Gas Division, I am concerned that today's Order fails to take advantage of those forward-looking opportunities that were presented.

The Commission was presented with a unique opportunity today to examine and test the accrual method of accounting for post-retirement benefits other than pensions ("PBOPs"). This Commission has stated that it will review the issue of accrual vs. cash (also known as pay-as-you-go) expensing of PBOPs on a case-by-case basis. However, when presented with the nearly perfect opportunity to adopt the accrual method in this one instance, this Commission declined.

Historically, this Commission has declined to adopt the accrual method because of high inter-generational costs, which in turn would have to be passed on to current rate payers. Yet unlike other cases, this was the first time the Commission was presented with a proposed accrual approach to expensing PBOPs that did NOT have enormous inter-generational costs. Because these costs don't presently exist, there is no need to fear that rates will go up precipitously. Rather, adoption of the accrual method of expensing PBOPs allows for greater accuracy in both current and future rates. This accuracy is the same reason that Citizens uses the accrual method for expensing all other obligations.

When faced with a nearly perfect "first-case" that did not have large inter-generational costs, the Commission resorted to questioning why the Company was attempting to use the accrual method now as if to suggest that there was some unsavory motivation. In truth, had the Company used the accrual method on its financial books and accrued a large inter-generational cost, this Commission would have declined to adopt the accrual method for ratemaking purposes because of the impact on current ratepayers.

By failing to adopt the accrual method of expensing PBOPs in this case, we have sacrificed future ratepayers for current ratepayers. In the not too distant future, the cash or pay-as-you-go method will become more expensive annually than the accrual method. At that point, future ratepayers will pay for an expense that actually is being incurred now but will not be paid for, and hence felt, until that future date. I fear this Commission has been short-sighted.

DECISION NO. 58664

I also fear that the Commission's short-sightedness extended to a refusal to defer capacity reservation charges paid for service at Flagstaff and Kingman. The Company adopted a contract that provided a second source of gas when it purchased the operations from Southern Union Gas. This second source not only allows for greater independence from having only one supply source but also increased the capacity available to serve the expanding populations. By refusing to defer these costs, we are punishing the Company for its desire to have sufficient capacity to meet its customers' projected demands.

Finally, I believe this Commission was short-sighted in its refusal to allow all "Target: Excellence" costs. This is not a fly-by-night attempt to jump on the Total Quality Method bandwagon. "Target: Excellence" is a serious, company-wide effort to improve the quality of its service, the quality of its management and the quality of all operations. The costs for which recovery is sought were expensed to improve the training of its employees. Well-trained employees are essential to good customer service, quality job performance and cost savings. These are the very goals that this Commission seeks to promote in all utilities we regulate. Consequently, this Commission should not have disallowed these costs but rather this Commission should have given kudos to the Company for its commitment to quality service and the attendant benefits.

For the foregoing reasons, I respectfully concur with today's Order only to the extent it is consistent with this special concurrence.

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS
JEFF HATCH-MILLER- CHAIRMAN
WILLIAM A. MUNDELL
MARC SPITZER
MIKE GLEASON
KRISTIN K. MAYES

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-06-0463

Direct Testimony of

Kentton C. Grant

on Behalf of

UNS Gas, Inc.

July 13, 2006

EXHIBIT
UNSG 27
admitted

TABLE OF CONTENTS

Exhibit KCG-1	Comparable Company Data
Exhibit KCG-2	Projected Growth Rates – Comparable Company Group
Exhibit KCG-3	Expected First Year Dividend – Comparable Company Group
Exhibit KCG-4	Multi-Stage DCF Analysis
Exhibit KCG-5	Application of Capital Asset Pricing Model
Exhibit KCG-6	Allowed Returns on Equity vs. 20-Year Treasury Bond
Exhibit KCG-7	Allowed ROE Premiums over 20-Year Treasury Bond
Exhibit KCG-8	U. S. Treasury Bill and Bond Yields
Exhibit KCG-9	Key Financial Indicator Forecast for UNS Gas

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Kentton C. Grant. My business address is One South Church Avenue, Tucson, Arizona, 85701.

Q. By whom are you employed and what are your duties and responsibilities?

A. I am employed by Tucson Electric Power Company ("TEP") as ~~General Manager~~ Vice President, ~~Financial Planning and Customer Pricing~~ Finance and Rates. In this role I am responsible for providing financial and regulatory support services to UniSource Energy Corporation ("UniSource Energy"), and its regulated utility subsidiaries. These subsidiaries include UNS Gas, Inc. ("UNS Gas"), UNS Electric, Inc. ("UNS Electric") and TEP.

Q. Please summarize your professional experience and education.

A. My educational achievements include a Master of Business Administration degree with a concentration in finance from the University of Texas at Austin, as well as a Bachelor of Science degree in Civil Engineering from Purdue University. I am a member of the Chartered Financial Analyst ("CFA") Institute, and in 1995, I was awarded the professional designation of CFA. I am also a member of the Society of Utility and Regulatory Financial Analysts, and in 1992, I was awarded the designation of Certified Rate of Return Analyst ("CRRA").

From 1984 to 1995, I was employed by the Public Utility Commission of Texas. During this period I served in various staff positions, including Director of the Financial Review Division. In that role I directed a staff responsible for performing financial analyses, accounting reviews and management audits of electric and telecommunications utilities.

As a staff member I provided expert testimony on a variety of financial topics including the cost of capital.

I joined TEP in 1995 as a senior financial analyst. In 1997, I was promoted to Director of Capital Resources and elected Assistant Treasurer. I was subsequently promoted to Manager of Financial Planning and in 2003, became a General Manager in TEP's Shared Services Unit. In these roles I have gained additional experience in financial forecasting, financial analysis, the structuring of new financings and other related activities.

Q. **What is the purpose of your direct testimony?**

A. In my direct testimony I support UNS Gas' request for a rate increase by: (i) providing an overview of the Company's financial condition; (ii) recommending a fair rate of return on common equity capital; (iii) presenting UNS Gas' weighted average cost of capital; and (iv) describing the financial impact of UNS Gas' requested rate relief. In my testimony, I also explain why it is important for the Arizona Corporation Commission ("Commission") to include construction work-in-progress ("CWIP") in UNS Gas' rate base. Finally, I am sponsoring Schedule A-3 (Summary Capital Structure), Schedule A-4 (Construction Expenditures and Gross Plant in Service), the "D" Schedules (Cost of Capital Information) and the "F" Schedules (Projections and Forecasts) in support of UNS Gas' request for a rate increase.

Q. **Please summarize the recommended fair rate of return, weighted average cost of capital, cost of debt and return on common equity UNS Gas is utilizing in this rate request.**

A. The Company's rate request reflects an overall rate of return and weighted average cost of capital of 8.80%. This overall rate of return is based on a 6.6% cost of debt, an 11.0% cost of common equity capital, and a capital structure consisting of 50% long-term debt and 50% common equity. The rate of return on fair value rate base is 7.43%.

II. FINANCIAL CONDITION OF UNS GAS.

Q. Please describe UNS Gas' current financial condition.

A. UNS Gas has a mixed financial profile. On the positive side, the Company has a healthy mix of debt and equity capital, a relatively low cost of long-term debt and a growing service area. However, these strengths are offset by weak operating cash flows, large construction spending needs due to rapid growth in UNS Gas' service territory and a limited borrowing capacity. Obviously, it is critical that UNS Gas has the financial resources necessary to meet the needs of its current and future customers. UNS Gas' requested rate increase is necessary to meet those needs.

Q. Has the Company's financial condition improved since UniSource Energy acquired the gas utility operations from Citizens Communications Company ("Citizens") in 2003?

A. The Company's financial condition has improved in certain respects but weakened in other respects. On the positive side, the Company's equity ratio (equity / total capitalization) has improved from 33% in August of 2003 to 45% at the end of the test year. This has been accomplished through the retention of 100% of annual earnings at UNS Gas and an additional equity infusion of $16 million made by UniSource Energy. The Company's short-term liquidity was also significantly enhanced through the establishment of a $40 million credit facility, shared with UNS Electric, which allows either company to borrow a maximum of $30 million under the facility at any given time. However, since the acquisition was completed, the Company's earnings and cash flow have declined significantly. The following table highlights the some of the key financial results from 2004 and 2005, the first two fiscal years following the acquisition, and forecasted financial results for 2006:

($000s)	2004 Actual	2005 Actual	2006 Forecast
Net Income	$5,703	$5,046	$3,696
Return on Avg. Equity	10.2%	7.3%	4.5%
Operating Cash Flow (a)	$20,541	$14,299	$15,850
Capital Expenditures (b)	$19,137	$23,578	$30,287
Net Cash Flow [(a) – (b)]	$1,404	($9,279)	($14,437)

Reduced earnings and cash flow have also contributed to a reduction in UNS Gas' borrowing capacity since the acquisition. In order to incur additional indebtedness, UNS Gas must first determine that it will be able to meet certain minimum financial ratios as specified in the Company's credit agreements. Under these agreements the Company must maintain a ratio of EBITDA (earnings before interest, taxes, depreciation and amortization) to interest charges of at least 2.5X. For calendar years 2004 and 2005 this interest coverage ratio was 3.38X and 3.26X, respectively. Assuming an interest rate of 6.6% on new borrowings, which reflects the applicable rate under UNS Gas' credit facility as of April 2006, the test year interest coverage ratio would have allowed additional borrowing of only $31 million at UNS Gas. On a forecasted basis, the Company is expected to have additional borrowing capacity of only $13 million by year-end 2006. This level of aggregate borrowing capacity is clearly inadequate for a company with approximately $130 million of annual revenues, high capital spending requirements and continuing financial exposure to abnormal weather conditions and natural gas price volatility.

Q. **Are the debt obligations of UNS Gas rated by the major credit rating agencies?**

A. No. Credit ratings assigned by Moody's, Standard & Poor's and Fitch were not required by the lenders to UNS Gas. However, the lenders who purchased $100 million of long-term notes from UNS Gas in 2003 did require a rating from the National Association of

Insurance Commissioners ("NAIC"). The rating assigned to these notes was NAIC-2, which is roughly equivalent to a low investment-grade rating of Baa from Moody's or BBB from Standard & Poor's or Fitch. Due to the recent decline in earnings and cash flow, as well as the increased volatility of natural gas prices, it is not clear whether UNS Gas would receive the same rating today if a new ratings request were made.

Q. How does UNS Gas' financial condition compare with other gas distribution utilities?

A. The Company's 7.3% return on average common equity in 2005 and the 4.5% projected return in 2006 are both quite low when compared with average industry returns. On a composite basis, the average annual return on common equity reported by Value Line for the natural gas distribution industry ranged from 10.5% to 11.8% over the period 2002-2004. In terms of capital structure, the 45% common equity ratio for UNS Gas at year-end 2005 was comparable to the 46% industry average reported by Value Line Investment Survey for year-end 2004. In terms of credit quality metrics, the cash flow realized by UNS Gas during 2005 lagged the industry by a considerable margin, while debt leverage was in line with industry norms. On each of three different cash flow metrics, UNS Gas lagged the industry median value for a group of 14 gas distribution companies rated by Standard & Poor's. The credit ratings for this industry group ranged from a low of BB- to a high of AA, with a median credit rating of BBB+. The following table compares the key credit quality metrics for UNS Gas (2005 actual and 2006 projected values) with the industry median values for 2004:

	2005 Actual	2006 Forecast	Industry Median
FFO Interest Coverage	3.3X	2.5X	4.6X
FFO to Total Debt	16%	9%	20%
Net Cash Flow / Capital Expenditures	61%	52%	88%
Total Debt / Total Capital	55%	55%	57%

FFO = Funds from Operations.
Net Cash Flow = Operating Cash Flow less Dividends Paid.

The gap between UNS Gas and the industry median value for Net Cash Flow / Capital Expenditures is of particular concern for two reasons. First, a ratio of less than 100% indicates a dependence on outside capital to fund ongoing capital expenditures. During 2005, UniSource Energy funded this gap through increased equity contributions. These contributions were made despite a reduction in earnings at UNS Gas and the absence of any common dividend payout from UNS Gas. The Company's other source of capital, borrowed funds, is also very limited due to weak interest coverage levels. Absent a significant increase in operating cash flow, it will be difficult for the Company to attract the capital needed to fund required capital expenditures. Second, the gap between UNS Gas and the industry median value is actually much larger than indicated in the table above when dividend payout policies are considered. The average dividend payout as a percentage of earnings for the gas distribution sector was 63% as reported by Value Line for 2004. Had UNS Gas paid out common dividends in 2005 at the industry average payout rate of 63%, the Company's ratio of Net Cash Flow / Capital Expenditures would have fallen from 61% to 47%.

Q. Are there specific aspects of this rate filing that are designed to improve UNS Gas' financial condition and borrowing capacity?

A. Yes. The requested increase in rates would result in improved cash flow and expanded borrowing capacity at UNS Gas. In addition, the use of a hypothetical capital structure would help UNS Gas make further progress in strengthening the Company's balance sheet and would reduce the Company's dependence on debt financing. The Company is also proposing changes in rate design that would better align fixed monthly customer charges to the fixed costs of operating and maintaining a gas distribution system. This change in rate design would lessen the Company's financial exposure to unusually mild weather conditions or reductions in average consumption. Proposed changes to the Purchase Gas Adjustor ("PGA") mechanism would also reduce the Company's financial exposure to large increases in the cost of natural gas, a commodity that has experienced significant price volatility over the past 18 months. These proposed changes in rate design and the PGA mechanism are critical to the Company's ability to forecast and fund short-term liquidity needs. The financial impact of the Company's rate request is described in greater detail later in my testimony, following the cost of capital discussion below.

III. COST OF CAPITAL METHODOLOGY.

Q. Please describe the methodology you have used to determine a recommended rate of return for UNS Gas.

A. I have employed the weighted average cost of capital methodology. There are three basic steps in calculating the weighted average cost of capital. First, it is necessary to analyze the firm's capital structure, identify the sources of capital, and determine the appropriate weighting for each source of capital. For UNS Gas, these sources consist of long-term debt and common equity capital. Second, the appropriate cost of each component of the capital structure must be determined. For long-term debt, it is customary for rate setting purposes to use the embedded cost of debt. For common equity, a variety of techniques are available to estimate the cost of this capital. Finally, the cost of each capital source is weighted by its appropriate percentage share of the capital structure. The sum of the weighted component costs represents the weighted average cost of capital. The calculation of UNS Gas' weighted average cost of capital is provided in the last section of my testimony. This recommended value, 8.80%, is also reflected in Schedule D-1 in the Company's rate filing.

IV. CAPITAL STRUCTURE.

Q. Please describe the capital structure for UNS Gas as of the end of the test year.

A. The capital structure for UNS Gas as of December 31, 2005 consisted of $100 million principal amount of long-term debt and approximately $80 million of common equity. After adjusting for unamortized issuance expenses, the long-term debt balance as of December 31, 2005 was $98.9 million. As reflected in the following table, long-term debt comprised approximately 55% of total capital whereas common equity represented approximately 45% of total capital:

	12/31/05 ($thousands)	% of Total
Long-Term Debt	$98,859	55.33%
Common Equity	79,804	44.67%
Total Capital	$178,663	100.00%

Q. Should this capital structure be adjusted for rate setting purposes?

A. Yes. I am recommending that the Commission adopt a capital structure consisting of 50% common equity and 50% long-term debt. Although the test-year capital structure for UNS Gas was in line with industry averages, it is reasonable for the Company to target a higher common equity ratio due to the Company's small size, large capital spending needs and limited borrowing capacity. As reflected in the financial forecast discussed in Section IX of my testimony, and as evidenced by the actions taken to date, it is management's intent to gradually strengthen the Company's balance sheet through a combination of retained earnings and additional equity contributions from UniSource Energy. Assuming the Company's rate request is approved, it is forecasted that UNS Gas will achieve a 50% common equity ratio by the end of 2008, the first full calendar year under the proposed rates.

Q. Please elaborate on the actions taken by management to strengthen the Company's balance sheet.

A. As described earlier, the Company's equity ratio has improved from 33% in August of 2003 to 45% at the end of the test year. This has been accomplished by retaining 100% of the annual earnings at UNS Gas and through additional equity investments made by UniSource Energy. Despite the fact that UNS Gas has not paid any dividends to-date, and has little prospect of doing so in the near future, UniSource Energy has contributed an additional $16 million of equity capital in order to improve the financial condition and creditworthiness of UNS Gas. Had UniSource Energy not made this investment, thereby causing UNS Gas to borrow additional funds instead, UNS Gas' equity ratio would have been only 36% at the end of the test year. Clearly, UNS Gas is making progress in improving its equity ratio, and this progress should be encouraged.

Q. Has the Commission adopted a hypothetical capital structure before?

A. Yes, in many cases, including the recent Southwest Gas Corporation ('SWG") rate case, Decision No. 68487 (February 23, 2006).

Q. Will the use of a hypothetical capital structure allow the Company to make progress in improving its financial condition?

A. Yes. While UNS Gas has made progress in improving its equity ratio, other financial metrics have deteriorated, as noted previously. Because of the current weakness in earnings and cash flow, it is important for the Company to continue strengthening its balance sheet. During periods such as this, it is important to have a strong balance sheet in order to offset the negative credit impact of weak cash flow ratios. Lenders are much more willing to finance a well capitalized firm, even during periods of temporary cash flow and earnings distress, relative to a firm that has less shareholder capital at risk. Additionally, by financing a larger portion of capital expenditures with equity capital, UNS Gas will be able to retain more of its borrowing capacity to meet unexpected contingencies.

Q. Should the necessity of large capital expenditures be considered?

A. Yes. UNS Gas will need to make large capital expenditures in order to serve its customers. In order to do so, it must have access to capital, both debt and equity. Adjusting the capital structure will help assure that adequate capital is available.

Q. What is your recommended capital structure for UNS Gas?

A. For the reasons that I have stated, I recommend use of a capital structure consisting of 50% common equity and 50% long-term debt.

V. <u>COST OF COMMON EQUITY CAPITAL.</u>

Q. Please provide an overview of the methodology used to estimate the cost of equity capital for UNS Gas.

A. Four stages of analysis were employed to derive an estimated cost of equity for UNS Gas. First, the estimated cost of equity for a group of comparable companies was determined. This range was developed using the discounted cash flow approach ("DCF") and the capital asset pricing model ("CAPM"). Second, we examined the risk profile of UNS Gas relative to the comparable company group in order to determine an appropriate point estimate for the Company's cost of equity. Third, the estimated cost of equity determined for UNS Gas was compared with the allowed returns on equity for other gas utilities in the United States. Based on a review of this data, and the relationship between allowed returns on equity and long-term interest rates, we were able to confirm the reasonableness of our cost of equity estimate for UNS Gas. Finally, we examined the financial impact of the recommended return on equity ("ROE") and the overall rate request on UNS Gas. This final step was taken in order to assess the Company's ability to attract capital on reasonable terms, a key objective to consider in setting the allowed rate of return for a regulated utility.

A. <u>Comparable Company Group.</u>

Q. Why did you analyze a group of comparable companies in order to estimate the cost of equity capital for UNS Gas?

A. Reliance on a comparable company analysis is important because UNS Gas does not have publicly traded equity securities. Additionally, the assets of UniSource Energy, the parent company of UNS Gas, are heavily weighted toward the electric utility industry. Although the risk profiles of electric distribution and gas distribution utilities are similar, TEP, the largest subsidiary of UniSource Energy has a significant investment in electric generating facilities. As a consequence, the cost of equity capital for UniSource Energy may not be representative of the cost of equity capital for UNS Gas.

Q. What criteria did you employ in selecting companies for the comparable company analysis?

A. As a starting point we evaluated each of the companies included in the natural gas distribution industry by Value Line Investment Survey ("Value Line"). From this group of sixteen companies we then selected eleven companies that met the following screening criteria:

(i) More than 60% of revenues derived from gas operations,

(ii) More than 50% of total gas throughput derived from distribution operations,

(iii) No significant ownership of electric generating capacity,

(iv) No pending mergers or acquisitions of any significance, and

(v) Common stock currently paying a dividend.

Exhibit KCG-1 provides summary information on each of the companies that were selected based on these criteria. Although each of these companies may have unique circumstances that would differentiate them from UNS Gas, as a group these companies have operating and financial characteristics similar to those of UNS Gas. The extent of this similarity is discussed further in Section VI of my testimony.

B. Application of DCF Model.

Q. Please explain the DCF methodology.

A. The DCF methodology is derived from the Gordon dividend growth model. In its original form, the Gordon growth model may be used as a tool for determining the value of a share of common stock. The theory holds that the price of a share is equal to the present value of all future dividends. It is expressed mathematically as follows:

$$P_0 = \frac{D_1}{(1 + k_1)^1} + \frac{D_2}{(1 + k_2)^2} + \ldots + \frac{D_n}{(1 + k_n)^n}$$

Where: P_0 = Current share price
D_n = Expected dividend in each year
k_n = Investors required rate of return in each year
n = One to infinity

If the dividends are assumed to grow at a constant rate "g" into the future, the required rate of return "k" is assumed to be constant from year to year, and "k" is greater than "g", then the equation above reduces to the following form as "n" approaches infinity:

$$P_0 = \frac{D_1}{(k - g)}$$

For purposes of estimating the cost of common equity capital, the equation above may be rearranged to solve for the investor's required rate of return:

$$k = \frac{D_1}{P_0} + g$$

Essentially, the constant growth DCF model recognizes that the return to the stockholder consists of two parts: dividend yield and growth. Equity investors expect to receive a portion of their total required return in the form of current dividends and the remainder though price appreciation. Unfortunately, the constant growth DCF model cannot be applied to companies having expected near-term growth rates that are significantly higher or lower than their long-term growth potential. In these situations, it is usually necessary to apply a multi-stage DCF model which incorporates the various growth rates expected over time.

Q. Please describe the multi-stage DCF model.

A. If the Gordon dividend growth model is modified to reflect the expected future price of the stock in terminal year "n", and assuming that the investor's required rate of return "k" is constant, the current value of a stock may be derived from the following equation:

$$P_0 = \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_n}{(1+k)^n} + \frac{P_n}{(1+k)^n}$$

Where: P_0 = Current share price
D_n = Expected dividend in each year
P_n = Expected share price in year "n"
n = Year of expected share price

If the expected growth rate "g" is constant beyond year "n", the expected value of "P_n" can be obtained from the constant growth DCF model:

$$Pn = \frac{Dn\,(1+g)}{(k-g)}$$

Substituting this equation for "P_n" in the modified Gordon growth model, the following multi-stage DCF equation is obtained:

$$P_0 = \frac{D_1}{(1+k)^1} + \frac{D_2}{(1+k)^2} + \ldots + \frac{D_n}{(1+k)^n} + \frac{D_n(1+g)}{(k-g)\,(1+k)^n}$$

Using this equation, the current share price, and the expected values for D_1 through D_n and "g", the required rate of return "k" may be calculated using an iterative solution process. The discount rate "k" which equates the current share price with the present value of future expected dividends represents the investor's required rate of return.

Q. How did you determine near-term dividend growth rates for each of the comparable companies?

A. We relied on estimates of future dividends and earnings growth published by Value Line, Thomson Financial Network ("Thomson") and SNL Financial ("SNL"). These estimates are all widely available in the investment community and are superior to estimates based solely on historical trend analysis. Published estimates are inherently forward looking, and presumably take into account historical financial trends as well as any future threats and opportunities.

Q. What specific growth rates did you select for each company?

A. Exhibit KCG-2 provides the range of growth estimates for each company, as well as the five-year growth rate selected for use in the multi-stage DCF model. The growth rates from Value Line were derived using the published point estimates for dividends per share ("DPS") and earnings per share ("EPS") for the 2009-2011 timeframe. The five-year EPS projections from Thomson and SNL represent the median or "consensus" growth estimates as determined through surveys of stock research analysts. Differences between these published growth rates for any given company may be expected due to differences in the scope and timing of the surveys conducted. For purposes of selecting a five-year dividend growth rate, we relied on the Value Line DPS growth rate if the rate fell within the range of published EPS estimates for the company in question. This was the case for four of the comparable companies (AGL Resources, Northwest Natural Gas, Piedmont Natural Gas and South Jersey Industries). For the other seven companies, we used the average of the Value Line DPS growth rate and the nearest EPS growth rate as the estimate for dividend growth over the next five years. Because analyst estimates for EPS growth are often influential in estimating future dividend growth, we believe that the growth rates selected for each company are representative of investor expectations.

Q. How did you calculate the expected first year dividend (D_1) for each company?

A. Exhibit KCG-3 shows the current quarterly dividend for each company, the five-year DCF growth rate for each company, and the projected quarterly dividends over the next four quarters. Projected quarterly dividends were increased from current levels based on each company's historical timing for dividend changes. The size of each projected dividend change was based on the five-year DCF growth rate. The expected first year dividend (D_1) was then derived by adding the projected quarterly dividends over the next four quarters.

Q. How did you determine the expected long-term growth rates to be used in the DCF model?

A. We considered several factors that would have a significant influence on long-term investor expectations. In addition to considering the published growth rates for the comparable company group provided in Exhibit KCG-2, we also examined published growth rates for the gas utility industry, published growth rates for the broader utility sector (including electric and water utilities), and prospects for growth in the U.S. economy as a whole. Once a reasonable estimate of long-term growth for the industry was established, we then adjusted this growth rate up or down to reflect unusually high or low growth rate expectations for specific companies.

Q. What is a reasonable estimate of expected long-term growth for the gas distribution industry?

A. An annual growth rate of six percent represents a reasonable estimate of investor expectations for earnings and dividends over the long-run. This value is consistent with the 6.1% median growth rate in EPS for the comparable company group as estimated by Value Line (see Exhibit KCG-2), and is also consistent with five-year estimates of EPS growth recently published by Thomson Financial for the gas utility industry (5.6%) and the broader utilities sector (6.4%). This value is also reasonable when compared with expectations for long-term growth in the U.S. economy. As a basic utility service, it is reasonable to assume that the gas utility industry will grow at a rate comparable to that of the overall economy over the long-run.

Projections of long-term economic growth vary considerably depending on the assumptions made. However, real economic growth in the United States has been remarkably consistent over long periods of time, averaging 3.4% per year from 1929 through 2005. Since this growth has occurred over numerous business cycles, and during extended periods of war and peace, it is reasonable to use this historical growth in real GDP as an estimate of future expected economic growth. In order to derive an estimate of nominal GDP growth, we added a long-term inflation rate of 2.9% to the estimated 3.4% growth in real GDP. The resulting growth in nominal GDP of 6.3% represents a reasonable expectation for future U.S economic growth and provides further support for a 6.0% long-term growth rate for the gas utility industry. The expected rate of inflation of 2.9% was calculated by subtracting the yield on 20-year inflation-indexed U.S. Treasury securities (2.4%) from the yield-to-maturity on 20-year fixed-rate U.S. Treasury bonds (5.3%) as of April 28, 2006.

Q. **How did you adjust the expected industry growth rate to arrive at company-specific growth rates?**

A. No adjustment was made for nine of the comparable companies, since the long-term growth rate for these companies was assumed to revert to the mean or expected long-term growth rate for the industry. However, adjustments to the industry growth rate were made for two companies to reflect unusually high or low published growth projections for these companies. Taking into account the EPS growth rates in Exhibit KCG-2, a 1% downward adjustment was made to arrive at a long-term expected growth rate for Nicor, Inc., and a 1% upward adjustment was made to arrive at a long-term expected growth rate for SWG. The expected long-term growth rates for each company, ranging from 5.0% to 7.0%, are shown on Exhibit KCG-4.

Q. How did you determine the current stock price for each company?

A. A simple average of the daily closing prices was calculated for each company for the month of April 2006.

Q. What results did you obtain from the multi-stage DCF model?

A. Exhibit KCG-4 summarizes the results obtained, as well as each of the input variables used in the multi-stage DCF calculations. The estimated cost of equity for each company fell within a range of 9.1% to 10.5%. The median value for the sample group was 9.9%.

C. <u>Application of CAPM.</u>

Q. Please describe the capital asset pricing model.

A. The CAPM was developed using modern portfolio theory, which is premised on the assumption that capital markets are highly efficient and that investors attempt to optimize their risk/return profiles through diversification. Defining investment risk as the variability of expected future returns, the CAPM further assumes that risk is comprised of two components: systematic risk and unsystematic risk. Systematic risk is unavoidable, and is tied to macroeconomic factors that affect all companies. Unsystematic risk is company-specific, and theoretically can be eliminated through portfolio diversification. As such, the CAPM holds that investors should only be compensated for systematic risk. Mathematically, the CAPM is expressed as follows:

$$k_s = r_f + B_s \times (k_m - r_f)$$

Where: k_s = expected return on stock "s"
r_f = expected risk-free rate of return
B_s = beta for stock "s"
k_m = expected return on overall stock market

As a measure of systematic risk, the "beta" coefficient measures the extent to which returns on a given stock are correlated with returns on the overall market. Historical values for beta can be determined statistically by comparing total returns on a stock to the total returns on a market index. The risk-free rate of return "r_f" is typically estimated using the yield-to-maturity ("YTM") on U.S. Treasury securities. For common stocks, which have no defined maturity date, the YTM on long-dated Treasury bonds should be used as the risk-free rate. The difference between the expected market return and the risk-free rate, shown above as (k_m – r_f), is frequently referred to as the market risk premium. Estimates for the market risk premium are typically derived by examining historical rates of return for common stocks and U.S. Treasury securities over long periods of time. The time series data published by Ibbotson Associates is a commonly used reference for historical return and risk premium data. Using expected values for the market risk premium, beta, and the risk-free rate, the CAPM can be used to estimate the expected rate of return (or cost of equity) for any given stock.

Q. How did you determine expected values for the market risk premium, beta, and the risk-free rate?

A. Using the Ibbotson Associates time series data, we selected the historical market risk premium for the period 1926-2005 as a proxy for the expected market risk premium. This value, 7.1%, represents the arithmetic average of the excess returns of large company stocks over 20-year U.S. Treasury bonds. For the risk-free rate we selected the YTM on 20-year U.S. Treasury bonds as of April 28, 2006, or 5.3%. The beta for each company represents the published estimate from Value Line.

Q. What results did you obtain from the CAPM?

A. Exhibit KCG-5 summarizes the results obtained, as well as each of the input variables used in the CAPM calculations. With the exception of Nicor, Inc., which had an unusually high value for beta, the estimated cost of equity for each company fell within a range of 9.9% to 11.7%. The median value for the sample group was 11.0%, again excluding Nicor, Inc.

D. <u>Cost of Equity for Comparable Companies</u>.

Q. What conclusions have you reached regarding the cost of equity for the comparable company group?

A. The range of estimates obtained from the DCF model is significantly lower than the range of estimates derived from the CAPM. As may be seen in the table below, the range of overlapping values is relatively narrow (9.9% to 10.5%). Recognizing that each methodology has its own strengths and weaknesses, and recognizing that cost of equity analysis is not an exact science, we have selected a wider range of 9.5% to 11.0% as our estimate of the cost of equity for the comparable company group. Only three of the eleven comparable companies had a DCF estimate falling below this range, while only two of the comparable companies had a CAPM estimate that exceeded this range.

<u>Summary of Comparable Company Analysis</u>

	DCF Model	CAPM	Recommended Range
Low end of range	9.1%	9.9%	9.5%
High end of range	10.5%	11.7%	11.0%

VI. RETURN ON EQUITY FOR UNS GAS.

Q. How did you determine the ROE for UNS Gas?

A. This is best accomplished by comparing the risk profile of UNS Gas to that of the comparable company group and selecting an appropriate point estimate based on the well established relationship between risk and expected return.

Q. How does the risk profile of UNS Gas differ from that of the comparable company group?

A. Relative to an investment in the group of comparable companies, an equity investment in UNS Gas is decidedly riskier. UNS Gas is much smaller than any of the comparable companies, thereby limiting the Company's ability to withstand financial shocks arising from operating emergencies, reductions in customer demand, adverse regulatory decisions or other unforeseen events. The Company is also experiencing a much higher growth rate in net plant investment than any of the comparable companies. As a consequence, there is a continuing need for outside capital and a concurrent reduction in financial returns due to the Company's reliance on an historical test-year for rate setting purposes. Additionally, many of the comparable companies have a rate de-coupling mechanism or weather normalization adjustor that limits financial exposure to mild winter weather and customer conservation. As a result, the credit ratings assigned to the comparable companies by Moody's and Standard & Poor's are generally higher than the ratings UNS Gas could expect to receive. Of the eleven companies in the comparable group, six enjoy investment grade credit ratings of Single-A or better, while the other five companies have a Triple-B (Baa/BBB) investment grade rating.

Q. Would you please elaborate on the growth that UNS Gas is experiencing?

A. Yes. The following table summarizes the actual and forecasted growth in net plant investment, number of retail customers and investment per customer since the gas distribution properties were acquired from Citizens in August 2003:

	Net Plant ($ Millions)	Customers	Investment per Customer
Aug. 2003	$138	127,616	$1,081
Dec. 2004	$161	133,403	$1,207
Dec. 2005	$177	138,797	$1,278
Dec. 2006 (Forecast)	$200	143,843	$1,390
Dec. 2007 (Forecast)	$218	150,198	$1,454
Dec. 2008 (Forecast)	$231	156,691	$1,474
% Growth 2003-2008:	67%	23%	36%

Although much of the growth in net plant investment is attributable to customer growth of approximately 4% per year, investment on a per-customer basis is also increasing due to higher construction costs, the need for system improvements and the low embedded cost of plant acquired from Citizens. Since the assets of UNS Gas were acquired at a purchase price below book value, a substantial gap exists between the embedded investment per customer and the incremental investment per customer. Due to the use of a historical test year for rate setting purposes, as well as the time required to process a rate application, this gap also makes it very difficult, if not impossible, for UNS Gas to earn its authorized rate of return.

Industry-wide growth in net plant investment is forecasted by Value Line to be approximately 5% per year over the period 2005 – 2010. Likewise, the median growth rate forecasted by Value Line for the comparable company group is 5.3% per year. It is clear that UNS Gas is experiencing plant growth well above industry norms, a situation that increases the Company's need for new capital and timely rate recognition of new plant investments.

Q. What allowed ROE do you recommend for UNS Gas in this proceeding?

A. I recommend that the Commission adopt an allowed ROE of 11.0% in this proceeding. This allowed ROE is supported by the range established for the comparable company group and, as discussed below, is reasonable when compared with the allowed returns recently granted to other gas utilities in United States. Additionally, this level of return should also be sufficient, when coupled with other aspects of the Company's rate request, to support the financial integrity of UNS Gas and allow it to access capital on reasonable terms.

Q. What allowed returns on equity have been authorized in other jurisdictions recently?

A. As may be seen in Exhibit KCG-6, allowed ROEs for gas utilities have generally fallen within a range of 10-12%. However, tracking a downward trend in long-term interest rates, allowed returns have also decreased somewhat over time. When these allowed ROEs are compared to the prevailing yield-to-maturity on 20-year U.S. Treasury bonds at the time each rate case was decided, an implied equity risk premium can be calculated. Since January 2004, these equity risk premiums have fallen within a range of 4.7% to 7.2% (see Exhibit KCG-7).

Q. If the observed relationship between allowed equity returns and long-term interest rates continues, what range of allowed ROEs would you expect in the current interest environment?

A. Exhibit KCG-8 shows the yield-to-maturity on 20-year and 90-day U.S. Treasury securities over the past two years as of April 2006. As can be seen, short-term interest rates have steadily increased over this time period, whereas long-term interest rates have only recently begun to climb after bottoming out in mid-2005. Based on the 5.3% yield on U.S. Treasury bonds at the end of April 2006, and the observed range of equity risk premiums described above, it is reasonable to expect allowed returns on equity for gas utilities in the range of 9.9% to 12.5%. The recommended ROE of 11.0% for UNS Gas is just below the midpoint of this range (11.2%).

VII. COST OF DEBT CAPITAL.

Q. What was UNS Gas' embedded cost of debt for the test year?

A. As shown on Schedule D-2 of the Company's Application, the weighted average cost of debt for UNS Gas was 6.60% as of the end of the test year.

Q. What cost of debt do you recommend in this case?

A. I recommend use of the 6.60% cost as of the end of the test year. This cost reflects the interest rate of 6.23% on the two long-term notes issued by UNS Gas in 2003, the amortization of related issuance costs, and 50% of the issuance cost amortization and commitment fees on the joint revolving credit facility established for UNS Gas and UNS Electric in 2005. Although UNS Gas had no borrowings outstanding on the revolving credit facility at the end of the test year, maintenance of this facility is critical for purposes of funding seasonal working capital needs and future PGA bank balances, as well as funding a portion of capital expenditures. During the first quarter of 2006, for example, the Company did use this facility to meet temporary funding needs, and is forecasted to borrow additional amounts in late 2006 and in 2007. As such, it is appropriate to reflect the annual fixed cost of this facility in the cost of debt for UNS Gas.

VIII. WEIGHTED AVERAGE COST OF CAPITAL.

Q. Please summarize your findings regarding the weighted average cost of capital for UNS Gas.

A. Based on the recommended capital structure, the proposed cost of debt, and UNS Gas' cost of equity capital, I recommend the Commission adopt an overall Rate of Return ("ROR") of 8.80%, calculated as follows:

	% of Capital Structure	Component Cost	Weighted Average Cost
Long-Term Debt	50%	6.60%	3.30%
Common Equity	50%	11.00%	5.50%
Total	100.00%		8.80%

Q. How does this compare to the Company's current authorized weighed average cost of capital?

A. It is a decrease, from 9.05% to 8.80%.

IX. FINANCIAL IMPACT OF RATE REQUEST.

Q. What is the financial impact of the Company's rate request?

A. Exhibit KCG-9 provides a summary of key financial indicators for the period 2004-2009 assuming the Company's rate request is granted in full and implemented in August 2007. As may be seen on page 1 of this exhibit, the Company's earnings and cash flow are forecasted to improve if the requested level of rate relief is granted. Reflecting the expected improvement in cash flow, two key measures of credit quality (FFO interest coverage and FFO as a percentage of total debt) are also forecasted to approach industry median levels by 2008. (See page 4 of Exhibit KCG-9.) However, as discussed previously, the Company is not forecasted to earn the recommended ROE of 11.0%. Additionally, as reflected on pages 2 and 3 of Exhibit KCG-9, UNS Gas will continue to depend on outside capital to fund projected plant growth. The top chart on page 2 indicates that internal cash flows are forecasted to cover less than 100% of capital expenditures, while the top chart on page 3 indicates that additional borrowing will be required even if additional equity capital is invested in the Company.

The forecast information presented in Exhibit KCG-9 is based on numerous base case assumptions regarding customer growth, use per customer, operating and capital expenditure levels, short-term interest rates and other factors that are subject to change over time. In addition, this forecast also assumes that the Company's proposed changes to the PGA mechanism are approved, thereby eliminating any large over- or under-recovery of gas commodity costs after the current PGA surcharge expires.

Q. **Is the recommended ROE of 11% sufficient to support the financial integrity of UNS Gas?**

A. Yes, so long as other key aspects of the Company's rate request are granted. Although the Company's financial forecast does not indicate that UNS Gas will actually be able to earn the 11% ROE recommended in this proceeding, the level of rate relief sought by the Company should enable it to access additional capital on reasonable terms. Additionally, requested changes in the Company's rate design and PGA mechanism should provide UNS Gas with greater stability in its earnings and cash flow. Considered in its entirety, the Company's rate request appears to be sufficient to support the financial integrity of UNS Gas. However, if the requested level of cash rate relief is materially reduced, or if the proposed changes to rate design and the PGA mechanism are denied, then a higher ROE would be warranted.

X. RATE BASE TREATMENT OF CONSTRUCTION WORK-IN-PROGRESS.

Q. Is it necessary to include CWIP in rate base in order to preserve the financial integrity of UNS Gas?

A. Yes, it is. UNS Gas will continue to be dependent on outside capital for the foreseeable future in order to fund system growth and capital improvements. As reflected in the bottom chart on page 2 of Exhibit KCG-9, the Company's capitalization is projected to grow by 24% over the next four years, from $180 million in 2005 to an estimated $223 million in 2009. Since the projected demand for capital exceeds the $30 million of borrowing capacity available under the Company's existing credit facility, UNS Gas will need to either attract new outside lenders or additional equity capital in order to fund system growth. For UNS Gas to attract this capital on reasonable terms, the Company must have an opportunity to earn a reasonable rate of return on its capital and have a financial profile comparable to that of other firms in the industry.

As reflected in the Company's rate application, rate base treatment of the $7.2 million test-year CWIP balance provides UNS Gas with approximately ~~$1.5~~ $1.3 million in additional annual revenues. Denial of this requested rate treatment would have a material adverse impact on the Company's rate relief and future earnings. The Company's ability to earn a reasonable return on its capital would be cast further into doubt, as the forecasted ROE for UNS Gas would drop by another 100 basis points (or 1%) relative to the base case forecast summarized in Exhibit KCG-9. Likewise, key cash flow indicators would also be weaker than indicated in Exhibit KCG-9. As a result, I believe it would be difficult for the Company to attract new capital on reasonable terms.

Q. Are there other valid reasons to include CWIP in rate base for UNS Gas?

A. Yes, there are. First, it should be recognized that this rate treatment represents one of the few tools available to help mitigate the effects of regulatory lag. Since UNS Gas is experiencing significant customer growth, and since the cost of new construction greatly exceeds the embedded cost of plant, the impact of regulatory lag on UNS Gas is more pronounced than most utilities. Second, due to the relatively short timeframe required for most construction projects on the UNS Gas system, a large portion of the CWIP balance at year-end 2005 has already been transferred to plant-in-service. Customers are already receiving a benefit from this investment, and the customer advances relating to these projects have already been recognized as a reduction to rate base. Third, by including CWIP in rate base in this proceeding, the time period between this rate case and the next rate filing by UNS Gas will hopefully be extended. Since the cost and time involved with rate case preparation are very significant for a small utility like UNS Gas, the extension of time between rate filings is beneficial to both the Company and its customers. UNS Gas still intends to file rate cases on a regular basis, but neither the Company nor its customers are served by forcing the Company to file a rate case shortly after the case concludes. Finally, the large negative acquisition adjustment to rate base agreed to by UNS Gas upon the acquisition of Citizens must be recognized. As a result of the purchase of the gas properties by UniSource Energy in 2003, current UNS Gas customers are benefiting from a significant discount to the original cost of the gas distribution system.

Q. **What do you recommend if the rate base treatment of CWIP is denied?**

A. As noted earlier, the authorized rate of return should be increased. In addition, if CWIP is not allowed in rate base, then the Commission should consider the rate base treatment of plant that was placed into service after the test year, otherwise known as Post-Test Year Plant. As of May 31, 2006, the amount of Post-Test Year Plant that was previously included in the test year CWIP balance was $5,051,252. This plant is already in service and serving customers. Since the balance of Post-Test Year Plant is growing monthly, due to the ongoing completion of projects included in the test-year CWIP balance, it would be appropriate to update this balance at a later date if Post-Test Year Plant is included in rate base.

Q. Has the Commission allowed the use of Post-Test Year Plant before?

A. Yes, Post-Test Year Plant was allowed in the following cases: *Rio Rico Utilities, Inc.*, Decision No. 67279 (October 5, 2004); *Arizona Water Co.*, Decision No. 66849 (March 19, 2004); and *Bella Vista Water Co., Inc.*, Decision No. 65350 (November 1, 2002).

Q. Please compare the use of CWIP and Post-Test Year Plant.

A. CWIP is a superior measure of the value of the Company's plant because it does not arbitrarily exclude the value of plant that is not yet in service. On a practical level, most gas utilities are constantly building new plant necessary to serve customers. In the case of UNS Gas, this factor is much more important because of the large amount of construction necessary to serve our customers. Thus, CWIP should be allowed. But if it is not, then at a minimum Post-Test Year Plant should be allowed. That would at least mitigate the harm to UNS Gas' future financial condition.

XI. <u>FINANCIAL IMPACT OF DEPRECIATION POLICY.</u>

Q. How does depreciation policy affect the financial condition of a regulated utility?

A. Depreciation is a non-cash expense included in the revenue requirement to provide a return of capital previously invested in long-lived assets. As a non-cash expense, depreciation is a source of internal cash flow that a utility can reinvest in new plant facilities. Higher annual depreciation rates will generate higher internal cash flows, thus improving a utility's credit profile and reducing a utility's dependence on outside capital over the short-run. However, since depreciation expense also reduces the balance of net plant included in rate base, over the long-run no financial advantage is gained by having higher annual depreciation rates. In general, it is best to design depreciation rates that properly reflect the useful economic lives of the assets placed into service.

Q. How do the depreciation rates recommended for UNS Gas compare with the rates previously approved for Citizens?

A. As discussed by UNS Gas witness Dr. Ronald E. White, the composite annual depreciation rate recommended for UNS Gas is 2.73%. While this rate is comparable to the composite rate approved in the 2003 Settlement Agreement, it is significantly lower than the composite depreciation rates of 3.51% and 3.69% previously used by Citizens for the Northern Arizona and Southern Arizona gas divisions, respectively. One of the key factors contributing to the reduction in depreciation rates is the over-depreciation of plant by Citizens prior to 2003.

Q. What is the financial impact of lower depreciation rates on UNS Gas?

A. The reduction in depreciation rates relative to prior periods contributes to a lower revenue requirement and reduced operating cash flows at UNS Gas. Over the short-run, this situation increases the Company's dependence on outside capital and lowers key cash flow ratios monitored by lenders. However, over the long-run, the Company's rate base and earnings will more properly reflect the useful life of the assets placed into service.

XII. SUMMARY OF SCHEDULES.

A. Schedules A-3 and A-4.

Q. Please describe the information contained in Schedules A-3 and A-4.

A. Schedule A-3 presents a summary of the capital structure, capital ratios and weighted cost of capital for the years ending December 31, 2003 and December 31, 2004, and the test year ending December 31, 2005. Schedule A-3 also presents similar information on a forecasted basis for the year ending December 31, 2006.

Schedule A-4 provides historical and projected information relating to construction expenditures, net plant in service and gross utility plant in service. The projected information for the period 2006-2008 is consistent with the base case financial forecast discussed elsewhere in my testimony. The values for net plant in service and gross utility plant are presented on a regulatory accounting basis, which differs slightly from the presentation used in the Company's audited financial statements and the financial forecast.

B. <u>Schedules D-1 through D-4.</u>

Q. Please describe Schedule D in the Company's Application.

A. Schedule D consists of four parts, Schedules D-1 through D-4.

Schedule D-1 contains the Company's actual and proposed capital structure and weighted average cost of capital for the test year ended December 31, 2005. This schedule also contains projected information pertaining to the Company's capital structure and weighted average cost of capital as of December 31, 2006.

Schedule D-2 contains detailed information on UNS Gas' cost of long-term debt. Schedule D-2, Page 1, provides a calculation of the weighted average cost of long-term debt, both actual and proposed, for the test year ended December 31, 2005. Schedule D-2, Page 2, contains a projection of the Company's cost of debt as of December 31, 2006.

Schedule D-3 indicates that UNS Gas had no preferred stock outstanding during the test year, and that there are no plans to issue preferred stock.

Schedule D-4 contains the Company's estimated cost of equity capital and the proposed rate of ROE for use in this proceeding.

C. Schedules F-1 through F-4.

Q. Please describe Schedule F in the Company's Application.

A. Schedule F consists of four parts, Schedules F-1 through F-4.

Schedule F-1 contains a summary income statement and a return on common equity calculation for the test year ended December 31, 2005. This same information is presented on a projected basis for the year ending December 31, 2006. The projected year information is presented using two different rate assumptions: (i) a continuation of present rates; and (ii) an assumed implementation of proposed rates as of January 1, 2006.

Schedule F-2 contains a summary cash flow statement for the test year ended December 31, 2005. This same information is presented on a projected basis for the year ending December 31, 2006. The projected year information is presented using two different rate assumptions: (i) a continuation of present rates; and (ii) an assumed implementation of proposed rates as of January 1, 2006.

Schedule F-3 contains information on the Company's construction expenditures during the test year ended December 31, 2005. This same information is presented on a projected basis for calendar years 2006, 2007 and 2008.

Schedule F-4 contains a description of key forecast assumptions used in preparing the projected information appearing in Schedules F-1 through F-3

Q. Please comment on the projected information appearing in Schedules F-1 and F-2.

A. The financial projections that assume a continuation of current rates through December 2006 were taken from a base case financial forecast prepared for UNS Gas, the same base case forecast discussed elsewhere in my testimony. It should be noted that this forecast is based on numerous assumptions regarding sales growth, natural gas prices, operating and capital expenditure levels, and other factors that are subject to change over time. Additional financial projections are provided in Schedules F-1 and F-2 that assume implementation of the Company's requested rates beginning January 2006. I would like to note that these additional projections are purely hypothetical and are included for the sole purpose of complying with the Commission's rate filing requirements. In Decision No. 66028 (July 3, 2003), the Commission ordered that UNS Gas' present rates remain in effect until August 1, 2007 unless emergency circumstances arise or other specific events occur. Thus, projections assuming that new rates are implemented in January 2006 have limited analytical value.

Q. Does this conclude your testimony?

A. Yes, it does.

EXHIBIT

KCG-1

Exhibit KCG-1

UNS Gas, Inc.
Comparable Company Data

	Gas Distribution Customers	Common Equity as % of Total Capital (12/31/2005)	Senior Unsecured Credit Rating S&P	Senior Unsecured Credit Rating Moody's	Market Capitalization ($ Millions) (12/31/2005)
AGL Resources Inc.	2,242,000	41.2%	BBB+	Baa1	$ 2,705
Atmos Energy Corp.	3,157,840	40.7%	BBB	Baa3	$ 2,107
Cascade Natural Gas Corporation	225,370	38.9%	BBB+	Baa1	$ 223
Laclede Group, Inc. (1)	629,722	44.8%	A	Baa2	$ 618
New Jersey Resources Corporation (2)	447,571	47.0%	A+	-	$ 1,154
Nicor Inc. (3)	1,923,900	42.0%	AA-	A1	$ 1,737
Northwest Natural Gas Company	617,163	47.2%	A+	A3	$ 943
Piedmont Natural Gas Company, Inc.	877,000	51.9%	A	A3	$ 1,853
South Jersey Industries, Inc. (4)	322,424	45.5%	-	Baa2	$ 845
Southwest Gas Corporation	1,713,000	34.4%	BBB-	Baa2	$ 1,038
WGL Holdings, Inc. (5)	1,012,105	56.0%	AA-	A2	$ 1,464
Median Value	877,000	44.8%	A	Baa1	$ 1,154

Notes

(1) S&P Corporate Rating for Laclede Group is A. Moody's Senior Secured Shelf ratings for Laclede Group and Laclede Gas are Baa2 and Baa1, respectively.

(2) S&P Corporate rating for New Jersey Natural Gas is A+.

(3) Moody's Corporate Rating for Northern Illinois Gas Company is A1.

(4) Moody's Senior Unsecured Rating for South Jersey Gas Co. is Baa2.

(5) S&P Corporate Rating for WGL Holdings, Inc is AA-. Moody's Senior Unsecured Rating for Washington Gas Light is A2.

EXHIBIT

KCG-2

Exhibit KCG-2

UNS Gas, Inc.
Projected Growth Rates for Earnings and Dividends
Comparable Company Group

	Value Line Dividend Growth (3 to 5 Years)	Projected Earnings Growth			
		Value Line (3 to 5 Years)	Thomson Financial (5-Year)	SNL Financial (5-Year)	5-Year Growth Rate for DCF
AGL Resources	3.9%	3.3%	5.0%	5.0%	3.9%
Atmos Energy Corp.	1.7%	7.8%	5.6%	5.5%	3.6%
Cascade Natural Gas Corporation	0.5%	11.6%	3.0%	3.0%	1.8%
Laclede Group, Inc.	1.7%	4.5%	N/A	5.0%	3.1%
New Jersey Resources Corporation	3.9%	4.2%	5.5%	6.0%	4.0%
Nicor Inc.	2.1%	3.9%	3.7%	3.7%	2.9%
Northwest Natural Gas Company	5.4%	6.1%	5.0%	5.5%	5.4%
Piedmont Natural Gas Company	5.1%	7.7%	4.2%	N/A	5.1%
South Jersey Industries, Inc.	5.5%	5.6%	6.0%	5.5%	5.5%
Southwest Gas Corporation	0.0%	10.4%	N/A	N/A	5.2%
WGL Holdings, Inc.	1.8%	6.7%	4.0%	4.0%	2.9%
Median Value for Group	2.1%	6.1%	5.0%	5.0%	3.9%

EXHIBIT

KCG-3

Exhibit KCG-3

UNS Gas, Inc.
Calculation of Expected First-Year Dividend
Comparable Company Group

	Current Quarterly Dividend	Last Change in Dividend Payment	Recent Ex-Dividend Date	5-Year Growth Rate for DCF	Expected Quarterly Dividends as of 4/30/06					Expected First-Year Dividend
					2Q 2006	3Q 2006	4Q 2006	1Q 2007	2Q 2007	
AGL Resources	$0.370	4Q 2005	02/15/06	3.9%	$0.370	$0.370	$0.385	$0.385		$1.509
Atmos Energy Corp.	$0.315	4Q 2005	02/23/06	3.6%	$0.315	$0.315	$0.326	$0.326		$1.283
Cascade Natural Gas Corporation	$0.240	None Recent	04/26/06	1.8%		$0.240	$0.240	$0.240	$0.240	$0.960
Laclede Group, Inc.	$0.355	2Q 2006	03/08/06	3.1%		$0.355	$0.355	$0.355	$0.366	$1.431
New Jersey Resources Corporation	$0.360	1Q 2006	03/13/06	4.0%		$0.360	$0.360	$0.375	$0.375	$1.469
Nicor Inc.	$0.465	None Recent	03/29/06	2.9%		$0.465	$0.465	$0.465	$0.465	$1.860
Northwest Natural Gas Company	$0.345	4Q 2005	04/26/06	5.4%		$0.345	$0.363	$0.363	$0.363	$1.435
Piedmont Natural Gas Company	$0.240	2Q 2006	03/22/06	5.1%		$0.240	$0.240	$0.240	$0.252	$0.972
South Jersey Industries, Inc.	$0.225	4Q 2005	03/08/06	5.5%		$0.225	$0.237	$0.237	$0.237	$0.937
Southwest Gas Corporation	$0.205	None Recent	02/13/06	5.2%	$0.205	$0.205	$0.205	$0.205		$0.820
WGL Holdings, Inc.	$0.338	2Q 2006	04/06/06	2.9%		$0.338	$0.338	$0.338	$0.348	$1.362

EXHIBIT

KCG-4

Exhibit KCG-4

UNS Gas, Inc.
Multi-Stage DCF Analysis
Comparable Company Group

	Recent Avg. Share Price	Projected Dividends					Long-Term Dividend Growth	Estimated Cost of Equity
		Year 1	Year 2	Year 3	Year 4	Year 5		
AGL Resources	$35.29	$1.51	$1.57	$1.63	$1.69	$1.76	6.0%	9.98%
Atmos Energy Corp.	$26.47	$1.28	$1.33	$1.38	$1.43	$1.48	6.0%	10.47%
Cascade Natural Gas Corporation	$19.63	$0.96	$0.98	$0.99	$1.01	$1.03	6.0%	10.22%
Laclede Group, Inc.	$33.86	$1.43	$1.48	$1.52	$1.57	$1.62	6.0%	9.82%
New Jersey Resources Corporation	$44.84	$1.47	$1.53	$1.59	$1.65	$1.72	6.0%	9.05%
Nicor Inc.	$39.71	$1.86	$1.91	$1.97	$2.03	$2.08	5.0%	9.35%
Northwest Natural Gas Company	$34.42	$1.44	$1.51	$1.59	$1.68	$1.77	6.0%	10.08%
Piedmont Natural Gas Company	$24.28	$0.97	$1.02	$1.07	$1.13	$1.18	6.0%	9.88%
South Jersey Industries, Inc.	$26.58	$0.94	$0.99	$1.04	$1.10	$1.16	6.0%	9.46%
Southwest Gas Corporation	$27.69	$0.82	$0.86	$0.91	$0.95	$1.00	7.0%	9.77%
WGL Holdings, Inc.	$29.43	$1.36	$1.40	$1.44	$1.48	$1.53	6.0%	10.16%

EXHIBIT

KCG-5

Exhibit KCG-5

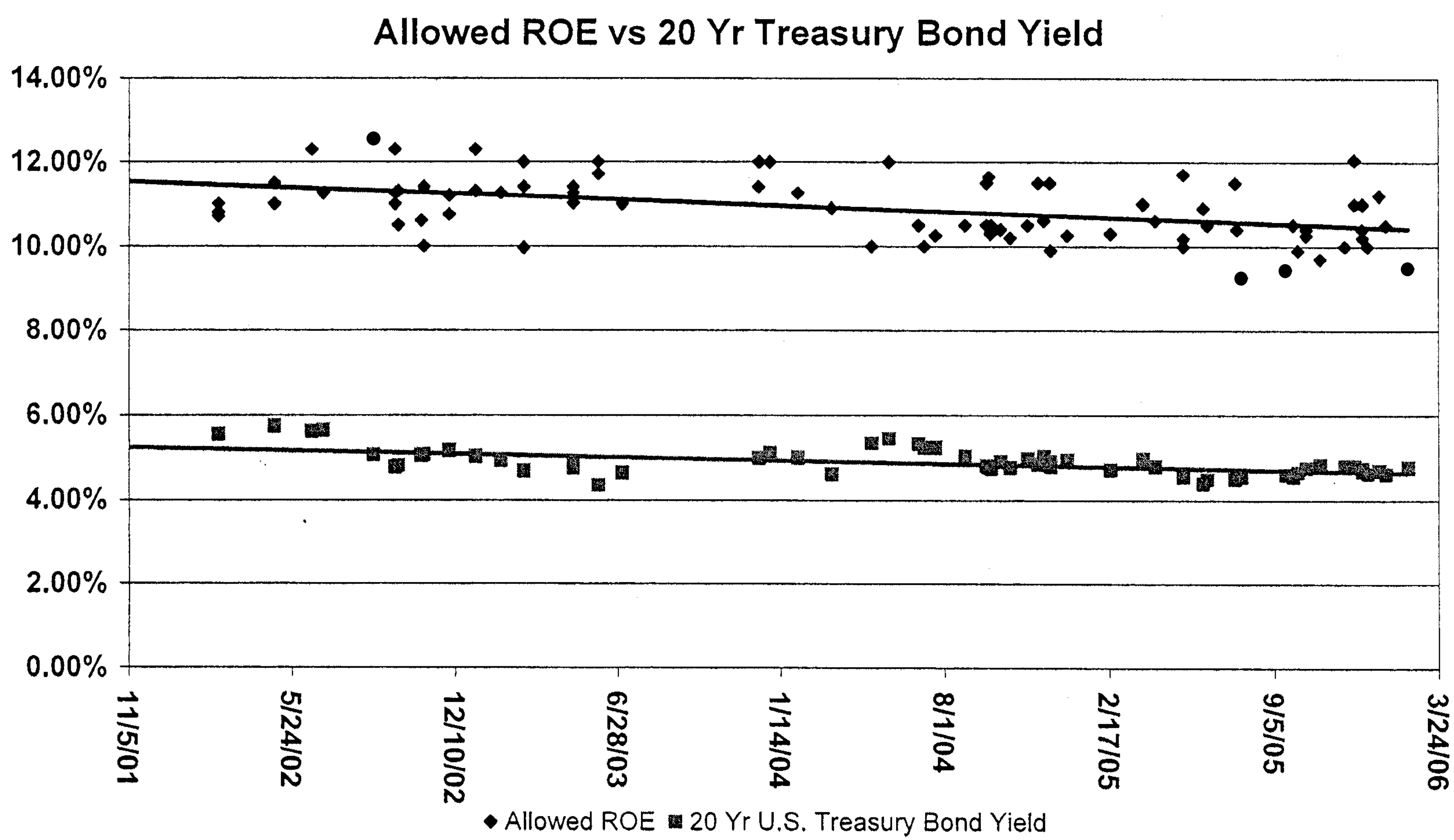
UNS Gas, Inc.
Application of Capital Asset Pricing Model
Comparable Company Group

	Risk-Free Rate		Beta		Equity Risk Premium		Estimated Cost of Equity
AGL Resources Inc.	5.3%	+	0.90	x	7.1%	=	11.7%
Atmos Energy Corp.	5.3%	+	0.70	x	7.1%	=	10.3%
Cascade Natural Gas Corporation	5.3%	+	0.80	x	7.1%	=	11.0%
Laclede Group, Inc.	5.3%	+	0.80	x	7.1%	=	11.0%
New Jersey Resources Corporation	5.3%	+	0.80	x	7.1%	=	11.0%
Nicor Inc.	5.3%	+	1.15	x	7.1%	=	13.5%
Northwest Natural Gas Company	5.3%	+	0.70	x	7.1%	=	10.3%
Piedmont Natural Gas Company	5.3%	+	0.75	x	7.1%	=	10.6%
South Jersey Industries, Inc.	5.3%	+	0.65	x	7.1%	=	9.9%
Southwest Gas Corporation	5.3%	+	0.80	x	7.1%	=	11.0%
WGL Holdings, Inc.	5.3%	+	0.80	x	7.1%	=	11.0%

EXHIBIT

KCG-6

Exhibit KCG - 6



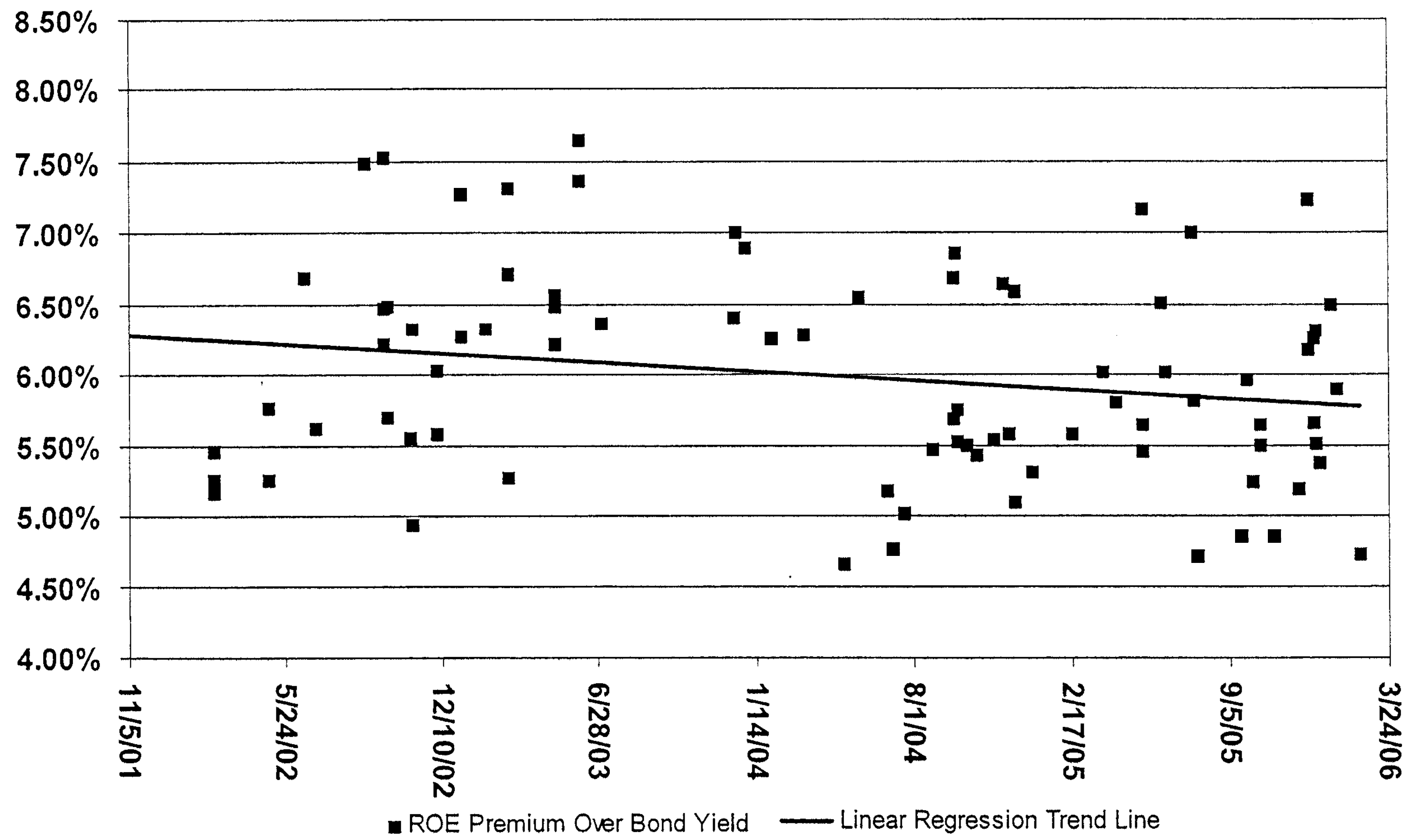
Note: Solid lines represent linear regression trend lines.
Source: 20 Yr U.S. Treasury yields obtained from the Federal Reserve Board of Governers web site: www.federalreserve.gov. Allowed ROE data obtained from the American Gas Association web site: www.aga.org.

EXHIBIT

KCG-7

Exhibit KCG - 7

Allowed ROE Premium over 20 Yr Treasury Bond Yield

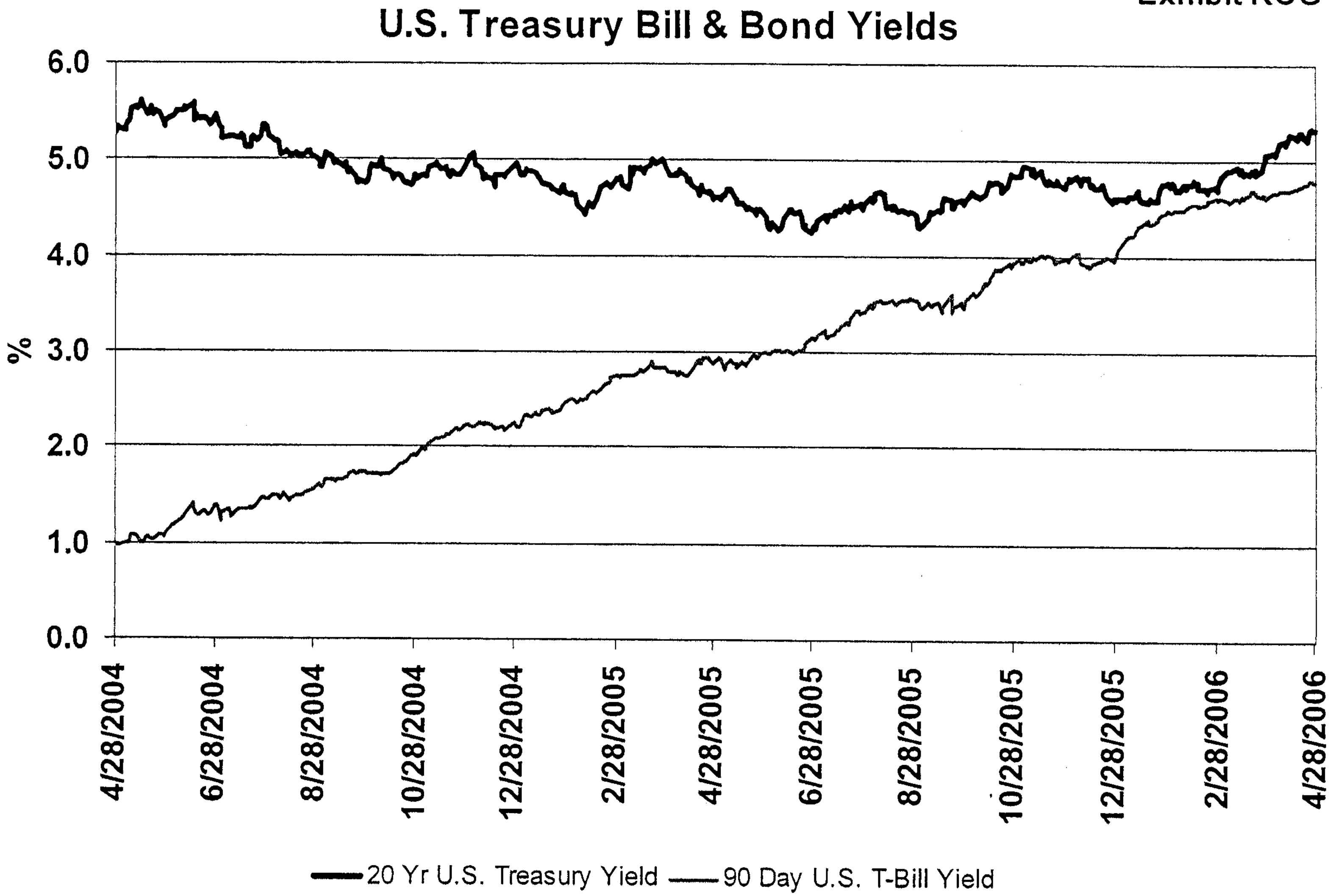


Source: 20 Yr U.S. Treasury yields obtained from the Federal Reserve Board of Governers web site: www.federalreserve.gov. Allowed ROE data obtained from the American Gas Association web site: www.aga.org.

EXHIBIT

KCG-8

Exhibit KCG - 8

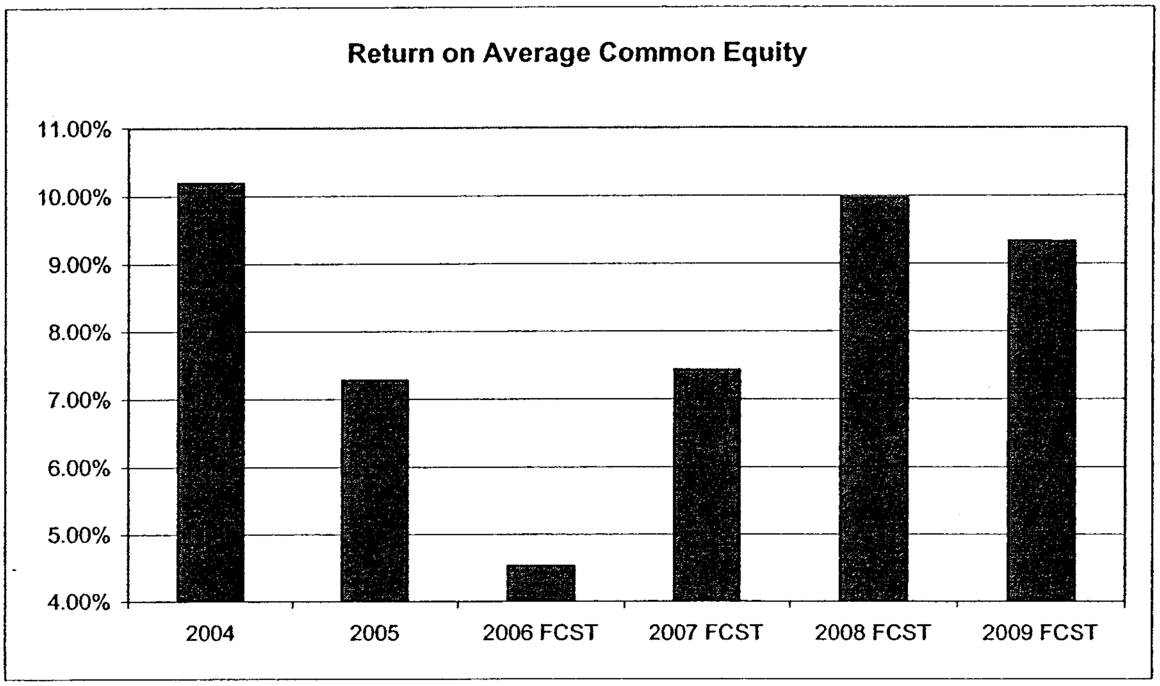


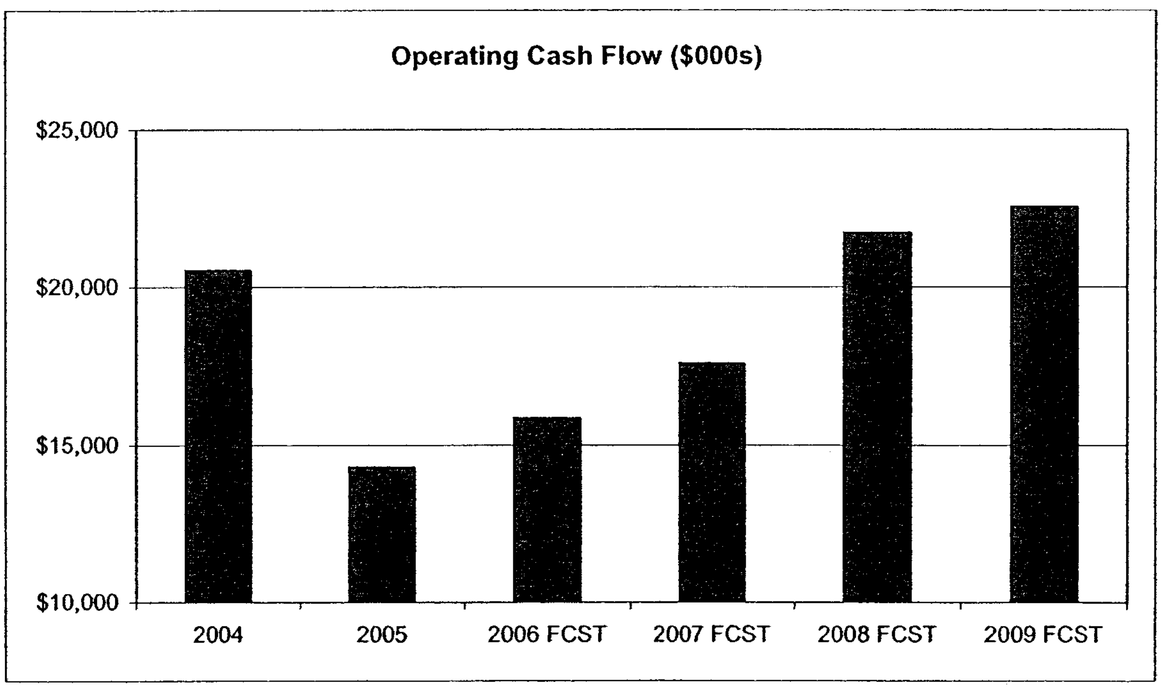
EXHIBIT

KCG-9

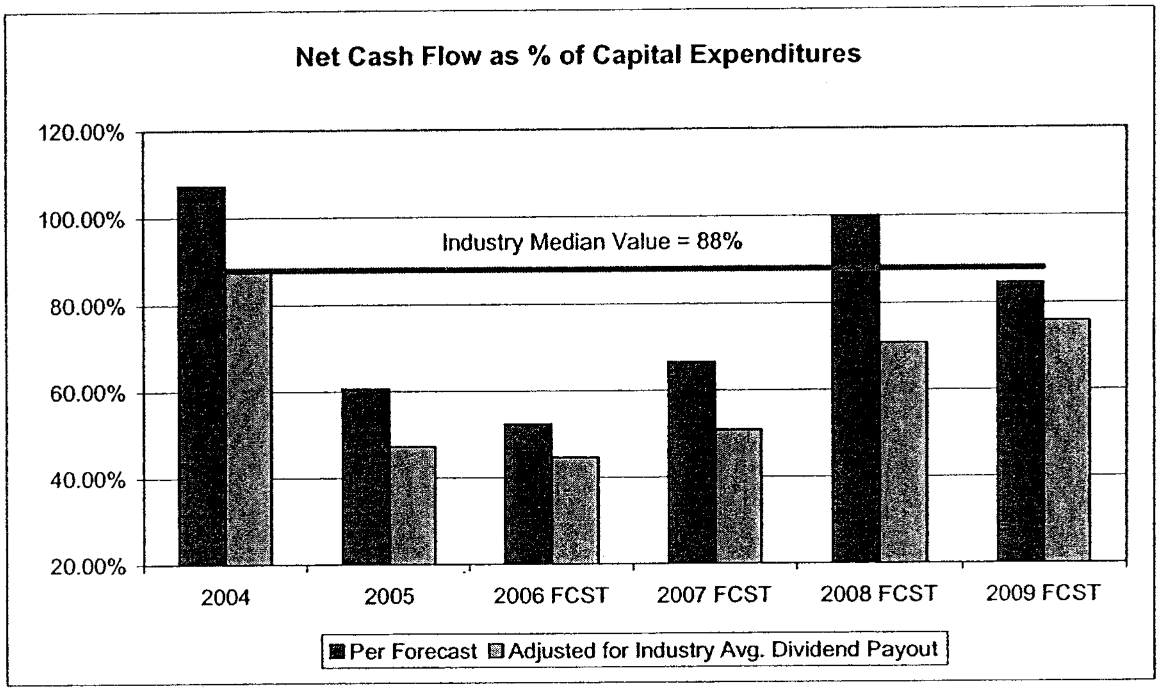
Exhibit KCG-9
Page 1 of 4

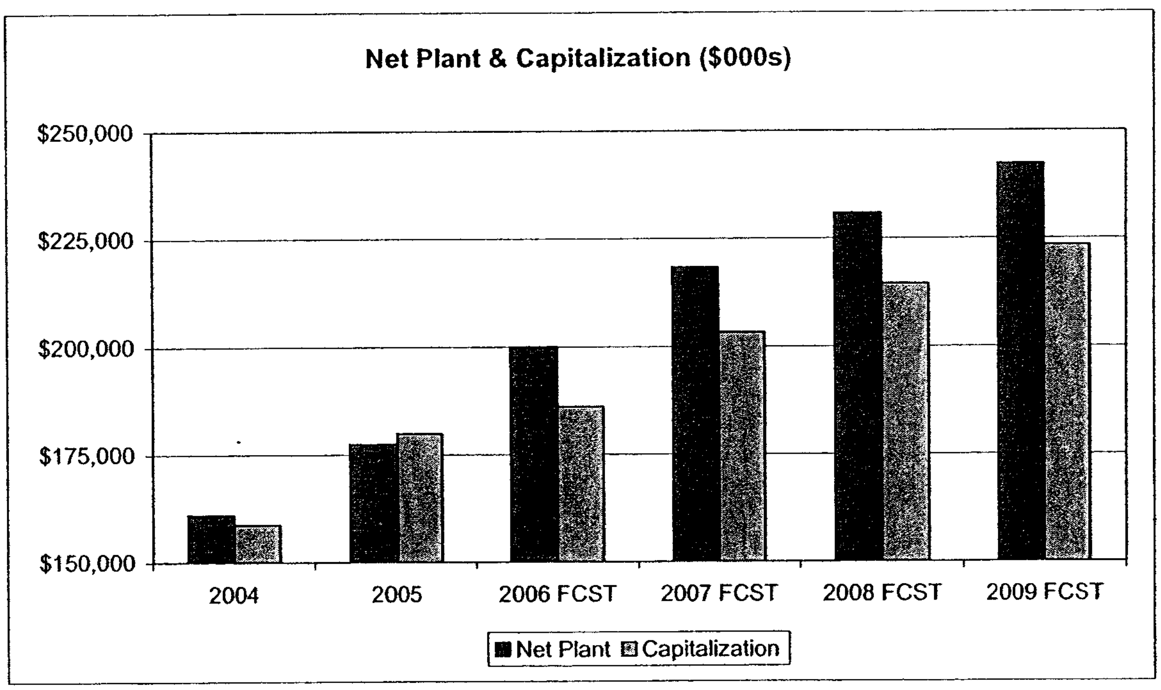
UNS Gas, Inc.
Base Case Financial Forecast
Summary of Key Financial Indicators





UNS Gas, Inc.
Base Case Financial Forecast
Summary of Key Financial Indicators





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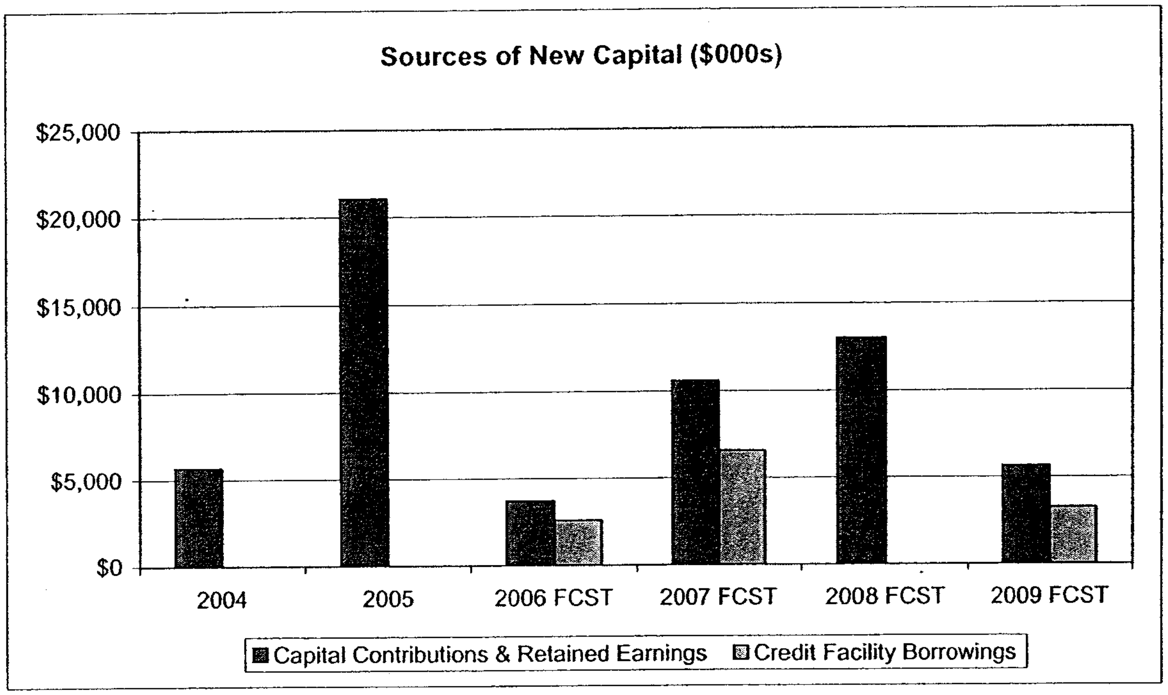

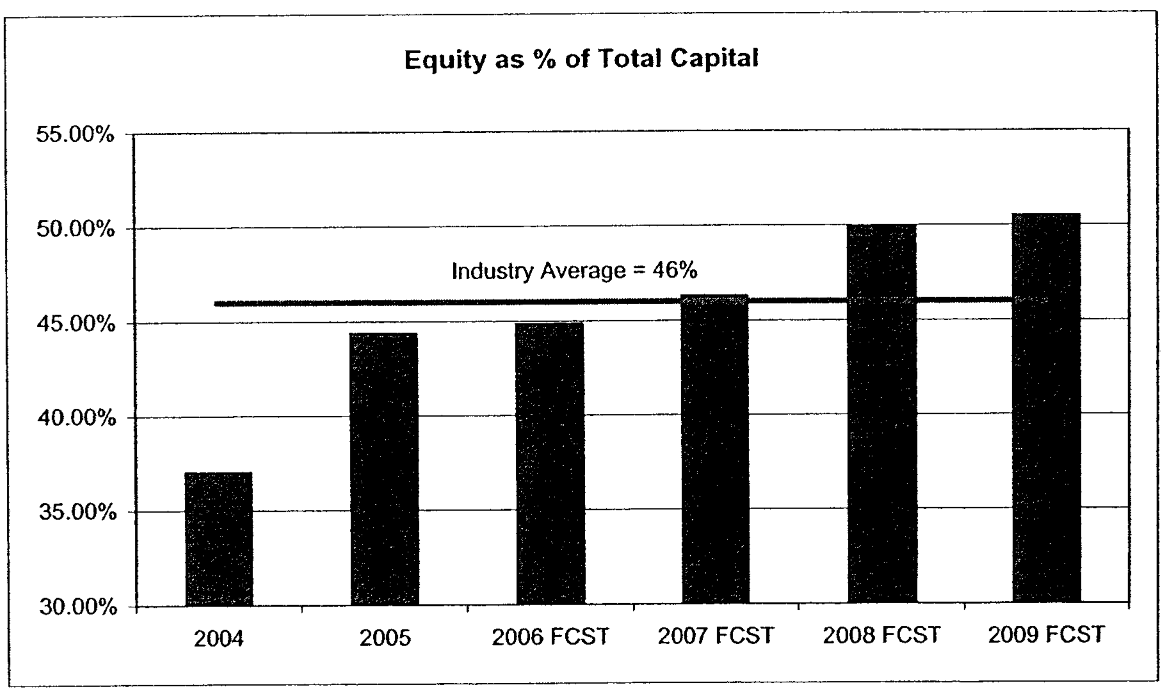

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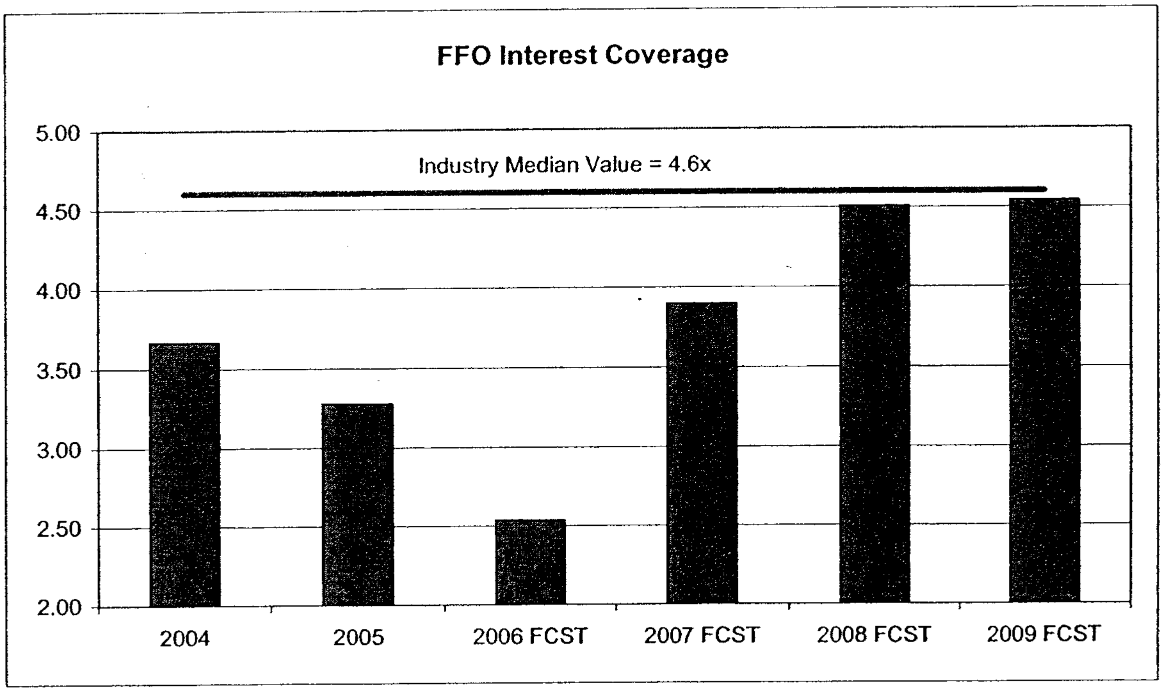

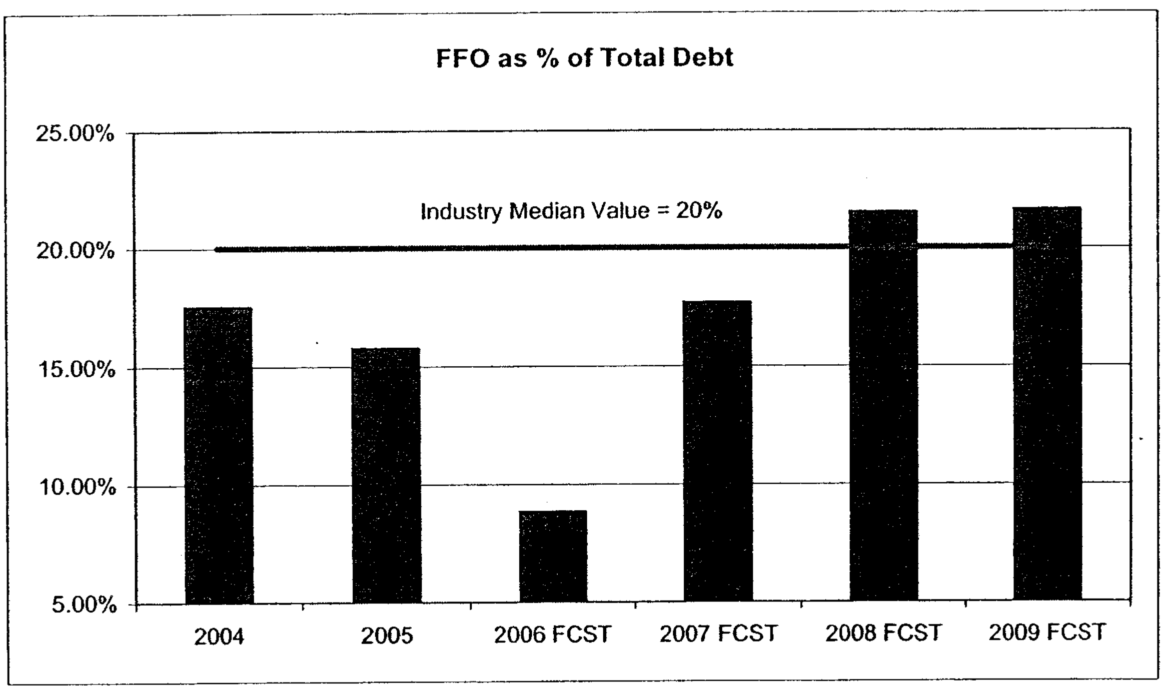

BEFORE THE ARIZONA CORPORATION COMMISSION

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 THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-06-063
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

Rebuttal Testimony of

Kentton C. Grant

on Behalf of

UNS Gas, Inc.

March 16, 2007

EXHIBIT
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UNSG 28
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TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Kentton C. Grant. My business address is One South Church Avenue, Tucson, Arizona, 85701.

Q. Are you the same Kentton C. Grant that filed Direct Testimony in this case?

A. Yes.

Q. Have you reviewed the Direct Testimony filed by the Commission Staff and Intervenors in this case?

A. Yes, I have.

Q. Please provide your general response to the Commission Staff and Intervenor Direct Testimony.

A. The rate increases recommended by the Commission Staff ("Staff") and by the Residential Utility Consumers Office ("RUCO") are insufficient to support the financial integrity of UNS Gas, Inc. ("UNS Gas"). Neither party presented an analysis of how their recommendations would impact the Company's cash flow and earnings, two critical elements to consider when evaluating the ability of UNS Gas to attract capital on reasonable terms. The allowed return on equity ("ROE") and the overall rate of return ("ROR") on invested capital recommended by each of these parties are also unreasonably low in light of the business risks faced by UNS Gas, the impact of growth and regulatory lag on the Company's financial performance, and the need to raise additional capital for plant investment. Finally, Staff and RUCO's rejection of the Company's request to include construction work-in-progress ("CWIP") in rate base appears to be based largely on philosophical grounds and does not take into account the financial realities facing

UNS Gas. Since neither party adjusted the test-ear balance of customer advances that are tied to this CWIP balance, the positions taken by Staff and RUCO actually serve to penalize UNS Gas for having an ongoing construction program. At a minimum, the balance of customer advances related to the test-ear CWIP balance should have been removed by the Commission Staff and RUCO as rate base adjustments. The Company's alternative request for a post test-year adjustment to rate base, which would include that portion of the test-year CWIP balance that has already been placed into service, was not even addressed by RUCO and was summarily dismissed by Staff. I am hopeful that once Staff and RUCO have had an opportunity to evaluate the financial impact of their rate recommendations on UNS Gas, that these parties will at least consider the Company's alternative request for a post-test-year adjustment to rate base.

Q. Which Commission Staff and/or Intervenor testimony will you be addressing in your Rebuttal Testimony?

A. I will be addressing the Direct Testimony of the following witnesses:

- William A. Rigsby on behalf of RUCO (Cost of capital)
- Marylee Diaz Cortez on behalf of RUCO (CWIP in rate base)
- David C. Parcell on behalf of Staff (Cost of capital & CWIP in rate base)
- Ralph C. Smith on behalf of Staff (CWIP and ROR on fair value rate base)

II. REBUTTAL TO RUCO WITNESS WILLIAM A. RIGSBY.

Q. Mr. Grant, could you please summarize your view of the Direct Testimony filed by Mr. William Rigsby on behalf of RUCO?

A. Yes. The allowed ROE of 9.64% recommended by Mr. Rigsby is unreasonably low. The results of his single-stage DCF analysis, which produces cost of equity estimates as low as 7.6% for the companies in his proxy group, should be given little to no weight in this proceeding. The results obtained from his CAPM analysis are more realistic, falling within a range of 9.7% to 11.36%. However, because Mr. Rigsby chooses to base his recommendation on an average of his DCF estimate (8.74%) and the midpoint of the CAPM range (10.53%), the end result of 9.64% is unreasonably low and is not supported by the range established in his own CAPM analysis.

I concur with Mr. Rigsby regarding the appropriate capital structure for UNS Gas. As he points out, the requested capital structure consisting of 50% equity and 50% debt is in line with industry averages. However, regarding the Company's cost of debt, I strongly disagree with Mr. Rigsby's disallowance of debt issuance costs and annual revolving credit fees. It is standard practice for both regulated and unregulated companies to amortize the costs of debt issuance over the respective lives of the debt obligations issued. It is also necessary, especially for a growing company like UNS Gas, to maintain lines of credit to meet short-term liquidity needs and to fund capital expenditures prior to the arrangement of long-term financing. For these reasons, Mr. Rigsby's cost of debt recommendation should be rejected.

Q. Please expand on your critique of Mr. Rigsby's DCF analysis.

A. Certainly. As can be seen on Schedule WAR-2 attached to his Direct Testimony, Mr. Rigsby uses dividend growth rates for his proxy group ranging from a low of 4.14% for WGL Holdings, Inc. to a high of 8.17% for Southwest Gas Corporation. Since these growth rates are used by Mr. Rigsby in a single-stage constant growth DCF model, he implicitly assumes that these growth rates will remain in effect in perpetuity. From the standpoint of market expectations, there are two serious problems with this assumption.

First, compared to most industries, the natural gas distribution industry remains highly regulated and is fairly homogeneous with respect to service offerings and type of capital investment. Although near-term expectations for dividend and earnings growth can vary widely between individual companies, over the long-run it is unrealistic to assume such a wide divergence in growth rates and shareholder returns. Over the long-run, investors are much more likely to expect a convergence of individual company growth rates toward the industry average growth rate. This approach to forecasting long-term growth rates, which assumes that growth rates for individual companies will revert to the industry average over time, is widely practiced by securities analysts and investors. Since Mr. Rigsby did not adjust his perpetual growth rates to account for this factor, the cost of equity estimates he obtained were unrealistically low for companies having the lowest near-term growth rates. Indeed, half of the companies in his proxy group have cost of equity estimates ranging from 7.63% to 8.29%, values that are just barely above comparable utility bond yields.

Second, when adjusted for inflation, the perpetual growth rates used by Mr. Rigsby assume a real rate of growth that is unrealistically low for most of the companies in his proxy group. Based on the difference between the yield on 20-year inflation indexed U.S. Treasury securities (2.45%) and the yield-to-maturity on 20-year fixed-rate U.S. Treasury bonds (4.96%), the expected long-term inflation rate for the U.S. economy was approximately 2.5% as of January 19, 2007, the terminal date used by Mr. Rigsby in his calculation of average stock prices in his DCF analysis. Subtracting this expected inflation rate from the dividend growth rates appearing in his Schedule WAR-2 results in a range of expected *real* dividend growth rates of 1.64% to 5.67%. It is hard to fathom that investors would expect any company, even a highly regulated distribution company, to grow its earnings and dividends at a perpetual growth rate of only 1.64% over the expected rate of inflation. When adjusted for inflation, five of the companies in his proxy group have a perpetual *real* growth rate of 1.81% or less. By contrast, expectations for long-term growth in the overall U.S. economy are likely closer to 3.5% in real terms. It is simply unrealistic to assume that dividends and earnings would grow at such a wide discount to overall economic growth for an industry providing basic utility infrastructure to an expanding U.S. economy.

Q. Do you have any other comments regarding Mr. Rigsby's cost of equity analysis?

A. Yes, I do. At page 52 of his Direct Testimony, Mr. Rigsby dismisses the company-specific risks faced by UNS Gas that were described on page 21 of my Direct Testimony. Despite the fact that UNS Gas is much smaller than any of the companies used in Mr. Rigsby's proxy group, and the fact that UNS Gas is growing at a much faster pace with a detrimental impact on the Company's earned ROR, no upward adjustment was made to his proxy group results to account for this incremental risk. Additionally, even though many of the companies in his proxy group have a rate de-coupling mechanism or weather normalization adjustor that limits financial exposure to mild winter weather and customer conservation, Mr. Rigsby made no upward adjustment to the proxy group results to reflect the increased risk UNS Gas would bear under RUCO's proposed rate design. So, even if the problems with Mr. Rigsby's proxy group analysis were to be remedied, an additional upward adjustment to the proxy group cost of equity would have to be made in order to arrive at a reasonable allowed ROE for UNS Gas.

Q. Do you think Mr. Rigsby has a good grasp of the additional risk faced by UNS Gas resulting from high customer growth and regulatory lag?

A. No, I do not. As stated at page 40 of his Direct Testimony, Mr. Rigsby cites the potential acceleration of growth in new construction projects and home developments in the Company's service territories as a positive factor for UNS Gas. However, as described at page 22 of my Direct Testimony, and in greater detail below in my Rebuttal Testimony to Ms. Diaz Cortez, the Company is negatively impacted over the short-run by high customer growth and related capital spending. Additionally, contrary to the suggestion by Mr. Rigsby at page 40, lines 9-14 of his Direct Testimony, the Company does not foresee – and Mr. Rigsby fails to cite any evidence of – any near-term decline in the cost of goods and services it purchases that could offset this negative impact from growth.

Q. Regarding his recommended cost of debt, does Mr. Rigsby offer any reason for disallowing the Company's debt issuance costs and revolving credit fees?

A. No. He simply states that these costs should have been written off by UNS Gas in prior periods.

Q. Is it customary for utilities to recover their debt issuance costs and revolving credit fees through an adjustment to the cost of debt capital?

A. Yes. Debt issuance costs are typically included in the cost of debt by amortizing these costs over the life of the respective debt obligations, and including this amortization expense as a component of interest expense in the cost of debt calculation. Likewise, since revolving credit fees are recorded as interest expense on a utility's financial statements, and are necessary for purposes of maintaining financial liquidity, it is also customary to include this expense when calculating the cost of debt. UNS Gas has proposed treating these costs in this manner, resulting in a cost of debt of 6.60%.

Q. Is UNS Gas obligated to amortize debt issuance costs over the life of the respective debt obligations?

A. Yes. The accounting guidelines issued by the Federal Energy Regulatory Commission ("FERC") require this method of accounting for natural gas companies. Specifically, these instructions state that "The premium, discount and expense shall be amortized over the life of the respective issues under a plan which will distribute the amounts equitably over the life of the securities." Clearly, UNS Gas is following standard industry practice with respect to its accounting and rate treatment of debt issuance costs.

Q. Does that conclude your rebuttal to the Direct Testimony of Mr. Rigsby?

A. Yes, it does.

III. REBUTTAL TO RUCO WITNESS MARYLEE DIAZ CORTEZ.

Q. Mr. Grant, could you please summarize your view of the Direct Testimony filed by Ms. Diaz Cortez on behalf of RUCO?

A. Yes. Ms. Diaz Cortez rejects the Company's request to include CWIP in rate base on several grounds. After describing at length how the rate base treatment of CWIP is not an "accepted" ratemaking treatment, and why the Company must demonstrate that it meets an "extraordinary circumstance" standard, she goes on to state that this ratemaking treatment is not necessary to maintain the Company's financial integrity. Ms. Diaz Cortez also questions the negative effects of regulatory lag and growth on UNS Gas' financial results, and refers to one of the Company's arguments on CWIP in rate base as being "disingenuous at best."

Q. Do you agree with Ms. Diaz Cortez' characterization of CWIP in rate base as not being an "accepted" ratemaking treatment?

A. No, I do not. The inclusion of CWIP in rate base as a means of supporting the financial integrity of public utilities has been an accepted form of ratemaking treatment for many years in many states. Although the standard for granting this ratemaking treatment varies by jurisdiction, I am not aware of any bright-line "extraordinary circumstance" standard that must be met in the State of Arizona to include CWIP in rate base. While I recognize that rate base treatment of CWIP is unusual in the sense that it has not been used for many years in this jurisdiction, it is certainly a tool that is available to the Commission for purposes of setting fair and reasonable rates.

Q. Are you aware of cases where CWIP was included in rate base in Arizona?

A. Certainly. Although I am not an attorney, I am aware of at least two Arizona Supreme Court cases decided in the 1970s that have discussed the issue of CWIP in rate base. For instance, it is my understanding that the Arizona Supreme Court did make the statement – in a rate case involving Arizona Public Service Company ("APS") – that the Commission could adopt any of a variety of approaches and consider plant under construction so long as the approach is not arbitrary.[1] In a subsequent Arizona Supreme Court decision involving an APS rate case, my understanding is that the Court specifically stated that CWIP may be included in fair value rate base and that it was reasonable for the Commission to allow inclusion of CWIP in determining rates.[2] I do not recall there being any language about how "extraordinary circumstances" were needed to put CWIP in rate base.

Q. Even if the Commission were to require a finding of "extraordinary circumstance" in order to allow CWIP in rate base, would UNS Gas meet such a standard?

A. Yes, I believe it would. As discussed at page 22 of my Direct Testimony, it will be difficult, if not impossible, for the Company to earn its authorized rate of return over the next several years. This is due primarily to the high rate of customer growth in UNS Gas' service territory and the wide gap between the Company's embedded cost of plant and incremental cost of plant on a per-customer basis. Additionally, this growth is causing UNS Gas to raise large sums of additional capital to fund necessary plant investments. At this same time, natural gas prices have become much more volatile than in the past, thereby exposing the Company to the risk of large purchased gas deferral balances and declining customer usage. The combination of these factors, in my opinion, constitutes extraordinary circumstances that justify CWIP in rate base.

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[1] Arizona Corp. Comm'n v. Arizona Public Service Co., 113 Ariz. 368, 555 P.2d 326 (1976).
[2] Arizona Community Action Assoc. v. Ariz. Corp. Comm'n, 123 Ariz. 228, 599 P.2d 184 (1979).

Q. At page 9 of her Direct Testimony, Ms. Diaz Cortez characterizes the Company's financial integrity argument as being "without merit." Did Ms. Diaz Cortez offer any financial analysis to support this conclusion?

A. No, she did not. Although she makes reference to the financial integrity of "Arizona utilities" in general, and cites the positive effects of growth and regulatory lag on UNS Gas, she provides no analysis of the Company's financial performance on either an actual or forecasted basis, and provides no quantitative support for her statements regarding regulatory lag and growth.

Q. Do you believe it is necessary to include CWIP in rate base in order to preserve the financial integrity of UNS Gas?

A. Yes, I do. As discussed on pages 27 through 28 of my Direct Testimony, the ability of UNS Gas to earn a reasonable rate of return on its invested capital and to generate a healthy level of internal cash flow is essential if the Company is to maintain continued access to capital on reasonable terms.

Q. Also at page 9 of her Direct Testimony, Ms. Diaz Cortez states that "...the Company's growth argument is without merit as growth has a positive effect on the Company, generating more revenue and cash flow." Do you agree with this statement?

A. No, I do not. While it is true that growth does generate additional revenue, and that over the long-run this growth will generate additional cash flow, Ms. Diaz Cortez ignores the fact that over the short-run the Company's earnings and cash flow are adversely affected by high customer growth. Meeting this growth requires substantial capital investment, currently at a level far exceeding the Company's internal cash flow. This additional investment creates additional fixed costs that UNS Gas must bear, including interest expense, depreciation expense and property taxes. Because of these additional costs, and the regulatory lag resulting from the use of an historical test year and a year-long rate review process, the Company's near-term earnings and cash flow are adversely affected by high customer growth.

Q. Can you provide an example showing the financial impact of customer growth and regulatory lag on UNS Gas?

A. Yes. In order to evaluate the financial impact of growth, we examined the actual growth in customers and net plant investment during calendar year 2006, the 12 month period immediately following the test year ending December 31, 2005.

Page 1 of Exhibit KCG-10 shows the increase in annual fixed costs associated with the $17 million increase in net plant investment that occurred in 2006. Applying the Company's requested pre-tax ROR, the composite depreciation rate and the average property tax rate to this increased plant investment, the Company's annual fixed costs increased by approximately $3.0 million in 2006. As shown on page 2 of Exhibit KCG-10, during this same period the Company added 6,255 customers. Using the normalized use per customer and average revenues per therm from the test year, an increase in annual delivery revenues of $1.8 million was estimated for these new customers. As summarized at the bottom of this same page, the difference between the $3.0 million of increased fixed costs and $1.8 million of increased delivery revenues represents an annual revenue *deficiency* of $1.2 million attributable to customer growth and plant investment. Stated another way, this $1.2 million deficiency represents the gap between the Company's required return on new plant investment and the Company's actual return on new plant investment. As a consequence, arguments to exclude CWIP from rate base on the basis of assumed growth-related benefits to UNS Gas simply do not hold water.

Q. Do you have any other comments regarding the example provided on Exhibit KCG-10?

A. Yes. Since additional operation and maintenance costs were not included in this example, and since the average use per new customer is probably lower than the embedded use per customer due to improved energy efficiencies, this example likely understates the true impact on UNS Gas. Additionally, since the plant investment balances used in the example already take into account the effects of depreciation and plant retirements, the "benefits" of regulatory lag cited by Ms. Diaz Cortez in her Direct Testimony page 9, lines 15-16, have been fully reflected in the analysis. Finally, it should be noted that this quantification of financial impact relates to only a single year. UNS Gas has not had a rate increase since August 2003, and will not be able to implement new rates from this proceeding until August 2007. Due to the passage of time, high customer growth and increasing plant investment on a per-customer basis, the cumulative annual revenue deficiency at UNS Gas is quite large. Since the rates UNS Gas charged are based on plant investment levels as of December 31, 2001, adjusted to reflect the Company's $30.7 million *negative* acquisition adjustment, there is an obvious need for adequate and timely rate relief at UNS Gas.

Q. Will the impact of growth and regulatory lag be as pronounced in future years?

A. Hopefully not. Although customer growth and plant investment are not forecasted to decrease anytime soon, the gap between the Company's embedded plant investment and incremental plant investment on a per-customer basis should narrow over time. As may be seen in the table below, plant investment on a per-customer basis has increased by 24% since the UNS Gas properties were acquired in August 2003. Over the next three years, this measure of plant investment is expected to increase by a slightly lesser amount of 19%. This table is similar to the one provided on page 22 of my Direct Testimony, but has been updated to reflect actual results for 2006 and the Company's current outlook for customer growth and capital spending.

	Net Plant ($ Millions)	Customers	Investment per Customer
Aug. 2003	$138	127,616	$1,081
Dec. 2004	$161	133,403	$1,207
Dec. 2005	$177	138,797	$1,278
Dec. 2006	$195	145,052	$1,344
Dec. 2007 (Forecast)	$225	150,965	$1,490
Dec. 2008 (Forecast)	$249	158,442	$1,572
Dec. 2009 (Forecast)	$267	166,456	$1,604
% Change 2003-2006	41.3%	13.7%	24.3%
% Change 2006-2009	36.9%	14.8%	19.3%

Q. Have the major credit rating agencies commented on the impact of growth and regulatory lag on gas distribution utilities?

A. Yes. All of the major credit rating agencies (Moody's, Standard & Poor's and Fitch) have commented on the need for timely cost recovery in rates and the impact of large capital spending requirements on gas utilities. Most noteworthy are two articles published by Moody's and Standard & Poor's. In a 2004 report entitled "Comparative ROE Attributes of US Local Gas Distribution Companies," which is attached as Exhibit KCG-11 to my Rebuttal Testimony, Moody's had the following observations:

> The single most common determinant as to whether a company met or exceeded its allowed ROE was the degree of regulatory lag and the timeliness of capital expenditure and cost recoveries. Companies growing very quickly or having protracted negotiations with their regulators tended to fare more poorly than those growing more slowly

> or able to obtain specific provisions for timely rate relief. (See page 1 of Exhibit KCG-11.)
>
> The consequence of recurring regulatory lag is that companies often find themselves in an increasingly negative free cash flow position. In addition, companies on a fast growth track have the problem accentuated and invariably find themselves having to issue debt to fund the deficits in operating cash flows which over time, increase leverage to higher levels and undermine a company's credit metrics. (See page 3 of Exhibit KCG-11.)

In a 2006 report entitled "Key Credit Factors for U.S. Natural Gas Distributors," which is attached as Exhibit KCG-12 to my Rebuttal Testimony, Standard & Poor's made the following comment:

> High growth within a service territory due to population influx and new construction could lead to an LDC's (local distribution company) greater profitability or rate stability. However, as evidenced by Southwest Gas' struggles, high growth sometimes cuts both ways. Arizona and Nevada benefit from rapid population growth, but the slow pace of regulatory rate adjustments acts as a drag on Southwest Gas' financial ratios because revenues fail to adequately compensate the LDC for its growth capital expenditures on a timely basis. (See page 5 of Exhibit KCG-12.)

Q. At page 8 of her Direct Testimony, Ms. Diaz Cortez states that "...rate base treatment of CWIP does not change a utility's level of earnings, merely the timing of earnings recovery." Do you agree with that statement?

A. If she is referring to a large multi-year construction project on which an allowance for funds used during construction ("AFUDC") is being accrued, then I would generally agree with her statement. However, in the case of UNS Gas, where the CWIP balance is comprised of many short-lived construction projects, I do not agree. As pointed out in my Direct Testimony, including the $7.2 million test-year balance of CWIP in rate base would provide the Company with an additional $1.5 million of pre-tax earnings and cash flow. Although this estimate has since been lowered to $1.3 million per year after further review, this contribution to earnings still far exceeds the $285,378 of AFUDC recorded by UNS Gas for all of 2006. And since nearly all of the $7.2 million test-year balance of CWIP has already been transferred to plant in service, additional accruals of AFUDC on this test-year balance will be immaterial. In light of the earnings shortfall illustrated in Exhibit KCG-10, and the lack of future AFUDC accruals on the test-year balance of CWIP, it is readily apparent that the inclusion of CWIP in rate base affects the level of earnings realized by UNS Gas. This rate treatment also provides an additional source of cash flow needed to fund capital expenditures, a benefit that non-cash accruals of AFUDC do not provide.

Q. **~~Should the Company be allowed to continue accruing AFUDC on new construction~~ projects even if CWIP is allowed in rate base?**

A. Yes. It is my understanding that accounting guidelines published by the FERC require utilities to subtract the amount of any CWIP allowed in rate base from the balance of future CWIP eligible for AFUDC accruals. While it would be reasonable to apply this guideline to long-term construction projects for which CWIP has been included in rate base, the majority of projects included in UNS Gas' test-year CWIP balance were short-term in nature. Given that only a small amount of AFUDC has been accrued on the test-year balance of CWIP, it would be unfair to require UNS Gas to cease accruing AFUDC on $7.2 million of CWIP on an ongoing basis, year after year. For this reason, should the Commission grant the Company's request to include CWIP in rate base, UNS Gas requests that the Commission include language in the final order that authorizes the Company to continue accruing AFUDC on all eligible construction projects.

Q. **At page 9 of her Direct Testimony, Ms. Diaz Cortez states that "The Company's argument that CWIP in rate base will lengthen the period between rate cases also has little merit." Do you agree with that statement?**

A. No. Although the timing of UNS Gas' next rate filing will depend on numerous factors, the earnings and cash flow benefit associated with CWIP in rate base should help to extend the period between this rate case and the next rate filing. As I pointed out in my

Direct Testimony, rate case preparation is very costly and time consuming for a company the size of UNS Gas, and an extension of time between rate filings is beneficial to both the Company and its customers.

Q. At page 10 of her Direct Testimony, Ms. Diaz Cortez characterizes one of the Company's arguments on CWIP in rate base as being "disingenuous at best." What is your response to this characterization?

A. It is unfortunate that Ms. Diaz Cortez portrays the Company as being disingenuous. Customers are receiving the full benefit of the negative acquisition adjustment, just as promised in 2003, and will continue to receive that benefit until the negative acquisition adjustment is fully amortized. Additionally, customers will have received the full benefit of a four-year rate moratorium, despite the obvious burden that rate freeze has imposed on UNS Gas. What could not be foreseen in 2003, however, was the significant amount of capital required to meet customer growth and system improvement needs. Similarly, it was difficult to predict the future impact of regulatory lag on UNS Gas. In short, the Company had no way of knowing in 2003 that it would need to request CWIP in rate base in 2006. Sadly, it appears that Ms. Diaz Cortez views this as an attempt by the Company to take back part of the benefit associated with the negative acquisition adjustment. By referring to the existence of a large negative acquisition adjustment in this rate case, the Company is simply pointing out a fact that cannot be ignored when discussing the need for timely and adequate rate relief.

Q. In excluding CWIP from rate base, Ms. Diaz Cortez made a $7.2 million downward adjustment to rate base. Did she make a corresponding adjustment to rate base to reduce customer advances?

A. No. At the end of the test year, the portion of customer advances payable by UNS Gas related to the $7.2 million CWIP balance was $4,158,264. Since the full balance of customer advances was deducted from rate base in the Company's rate filing, Ms. Diaz Cortez should have adjusted the balance of customer advances by this amount. By denying CWIP in rate base, and not adjusting the balance of customer advances, the result is to penalize UNS Gas for carrying a balance of CWIP at the end of the test year.

Q. Did Ms. Diaz Cortez address the Company's alternative proposal for a post-test year adjustment to rate base?

A. No, I did not find any reference to that proposal in her Direct Testimony. It is possible that her views on post test-year plant adjustments are similar to the views she expressed on CWIP in rate base. However, it should be noted that as of December 31, 2006, $6.8 million of the test year balance of CWIP had already been closed to plant in service and was providing service to UNS Gas customers.

Q. Does that conclude your rebuttal to the Direct Testimony of Ms. Diaz Cortez?

A. Yes, it does.

IV. <u>REBUTTAL TO STAFF WITNESS DAVID C. PARCELL.</u>

Q. Mr. Grant, could you summarize your view of the Direct Testimony filed by Mr. David Parcell on behalf of the Commission Staff?

A. Yes. The allowed ROE recommended by Mr. Parcell understates the cost of equity to UNS Gas by a substantial margin. This is due primarily to the conclusions he reached as a result of his CAPM analysis and comparable earnings approach, as well as to his dismissal of Company-specific risk factors at UNS Gas. Mr. Parcell also failed to consider these Company-specific risks in rejecting the Company's proposed capital structure, and relied upon balance sheet data for a group of higher leveraged *electric* utilities in making his ultimate recommendation. In rejecting the Company's request for

CWIP in rate base, Mr. Parcell mistakenly assumed that UNS Gas receives its financing based on the credit quality of UniSource Energy Corporation ("UniSource Energy"), and not on the "...situation of the Company itself." Additionally, other than a hypothetical interest coverage test that failed to consider the large reduction to the Company's rate proposal being recommended by Staff, Mr. Parcell did not present any quantitative financial analysis on the subject of financial integrity.

Q. Please elaborate on Mr. Parcell's cost of equity analysis.

A. Certainly. Regarding his DCF analysis, I agree with the view he expressed on page 27 of his Direct Testimony where he described current financial conditions driving DCF results to historically-low standards. In recognition of this, he used the upper end of his DCF analysis for purposes of estimating the cost of equity for UNS Gas. The upper end of his DCF range (9.25% to 10.5%) is comparable to the DCF results I obtained for the comparable company group in my Direct Testimony (9.1% to 10.5%).

Regarding Mr. Parcell's application of the CAPM, I would note that the range of results obtained for the companies in his comparison group of combination gas and electric utilities ranged from 9.0% to 12.2%, while the results he obtained using my comparable company group ranged from 9.0% to 12.5% (see Schedule 9 attached to his Direct Testimony). However, due to his reliance on mean and median values, the range he ultimately relied upon was 9.5% to 10.25%. By contrast, the range I obtained from my comparable company CAPM analysis was 9.9% to 11.7%, using a risk-free rate of 5.3% and an equity risk premium of 7.1%. This difference is largely attributable to Mr. Parcell's use of a lower risk-free interest rate (based on updated bond market data) and his use of a significantly lower market risk premium.

Q. Please comment on the equity risk premium used by Mr. Parcell in his CAPM analysis.

A. Mr. Parcell used an equity risk premium of 5.9%, which is based on the difference between historical returns on large stocks and long-term government bonds using both arithmetic and geometric mean returns. By contrast, the 7.1% equity risk premium used in my CAPM analysis was based solely on arithmetic mean returns. Because an arithmetic mean return reflects the mathematical average of historical returns realized over each discrete 12-month period, the use of a risk premium based on arithmetic mean returns is more appropriate when calculating a discount rate (*i.e.*, the cost of capital) that is used for discounting future annual cash flows (*i.e.*, dividends and capital gains). By contrast, the geometric mean return, which equals the compound average return earned over a multi-year period, is appropriate for reporting and comparing returns over historical time periods. Since the geometric mean is always less than the arithmetic mean for any series of data having non-constant annual rates of return, Mr. Parcell's application of the CAPM serves to inappropriately understate the cost of equity capital for the companies he examined.

The use of arithmetic mean returns versus geometric mean returns is specifically addressed by Ibbotson Associates, the publisher of historical financial return data cited in the Direct Testimony of Mr. Parcell and Mr. Rigsby as well as in my own Direct Testimony. On page 77 of the 2006 Yearbook (Valuation Edition) published by Ibbotson Associates, the following commentary is provided:

> The equity risk premium data presented in this book are arithmetic average risk premia as opposed to geometric average risk premia. The arithmetic average risk premium can be demonstrated to be most appropriate when discounting future cash flows. For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. This is because both the CAPM and the building block approach are additive models, in which the cost of capital is the

> sum of its parts. The geometric average is more appropriate for reporting past performance, since it represents the compound average return.

Q. **Did Mr. Parcell also conduct a comparable earnings analysis?**

A. Yes, he did. As reflected in the table on page 32 of his Direct Testimony, he indicated that the average historical earned ROE for the proxy groups he examined ranged from 10.7% to 11.8%, while the average prospective ROE ranged from 10.0% to 11.7%. However, as indicated on pages 33 and 34 of his Direct Testimony, Mr. Parcell cites historically high market-to-book ratios for utilities as a reason for recommending a 10.0% cost of equity based on this analysis. While I do not dispute the average ROE data cited by Mr. Parcell, I do take issue with his conclusion that a 10% cost of equity is reasonable based on this data. The fact that market-to-book ratios for regulated utilities routinely exceed a value of 100% does not diminish the fact that utilities such as UNS Gas must compete for equity capital with other utilities. If earned ROEs for utilities are in the range of 10-12% on both a prospective and historical basis, it is unreasonable to assume that any utility would be able to successfully compete for equity capital with an allowed ROE at or below the low end of this range. Stated another way, if Mr. Parcell's objective is to achieve a market-to-book ratio of 100% when the industry average ratio is closer to 180%, the ability of UNS Gas to successfully compete for equity capital would be substantially reduced.

Q. **Do you have any further comments regarding Mr. Parcell's cost of equity analysis?**

A. Yes. For the reasons described above, I believe that his recommended cost of equity is low relative to the actual cost of equity for the proxy groups he examined. In addition, Mr. Parcell also failed to account for the Company-specific risk factors that serve to increase the cost of equity capital for UNS Gas relative to the proxy group companies. For example, on page 38 of his Direct Testimony Mr. Parcell dismisses the small size of UNS Gas because it is owned by UniSource Energy. But he offers no reason why

UniSource Energy would be more willing than other investors to accept the risk of investing in a small utility. Mr. Parcell also dismisses the financial impact of growth on the Company by citing a report published by Standard & Poor's in 2003, a point in time when the effects of growth and regulatory lag on UNS Gas had yet to be fully appreciated. By dismissing these Company-specific risk factors, as well as other risk factors discussed in my Direct Testimony, Mr. Parcell has recommended an allowed ROE for UNS Gas that is well below the Company's actual cost of equity.

Q. Did Mr. Parcell agree with the Company's proposed capital structure for UNS Gas?

A. No, he did not. Instead of using the proposed hypothetical capital structure consisting of 50% common equity and 50% long-term debt, which RUCO witness Rigsby also found to be reasonable, Mr. Parcell used the historical test year capital structure consisting of approximately 45% common equity and 55% long-term debt.

Q. At page 18 of his Direct Testimony, Mr. Parcell states that "...it is proper to ascertain whether the utility's capital structure is appropriate relative to its level of business risk and relative to other utilities." Did Mr. Parcell provide such an evaluation of the Company's capital structure?

A. Yes, but only to a limited extent. At page 20 of his Direct Testimony he compares the equity ratio of UNS Gas to the equity ratios for two groups of utilities, neither of which is specific to the gas distribution industry. ~~The equity ratios for these groups are significantly lower than the ratios identified in my Direct Testimony as well as that of Mr. Rigsby for gas distribution utilities.~~ Also, I could not find any discussion in Mr. Parcell's Direct Testimony regarding why his recommended capital structure was appropriate relative to the level of business risk faced by UNS Gas.

Q. At page 36 of his Direct Testimony, Mr. Parcell concludes that his cost of capital recommendation provides the Company with "a sufficient level of earnings to maintain its financial integrity." Do you agree with his conclusion?

A. No, I do not. No attempt was made by Mr. Parcell to determine whether or not the Company could actually earn his recommended ROE of 10.0% or his overall ROR of 8.12%. Based on all of the adjustments made by Staff, the recommended rate increase for UNS Gas is only $4.7 million, or 49% of the Company's requested increase. If Staff's recommendations were accepted in their entirety, the Company would have no opportunity to actually earn the ROR recommended by Mr. Parcell. As a result, the pre-tax interest coverage calculation presented on Schedule 14 attached to his Direct Testimony represents nothing more than a hypothetical example. While I appreciate Mr. Parcell's intent, which is to examine the impact of his recommendations on the Company financial integrity, it does not take into account the numerous adjustments made by other Staff witnesses that serve to limit any improvement in the Company's earnings and cash flow.

Q. Did Mr. Parcell make any other observations regarding the Company's financial integrity?

A. Yes. At pages 16 to 17 of his Direct Testimony he addresses the Company's ability to attract capital. In this section of his Direct Testimony, he states that it is not "necessary" for UNS Gas to include CWIP in rate base in order to attract capital. In support of his conclusion, he cites rating agency reports that refer to UNS Gas as "low risk." However, the only rating agency report specifically cited by Mr. Parcell that refers to UNS Gas is a report by Standard & Poor's published in 2003. This report is over three years old and was written at a time when natural gas prices were much lower and when the cumulative effects of growth and regulatory lag on UNS Gas had not yet materialized. Mr. Parcell also makes reference to the supposed ability of UNS Gas to attract financing based on the credit quality of UniSource Energy. However, this assumption is incorrect, since no guarantees of UNS Gas debt obligations have been issued by UniSource Energy, TEP, or any other corporate affiliate other than UniSource Energy Services ("UES"), the parent company of UNS Gas and UNS Electric.

Q. Do you agree with Mr. Parcell's conclusion that CWIP is not necessary for the attraction of capital by UNS Gas?

A. Over the short-run, I agree that UNS Gas could continue to attract capital without having CWIP in rate base. However, what Mr. Parcell does not address is the ability of the Company to attract capital on *reasonable terms*. Facing the prospect of below-market returns on equity, high capital spending requirements, and no prospect of common dividend payments, it would be difficult to convince any prospective equity investor to commit additional equity capital to UNS Gas. Under these circumstances, the Company would have to rely more heavily on debt capital to fund its capital spending needs. With this additional debt leverage comes additional lending risk, and the cost of debt to UNS Gas would likely increase significantly. Additionally, it should be recognized that the Company's borrowing capacity is not infinite. So while Mr. Parcell is correct that additional capital could probably be attracted over the short-run, the cost of this capital and long-term effects on the Company cannot be ignored.

Q. Is the calculation of a hypothetical interest coverage ratio sufficient to determine whether or not UNS Gas will be able to attract capital on reasonable terms?

A. No, it is not. In order to assess the real financial impact of Staff's recommendations, it is necessary to examine the Company's financial forecast and to adjust that forecast for the reduced level of rate relief recommended by Staff. Financial forecasts for UNS Gas were provided to Staff on at least two occasions through the discovery process, along with supporting calculations of key financial indicators. While I am well aware of the complexities involved in adjusting financial forecasts, it is a relatively easy task to assess the impact of a reduced rate recommendation on certain key financial measures such as net income, operating cash flow and return on equity.

Q. How does Staff's recommended rate increase impact key financial indicators forecasted for UNS Gas?

A. Staff has recommended a $4.9 million reduction to the Company's requested level of rate relief based on test-year sales levels. Adjusting this figure for two additional years of sales growth, this difference in annual revenues would grow to approximately $5.3 million by 2008. On an after-tax basis, this represents a decrease of approximately $3.2 million in net income and operating cash flow relative to the Company's base case financial forecast for 2008, the results of which were summarized in Exhibit KCG-9 attached to my Direct Testimony. In that base case forecast, the Company projected net income of $10.0 million, a return on average common equity of 10.0%, and operating cash flow of $21.7 million in 2008. As reflected in the following table, the Company's financial forecast would reflect a projected net income of only $6.8 million, a return on average common equity of approximately 6.8%, and operating cash flow of $18.5 million in 2008 when adjusted for the reduced level of rate relief recommended by Staff.

($ millions)	Company Forecast (Exhibit KCG-9)	Adjustment	Forecast Adjusted for Staff Proposal
Net Income	$10.0	($3.2)	$6.8
Return on Equity	10.0%	x (6.8 / 10.0)	6.8%
Operating Cash Flow	$21.7	($3.2)	$18.5

If Mr. Parcell's hypothetical 10.0% earned ROE on Schedule 14 of his Direct Testimony is replaced with the 6.8% adjusted ROE from the table above, the pre-tax coverage ratio calculated by Mr. Parcell would fall from 3.04X to 2.39X. According to Mr. Parcell's

Exhibit DCP-1, Schedule 14 in his Direct Testimony, a minimum coverage ratio of 2.4X is required to achieve a minimum "BBB" investment-grade credit rating.

Q. Does UNS Gas have a more recent base case financial forecast that can be used to evaluate the prospective financial condition of the Company?

A. Yes. Exhibit KCG-13 provides an updated summary of projected key financial indicators. This forecast assumes that the Company's rate request is granted in full, and has been updated to reflect actual results for 2006 and to incorporate new capital spending and operating budget projections for 2007 and beyond. As may be seen on page 1 of that exhibit, operating cash flow was abnormally high in 2006 due to the recovery of the Company's large PGA bank balance.

Q. Does UNS Gas have a similar financial forecast that incorporates Staff's recommended level of rate relief?

A. Yes. The key financial indicators for that forecast may be found in Exhibit KCG-14. Although the forecasted results for 2008 are not the same as estimated in the table above, they are very similar despite the use of updated forecast assumptions. Specifically, forecasted values for net income, return on average equity and operating cash flow are $6.9 million, 7.4% and $17.8 million, respectively.

Q. Do you have any comments regarding the financial forecast summarized in Exhibit KCG-14?

A. Yes. As may be seen on page 1 of that exhibit, the Company's earned ROE is expected to improve only slightly and is not expected to come close to Staff's recommended ROE in future years. Likewise, operating cash flows are expected increase only slightly over 2005 test year levels. As may be seen on page 2, the percentage of capital expenditures funded with internal cash flow is forecasted to remain quite low over the next three years, indicating a large need for additional capital. Absent additional equity contributions, the Company's borrowings are forecasted to increase significantly. As may be seen on pages 3 and 4, this additional borrowing serves to limit any balance sheet improvement at UNS Gas and contributes to weak cash flow coverage ratios relative to industry median values. With reduced borrowing capacity, the Company's ability to finance unexpected increases in the PGA bank balance, potential collateral calls by wholesale gas providers, or unanticipated capital expenditures would be greatly diminished. Under such circumstances, it would be difficult for the Company to attract additional capital on reasonable terms.

Q. **Do you have any other comments regarding Mr. Parcell's cost of capital recommendations?**

A. Mr. Parcell's cost of capital recommendations – specifically his recommendations on cost of equity and capital structure – will put UNS Gas at a disadvantage as far as being able to attract capital on reasonable terms. If Staff's recommended ROE and overall rate proposal are accepted, the financial integrity of UNS Gas will suffer and its ability to improve its capital structure will be adversely affected.

Q. **Does that conclude your rebuttal to the Direct Testimony of Mr. Parcell?**

A. Yes, it does.

V. REBUTTAL TO STAFF WITNESS RALPH C. SMITH.

Q. **Mr. Grant, could you please summarize your view of the Direct Testimony filed by Mr. Ralph Smith on behalf of the Commission Staff?**

A. Yes. Similar to Ms. Diaz Cortez, Mr. Smith rejects the Company's request for CWIP in rate base largely on philosophical grounds. Mr. Smith also makes reference to a "burden of proof" that UNS Gas has not met, but does not offer any description of what this standard might be. Although he recognizes that the inclusion of CWIP in rate base is up to the discretion of the Commission, he offers several reasons why Staff does not recommend this ratemaking treatment.

Q. What specific reasons are offered by Mr. Smith in rejecting the Company's request for CWIP in rate base?

A. On page 9 of his Direct Testimony, Mr. Smith offers four reasons for rejecting the Company's request for CWIP in rate base. The first two reasons, that CWIP in rate base is not normally allowed by the Commission, and that projects included in the test year CWIP balance were not yet in service as of the test year, are merely statements of the obvious. The third reason, which relates to the need to recognize revenues produced by projects included in the CWIP balance, has already been addressed in my rebuttal of Ms. Diaz Cortez. The fourth and final reason, that the Company has made no specific enforceable commitment to a rate case moratorium period, erroneously assumes that UNS Gas is in a position to make such a commitment prior to knowing how much of a rate increase it will receive in this proceeding.

The most meaningful reason offered by Mr. Smith for rejecting the Company's request is only mentioned in passing, on lines 8 to 9 at page 9 of his Direct Testimony. Here he refers to the Company's failure to meet a "burden of proof" showing why it requires this ratemaking treatment. However, I could not find a description anywhere in Mr. Smith's Direct Testimony of what this burden of proof entails or what evidence the Company would need to present to meet this burden. Presumably it is a standard based on the ability to attract capital, the subject addressed by Mr. Parcell at pages 16 to 17 of his Direct Testimony. The only other statement I could find regarding the Company's failure to meet this burden of proof appears at page 10, lines 23-25 of Mr. Smith's Direct Testimony, where he states that "In the current case, UNS Gas has not demonstrated convincingly that it requires an exception to the Commission's standard ratemaking treatment of excluding CWIP from rate base."

Q. In excluding CWIP from rate base, Mr. Smith made a $7.2 million downward adjustment to rate base. Did he make a corresponding adjustment to rate base to reduce customer advances?

A. No. At the end of the test year, the portion of customer advances payable by UNS Gas related to the $7.2 million CWIP balance was $4,158,264. Since the full balance of customer advances was deducted from rate base in the Company's rate filing, Mr. Smith should have adjusted the balance of customer advances by this amount. By denying CWIP in rate base, and not adjusting the balance of customer advances, the result is to penalize UNS Gas for carrying a balance of CWIP at the end of the test year.

Q. Did Mr. Smith consider the Company's alternative request for including post-test year plant additions in rate base?

A. Yes, he did. However, he did not have any additional reasons to offer for rejecting this ratemaking alternative.

Q. What would be the impact on Staff's proposed revenue requirement if Staff included either a post-test year adjustment to rate base or removed the customer advances related to the test year CWIP balance?

A. Including a $6.8 million post-test year adjustment to rate base would increase Staff's proposed revenue requirement by approximately $1.1 million. Removing $4.2 million of customer advances from rate base would increase Staff's proposed revenue requirement by approximately $500,000.

Q. Did Mr. Smith adjust the cost of capital recommended by Staff witness Parcell before applying it to Staff's fair value rate base?

A. Yes, he did. Consistent with prior Commission practice, he lowered the overall ROR applied to fair value rate base in order to achieve the same level of operating income calculated using Mr. Parcell's cost of capital and Staff's original cost rate base.

Q. Is this ROR adjustment the same as addressed in the recent Arizona Court of Appeals ruling involving Chaparral City Water Company, the Commission and RUCO?

A. Yes. My non-legal understanding of that ruling dated February 13, 2007, is that the Arizona Court of Appeals found that Staff's determination of operating income ignored fair value rate base, and that the Commission must use fair value rate base to set rates per the Arizona Constitution.

Q. What action do you recommend in light of this court ruling?

A. I recommend that the Commission apply the weighted cost of capital (or overall ROR) to the Company's fair value rate base for purposes of setting rates in this proceeding. To the extent such a calculation would result in a higher rate increase than proposed by the Company, UNS Gas would still be limited to the original rate relief sought in the Company's rate application.

Q. Do you have any other comments on Mr. Smith's Direct Testimony?

A. No. Most of his concerns regarding CWIP in rate base are similar to the concerns voiced by Ms. Diaz Cortez, which I have already addressed earlier in my Rebuttal Testimony.

Q. Does that conclude your rebuttal to Mr. Smith's Direct Testimony?

A. Yes, it does.

VI. CONCLUSION.

Q. Mr. Grant, do you have any concluding testimony?

A. Yes, I do. For the reasons stated in my Direct Testimony and reiterated here in my rebuttal testimony, I recommend that the Commission adopt an allowed ROE of 11.0% and an overall ROR of 8.80% for UNS Gas. Additionally, in light of the recent Arizona Court of Appeals ruling regarding the use of fair value rate base in setting rates, I recommend that the Commission apply this 8.80% ROR to the Company's fair value rate base for purposes of setting rates in this proceeding. To the extent such a calculation would result in a higher rate increase than originally proposed by the Company, UNS Gas would still be limited to the rate relief sought in the Company's rate application.

Contrary to the positions taken by Staff and RUCO, the inclusion of test year CWIP in rate base is needed to preserve the Company's financial integrity. The Company's net plant investment has increased by 41% since the August 2003 acquisition of gas properties from Citizens Communications Company, and is expected to increase by another 37% over the next three years. This growth in net plant investment creates a huge demand for capital and an obvious need for timely and supportive rate relief. I believe I have provided ample evidence and UNS Gas has therefore met whatever burden it may have to justify the inclusion of CWIP in rate base and why doing so is also fair and reasonable. In the alternative, should the Commission decide not to include CWIP in rate base, UNS Gas urges the Commission to allow a post test-year adjustment to rate base to include plant already placed into service. As of December 31, 2006, this amount represented $6.8 million, or approximately 94% of the $7.2 million test year CWIP balance.

Q. Does this conclude your Rebuttal Testimony?

A. Yes, it does.

EXHIBIT

KCG-10

UNS Gas, Inc.
Impact of 2006 Plant and Customer Additions on Annual Revenue Deficiency

Increase to Annual Fixed Costs from 2006 Plant Additions

Net Utility Plant at 12/31/06	$195,131,000
Less: Net Utility Plant at 12/31/05 (end of test year)	($177,420,000)
Increase in Net Plant for Year Ended 12/31/06	$17,711,000
x Fixed Cost Factor	17.23%
Increase in Annual Fixed Costs	**$3,052,225**

Derivation of Fixed Cost Factor:

	% Capital Structure	Cost	Weighted Cost	Tax Factor	Pre-Tax Cost
Equity Capital	50.00%	11.00%	5.50%	1.637	9.00%
Debt Capital	50.00%	6.60%	3.30%	1.000	3.30%
	100.00%		8.80%		12.30%
		Composite Depreciation Rate			2.73%
		Composite Property Tax Rate			2.20%
		Annual Fixed Cost of Plant Additions			17.23%

UNS Gas, Inc.
Impact of 2006 Plant and Customer Additions on Annual Revenue Deficiency

Increase to Annual Delivery Revenues from 2006 Customer Additions

	Residential	Small Commercial	Small Public Authority	Industrial & Other	Total
Customers at 12/31/06	132,534	11,416	1,059	43	145,052
Less: Customers at 12/31/05 (test year end)	(126,682)	(11,017)	(1,054)	(44)	(138,797)
Increase in Customers for Year Ended 12/31/06	5,852	399	5	(1)	6,255
x Use per Customer (normalized test year)	568	2,657	5,510	N/A	706
Increase in Annual Therm Sales	3,325,295	1,060,236	27,550	-	4,413,081
x Average Delivery Revenues per Therm (test year)	$0.4480	$0.2941	$0.2621	N/A	$0.4099
Increase in Annual Delivery Revenues	$1,489,800	$311,773	$7,221	-	**$1,808,794**

Increase to Annual Revenue Deficiency from 2006 Plant and Customer Additions

Increase in Fixed Costs	$3,052,225
Less: Increase in Delivery Revenues	($1,808,794)
Increase to Revenue Deficiency	**$1,243,431**

EXHIBIT

KCG-11

Special Comment

July 2004

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Comparative ROE Attributes of US Local Gas Distribution Companies

Summary Opinion

- Moody's reviewed its portfolio of local gas distribution companies (LDCs) in search of the characteristics that differentiated those companies that either met or exceeded their allowed rates of equity return (ROE) from its utility commissions with those that did not.
- We found a positive correlation between ROEs and credit ratings. Companies that either met or exceeded their allowed rates of equity return (ROE) were more likely to have higher credit ratings, were concentrated in urban areas, and focused their operations in a single-state jurisdiction with more mature customer profiles. In addition, they tended to be larger companies with larger total number of customers and delivered the most gas volumes.
- Companies performing well also tended to have formal weather normalization clauses (WNC) in place that have helped to steady their operating performance and credit metrics which resulted in the higher credit ratings.
- The single most common determinant as to whether a company met or exceeded its allowed ROE was the degree of regulatory lag and the timeliness of capital expenditure and cost recoveries. Companies growing very quickly or having protracted negotiations with their regulators tended to fare more poorly than those growing more slowly or able to obtain specific provisions for timely rate relief.
- Companies having significant amounts of goodwill were at a distinct disadvantage compared with their peers, as they typically are not allowed to earn returns on the premium portion of acquisition assets.
- While in several respects LDCs were equally concerned with improving operating efficiencies through automation, centralizing shared services and implementing various programs for workforce reduction as a means to contain the ever-rising costs of salary, pension and medical benefits, the ones that met or exceeded their allowed ROEs had lower operating expense to employee ratios.

Introduction

As LDCs have embarked on a "back to basics" strategy, overall efficiency of operations and returns on capital employed resurface as key factors in the rating process. We therefore analyzed our portfolio of 32 issuers with a view toward identifying the key factors that separate the LDCs' ability to achieve or exceed their allowed returns. We define "realized" as those gas LDCs that had either met or exceeded their regulated allowed rates of equity return (ROE) on a consistent basis during the past three fiscal years ending with 2003. Where no specific rates were stipulated, Moody's still recognized a company as "realized" if they achieved an ROE of at least 10% during the past three years. Companies that were within one percentage point of making their allowed ROEs were deemed to have met their targets. Those companies not able to realize their allowed ROEs are designated in this study as "not-realized."

From this point of demarcation, the analysis then moves on toward identifying the various factors that may have contributed toward an LDC's success. Some of these points might be intuitive (size and density of population served), while others were more empirical (variances in regulatory lag).

By analyzing the attributes of these realized LDCs, one could discern a pattern for likely future success that could serve as a guide for management focus on key factors for improving their returns as well as assisting investors with differentiating the companies that have stronger operating performance.

While almost all issuers approached were able to respond, some of their reports had to be excluded from consideration as they were compiled in a manner which made comparisons difficult. For example, in cases where a company co-mingled electric and gas utility data, the responses were deleted as the focus of this study is only on gas LDCs. It is also important to recognize that in a few cases issuers have asked that their names and figures be kept confidential and as a result, their responses were included as part of the general study without any attempts at identification or attribution. Altogether, Moody's identified 15 LDCs that either met or exceeded their allowed ROEs while 17 others did not.

Not surprisingly, the realized LDCs (henceforth known as the R-class) tended to have more "A" credit ratings relative to "Baa" credit ratings than those companies that did not meet their allowed ROEs (known as the NR-class). In fact, the ratio of issuers rated "A" vs. those rated "Baa" is 2.75 for the R-class compared with 1.125 for the NR-class.

Focused Critical Mass

The R-class names also tend to have the largest number of gas customers, deliver the most volumes of gas as measured in Bcf, are focused in a single-state jurisdiction and are more likely to be located in urban[1] areas with a more mature customer profile exhibiting slower but steady growth as opposed to newer and rapid growth.

The average number of R-class customers is approximately 1.1 million compared with the 653 thousand average for the NR-class, while the volume of R-class delivered gas averages 222Bcf compared with 114Bcf for the NR-class.

The overwhelming majority of R-class LDCs are focused on a single-state vs. multiple states (11:4) compared with the NR-class LDCs (6:11) and are more likely to be operating in urban areas rather than rural (2.25 urban/rural ratio for R compared with 1.7 ratio for NR). Moreover, the average customer growth rate for the R-companies is 1.5%p.a. while that for the NR companies is 2.0%p.a. While different companies may experience different rates of customer growth, the ideal range appears to lie between 1.5%-3.0% p.a. Anything slower could hinder the generation of earnings growth to satisfy equity investors while anything faster could push up various cost factors which when combined with the sector's "regulatory lag" could compress a company's ROE and credit metrics.

The above numbers suggest that the profile of the R-companies are larger, more firmly established or entrenched in their single-state jurisdictions which tend to be more urban than rural and are growing at a slower but steady rate in comparison with the NR-companies. The single state focus and critical mass developed in key urban areas of the state appear to position these LDCs well for steady and successful growth. A good example of an R-company fitting this profile might be Southern California Gas Company (rated A2 Sr. Unsec.) with 5.4 million customers (growing at about 1% p.a.) delivering approximately 939Bcf of gas each year in the State of California with 97% of the company's operations concentrated in urban areas. Its authorized ROE for 2003 was 10.82% but it achieved 15.64% instead.

Impact of Weather

Moody's has taken the position for some time that gas LDCs are far better off having weather normalization clauses (or their equivalent) built into their basic rate designs (see Special Comment #76344 published in October of 2002 titled *Negative Rating Trend for Local Gas Distribution Companies: Impact of Diversification And Warm Weather*). This opinion seems to be reinforced by the fact that nine of the 15 R LDCs have formally approved weather normalization clauses (WNC) or recognized weather mitigants built into their rate designs compared with only five out of the 17 LDCs that were NR.

Companies that do not have such WNC provisions for the majority of their customer base which did not make their target ROEs and cited warm weather as part of the reason include Cascade Natural Gas, SEMCO Energy, Southwest Gas Corporation and Vectren's Indiana Gas Company. In the case of Indiana Gas Company, the company estimates that a 1% annualized deviation from normal heating weather would impact pre-tax margins by $900,000, a condition which the company is presently attempting to rectify in its current rate filing through the introduction of a WNC feature.

One company in the R-class that was afflicted by warmer than normal winters and has since implemented a weather mitigation rate design is Laclede Gas Company. In its 10-Q filing for the six months ending March 31, 2004

1. *For purposes of this study, Moody's defines urban as any city or town that is served by the LDC's main gas line in a contiguous flow of proximity for 100,000 or more customers. Any number less is considered rural.*

when temperatures in its service area were 12% warmer than normal and 14% warmer than the same period last year, Laclede Gas Company states: "The magnitude of the effect of lower sales was smaller than would have previously been the case due to the impact of the fully-implemented weather mitigation rate design that produced higher margin revenue for the six months ended March 31, 2004, compared with the same period last year."

While various forms of weather mitigants are available to LDCs (weather insurance, weather derivatives, use of declining block rates), Moody's finds that WNC or their rate design equivalents are the most cost-effective means of protecting against warmer than normal weather conditions.

It is worth noting however, that the loss of gas volumes resulting from customer energy conservation (or improved efficiency ratings of customer home insulation and equipment) is a separate but growing factor in reducing LDC operating margins. Two companies that report meaningful reductions in gross margins on account of energy conservation by their customers in recent years are Public Service Company of North Carolina, Inc. (PSNC at 8%) and Questar Gas Corporation (7%). Altogether nine R-class companies and 10 NR-class companies report having suffered some degree of gross margins on account of gas conservation. Some companies are also building this factor into their volumetric rate designs or implementing "conservation" margin trackers to protect margins. These margin trackers allow LDCs to recover from customers a portion of gross margins lost on account of customer gas consumption declines resulting from their energy conservation measures.

Impact of Regulatory Lag

The most common explanation offered by LDCs for not being able to meet their allowed ROE is the impact of regulatory lag, especially as it affects the most significant component of cost, the depreciation, depletion and amortization portion resulting from capital expenditures. The average time frame for R-class LDCs to recover capital expenditure costs is over an average depreciable life of their assets of 374.5 months compared with 386.6 months for the NR-class companies. While this may not appear to make much of a difference in and of itself, it is noteworthy when combined with the fact that the faster growing NR-class companies appear to be more burdened with the "growth" component of capital expenditures as opposed to the "maintenance" capital expenditures which appear to be the focus of the more established R-class companies

The consequence of recurring regulatory lag is that companies often find themselves in an increasingly negative free cash flow[2] position. In addition, companies on a fast growth track have this problem accentuated and invariably find themselves having to issue debt to fund the deficits in operating cash flows which over time, increase leverage to higher levels and undermine a company's credit metrics.

In 2003 for example, the average growth capital expenditure for the R-class companies was $29.3 million compared with $43.8 million for the NR-class companies, which was 50% more. In absolute terms, the total growth capital expenditure for the R-class was $439 million compared with $701 million for the NR-class companies. In fact, the total number spent by the NR-class LDCs on growth capital expenditures was substantially higher than that spent by the R-class for each of the past five years under study. The average of the maintenance capital expenditures however, spent by the R-class is 42% higher at $59.3 million in 2003 compared with $41.8 million for the NR-class. The credit implications of this greater emphasis on growth capital expenditures on the part of NR companies is more evident when we also consider their lower free cash flows, gross cash flow to capital expenditures and retained cash flow to debt ratios compared with those of the R companies. When we consider the lower free cash flows and retained cash flow to debt ratios of the NR companies it is easier to understand why their credit metrics and credit ratings are relatively lower than those of the R companies. These weaker credit measures for the NR companies are apparent in the Appendix that follows this study.

This difference in emphasis in capital expenditure spending also appears to take on greater significance when the we take into account the comments made by at least three LDCs (National Fuel Gas, Questar Gas Company and Vectren for Indiana Gas Company) in stating that the maintenance expenditures (as in repairing leaks) tend to be recovered over a 12 month period rather than over the depreciable life of assets which is what is applied in the case of growth capital expenditures. If this difference in regulatory treatment is applied in other jurisdictions, it could help to explain why higher spending in growth capital expenditure programs over maintenance may hinder the NR-class LDCs from attaining their allowed ROEs. Companies that have cited capital expenditures related to infrastructure investments as a reason for regulatory lag leading to lower ROE include Southwest Gas Corporation, TXU Gas Company and Yankee Gas Services Company.

2. *Moody's defines free cash flow as gross cash flow from operations less capital expenditures, cash dividends and adjusting for deferred taxes. It serves as a measure of a company's ability to self-fund its operating needs.*

LDCs in at least four states are able to use forward test year data: California, Illinois, New York and Wisconsin, which tend to favor their LDCs and help close the gap caused by regulatory lag. Illinois in fact, allows for future test years as long as they do not exceed 24 months from the date of filing. Furthermore, Laclede Gas Company states that the Missouri legislature passed a recent law known as the Infrastructure System Replacement Surcharge that allows gas companies to file for a surcharge twice a year to recover depreciation expense, property taxes and a return on investment for all safety related or government mandated line replacements and relocations since the last rate case. Clearly LDCs in these states have better prospects for recovering their costs and reaching their target rates of return.

Impact of Goodwill

Another deterrent to achieving allowed ROEs is the regulatory treatment of goodwill which arises in acquisitions under purchase accounting. Most regulators do not allow any returns to be made on assets represented by goodwill, which oftentimes is funded through the issuance of debt that needs to be serviced each year as a fixed charge. Keyspan for example, mentions that a substantial portion of the shortfalls in the earned ROEs for their New England LDCs, Boston Gas and Colonial Gas, are attributable to the non-recoverability through basic rates on the goodwill incurred in connection with the acquisition of these properties in 2000.

Another example is the case of Wisconsin Gas Company. The Public Service Commission of Wisconsin does not recognize for ratemaking purposes the goodwill that was pushed down to Wisconsin Gas in its acquisition by Wisconsin Energy Corp. Consequently, while Wisconsin Gas has met its allowed rates of return on a regulatory basis, its US-GAAP ROEs adjusted for goodwill have been a fraction of its allowed levels. In adopting SFAS 142, Wisconsin Gas wrote down most of the goodwill that it incurred in its acquisition, in recognition of the high multiple that was paid in that merger and the level of returns that the utility is able to generate. This non-cash charge has brought Wisconsin Gas's US-GAAP ROEs closer to its allowed ROEs.

Workforce Reduction as a Means of Cost Control

Both R-class and NR-class LDCs have employed various means of workforce reduction as a means of containing rising costs of operation. This is done either unilaterally as part of a labor bargaining process or in conjunction with automating various repetitive functions such as in the use of automated meter readings in its gas operations.

While pension expense, medical expense and bad debt expense average 4%, 7% and 6% respectively, for both classes of LDCs as a percentage of total operating expense, workforce as a percentage of operating expense averages 48%. Companies are aiming to gradually reduce the number of employees in order to better contain not only wages and salaries but also the rises in costs of pension and medical benefits. In this regard, it is interesting to note that while the average number of employees for the R-class LDCs is greater than those in the NR-class (1,695 in 2003 to 1,042) perhaps because of their larger size, the total operating expense to employee ratio is lower ($122,180 to $142,109).

In terms of actual workforce reduction and the use of automation in operations, the reported figures are very similar between the two classes of LDCs. In the R-class, 12 companies report having taken actions to reduce the number of employees in recent years compared with 10 in the NR-class. While ten companies in each class report having automated various aspects of operations, few have specifically quantified their automated savings. One company however, that has made strides in the area of automated meter reading and been able to calculate the savings is The Peoples Gas Light and Coke Company (Peoples Gas). Peoples Gas states that it began its automated meter reading program in the mid-1990's with over 90% of all meters being automated by the end of 2002. The cost of meter reading in 1995 was $4.8 million for Peoples Gas and this cost fell to $2.2 million in 2002, representing a 54% reduction in this component of operating expenditures. Peoples Gas also noted additional savings from automated meter reading in the form of reduced estimated billing costs, billing error costs, non-registering meters, theft, and unauthorized use, which were not quantified. It appears that for some companies such as Peoples Gas which considers its customer base to be 100% urban, the benefits of automation could go farther given their greater customer concentration in the urban areas serviced by the company. This could be a case where customer concentration in urban areas might work towards the benefit of the LDCs located in large population centers.

The ability to control the number of employees is one key to controlling expenses. It stands to reason that companies growing the fastest would have the greatest pressures on rising employee count and employee benefits, which are more difficult to control than those companies experiencing slower growth. LDCs that have cited workforce restructuring charges or rising pension and medical expenses as special challenges in meeting their allowed ROEs include Cascade Natural Gas Corporation and Yankee Gas Services Company.

Conclusion

In its study of LDC ROE attributes, Moody's finds that the portfolio of companies could be divided into two approximately equal camps, those that meet or exceed their allowed ROEs and those that do not. Those companies that do realize their allowed ROEs (R-class companies), have a higher proportion of "A" credit ratings, tend to be focused in one-state jurisdictions and operate more often in urban areas compared with those with lower ROEs (NR-class companies). In addition, the R-class companies have a tendency to be larger, deliver greater volumes of gas, are more mature, experience slower or steady growth and concentrate on maintaining their operating systems rather than on expanding them into new service territories and are better positioned to control the rising operating costs of employee pension and medical benefits through workforce reduction programs. Their larger size and scope of operations tend to avail the R-class companies greater critical mass (especially when combined with urban concentration) and enable them to have better economies of scale in their operations.

Other factors that impact an LDC's relative success in achieving their allowed ROEs are the existence of weather normalization clauses or their rate design equivalents, the absence of goodwill from prior acquisitions and the widespread use of automation and central shared services to reduce duplication of functions at the field divisions. Finally, a progressive and supportive regulatory environment would certainly help companies achieve their earnings goals more easily. Given the pervasive "regulatory lag" that permeates the industry, jurisdictions that permit the use of future test periods for cost recovery, especially capital cost recovery, would go a long way toward helping these companies attain their allowed rates of return on equity and help stabilize their credit metrics.

Companies that actively seek to promote growth could find themselves squeezed by a combination of high growth capital expenditures, rising workforce, rising costs of employee pension and medical benefits, which when superimposed with goodwill, the absence of cost effective weather protection and ongoing regulatory lag, could keep them from achieving their full allowed rates of return.

Atmos Energy Corporation currently attains their allowed ROE in most of their 15 regulatory jurisdictions that are largely rural and mature. However, the proportion of maintenance capital expenditures far outweigh those for growth capital expenditures and many of its jurisdictions employ weather protection in their rate designs. Moreover, its operating expense to employee and operating expense to gross margin ratios are considerably less than the average of the 32 LDCs analyzed. Also, Atmos has one of the lowest proportions of unionized workforce at 10% compared with the 54% average for the industry, which undoubtedly gives it significant leverage to affect cost controls in the employment and benefits areas. Moody's notes that Atmos recently agreed to acquire the assets of TXU Gas, a neighboring utility in a more urban, somewhat higher growth service territory. It remains to be seen how this major acquisition that would roughly double its assets would affect Atmos's efficiency.

It is by examining the particular circumstances of individual issuers in comparison with the norms of the industry that we could attain a better understanding of the factors that impact their overall operating performance as we incorporate these findings into the credit ratings. As LDCs re-focus on their core regulated business, Moody's will continue to monitor their key operating as well as financial metrics in the overall credit evaluation process.

Related Research

Special Comment

Negative Rating Trend For Local Gas Distribution Companies: Impact Of Diversification And Warm Weather, October 2002 (# 76344)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

Appendix

Chart 1

Customer Size and Volumes Distributed in BCF of Gas

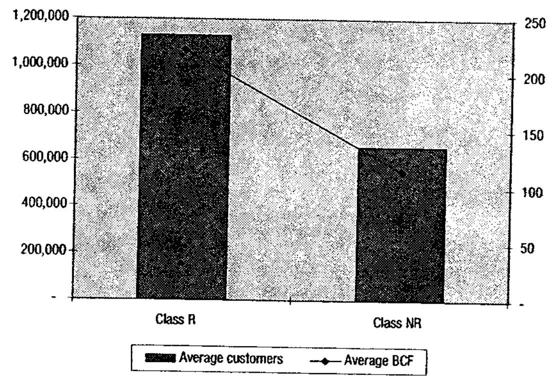
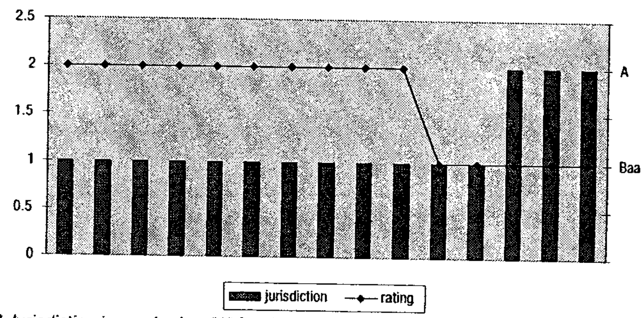


Chart 2

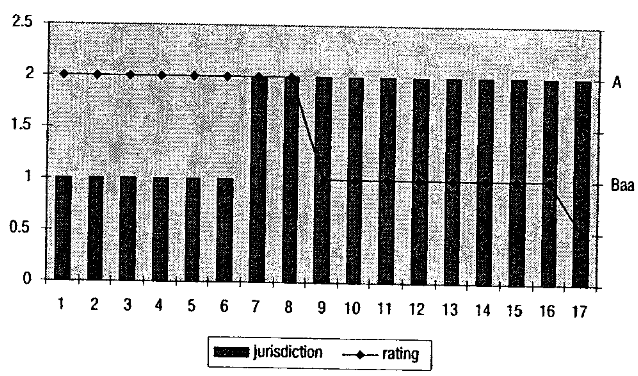
Class R Rating vs. Jurisdiction*



** Jurisdiction is graphed as "1" for single jurisdiction and "2" for multiple*

Chart 3

Class NR Rating vs. Jurisdiction*



** Jurisdiction is graphed as "1" for single jurisdiction and "2" for multiple*

Chart 4

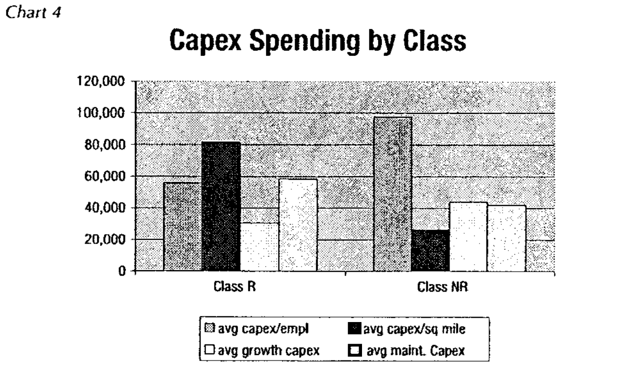


Chart 5

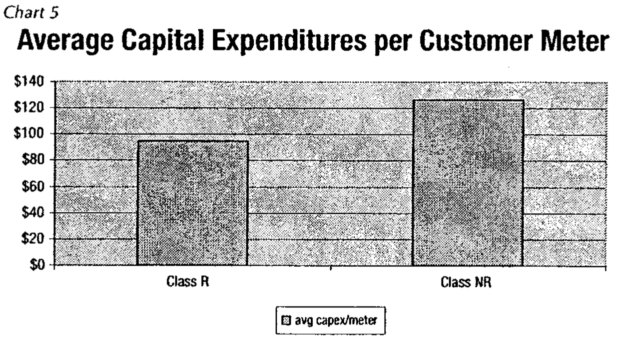


Chart 6

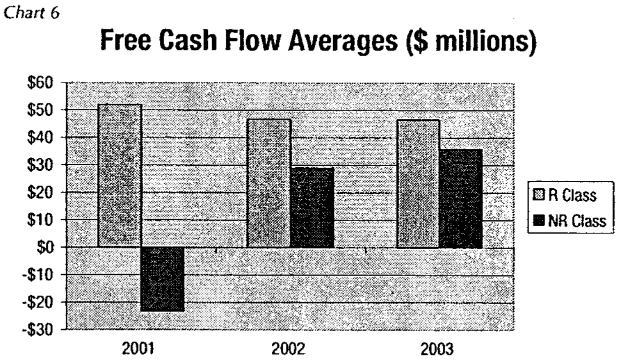


Chart 7

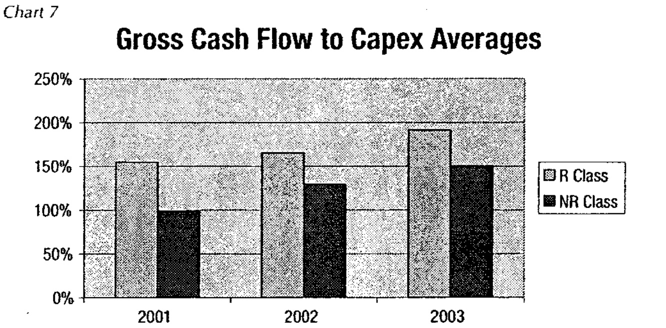
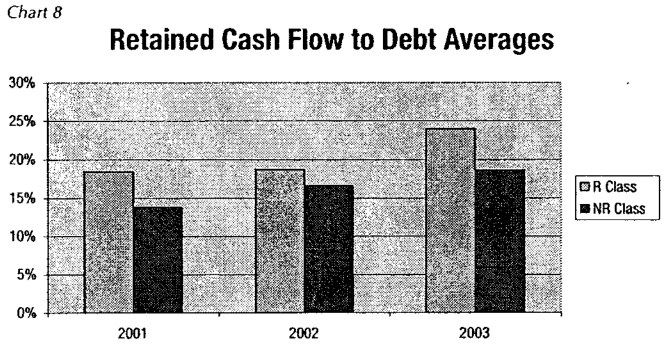


Chart 8



Selected Statistics for 2003

	% Rural customers	Urban customers	Number of customers	Annual Gas Volume (BCF)	5 yr avg customer growth	CAPEX Reg. Lag (Mos.)
Average Total	43%	57%	875,181	165	2.2%	381
Average R	**35%**	**65%**	**1,126,191**	**222**	**1.6%**	**374.5**
Average NR	49%	51%	653,703	114	2.2%	386.6

	GCF	Operating expense/ employee	Opex/ sq mile service area	Gross cash flow/ sq mile service area	Operating expense as % of gross margins	Workforce expense/ operating exp	Pension expense/ operating exp	Medical expense/ operating exp	Bad debt expense/ operating exp	% of Unionized workforce
Average Total	126,131	133,223	15,579	12,048	46%	48%	4%	7%	6%	54%
Average R	153,524	122,180	18,934	13,863	47%	49%	4%	7%	7%	55%
Average NR	101,961	142,109	12,643	10,460	46%	48%	4%	7%	6%	53%

$thousands	Growth Capex	Maintenance Capex	Total Capex	Capex per meter	Capex per employee	Capex per sq mile
Average Total	35,798	50,321	86,644	112	77,346	52,116
Average R	29,298	59,322	88,888	95	55,748	81,710
Average NR	43,806	41,883	84,664	126	97,595	26,221

EXHIBIT

KCG-12

STANDARD
&POOR'S

COMMENTARY REPORT

Key Credit Factors For U.S. Natural Gas Distributors

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On its surface, analyzing U.S. gas distributors' credit quality would appear straightforward. After all, the core business simply involves distributing a commodity to mainly captive customers within a given service territory under a regulated environment. What could be more uncomplicated or have lower business risk? But, in reality, the universe of local natural gas distribution companies (LDCs) that Standard & Poor's Ratings Services rates has great credit diversity, as evidenced by ratings ranging from 'AA-' to 'BB-'.

Thus, the business risk profile is a defining attribute of an LDC's creditworthiness, as is the case with any corporate issuer. In most cases, Standard & Poor's categorizes pure LDCs as having well above average ('1' and '2') or above average ('3') business profiles (business profiles are categorized from '1' (strong) to '10' (weak)). Nonregulated business segments outside the relatively low-risk gas distribution arena generally weaken a company's business risk profile.

Clearly, higher-risk activities pressure the consolidated profiles and often require stronger financial performance to merit the same rating as a pure LDC. ONEOK Inc. (BBB/Watch Neg/A-2), an extreme example, has gas gathering and processing and energy trading and marketing activities that account for roughly two-thirds of its business mix and elevate the company's business profile to '6'. The inherent volatility of ONEOK's higher-risk businesses dwarfs the relative stability of its regulated gas distribution operations and exposes the company to greater cash flow volatility.

We look at five broad categories when reviewing an LDC's business risk profile: regulation, markets and competition, operations, management, and diversified activities. Below, key factors are highlighted and specific LDCs are identified that demonstrate strong or weak characteristics along these lines.

Publication Date
3, 2006

The business risk profiles of 14 LDCs operating in the U.S. can be seen in table 1.

Table 1

U.S. Gas Distributors Comparison

Company	Rating	Business profile	Gas adjustment mechanism	Supply position	Storage capacity (%)	Hedging policy in place
AGL Resources Inc.	A-/Negative/A-2	4	Yes	4	35	Yes
Cascade Natural Gas Corp.	BBB+/Stable/—	2	Yes	3	25	Yes
New Jersey Natural Gas Co.	A+/Stable/A-1	2	Yes	2	60	Yes
Nicor Inc.	AA/Negative/A-1+	3	Yes	8	55	Yes
Northwest Natural Gas Co.	A+/Stable/A-1	1	Yes	1	58	Yes
ONEOK Inc.	BBB/Watch Neg/A-2	7	Yes	8	15	Yes
Peoples Energy Corp.	A-/Negative/A-2	5	Yes	6	60	Yes
Piedmont Natural Gas Co. Inc.	A/Stable/—	2	Yes	5	50	Yes
SEMCO Energy Inc.	BB-/Stable/—	5	yes	4	35	Yes
South Jersey Gas Co.	BBB+/Neg/—	3	Yes	2	40	Yes
Southern Union Co.	BBB/Negative/—	3	Yes	8	30	Yes
Southwest Gas Corp.	BBB-/Stable/—	3	Yes	6	10	Yes
UGI Utilities Inc.	BBB/Watch Neg/—	4	Yes	3	N.A.	Yes
WGL Holdings Inc.	AA-/Negative/A-1	3	Yes	4	30	Yes

N.A.—Not available.

Regulation

Table 2

Regulatory Comparison

Company	Weather normalization	Allowed ROE (%)	Earnings sharing	Regulatory protection of LDC finances
AGL Resources Inc.	Yes	11 to 11.5	Yes	No
Cascade Natural Gas Corp.	No	11 to 11.5	Yes	No
New Jersey Natural Gas Co.	Yes	> 11.5	Yes	No
Nicor Inc.	Yes	11 to 11.5	No	No
Northwest Natural Gas Co.	Yes	< 11	Yes	No
ONEOK Inc.	Yes	N.A.	No	No
People's Energy Corp.	No	11 to 11.5	No	No
Piedmont Natural Gas Co. Inc.	Yes	> 11.5	No	No
SEMCO Energy Inc.	No	11 to 11.5	No	No
South Jersey Gas Co.	Yes	< 11	Yes	No
Southern Union Co.	No	< 11	Yes	Yes
Southwest Gas Corp.	No	< 11	No	No
UGI Utilities Inc.	No	N.A.	No	Yes
WGL Holdings Inc.	No	< 11	No	No

N.A—Not available. LDC—Local distribution company. > — Greater than. < — Less than.

A prolonged period of high natural gas prices without timely reimbursement of deferred gas cost balances will rapidly deplete an LDC's liquidity. Given today's high and volatile natural gas prices, maintaining strong credit quality necessitates that ratepayers bear the responsibility for commodity costs. Automatic pass-through mechanisms linked to gas price indices provide the strongest level of support because they largely remove regulatory risk from the picture. Lesser clauses, including mechanisms that require after-the-fact sign-off by regulators, introduce the potential for disallowance if the regulator deems gas to be purchased at imprudent cost levels. New Jersey LDCs, for instance, can adjust rates up to three times a year without an official rate case. Although this acts as a pressure release valve in high-price environments, it still exposes LDCs to regulatory uncertainty when the price of gas rises above a preset level. In such circumstances, history provides Standard & Poor's with its best guide to regulators' willingness to accommodate LDCs in their jurisdiction.

Due to the extreme volatility and significant increase in gas prices over the past few heating seasons, more state regulators have revised the timing of their gas adjustment clauses by providing monthly gas adjustment clauses rather than the seasonal end of the heating season adjustment. This expedited treatment helps LDCs to reduce any regulatory lag to recover costs and streamline working capital needs, which in turn should allow LDCs to modestly temper rising gas bills to their customers. In today's new cost paradigm, how quickly the purchased-gas adjustment is "trued up" can have a significant bearing on an LDC's credit quality. Slow recovery could impinge on the firm's liquidity as short-term funds are consumed to finance high-cost gas working-capital needs. In turn, this may necessitate a larger bank line that increases borrowing costs or increased debt levels to term out the short-term borrowings with medium-term notes, potentially increasing pressure on a company's financial profile.

However, some companies like Piedmont Natural Gas Co. Inc. (A/Stable/—) have actually begun the new year by requesting the North Carolina Utilities Commission to reduce the wholesale benchmark to calculate its retail rates from an approved $13 per thousand cubic feet (mcf) in December 2005 to $11 per mcf in January, and make the change effective as of Jan. 1, 2006. This unprecedented request is primarily due to the recent decline in gas prices from peak highs in December 2005 of $15.78 per million Btu to about $7.20 per million Btu today. This represents an example of a working relationship between regulators and LDCs to contain high gas costs and customers' bills.

Weather protection

An LDC's ability to collect a consistent cash stream, regardless of a service territory's weather conditions, provides an important level of stability. Several warmer-than-normal winters or cooler-than-normal summers could significantly change an LDC's financial health unless regulators provide normalization measures. Such protection can be achieved via a normalization clause or rate design. Some jurisdictions such as New Jersey recognize the potential implications of adverse temperatures on unprotected LDCs and provide support accordingly. Other jurisdictions are not as accommodating. SEMCO Energy Inc. and Southwest Gas Corp. have seen their financial profiles weaken partially in response to significant adverse weather conditions.

The growing popularity of weather derivatives serves as an additional avenue for LDCs to pursue weather protection. Regulators that recognize these products as a way to reduce risk for LDCs and their ratepayers tend to allow for derivative cost pass-throughs and do not question the prudence of the strategy.

Earnings sharing

Mechanisms that mandate earnings sharing between shareholders and ratepayers compensate well run LDCs with a share of the profits when companies earn more than their allowed ROE. This gives management an incentive to make their companies' operations more efficient. Sharing also provides downside protection to shareholders and partially shields LDCs during troubled times by, in effect, requiring ratepayers to foot the bill for a portion of lost earnings. AGL Resources Inc., Cascade Natural Gas Corp., Northwest Natural Gas Co., and Southern Union Co. all benefit from earnings sharing in at least a portion of their respective service territories.

Allowed ROE

Like all other for-profit businesses, earning a healthy ROE helps drive success. Fairly set ROEs provide LDCs with capital for system maintenance, growth projects, and capital structure improvement.

Other regulatory mechanisms

Both regulators and LDCs are increasing customer-education programs on energy efficiency and conservation. Lawmakers, state regulators, and LDCs are in preliminary discussions to potentially restructure the current rate structures to encourage these goals of energy conservation and efficiency without hurting an LDC's bottom line and still allow companies to achieve their approved regulated rate of return. In essence, "conservation tariffs" would aim to decouple earnings and rates of return from delivered volumes and should eliminate a current major disincentive for utilities to develop such conservation programs. This would also better align the interest of consumers with utility shareholders by implementing innovative rate designs that would encourage energy conservation and efficiency.

Northwest Natural has a very constructive relationship with the Oregon Public Utility Commission (OPUC) that has resulted in favorable rate design and incentive programs. Northwest Natural is one of the few LDCs that operates under a conservation tariff that insulates its margins from a decline in gas usage levels. Northwest Natural also has a purchased-gas adjustment tariff under which 67% of any difference between actual gas costs and estimated costs (incorporated into rates) will be deferred and charged to customers in subsequent periods, providing protection against commodity price volatility. Finally, Northwest Natural also operates under a weather-normalization tariff that neutralizes 80% of the impact of varying weather patterns on a monthly basis without any dead bands. Oregon regulation also provides for a future test year for ratemaking purposes, thereby minimizing the potential for regulatory lag. All these measures provide for highly stable revenues and margins and contribute to Northwest Natural's solid and very low risk business profile of '1'.

Financial protection from affiliates

Earning a good return provides little benefit if the corporate entity squanders the proceeds. An LDC's credit quality suffers when parent or affiliate companies extract cash proceeds and invest in higher-risk businesses without producing commensurate returns. Regulatory restrictions preventing such dividend flow or mandating minimum equity layers buffer LDCs from more aggressive management teams. Northwest Natural benefits from strong regulatory oversight in Oregon that serves as a template for protecting an LDC's financial interests. In Missouri, regulators have restricted Southern Union from further investment in Panhandle Eastern Pipe Line LLC subsequent to its significant acquisition of the pipeline from CMS Energy Corp. WGL Holdings Inc.'s LDC must gain prior approval from Virginia's regulators to provide intercompany loans to its parent or affiliates, thus contributing to its credit strength. These protective measures provide an added degree of comfort for bondholders.

Markets And Competition

Table 3

Markets and Competition Comparison

Company	Service territory growth (%)	Service territory saturation (%)	Customer mix* (%)
AGL Resources Inc.	1.5 to 2.5	N.A.	80 to 90
Cascade Natural Gas Corp.	> 2.5	< 60	< 80
New Jersey Natural Gas Co.	> 2.5	> 90	80 to 90
Nicor Inc.	1.5 to 2.0	> 90	< 80
Northwest Natural Gas Co.	> 2.5	< 60	80 to 90
ONEOK Inc.	< 1.5	> 90	> 90
People's Energy Corp.	> 2.5	< 60	80 to 90
Piedmont Natural Gas Co. Inc.	> 2.5	< 60	80 to 90
SEMCO Energy Inc.	1.5 to 2.0	60 to 90	< 80
South Jersey Gas Co.	> 2.5	60 to 90	80 to 90
Southern Union Co.	< 1.5	< 60	80 to 90
Southwest Gas Corp.	> 2.5	< 60	80 to 90
UGI Utilities Inc.	> 2.5	60 to 90	< 80
WGL Holdings Inc.	> 2.5	< 60	80 to 90

*Customer mix defined as residential and commercial margins as % of total gross margins. > — Greater than. < — Less than.

Service territory growth

High growth within a service territory due to population influx and new construction could lead to an LDC's greater profitability or rate stability. However, as evidenced by Southwest Gas' struggles, high growth sometimes cuts both ways. Arizona and Nevada benefit from rapid population growth, but the slow pace of regulatory rate adjustments acts as a drag on Southwest Gas' financial ratios because revenues fail to adequately compensate the LDC for its growth capital expenditures on a timely basis. Slower growth in Illinois, on the other hand, provides limited upside for companies, such as Nicor Gas Co. and Peoples Energy Corp., but alleviates the associated regulatory dependence faced by Southwest Gas.

Service territory saturation

Customer saturation refers to the proportion of customers in a given area that use their LDC's services. LDCs that operate in service territories with low growth potential still can grow at healthy rates if a relatively low level of customer saturation permeates the service territory. For example, customers who convert to natural gas from other fuel sources (such as oil) provide growth opportunities to LDCs operating in low population growth service areas. Northwest Natural benefits from its sub-50% saturation rate and good service territory growth, while Peoples Energy faces a disadvantageous combination of a relatively high saturation rate and low service territory growth.

Customer mix

An LDC serving a large proportion of industrial or wholesale customers faces greater instability than an LDC serving only residential customers. Nicor and Peoples Energy, for instance, serve a broad customer base consisting of many small retail users, as opposed to a few large industrial users, which reduces dependence on individual customers. LDCs that depend on the sustainability of a few key industrial users carry not only gas distribution risk, but also business risk associated with the large customers. Furthermore, large users often have greater financial incentive to switch to alternative fuel sources because of extreme input cost sensitivity in certain energy-intensive industries.

Protection against bypass

Due to their proximity to interstate gas pipelines, some large customers have the ability to directly tie into a transmission line and completely bypass LDCs' services. Although such pipelines provide key sources of gas supply for LDCs, it is important to recognize this bypass risk. Ideally located LDCs have adequate transmission access but have industrial customers far from interstate pipelines.

Wealth demographics

A wealthy customer base reduces the risk of customer nonpayment and often translates into less resistance to distribution rate increases. Furthermore, wealthy customers are less sensitive to their marginal gas consumption, which can lead to higher usage. Suburban areas of New Jersey—outside of New York City and Philadelphia—offer examples of high-wealth customer concentrations that benefit the regional LDCs.

Operations

Supply position

Drawing from a single interstate pipeline or relying on a particular gas basin exposes LDCs to event risk and negative supply shocks, respectively. The ability to access multiple sources of gas supply through multiple pipelines protects LDCs from such disruptions. With its strategic location in Chicago, Ill., Peoples Energy has an ideal supply position. The company has direct interconnections to six major pipelines (Natural Gas Pipeline Co. of America, ANR Pipeline Co., Trunkline Gas Co., Midwestern Gas Transmission Co., Northern Border Pipeline Co., and Alliance Pipeline L.P.) and can draw gas from the Midcontinent, Gulf Coast, and Canada. The numerous pipeline connections allow the company to negotiate gas purchases and storage arrangements at competitive prices.

Storage position

Adequate storage access not only helps supply incremental gas needed to meet peak demand, but also provides opportunities for LDCs without purchased-gas adjustment clauses to arbitrage seasonal pricing fluctuations. LDCs benefit from storage if the cost of buying peak gas exceeds the cost of making off-season purchases and the associated carrying cost. Northwest Natural can meet more than 60% of peak demand with company-owned storage, leased storage, and recall agreements. Such storage has lowered the company's average commodity costs and allowed it to meet peak demand without having to pay for additional transportation costs.

System condition

Outdated systems requiring extensive maintenance and capital expenditures lower LDCs' profitability and efficiency metrics. Newly installed systems mainly consisting of plastic pipe require limited expenditures over the long term compared with older, cast-iron systems that need replacing as they age. In addition, LDCs generate operational efficiencies through the use of new technology. Technology allows Southwest Gas field employees to receive work orders without driving to the office in the morning and read meters without leaving their vehicles. Although often involving material upfront costs, such technological improvements provide significant long-term savings.

Hedging

LDCs can hedge against gas price volatility by using financial instruments and locking in long-term purchase contracts with its suppliers. The hedging of fixed-price purchases reduces exposure to physical market price volatility, preserves the value of storage inventories, and provides risk-management services to a variety of customers. Those companies that have locked in prices through long-term contracts, financial instruments, or both that are below the high average prices over the past three heating seasons have reduced their exposure to high gas prices. Many LDCs' hedging programs need to be preapproved by regulators. We view prudent, consistent hedging programs that have been preapproved by regulators as a credit strength. For example, Piedmont Natural Gas provides a hedging program, which requires preapproval by its regulators.

Management

As in all business segments, ownership structure, management practices, internal controls, corporate governance, and financial disclosure policies fall under the management umbrella and are all regularly examined as part of our ratings methodology for LDCs.

Within the ownership structure analysis, links to parent companies or affiliates are important considerations. Ownership by stronger or weaker parents substantially affects the rated entity's credit quality. The nature of the owner—holding company or strategically linked business—can also hold significant implications for business and financial aspects of the rated entity. Standard & Poor's deems many LDCs to have the same creditworthiness as other entities within their corporate structure because of strategic linkages and the free flow of funds among the entities.

Assessment of management personnel and practices is an especially significant determinant of a rating. Standard & Poor's analysis considers many factors that pertain to management, including track record and competence, management background and reputation, and management depth and turnover. Business strategies that stray from core competencies, initiatives that bear elevated risk, and actions inconsistent with public or private statements detract from credit quality. We place a higher degree of confidence in management teams that possess significant industry experience, consistently meet or exceed forecast projections, and deal openly with pressing credit issues.

Financial disclosure and management oversight help round out the broader area of governance. Does an impartial board of directors help monitor critical decisions? Are all potential conflicts of interest disclosed in a timely manner? Are all SEC filings on time? The answers to these questions help provide intangibles to the rating process.

Rating Actions

There have been several adverse rating actions in the LDC universe over the past three to four heating seasons (36-40 months) for a variety of reasons, with 10 outlook revisions to negative, five CreditWatch placements with negative implications, and five downgrades. During 2005, there were two outlook revisions (one to negative from stable and one to stable from positive), one CreditWatch placement with negative implications, and one downgrade compared with only one upgrade that occurred in early January 2005. Thus far in 2006, there has been two rating actions, with a negative outlook revision from stable and a CreditWatch placement with negative implications, due to a combination of increased regulatory uncertainty and increased exposure to nonregulated activities.

These adverse rating actions have been due to some combination of the following:

- Sustained high leverage and weaker-than-expected credit protection measures,
- Increased exposure to, or investment in, nonregulated businesses,
- Increased debt-financed acquisitions or capital investments, and
- Weak regulatory mechanisms and support.

Conversely, the favorable rating actions during the past three heating seasons, which have been more modest, have consisted of three upgrades, one outlook revision to positive (which recently was revised back to stable in 2005), and two rating affirmations with an outlook revision to stable from negative. These positive rating actions have been attributable to:

- Increasing customer growth and improving cash flow and financial profile, while maintaining sound liquidity,
- Prudent financings by using a combination of debt and equity as well as the successful integration of acquisitions in certain cases, and
- Demonstrated strength of regulatory support and rate mechanisms during challenging, high natural gas price heating seasons.

The outlook for the LDC universe continues to have some negative pressures with eight out of the 14 rated LDCs possessing a negative outlook or CreditWatch with negative implications, and no company with a positive outlook. The remaining six LDCs have a stable outlook (two of which were recently downgraded in 2005). In general, the majority of the LDCs possess 'A' ratings, a stable outlook, or both which represent our general view of LDCs' cash-flow stability and low business risk profiles.

Nevertheless, current high gas prices will remain a challenge for all LDCs and may further pressure ratings for those LDCs that have a negative outlook and whose financial measures are somewhat stretched for their current ratings. In addition, management's financial policy and commitment to credit quality will also play an integral role in a company's ability to manage and sustain its credit quality during a fourth consecutive heating season with a higher-than-average natural gas pricing environment.

Table 4

Financial Profile Comparison*

Company	FFO interest coverage (x)	FFO to total debt (%)	Net cash flow/capital expenditures (%)	Discretionary cash flow (mil. $)	Average return on capital 2002-2004 (%)	Total debt to total capital (%)
AGL Resources Inc.	5.0	18.4	86.7	(52.0)	10.5	59.2
Cascade Natural Gas Corp.	4.3	24.5	79.9	(18.3)	9.6	59.8
New Jersey Natural Gas Co.	7.0	19.1	87.3	(157.9)	12.4	56.6
Nicor Inc.	6.6	26.1	96.4	45.3	9.7	58.3
Northwest Natural Gas Co.	4.2	20.0	51.9	67.2	8.8	51.4
ONEOK Inc.	4.8	19.8	169.5	(148.5)	10.5	63.8
People's Energy Corp.	4.9	20.6	63.3	(66.6)	8.8	52.9
Piedmont Natural Gas Co. Inc.	3.8	16.4	58.1	(50.7)	10.9	47.8
SEMCO Energy Inc.	1.8	6.7	101.6	6.0	7.1	71.8
South Jersey Gas Co.	5.3	20.9	89.6	(15.3)	9.8	55.2
Southern Union Co.	3.4	12.3	96.0	(28.6)	2.9	55.0
Southwest Gas Corp.	3.6	18.0	70.3	(180.0)	7.1	66.8
UGI Utilities Inc.	3.5	21.4	204.8	67.8	13.0	65.6
WGL Holdings Inc.	5.5	26.4	131.4	66.4	10.0	46.8

*Financials as of fiscal year-end 2004. FFO—Funds from operations.

We expect many of these companies listed in the table above to either maintain or continue to gradually improve their financial profiles. Still, the outlook for six LDCs is negative. The negative outlook for Southern Union, Nicor Inc., and AGL primarily reflects their increased financial leverage and weakened credit protection measures and their respective near-term challenges to significantly improve their financial profiles. In addition, AGL's and UGI Utilities Inc.'s negative outlooks are also related to their increased exposure to nonregulated operations (i.e., energy marketing and propane business) increasing their business risk profiles and need to generate stronger financial measures commensurate with their respective ratings. Finally, the negative outlook on WGL reflects its absence of weather normalization and increased exposure to its retail energy marketing business, which could further reduce the company's current liquidity cushion.

Cascade Natural Gas has a positive outlook tied to its improving financial profile based on solid customer growth, a reliable purchased-gas adjustment mechanism that ensures full recovery of gas supply costs, and a manageable capital spending program that should allow the company to continue to meet its debt reduction plans in 2006.

The Credit Challenges Ahead

Regulators will always have to balance timely and prudent gas cost recovery with ratepayer resistance to rising gas bills. Continued regulatory support is paramount to credit quality for LDCs, especially during periods of prolonged high natural gas prices and the likely need for LDCs to fund working capital needs with additional debt. LDCs will remain challenged in this elevated gas price environment to reduce short-term debt balances and avoid creeping debt leverage, which could trigger deterioration in credit quality.

Peoples energy is an example of how an uncertain and challenging regulatory environment can put pressure on a company's credit quality. In February 2006, Standard & Poor's revised the outlook on Peoples Energy to negative from stable due to the challenging regulatory climate in Illinois, which has become highly politicized as the historically supportive gas distribution regulation has become more contentious. In addition, the outlook revision also incorporated the company's continued increased investment in nonregulated diversified businesses, which include oil and gas production, power generation, midstream services, and retail energy services.

In the end, a company's business risk profile must be analyzed in conjunction with its financial risk profile (see table 4). Because investors in the LDC universe rely on stable cash flow, strong financial metrics may simply overpower chinks in the business profile armor. Nicor's stratospheric cash flow ratios drive the company's 'AA' rating despite average regulatory, market, and competition characteristics. Good financial metrics at New Jersey Natural Gas also support that company's strong rating.

More recently, Standard & Poor's has further scrutinized the financial profiles and overall liquidity for companies that have increased their exposure to nonregulated energy trading activities. For example, AGL's credit quality is tempered by the heavy liquidity requirements of its nonregulated businesses (primarily through its subsidiary Sequent, a gas marketing and trading company) and the company's growth strategy that could potentially increase its exposure to unregulated activities (see table 5).

Table 5

Diversified Activities Comparison

Company	Diversified activities as % of consolidated entity	Main areas of focus
AGL Resources Inc.	20	Wholesale and retail services
Cascade Natural Gas Corp.	Less than 5	Retail gas marketing to a small number of large customers
New Jersey Natural Gas Co.	22	Natural gas utility, energy marketing, and pipeline capacity management
Nicor Inc.	10	Shipping
Northwest Natural Gas Co.	9	Interstate gas storage
ONEOK Inc.	70	Gas gathering and processing; energy marketing and trading
Peoples Energy Corp.	10	Gas distribution
Piedmont Natural Gas Co. Inc.	10	Pipelines and retail gas marketing
SEMCO Energy Inc.	90	Propane and retail energy services
South Jersey Gas Co.	30	Natural gas utility, energy marketing, and marina energy (Borgata project in Atlantic City, N.J.)

Table 5

Diversified Activities Comparison

Company	Diversified activities as % of consolidated entity	Main areas of focus
Southern Union Co.	88	Natural gas pipelines; gas gathering and processing
Southwest Gas Corp.	Less than 10	Construction
UGI Utilities Inc.	50	Propane and retail energy services
WGL Holdings Inc.	2	Retail gas

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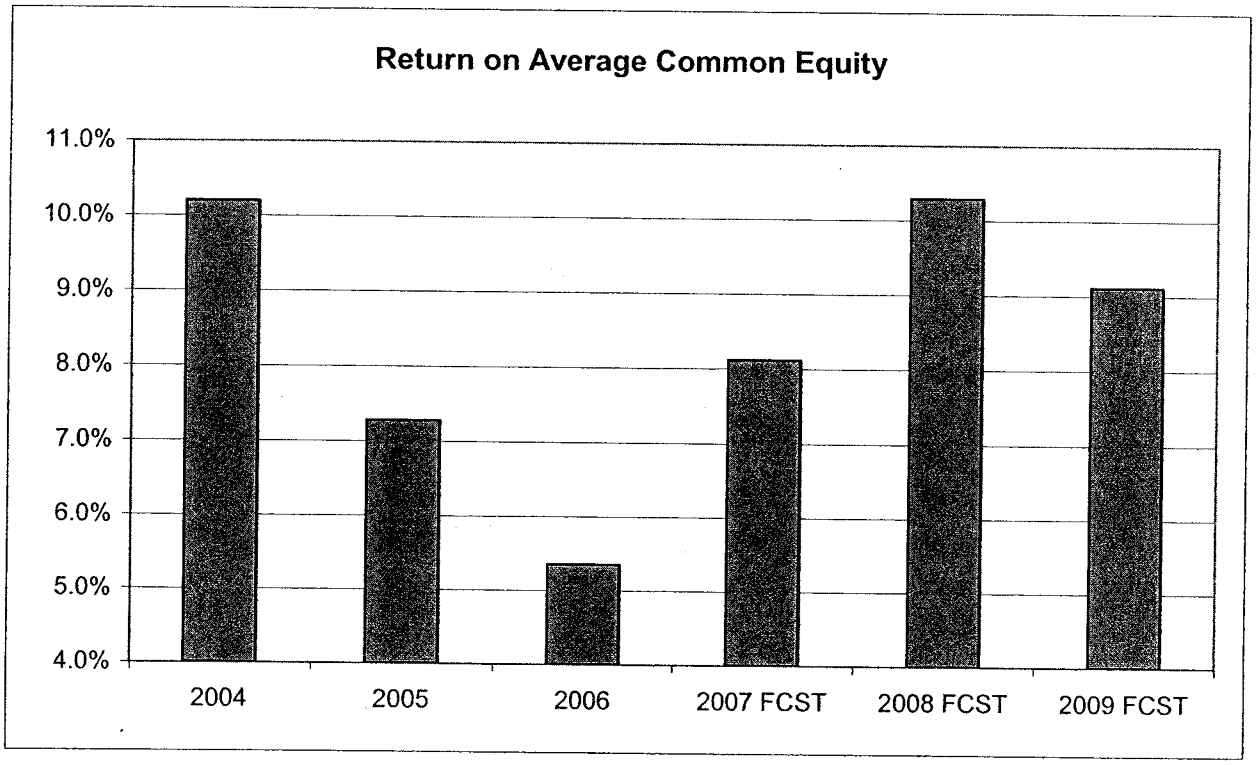
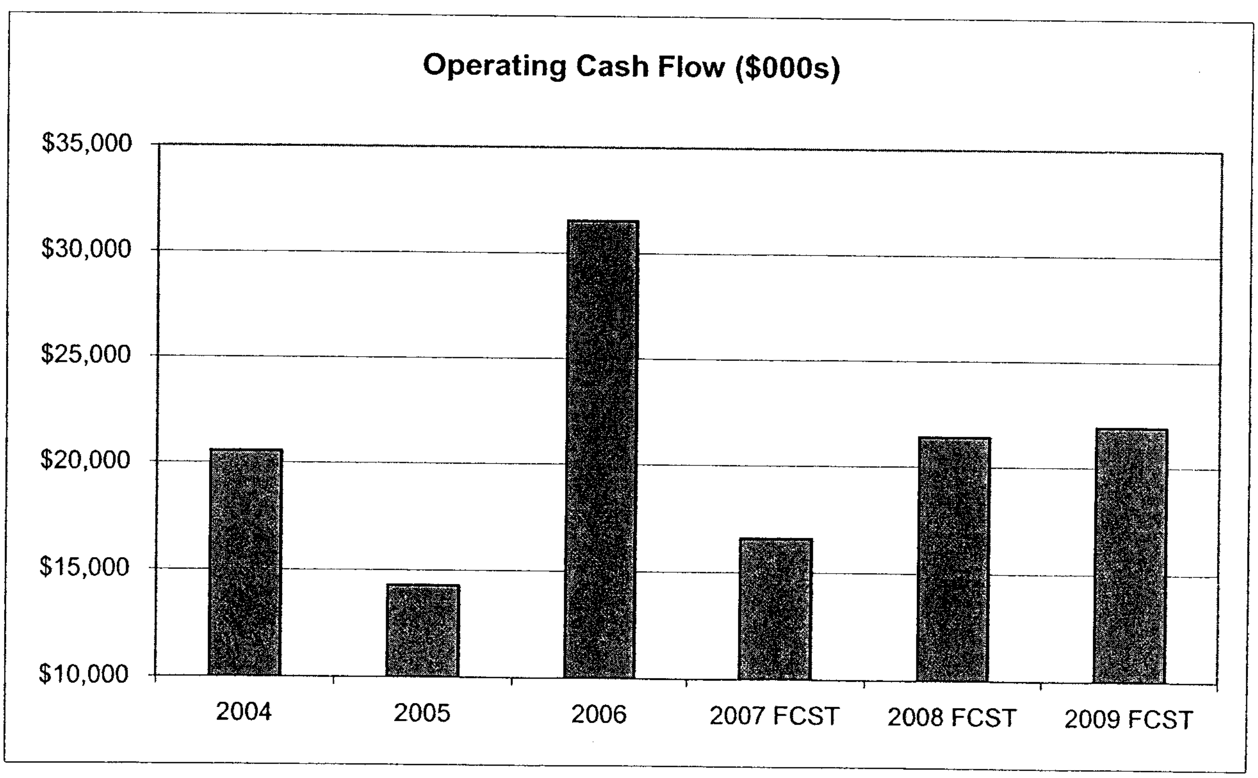
EXHIBIT

KCG-13

UNS Gas, Inc.
Updated Financial Forecast with Company's Proposed Rates
Summary of Key Financial Indicators





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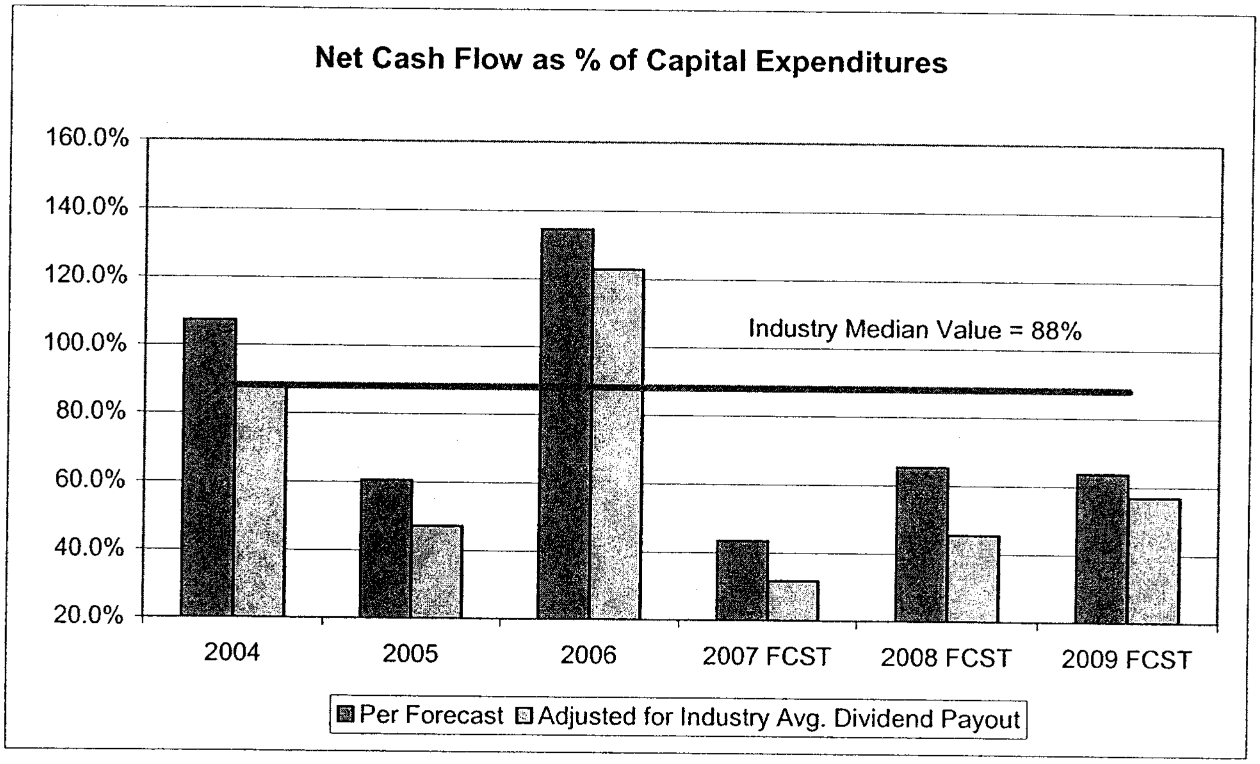

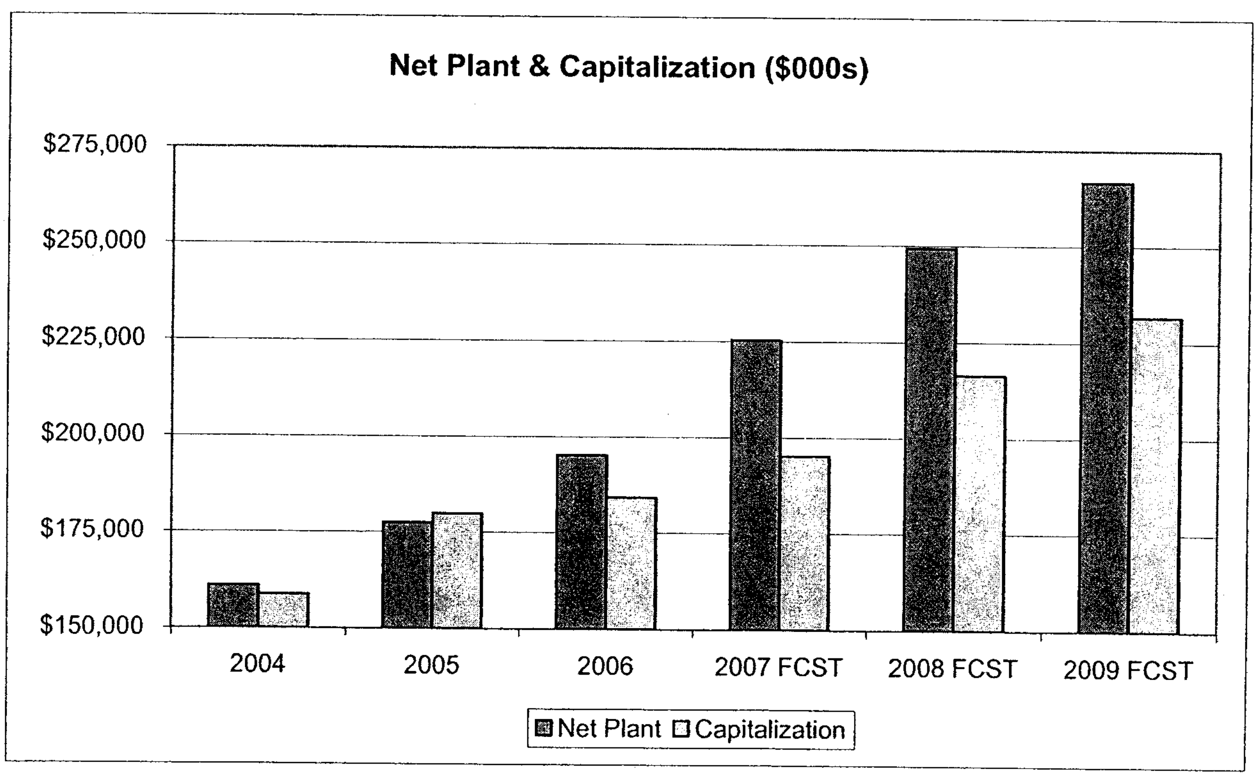

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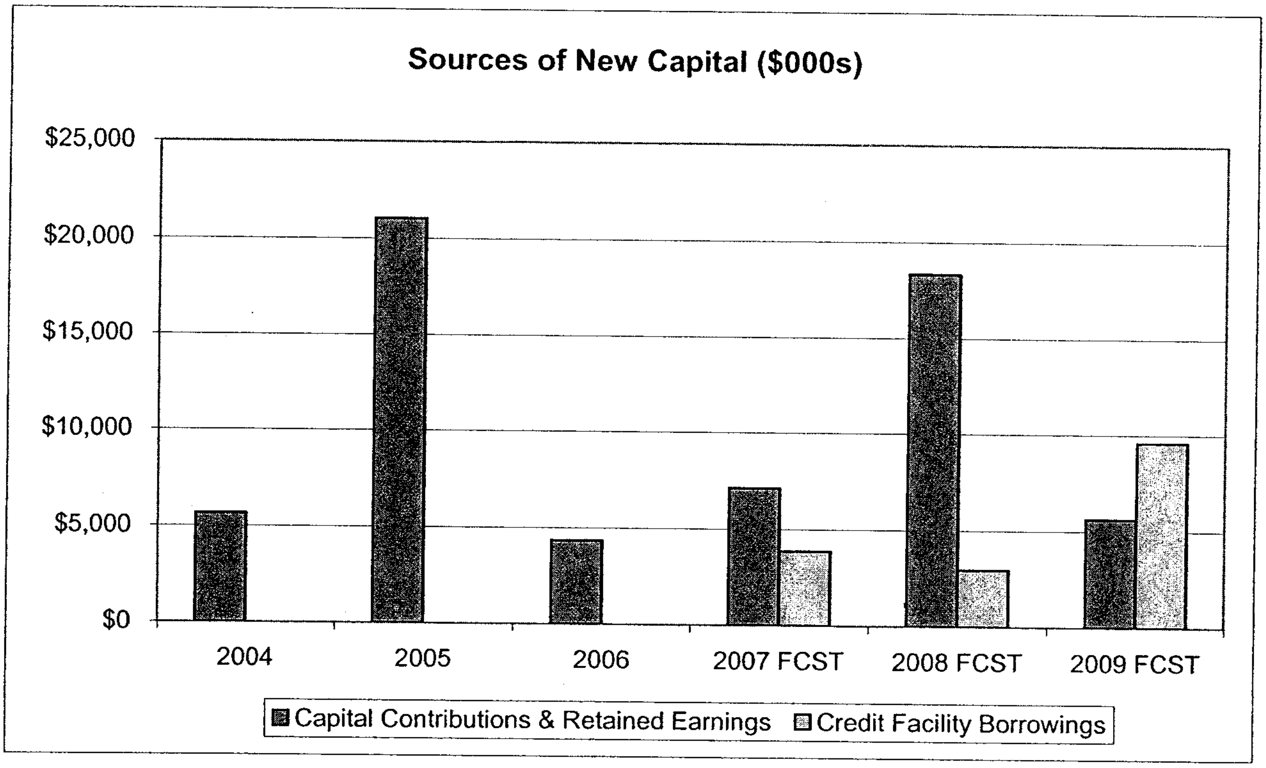

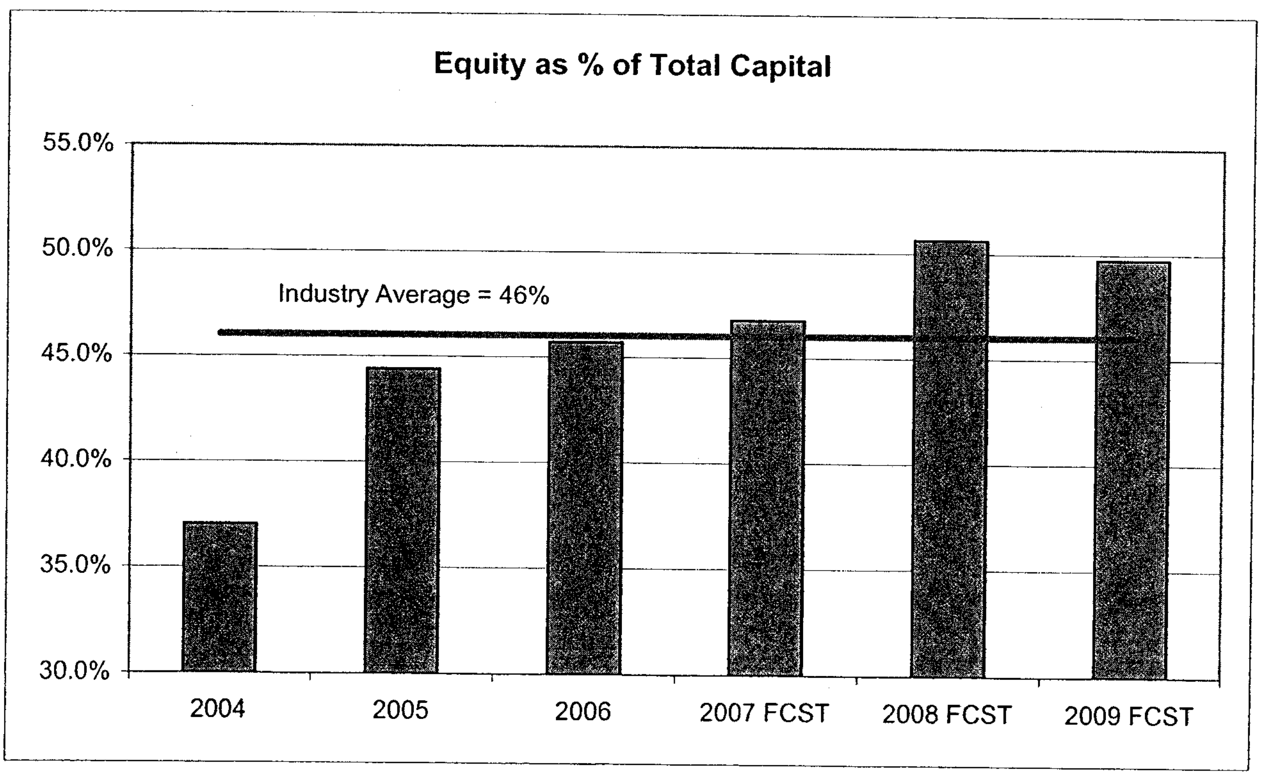

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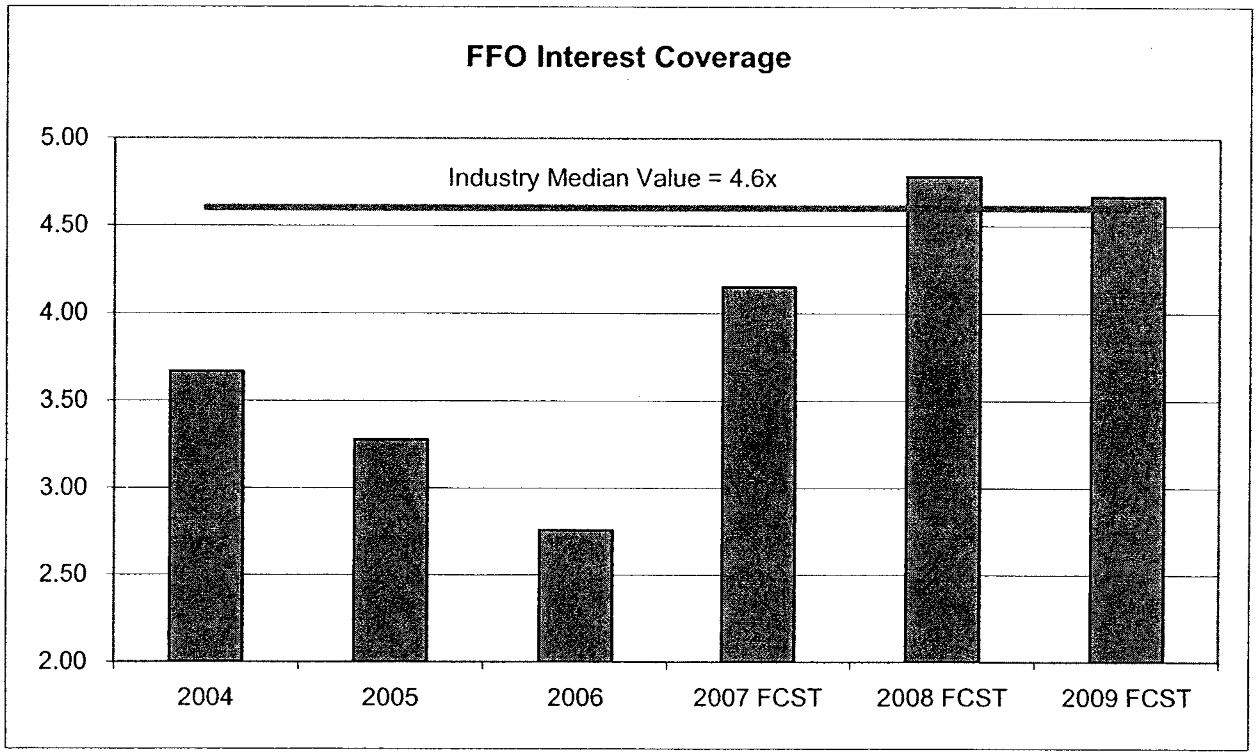
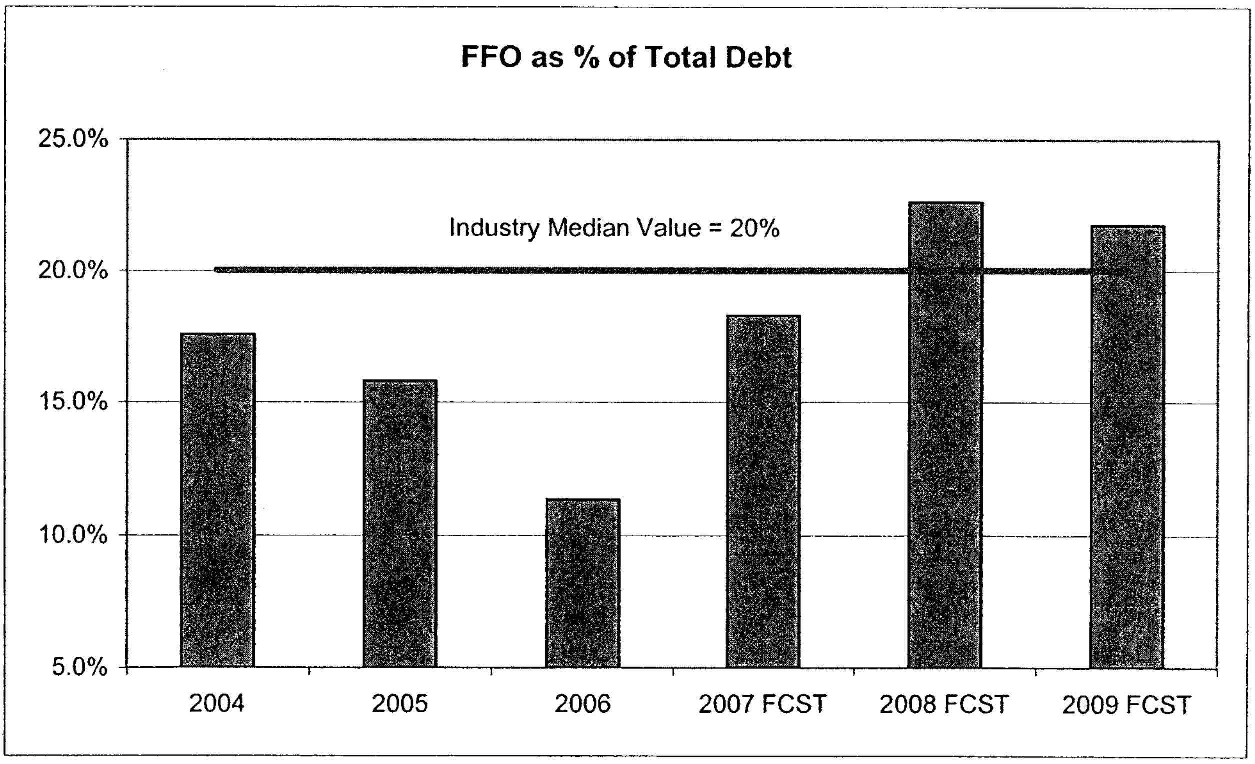
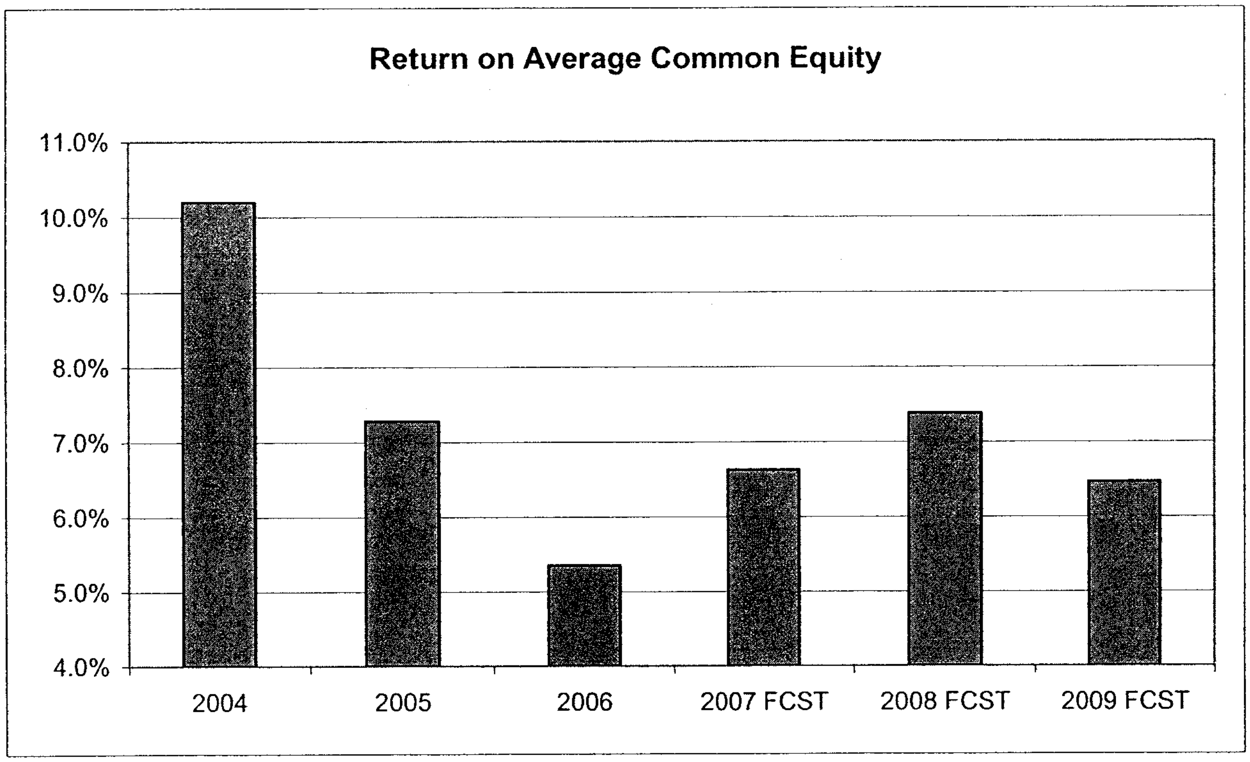


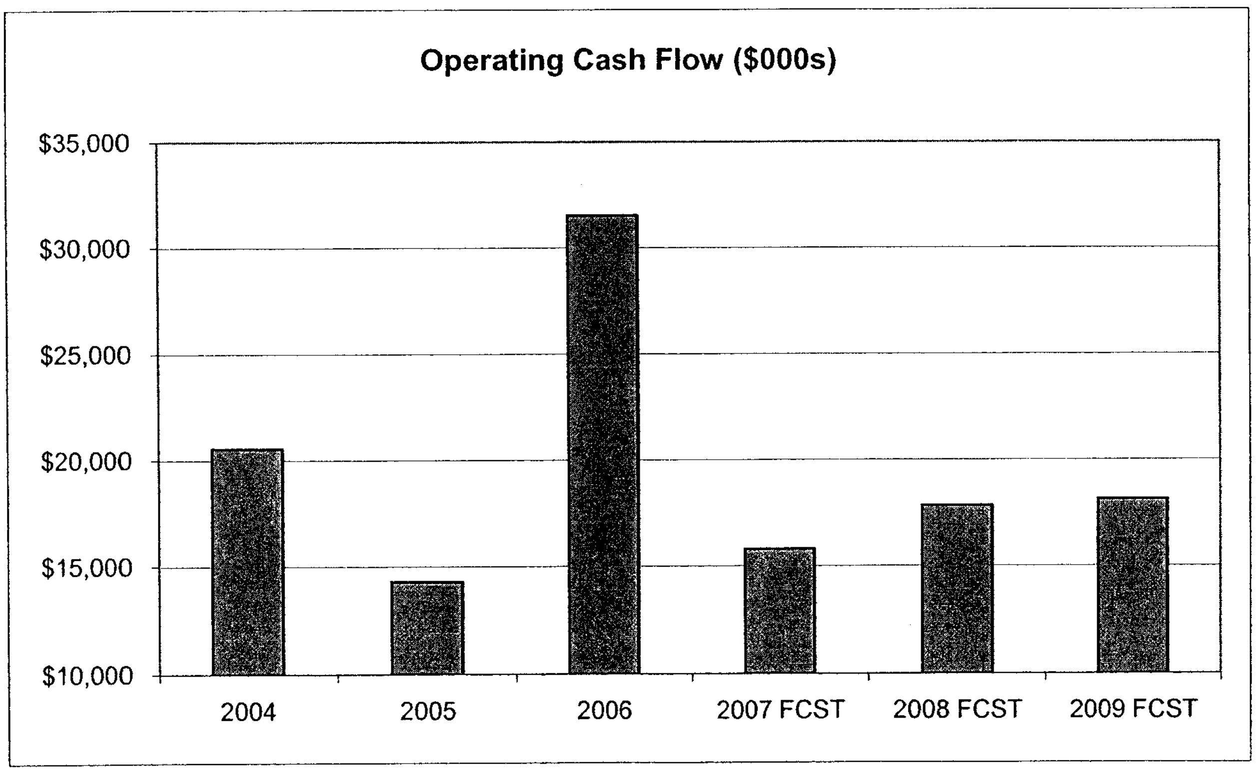


EXHIBIT

KCG-14

UNS Gas, Inc.
Updated Financial Forecast with Staff's Proposed Rates
Summary of Key Financial Indicators





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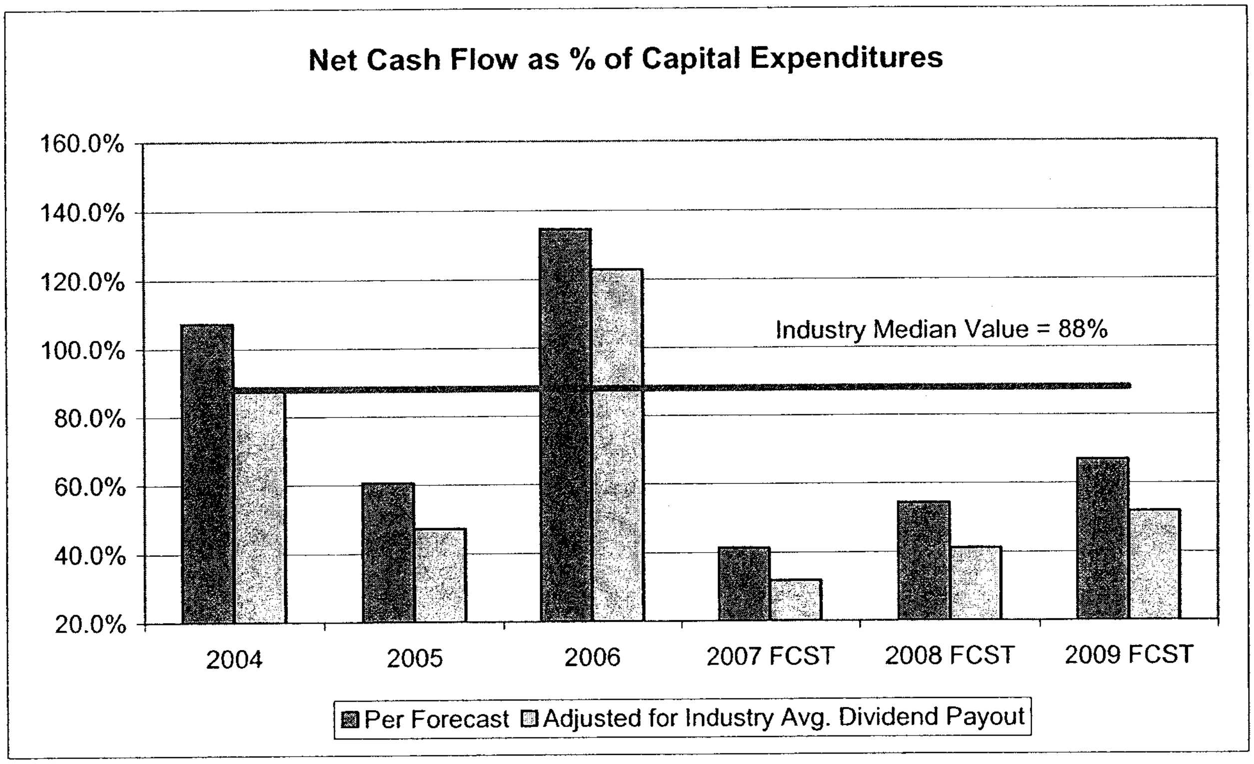

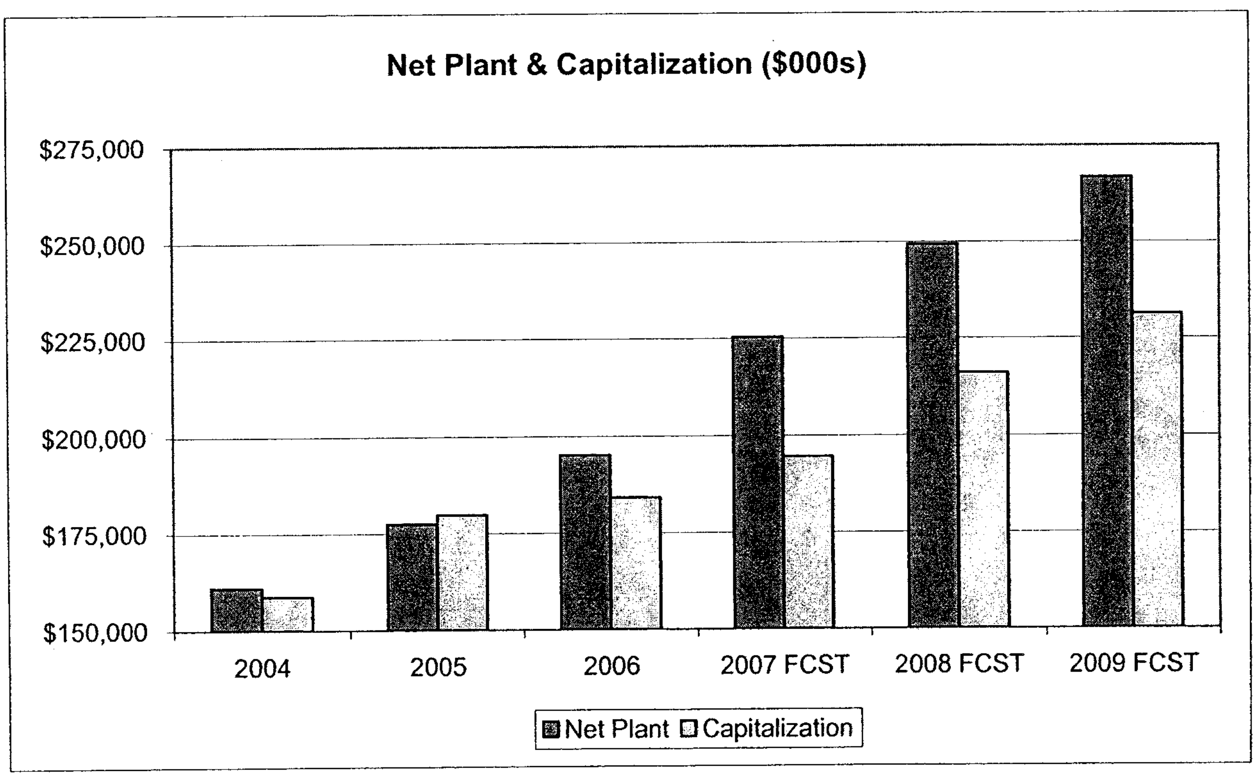

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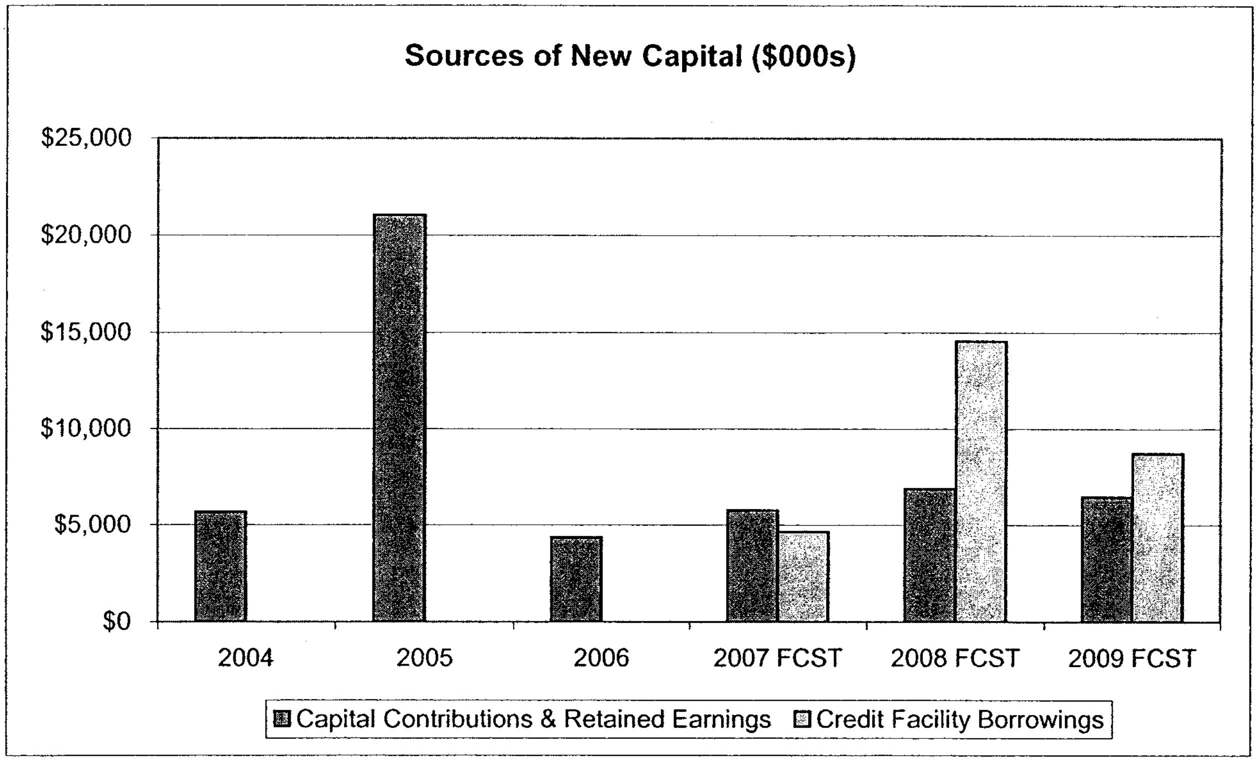

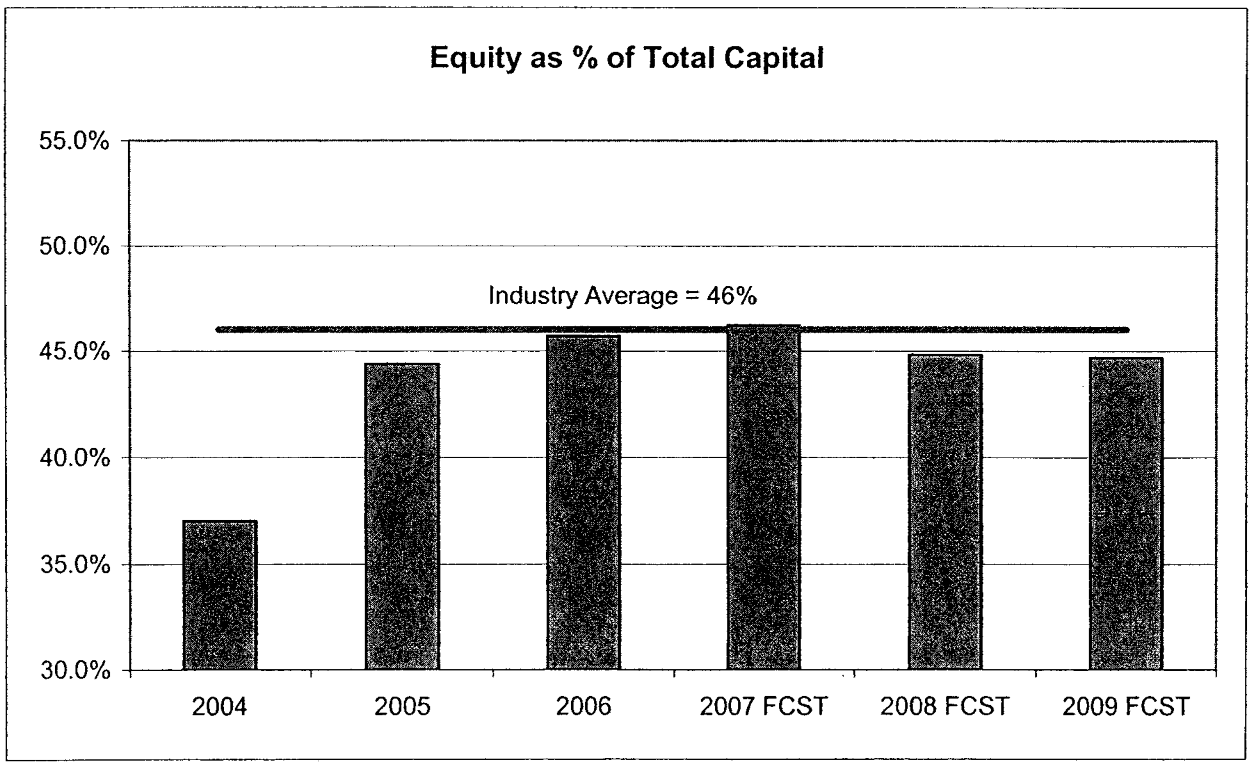

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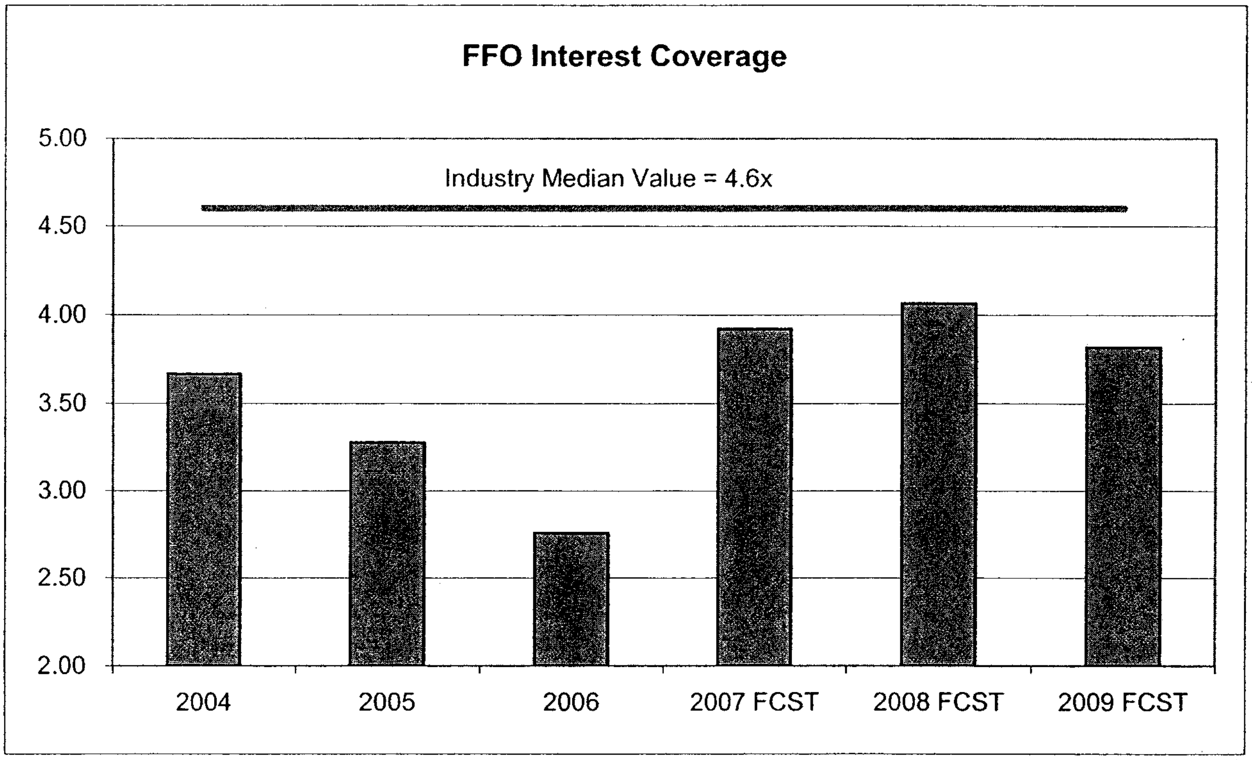

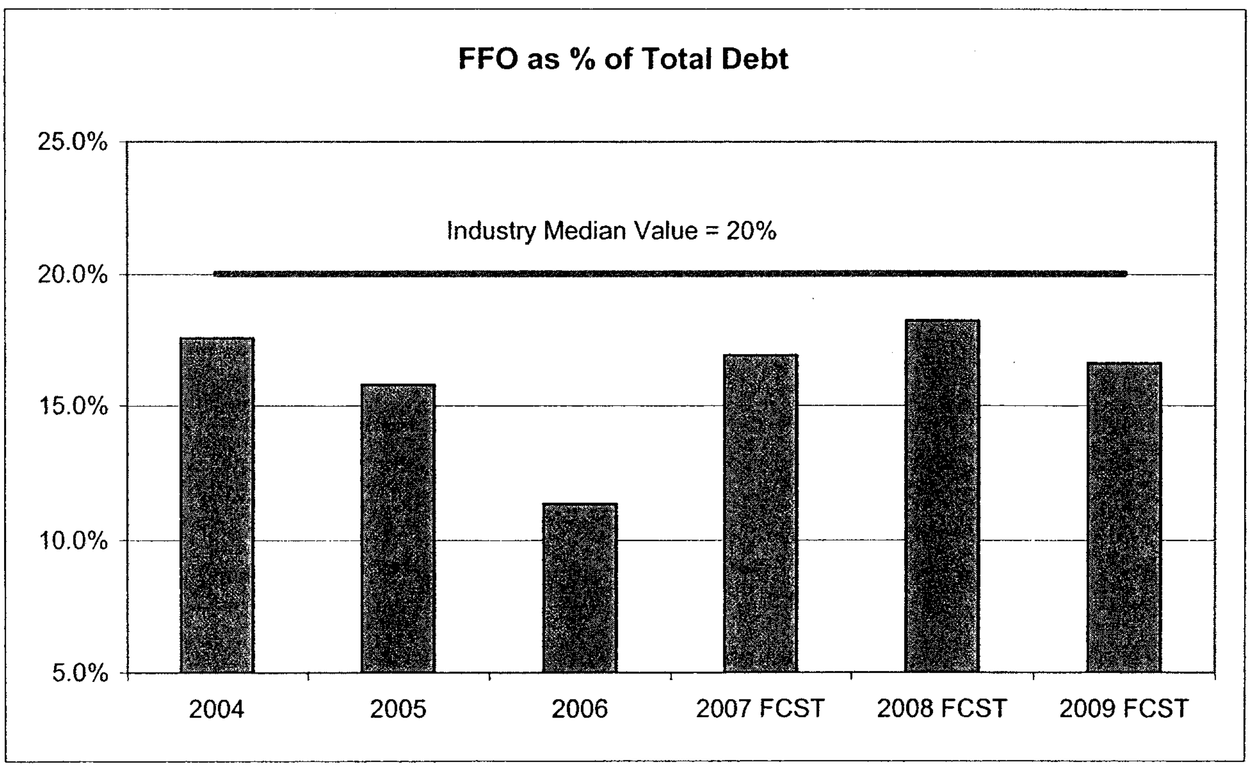

BEFORE THE ARIZONA CORPORATION COMMISSION

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 THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-06-463
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

Rejoinder Testimony of

Kentton C. Grant

on Behalf of

UNS Gas, Inc.

April 11, 2007

EXHIBIT
tabbies
UNSG-79
admitted

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and address.

A. My name is Kentton C. Grant. My business address is One South Church Avenue, Tucson, Arizona, 85701.

Q. Are you the same Kentton C. Grant that filed Direct and Rebuttal Testimony in this case?

A. Yes.

Q. Have you reviewed the Surrebuttal Testimony filed by the Commission Staff and Intervenors in this case?

A. Yes, I have.

Q. Please provide your general response to the Surrebuttal Testimony filed by the Commission Staff and the Intervenors.

A. Most of the issues raised in my Rebuttal Testimony still remain open. The Staff rejects the Company's request to include construction work-in-progress ("CWIP") in rate base, and continues to insist that *all* customer advances be used to reduce rate base, even those advances related to the test year-end CWIP balance. Additionally, the position taken by Staff on what constitutes a reasonable rate of return ("ROR") on fair value rate base ("FVRB") is mathematically equivalent to the position previously taken by Staff, and as a result, is not responsive to the concerns expressed by the Arizona Court of Appeals in a ruling involving Chaparral City Water Company ("Chaparral"). The Commission Staff ("Staff") also continues to recommend an unreasonably low return on equity ("ROE") and the use of a capital structure that is more highly leveraged than is typical for gas distribution utilities.

With respect to the Surrebuttal Testimony filed by the Residential Utility Consumers Office ("RUCO"), it appears that the Company and RUCO are now in agreement on the appropriate cost of debt and capital structure for UNS Gas. However, similar to Staff, RUCO continues to recommend an unreasonably low ROE, the exclusion of CWIP from rate base, and the use of *all* customer advances to reduce rate base, even those advances related to the test year-end CWIP balance. These positions, when coupled with the other revenue requirement adjustments and rate design positions advocated by RUCO and Staff, will not provide UNS Gas with an opportunity to earn a reasonable ROR on its investment, will harm the Company's ability to attract capital on reasonable terms, and will hasten the filing of yet another costly rate case for UNS Gas if they are ultimately adopted by the Commission.

Q. Which Commission Staff and/or Intervenor Testimony will you be addressing in your Rejoinder Testimony?

A. I will be addressing the Testimony of the following witnesses:

- Ralph C. Smith on behalf of Staff
- David C. Parcell on behalf of Staff
- Marylee Diaz Cortez on behalf of RUCO
- William A. Rigsby on behalf of RUCO

II. RESPONSE TO STAFF WITNESS RALPH SMITH.

Q. What issues raised by Mr. Smith in his Surrebuttal Testimony do you wish to address?

A. There are three issues raised by Mr. Smith that require further discussion. First, I address the standards now articulated by Mr. Smith for the granting of CWIP in rate base, and demonstrate once again why UNS Gas should be permitted to include CWIP in rate base.

Second, I discuss Mr. Smith's characterization of the financial forecasts that were included in my Direct and Rebuttal Testimony. Finally, I address Mr. Smith's concerns regarding the rate treatment of customer advances, and provide an illustrative example of how Staff's position on this issue imposes a financial penalty on UNS Gas.

Q. What standards has Mr. Smith articulated for the purpose of determining whether or not CWIP can be included in rate base?

A. At page 10, lines 16 through 20 of his Surrebuttal Testimony, Mr. Smith states the following:

> "...UNS Gas must show convincingly that it is different in significantly important aspects than the comparable circumstances in the other utility rate cases over the past decades where CWIP was excluded from rate base. In other words, UNS Gas must show how it is different from the normal circumstances of a regulated Arizona public utility where CWIP has been excluded from rate base."

Additionally, at page 11 of his Surrebuttal Testimony, Mr. Smith appears to describe another standard, one based on financial need. At lines 7 through 9 of that page, Mr. Smith makes the following statement:

> "Nor has Mr. Grant demonstrated that UNS Gas is in financial distress, that it cannot continue to attract capital at favorable terms if CWIP continues to be excluded from rate base, or that UNS Gas is different in terms of its customer growth and regulatory lag situation than the other major utilities in Arizona which do not have CWIP included in rate base."

Based on these comments, it appears that Staff is recommending the application of both an "extraordinary circumstances" test and a "financial distress" test in determining whether or not to allow CWIP in rate base.

Q. Do you agree that these standards are appropriate?

A. Yes and no. I do not object to the application of an "extraordinary circumstances" test, since CWIP is not normally included in rate base for regulated utilities. However, I do object to the application of a "financial distress" test.

Q. Please explain.

A. Certainly. By the time a utility can demonstrate that it is in "financial distress," damage to the utility's credit and access to capital has already been done. The whole purpose of including CWIP in rate base is to support the utility's credit and access to capital, and to avoid the increased cost and reduced availability of capital associated with financial distress. If this same standard were applied in a medical setting, only those patients who become critically ill would be eligible for health care. By the time care is finally administered, it may be too late to save the patient.

Q. Has UNS Gas demonstrated that it is facing extraordinary circumstances, and that rate base treatment of CWIP is needed to assure continued access to capital on reasonable terms?

A. Yes. It is readily apparent that UNS Gas is being seriously challenged by the growth in net plant investment required to add new customers and to make necessary system improvements. As documented in Exhibit KCG-15, this rate of growth is substantially higher than the growth experienced by the three largest investor-owned utilities in the State of Arizona, which was recently recognized as being the fastest-growing state in the Union. This situation clearly represents an extraordinary circumstance that warrants special attention by the Commission and by the management of UNS Gas. Additionally, through my Direct and Rebuttal Testimony, I have provided ample evidence of the need for additional capital and the need for timely rate relief as requested by UNS Gas. Without CWIP in rate base, or the inclusion of a substantial post-test year plant adjustment, it would be difficult for the Company to continue to attract capital on reasonable terms. Under the circumstances, a dose of preventative medicine is clearly preferable to a "wait and see" approach.

Q. At pages 8 and 9 of his Surrebuttal Testimony, Mr. Smith discusses your use of financial projections in support the Company's request for CWIP in rate base. Do you agree with his position on the use of financial forecast information?

A. No, I do not. Mr. Smith does not believe the Commission should place much reliance on financial forecast information, since it is "subject to change and can be inaccurate." However, based on my prior experience in utility rate proceedings, as well as my experience as a utility finance professional, it is essential to consider the financial forecast of a utility seeking rate treatment on the basis of financial integrity. While it is true that financial forecasts change over time, and that they are not perfect predictors of future financial performance, they are nonetheless essential to any discussion of financial integrity. The forecast information provided in my Rebuttal Testimony reflects the best information available to the Company at this time. It is consistent with the forecast information used by management to evaluate short-term borrowing needs, longer-term financing needs, and to prepare estimates of consolidated earnings at UniSource Energy. While it may not be perfect, the financial forecast information contained in Exhibits KCG-13 and KCG-14 (included in my Rebuttal Testimony) represents the best information available concerning the Company's future financial performance under the rate proposals made by UNS Gas and by Staff.

Q. At page 9 of his Surrebuttal Testimony, Mr. Smith criticizes the financial forecast that you prepared in order to reflect Staff's rate proposal. Do you have any reaction to this criticism?

A. Yes. Apparently Mr. Smith believes that this financial forecast should be adjusted to remove costs and expenses that have been disallowed by Staff. Unfortunately, these costs and expenses will not disappear just because Staff recommends disallowance of these costs for rate setting purposes. The financial forecast referenced by Mr. Smith reflects the operating budget and capital budget established for UNS Gas, and this budget was set based on spending levels necessary to maintain high quality service and to expand the Company's facilities to meet customer growth. Unless Mr. Smith is advocating a reduction in service levels or infrastructure investment, there is no reason to adjust the financial forecast as he recommended.

Q. At page 15 of his Surrebuttal Testimony, Mr. Smith states that the Commission's rules require that customer advances be reflected as a deduction from rate base. Do you believe that all customer advances must be deducted from rate base under the Commission's rules?

A. No. I am not aware of any requirement to deduct 100% of customer advances at test year-end from rate base. I believe it is up to the discretion of the Commission to determine how much of the customer advance balance should be used to reduce rate base. For example, in the last Southwest Gas rate case, the company proposed using a thirteen month average of customer advances in lieu of the test year-end balance for purposes of calculating a rate base deduction. This average balance, which was less than the test year-end balance, was incorporated by the Commission in its final rate order.

Q. Mr. Smith also states that the accrual of an allowance for funds used during construction ("AFUDC") also represents a reason to deduct all customer advances from rate base. Do you agree with this position?

A. No. Since most of the projects included in the test year-end CWIP balance were completed fairly quickly, with 94% of the balance closed to plant-in-service by December 31, 2006, the accrual of AFUDC on the test year-end CWIP balance was fairly small, both in absolute terms and relative to the annual revenue requirement on these projects when they were completed. Since UNS Gas did not reduce its accrual of AFUDC to reflect the related balance of customer advances, Mr. Smith is concerned that UNS Gas would earn a "double rate of return" if the entire balance of customer advances is not used to offset rate base. However, as noted above, the amount of any AFUDC associated with customer advances was likely very small, and certainly pales in comparison to the return that UNS Gas will be foregoing on the test year CWIP balance if CWIP is excluded from rate base. By raising this issue, I believe that Mr. Smith is making a mountain out of a mole hill, and is using this issue to unfairly reduce the Company's rate base by the entire balance of customer advances, even those advances that are clearly tied to the test year balance of CWIP.

Q. Can you provide an example of how customer advances are used to fund construction, and how that affects the Company's net investment in a construction project over time?

A. Yes. Exhibit KCG-16 provides an illustrative example using data from a real life project that was included in the test year-end CWIP balance. As may be seen on the left hand side of this exhibit, the process begins with the payment of an advance by the developer, after which the proceeds are used by the Company to construct the gas distribution lines necessary for providing service. As new customers are hooked-up to the completed facilities, repayment of the advanced sum is made to the developer over time according to the terms of the contract. If a sufficient number of new customers are not added by the end of the five-year contract term, then all or a portion of the advance would be converted to a contribution in aid of construction ("CIAC") and used to reduce the Company's net plant investment.

As may be seen on the right hand side of this exhibit, a total of $167,327 was advanced in June 2005 for the construction of this particular project. Since customer advances are treated as taxable income by the Internal Revenue Service, the Company recorded a tax liability equal to approximately 40% of the amount advanced. By the end of 2005, a total of $102,797 had been expended on construction of the project, with this amount being recorded as CWIP on the Company's books. As may be seen, the Company's investment in the project, net of the customer advance and related tax liability, was $2,401 as of the end of the test year. The project was then completed and transferred to plant-in-service in the first quarter of 2006 at a total cost of $207,680. The Company's net investment at that time, only 90 days after the end of the test year, was $107,284. Assuming that new customers are added in sufficient numbers to allow for a partial repayment of the advance in 2007 and full repayment in 2008, the Company's net investment in the project will increase to $207,680 by the end of 2008. For the sake of simplicity, accruals of depreciation expense and deferred income tax expense were not included in this schedule.

Q. If CWIP is excluded from rate base, and Mr. Smith's recommendation on customer advances is adopted, how would this project be reflected in rate base?

A. The Company's test year rate base would be reduced by $167,327, despite having a net positive investment of $2,401 in the project.

Q. Did the Company continue to accrue AFUDC on the project after the end of the test year, thereby offsetting the impact of not having CWIP in rate base?

A. The Company did continue to accrue AFUDC on the project until it was completed in the first quarter of 2006. However, the amount of AFUDC recorded was quite small and ceased in its entirety by March 31, 2006.

Q. If CWIP is included in rate base as proposed by the Company, how would this project be reflected in rate base?

A. The CWIP balance of $102,797 would be included in rate base, offset by the $167,327 in customer advances. Although the Company would experience a net reduction to rate base of $64,530, this amount is considerably less than the rate base deduction that would result from Staff's recommended approach. Additionally, since the aggregate balance of test year CWIP exceeds the aggregate balance of test year advances by approximately $3 million, the Company's approach would result in a net increase to rate base with related benefits to both earnings and cash flow.

Q. Please summarize the aggregate impact on rate base associated with the Company's position and Staff's position on the issue of CWIP and customer advances.

A. Certainly. Exhibit KCG-17 provides a summary of the rate base impact under each proposal. As may be seen, the Company's proposal would increase rate base by approximately $3 million, reflecting the Company's $7 million investment in CWIP net of $4 million in related customer advances. In contrast, Staff's proposal would serve to reduce rate base by the $4 million balance of customer advances, a position that clearly penalizes the Company. At a minimum, if Staff still believes that CWIP should be excluded from rate base, the related $4 million balance of customer advances should not be used to reduce rate base. The last row of Exhibit KCG-17 reflects this adjustment to Staff's position.

Q. Does that conclude your response to the Surrebuttal Testimony of Mr. Smith?

A. Yes, it does.

III. <u>RESPONSE TO STAFF WITNESS DAVID PARCELL.</u>

Q. What aspects of Mr. Parcell's Surrebuttal Testimony are you addressing in your rejoinder Testimony?

A. I address several issues raised in Mr. Parcell's Surrebuttal Testimony. These issues include the proper use of and reliance on the CAPM, the risk of investing in UNS Gas relative to other gas distribution utilities, the appropriate capital structure for UNS Gas, and Mr. Parcell's recommendation concerning the appropriate ROR to be applied to FVRB.

Q. At page 2 of his Surrebuttal Testimony, Mr. Parcell refers to your "exclusive reliance" on the CAPM in formulating a cost of equity recommendation. Did you rely exclusively on your CAPM analysis and ignore the results of your DCF analysis?

A. No. As described in my Direct Testimony, I used both the CAPM and the DCF model to estimate the cost of equity for a comparable group of gas distribution utilities. I then compared the risk of UNS Gas relative to the comparable company group, and determined that the cost of equity for UNS Gas lies at the high end of the range for that group (9.5% to 11.0%). Although the results of the CAPM were used to establish the high end of this range, that does not mean I relied exclusively on the CAPM for purposes of recommending an appropriate ROE for UNS Gas.

Q. At pages 3 and 4 of his Surrebuttal Testimony, Mr. Parcell makes a case for using geometric mean returns to derive the market risk premium in the CAPM. Do you concur with Mr. Parcell's conclusion that both geometric mean returns and arithmetic mean returns should be considered?

A. No, I do not. As stated below in my response to RUCO witness William Rigsby, arithmetic mean returns are more relevant to investors when forming expectations of future investment returns. Mr. Parcell's references to the geometric returns published by mutual fund companies and Value Line are not particularly relevant, since they refer to past historical performance as opposed to future expected performance. As I have stated previously, it is common to use the compound or geometric average of investment returns when comparing the performance of different investments over historical time periods.

Q. At page 5 of his Surrebuttal Testimony, Mr. Parcell states that I refer to "size" as the "primary Company-specific risk factor" facing UNS Gas. Is that characterization accurate?

A. No, it is not. The small size of UNS Gas relative to other gas distribution utilities is only one of the factors I cited. In fact, I devoted significantly more discussion to the risks associated with high customer growth and regulatory lag.

Q. Should the allowed ROE for UNS Gas depend on who owns the Company's stock as Mr. Parcell advocates, or should it instead be based on the risks to which the capital is exposed?

A. The allowed return should be based on the risk to which the capital is exposed, and not on the identity of the shareholder making such an investment. Although UNS Gas is clearly part of a larger corporate family, the fact that UNS Gas is relatively small and faces other company-specific risks is just as relevant to UniSource Energy Corporation as it would be to any other potential shareholder of UNS Gas.

Q. At page 6 of his Surrebuttal Testimony, Mr. Parcell states that you offered "no reasons at all" why the Commission should adopt a hypothetical capital structure for UNS Gas. Is that statement accurate?

A. No, it is not. The reasons I offered for using a hypothetical capital structure may be found at pages 8 through 10 of my Direct Testimony. I found it encouraging that at least one party to this case, RUCO, was willing to consider my recommendation and adopt it as part of their filing.

Q. With regard to establishing a ROR on FVRB, Staff witnesses David Parcell and Ralph Smith repeatedly state that the Commission is not required to use the weighted average cost of capital applied to original cost rate base ("OCRB"). Is that your opinion as well?

A. Yes. My non-legal opinion is that the Commission has wide latitude in setting a reasonable ROR on fair value rate base. However, the ROR must still be adequate to support the credit of the Company and to allow it to access capital on reasonable terms.

Q. Why do you recommend using the weighted average cost of capital as the ROR on fair value rate base?

A. For two reasons. First, it seems to be the most straightforward solution to the issue raised by the Court of Appeals in the recent Chaparral case. Second, it will not result in a larger rate increase than originally requested by UNS Gas. That is because the Company is willing limit the rate increase to the amount it applied for last July.

Q. Mr. Parcell has recommending applying a zero percent cost of capital to the difference between FVRB and OCRB. Do you view his recommendation as being responsive to the recent Court of Appeals ruling?

A. No, I do not. Although I am not a lawyer, and am not offering a legal opinion, it apparent that this approach is mathematically equivalent to the approach previously used by Staff and expressly rejected by the Court of Appeals in the Chaparral case.

Q. At page 9 of his Surrebuttal Testimony, Mr. Parcell states that "...the cost of capital cannot be applied to the fair value rate base since there is no financial link between the two concepts." Do you agree with this statement?

A. No, I do not. The fair value of a utility's assets has a subtle, yet very real, impact on a utility's cost of capital. To the extent that fair value exceeds original cost, lenders will be more comfortable with the collateral securing their loans and will tend to extend more credit to the utility on better terms. Likewise, shareholders may be more willing to commit capital if they believe that fair value exceeds original cost by a substantial margin. That is because such value could potentially be unlocked through a sale of the Company, a sale of assets, or a spin-off of assets to shareholders. As a result, the cost of capital is likely lower for a utility having a fair value that is substantially higher than original cost. Since customers benefit from this lower cost of capital, it would not be unreasonable to allow shareholders to share a portion of this benefit as well.

Q. Does that conclude your response to the Surrebuttal Testimony of Mr. Parcell?

A. Yes, it does.

IV. RESPONSE TO RUCO WITNESS MARYLEE DIAZ CORTEZ.

Q. What issues raised by Ms. Diaz Cortez in her Surrebuttal Testimony do you care to address in this rejoinder Testimony?

A. My comments address that portion of her Surrebuttal Testimony pertaining to the rate base treatment of contributions in aid of construction ("CIAC"). Although UNS Gas did not raise the issue of CIAC in its Rebuttal Testimony, it appears that she views CIAC as being equivalent to customer advances, a topic the Company did raise in its Rebuttal Testimony. Additionally, I provide a brief response to the comments made by Ms. Diaz Cortez on the appropriate ROR to be applied to FVRB.

Q. Is CIAC the same as a customer advance?

A. No, it is not. A contribution in aid of construction is permanent and is recorded as a reduction to net plant at the time of the contribution. In contrast, a customer advance represents a form of financing, an amount that must be repaid to the developer if new customers are added over the timeframe specified by contract. If a sufficient number of new customers are not added by the time specified in the contract, then all or a portion of the advance will be retained by the utility and treated as a CIAC for accounting purposes.

Q. In what context did Ms. Diaz Cortez raise the issue of CIAC?

A. On page 8 of her Surrebuttal Testimony she discusses the treatment of CIAC as part of her discussion on CWIP in rate base. Based on her references to the Company's position on CWIP in rate base, I believe she is using the term CIAC interchangeably with customer advances.

Q. Assuming she is referring to the rate treatment of customer advances, do you agree with her position that all customer advances should serve to reduce rate base even if CWIP is excluded from rate base?

A. No, I do not. This issue was addressed previously in my Rebuttal Testimony, and was discussed above in response to the Surrebuttal Testimony filed by Staff witness Ralph Smith.

Q. At page 3 of her Surrebuttal Testimony, Ms. Diaz Cortez claims that the Company revised its original rate application to reflect the recent Court of Appeals ruling involving Chaparral City Water Company. Did the Company revise its original application as claimed by Ms. Diaz Cortez?

A. No. The Company is still seeking the rate relief it sought when the case was originally filed in July 2006. The only exception to this pertains to some minor downward adjustments that were explained by Mr. Dukes in his Rebuttal Testimony which caused our requested rate increase to fall from $9.647 million to $9.487 million. The discussion of the Chaparral case provided in my Rebuttal Testimony was not intended to generate additional rate relief above and beyond that originally requested by UNS Gas. Instead, my comments were offered under the belief that this recent court ruling will be at least relevant to the setting of a fair ROR for utilities operating under the Commission's rate authority.

Q. Does that conclude your response to the Surrebuttal Testimony of Ms. Diaz Cortez?

A. Yes, it does.

V. RESPONSE TO RUCO WITNESS WILLIAM A. RIGSBY.

Q. What aspects of Mr. Rigsby's Surrebuttal Testimony are you addressing in this Rejoinder Testimony?

A. There are four issues I wish to address. Specifically, I would like to address Mr. Rigsby's views on the appropriate long-term growth rates to be used in a discounted cash flow ("DCF") analysis, his views on the use of geometric versus arithmetic mean returns in calculating an appropriate risk premium to be used in the capital asset pricing model ("CAPM"), his position on the risk of investing in UNS Gas relative to other gas distribution utilities, and his characterization of the Company's proposal for a rate decoupling mechanism.

Q. At pages 6 through 9 of his Surrebuttal Testimony, Mr. Rigsby offers additional support for the widely divergent growth rates used in his constant growth DCF analysis. Do you concur with the views expressed in that section of his Testimony?

A. No, I do not. Instead of focusing on the issue of estimating dividend growth rates over the *long-run*, which I raised in my Rebuttal Testimony, Mr. Rigsby focuses his discussion on the divergence of utility growth rates over the *short-run*, and makes several comments that mischaracterize statements made in my Rebuttal Testimony. Contrary to Mr. Rigsby's assertions, nowhere in my testimony have I suggested that investors look at all gas utility stocks as being equivalent to one another. Just like Mr. Rigsby, I devoted a significant amount of time evaluating the risk profile and near-term growth estimates for each company included in my DCF analysis, and in fact used a very wide range of growth rates over the first five years of that analysis. However, where I differ with Mr. Rigsby is in the selection of sustainable *long-term* growth rates. Mr. Rigsby blindly assumes that a three to five-year growth rate will continue into perpetuity for each of the companies in his DCF analysis, irrespective of the fact that all of these companies are members of same regulated industry and are impacted by same macroeconomic factors affecting the United States economy as a whole.

Q. At pages 12 through 16 of his Surrebuttal Testimony, Mr. Rigsby provides a lengthy discourse on the merits of using geometric mean returns to quantify the expected market risk premium in the CAPM. Do you agree with his conclusion that geometric mean return data should be used when applying the CAPM?

A. No, I do not. And given that Mr. Rigsby has offered a numerical example to support his position, I feel compelled to offer an example of my own.

Q. What issues do you have with the numerical example provided at pages 13 and 14 of Mr. Rigsby's Surrebuttal Testimony?

A. First, the example used by Mr. Rigsby involves the loss of capital on an investment. Since rational investors do not *expect* to lose money on their investments, this example is of limited value in assessing future return expectations. Second, the example is self-fulfilling, since the investment returns (or losses) are presented on an ex post basis. As was previously discussed in my Rebuttal Testimony, the geometric average is commonly used to report historical return performance. However, that does not make it suitable for the calculation of a forward-looking risk premium in the CAPM.

Q. How would you adjust Mr. Rigsby's example to make it relevant to a discussion of expected future returns?

A. First, I would state the investor expectations on an ex ante basis. Second, I would describe the expected returns as a range of potential outcomes having an expected value that is positive. Third, in order to simplify the example as Mr. Rigsby did, I would express the range of expected annual returns as either a positive return or negative return, with a 50% probability of realizing either return in a given year. If these returns are expressed as either a 30% positive return or a 10% negative return, the expected return in any given year would be 10% positive, calculated as follows:

$$\text{Expected annual return} = (30\% \times 0.5) + (-10\% \times 0.5)$$
$$= 15\% - 5\%$$
$$= 10\%$$

Over a two year period, if \$100 is invested at the outset, the range of expected outcomes would be as follows, listed from best to worst:

$$\text{Outcome 1} = \$100 \times (1.30) \times (1.30) = \$169$$
$$\text{Outcome 2} = \$100 \times (1.30) \times (0.90) = \$117$$
$$\text{Outcome 3} = \$100 \times (0.90) \times (1.30) = \$117$$
$$\text{Outcome 4} = \$100 \times (0.90) \times (0.90) = \$81$$

Since each outcome has a 25% chance of occurring, the expected outcome on a probabilistic basis is \$121, calculated as follows:

$$\text{Expected Outcome} = (\$169 \times 0.25) + (\$117 \times 0.25) + (\$117 \times 0.25) + (\$81 \times 0.25)$$
$$= \$121$$

The annual rate of return corresponding to this expected outcome is 10%, which represents the arithmetic average of the expected annual returns of 30% and minus 10%. This is demonstrated as follows:

$$\text{Expected Outcome} = \$100 \times 1.10 \times 1.10 = \$121$$

By contrast, if the geometric average of expected annual returns is used to forecast expected outcomes, the expected ending value will be understated on a probability-weighted basis. That is because the geometric average of 8.2% (calculated below) produces an expected ending value of only \$117:

$$\text{Geometric Average Return} = (1.30 \times 0.90)^{1/2} - 1.0$$
$$= (1.17)^{1/2} - 1.0$$
$$= .082$$

$$\text{Expected Outcome} = \$100 \times 1.082 \times 1.082$$
$$= \$117$$

As demonstrated by this simple example, use of the arithmetic mean return is more relevant to an investor when forming expectations of future potential returns. Use of the geometric mean return, on the other hand, serves to understate the future expected returns on a probability-weighted basis, and is more relevant to a calculation of historical investment returns.

Q. At pages 10 through 12 of his Testimony, Mr. Rigsby dismisses the additional risks faced by UNS Gas relative to other gas distribution utilities. Are these risks real and relevant to the setting of an allowed ROR for UNS Gas?

A. Yes, these additional risks are both real and relevant to the setting of a reasonable ROR for UNS Gas. Unfortunately, Mr. Rigsby would prefer to ignore these risks and avoid any discussion of how to quantify the cost of this risk. For example, at page 10 of his Surrebuttal Testimony (lines 19 through 23), Mr. Rigsby states 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." He goes on to state that "If a utility's management can't deal with that fact of life then they should consider getting into another business."

Q. Has UNS Gas attempted to quantify the financial burden associated with high customer growth and regulatory lag?

A. Yes. Included in both my Direct and Rebuttal Testimony are tables demonstrating the extraordinary amount of growth in net plant investment that has occurred in order to meet customer growth and to maintain a highly reliable gas distribution system. Additionally, I have provided financial forecasts demonstrating that it is highly unlikely that UNS Gas will actually be able to earn its requested ROE, even if the Company's rate request is granted in its entirety. I have also provided an analysis, contained in Exhibit KCG-10 attached to my Rebuttal Testimony, that demonstrates the short-term financial impact of high plant growth and regulatory lag on UNS Gas. Although this growth can be beneficial over the long-term, as described in my Rebuttal Testimony, it is clearly detrimental to UNS Gas over the short-run due to the use of an historical test year to set rates. As a consequence, I do not find Mr. Rigsby's comments on the subject of growth to be particularly helpful.

Q. What are the consequences of earning a below-market ROE?

A. If a firm cannot earn its cost of capital on new capital investments, investors will pull out of the firm and deploy their capital elsewhere. If a firm continues to under-earn on its capital investments, the market value of the firm will shrink and the cost of capital will eventually rise in response to a weakened financial profile. From the standpoint of a regulated utility, an increasing cost of capital and a weakened financial profile are not in the best interest of consumers. As a consequence, even if Mr. Rigsby is not concerned about making "tough luck" comments aimed at management, he should be concerned about how such comments are perceived by investors.

Q. Do you have any other observations regarding the impact of growth and regulatory lag on UNS Gas?

A. Yes. Prompted in part by the comments of Mr. Rigsby, as well as the Surrebuttal Testimony of Staff witness Ralph Smith, the Company examined growth rate data for the three largest investor-owned utilities in Arizona. The results of that examination are contained in Exhibit KCG-15. The source data for this exhibit was taken from Securities and Exchange Commission filings and from SNL DataSource, a financial database containing publicly available information on investor-owned utilities.

As may be seen in Exhibit KCG-15, since 1995 the compound annual growth rate in net plant investment has ranged from a low of 3.7% for Tucson Electric Power Company ("TEP") to a high of 8.1% for Southwest Gas Corporation ("SWG"). By contrast, the compound annual growth rate for UNS Gas was 10.6% over the past three years and is forecasted to be 11.0% over the next three years. In terms of absolute growth over the past three years, the growth in net plant investment has ranged from a low of 11.6% for TEP to a high of 28.9% for Arizona Public Service Company ("APS"), a value inflated by the recent transfer of the Redhawk and West Phoenix generating facilities to APS. By contrast, UNS Gas has experienced a 35.4% increase in net plant investment since December 2003.

On a per-customer basis, the growth in net plant investment experienced by UNS Gas is even more pronounced. Since 1995 the compound annual growth in net plant investment per customer has ranged from a low of 0.9% for APS to a high of 2.6% for SWG. By contrast, UNS Gas has experienced a compound growth rate of 6.0% over the past three years and is forecasted to be 6.1% over the next three years. In terms of absolute growth over the past three years, the growth in net plant investment per customer has ranged from a low of 3.1% for SWG to a high of 14.3% for APS. By contrast, UNS Gas experienced a 19.1% increase in net plant investment per customer since December 2003.

The key point to be made here is that UNS Gas is growing substantially faster than any of the major investor-owned utilities in Arizona when measured in terms of net plant investment. On an absolute basis, this growth rate indicates a substantial need for new debt and equity capital. On a per-customer basis, this growth rate indicates the severity of the financial challenge faced by UNS Gas in a regulatory jurisdiction that requires the use of an historical test year and embedded cost pricing principles.

Q. **On page 10 of his Surrebuttal Testimony, Mr. Rigsby states that the implementation of a rate decoupling mechanism would "...remove all of the risk associated with operating income volatility," and implies that UNS Gas is seeking a "guaranteed return on investment." Are those statements accurate?**

A. No, they are not. While the proposed rate decoupling mechanism is designed to *reduce* the volatility of operating income, it cannot *eliminate* operating income volatility nor provide UNS Gas with a "guaranteed" return on investment. The Company would still be at risk for its recovery of operation and maintenance expenses, property taxes and depreciation expense. Additionally, UNS Gas would also be at risk for the return requirements on new capital investment. The proposed decoupling mechanism only serves to provide additional assurance that the Company will actually be able to collect the delivery revenues determined to be appropriate in this proceeding, based on costs and usage levels for the test year ending December 31, 2005.

Q. Have the rating agencies commented on the credit implications of rate decoupling mechanisms?

A. Yes, they have. In June 2006 Moody's Investors Service provided substantial commentary on the credit rating implications of rate decoupling mechanisms. A copy of that report is attached as Exhibit KCG-18 to this Rejoinder Testimony. On the first page of that report, Moody's offers the following observation:

> "LDCs (local distribution companies) that have, or soon expect to have, RD (revenue decoupling) stand a better chance than others in being able to maintain their credit ratings or stabilize their credit outlook in face of adversity. This difference between those companies that have RD and those that do not will tend to be further accentuated as the credit demarcation reflected through rating actions becomes more evident."

On page 4 of that same report, Moody's goes on to describe the problems associated with traditional gas utility rate design:

> "In attempting to grapple with the conservation issue, LDCs are in fact, having to dispel the notion that their fixed charges should be recovered from volumetric sales of gas. As the fixed charges appear year in and year out regardless of gas usage, the volumetric approach to cost recovery for operating a gas distribution system is a faulty equation which needs to be rectified in ratemaking. It would appear, therefore, that unless and until this anomaly is corrected, the LDC would lack the necessary tools with which to earn its allowed rate of return."

Later in that same report, Moody's makes reference to several utilities that have already received regulatory approval for rate decoupling mechanisms, and to others who are in the process of applying for this rate treatment.

Q. If the Company's rate decoupling mechanism is approved by the Commission, would a reduction to the Company's allowed ROE be warranted as suggested by Mr. Rigsby?

A. No. At least four of the companies in my comparable company group already have rate decoupling mechanisms, and at least three others have weather normalization clauses that adjust revenues to compensate for abnormal sales levels due to weather conditions. Even if a rate decoupling mechanism is approved, an equity investment in UNS Gas would still be much riskier than most gas utilities due to the Company's small size, the combined effects of high customer growth and regulatory lag, and the lack of any common dividend payment. On the contrary, if the Commission were to leave the Company's volumetric rate design largely intact, I would recommend an even higher ROE for use in this proceeding.

Q. Does that conclude your response to the Surrebuttal Testimony of Mr. Rigsby?

A. Yes, it does.

VI. CONCLUSION.

Q. Mr. Grant, do you have any concluding remarks?

A. Yes, I do. It should be abundantly clear by this point that UNS Gas is facing an extraordinary challenge in meeting the growth occurring on its system. It is because of this growth, as well as increases in both operating and capital costs, that the Company is seeking a rate increase at this time. As discussed, a critical component of the Company's rate request is the proposal to include the test year balance of CWIP in rate base. This request should be granted based on the need to maintain continued access to capital on reasonable terms. Additionally, in light of the company-specific risks faced by UNS Gas, it would be reasonable to grant the Company an allowed ROE that is higher than the returns awarded to larger and more established publicly traded utilities. Finally, substantial changes to the Company's rate design are also warranted. Due to high natural gas prices, customer conservation and highly variable weather conditions, it is becoming increasingly difficult for UNS Gas to maintain an adequate and consistent level of earnings and cash flow under a volumetric rate design.

Q. Does this conclude your Rejoinder Testimony?

A. Yes, it does.

EXHIBIT

KCG-15

Growth Rates Experienced by Arizona Utilities

Southwest Gas Corporation

	Net Plant ($ Millions)	Customers	Investment per Customer
1995	$1,138	985,043	$1,155
1996	$1,278	1,044,506	$1,224
1997	$1,360	1,104,060	$1,232
1998	$1,459	1,162,831	$1,255
1999	$1,581	1,224,770	$1,291
2000	$1,686	1,289,104	$1,308
2001	$1,826	1,348,970	$1,354
2002	$2,034	1,407,286	$1,445
2003	$2,176	1,467,752	$1,483
2004	$2,336	1,550,509	$1,507
2005	$2,489	1,645,004	$1,513
2006	$2,668	1,745,125	$1,529
Compound Annual Growth Rate (1995 - 2006)	8.1%	5.3%	2.6%
Absolute Growth Over Last 3 Years (2003 - 2006)	22.6%	18.9%	3.1%

Arizona Public Service Company

	Net Plant ($ Millions)	Customers	Investment per Customer
1995	$4,647	704,993	$6,592
1996	$4,655	737,504	$6,312
1997	$4,678	766,531	$6,103
1998	$4,731	796,410	$5,940
1999	$4,753	826,935	$5,748
2000	$4,910	864,990	$5,676
2001	$5,059	892,805	$5,666
2002	$5,886	921,251	$6,389
2003	$6,070	953,251	$6,368
2004	$6,258	989,502	$6,324
2005	$7,525	1,033,423	$7,282
2006	$7,827	1,075,191	$7,280
Compound Annual Growth Rate (1995 - 2006)	4.9%	3.9%	0.9%
Absolute Growth Over Last 3 Years (2003 - 2006)	28.9%	12.8%	14.3%

Growth Rates Experienced by Arizona Utilities

Tucson Electric Power Company

	Net Plant ($ Millions)	Customers	Investment per Customer
1995	$1,125	302,517	$3,719
1996	$1,117	310,950	$3,592
1997	$1,116	316,895	$3,522
1998	$1,114	324,866	$3,429
1999	$1,293	334,137	$3,869
2000	$1,298	342,914	$3,786
2001	$1,299	350,938	$3,701
2002	$1,480	359,372	$4,118
2003	$1,506	367,239	$4,101
2004	$1,538	375,532	$4,096
2005	$1,616	384,898	$4,199
2006	$1,681	392,477	$4,283
Compound Annual Growth Rate (1995 - 2006)	3.7%	2.4%	1.3%
Absolute Growth Over Last 3 Years (2003 - 2006)	11.6%	6.9%	4.4%

UNS Gas, Inc.

	Net Plant ($ Millions)	Customers	Investment per Customer
2003	$144	127,577	$1,129
2004	$161	133,403	$1,207
2005	$177	138,797	$1,275
2006	$195	145,052	$1,344
2007 Fcst.	$225	150,962	$1,490
2008 Fcst.	$249	158,439	$1,572
2009 Fcst.	$267	166,453	$1,604
<u>Compund Annual Growth Rates</u>			
2003-2006	10.6%	4.4%	6.0%
2006-2009 Fcst.	11.0%	4.7%	6.1%
<u>Absolute Growth</u>			
2003-2006	35.4%	13.7%	19.1%
2006-2009 Fcst.	36.9%	14.8%	19.3%

EXHIBIT

KCG-16

Exhibit KCG-16

UNS Gas, Inc.
Example of Construction Project Funding with Customer Advances

Event	Event Timeline	Date	CWIP	Plant in Service	Advance	Tax Liab. on Advance	Net Investment
			Net Investment in Project by UNS Gas, Inc.				
Developer Advances Funds to UNS Gas for Construction of Distribution Facilities	2Q 2005	6/30/2005	$ -	$ -	$ (167,327)	$ 66,931	**$ (100,396)**
UNS Gas Constructs Distribution Facilities with Funds Advanced from Developer	3Q 2005 Through 1Q 2006	12/31/2005	$ 102,797	$ -	$ (167,327)	$ 66,931	**$ 2,401**
Distribution Facilities Completed & Recorded as Plant in Service	1Q 2006	3/31/2006	$ -	$ 207,680	$ (167,327)	$ 66,931	**$ 107,284**
Advance is Repaid to Developer as New Customers are Added	2006 Through 2008	12/31/2007	$ -	$ 207,680	$ (83,664)	$ 33,465	**$ 157,482**
Entire Balance of Advance is Repaid per Terms of Contract (Development is Completed)	2008	12/31/2008	$ -	$ 207,680	$ -	$ -	**$ 207,680**

$$ $$ $$

EXHIBIT

KCG-17

Exhibit KCG-17

UNS Gas, Inc.
Impact of CWIP and Customer Advances on Test Year Rate Base

	Balance of CWIP	Balance of Advances Related to CWIP	Net Impact on Rate Base
Company Proposal	$ 7,189,231	$ (4,158,264)	$ 3,030,967
Staff Proposal	$ -	$ (4,158,264)	$ (4,158,264)
Staff Proposal Adjusted for Customer Advances	$ -	$ -	$ -

EXHIBIT

KCG-18

Special Comment

June 2006

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Local Gas Distribution Companies: Update on Revenue Decoupling And Implications for Credit Ratings

Summary Opinion

- With natural gas prices expected to remain at high levels, local gas distribution companies (LDCs) face earnings and cash flow pressures as their customers increase conservation efforts. In addition, bad debt expense has increased as more customers face increasing difficulties in paying their bills. Furthermore, LDC volumes remain subject to weather conditions.
- Moody's analyzed its gas LDCs (local distribution companies) and notes that weather normalized winter gas consumption in per customer usage has declined at an increased pace since 2003. This decline coincides with a period of steadily rising natural gas prices for the LDCs and steadily falling heating degree days.
- Had gross margins (gas revenues less cost of gas and associated gas taxes) been fully protected against gas consumption declines on account of customer conservation during the past five winters, they would have been higher by an average of $5.2 million in 2004 and $4.6 million in 2005. One company would have increased its profits by $18.3 and $11.6 million in those two years (3% and 2% of gas margins, respectively).
- Bad debt expense has shown a steady average increase in each of the past four winters, tracking the increase in natural gas prices during the same period.
- Despite the general increase in working capital and natural gas prices, LDC short-term debt has remained relatively flat from 2003-2005.
- Except for a handful of jurisdictions that employ full revenue decoupling (RD) through a mechanism akin to "balancing accounts" (California, Maryland and North Carolina), most companies prefer to keep the weather normalization clause (WNC) rate design separate from the conservation margin tracker.
- While some jurisdictions permit the application for RD to be requested outside the procedural norms of a full rate case, most would prefer a full rate case or rate review.
- LDCs pursuing a full or partial RD feel that it is an important aspect of their rate design requirements and most companies indicated that they would continue filing for it until their regulators gave final approval.
- Moody's observes that in the face of volatile natural gas prices, volatile weather patterns and other exogenous forces that would prompt gas customers to curtail gas consumption volumes from their utilities, LDC earnings and credit metrics will come under pressure.
- LDCs that have, or soon expect to have, RD stand a better chance than others in being able to maintain their credit ratings or stabilize their credit outlook in face of adversity. This difference between those companies that have RD and those that do not will tend to be further accentuated as the credit demarcation reflected through rating actions becomes more evident.

Moody's Investors Service
Global Credit Research

Introduction

At this time last year, Moody's published its first study dedicated to the question of gas conservation and its impact on gas LDC earnings and credit ratings (see Moody's June 2005 Special Comment titled *Impact of Conservation on Gas Margins and Financial Stability in The Gas LDC Sector).* We found that while many companies were aware of the conservation factor and 18 of the 34 gas LDCs followed by Moody's could quantify the loss in their per customer volume consumption, only a handful of companies had taken the step to incorporate it into their rate design so that their gross margins would be unaffected. Last year we also discussed how three companies were approaching this rate design feature through slightly different decoupling mechanisms. While the approach may be different, the concept and end result are not. Companies in the gas utility business are increasingly interested in not only protecting themselves against gross margin variations caused by customer conservation (partial decoupling), but also by weather variations (full decoupling).

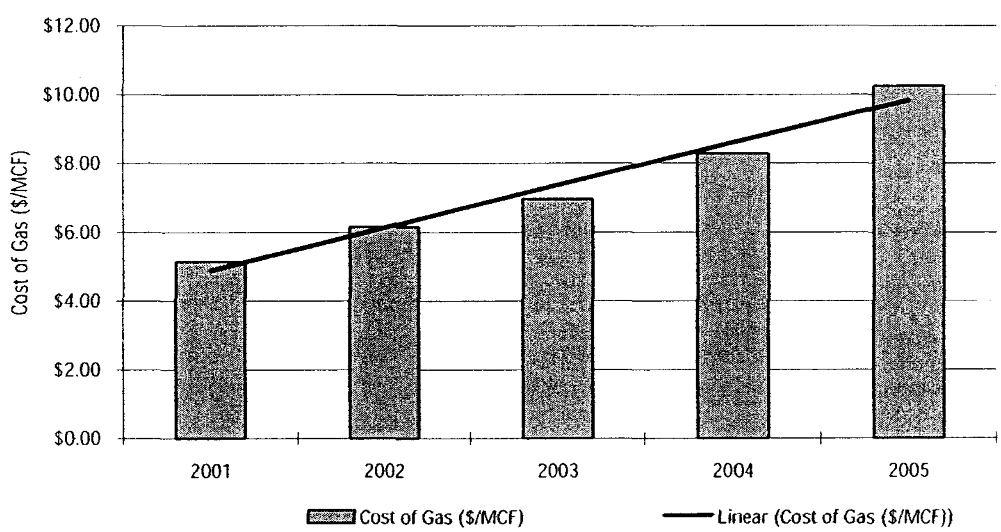
In keeping with the evolving convention, we will refer to these mechanisms as revenue decoupling (RD) in general terms and to "partial decoupling" to mean rate design protection for conservation or "full decoupling" to mean rate design protection for both conservation and weather variations. When a company only has weather normalization clause protection, we refer to the rate design as WNC. Fewer companies have conservation rate design protection without also having WNC as permanent features of their ratemaking.

As with our previous study, we define "conservation" as any technical advancement that improves home heating or gas appliance efficiencies as well as the curtailment of consumption on account of high gas commodity prices. Twenty three of the 34 gas LDCs followed by Moody's responded to various questions posed by Moody's and their results have been tabulated and presented in this paper in aggregate form in order to protect the confidentiality of information submitted.

Nationwide Trend of Rising Gas Prices and Falling Heating Degree Days

Companies overall responded that they were experiencing rising natural gas prices during the past five winter heating seasons, with their average gas purchase prices depicted in the graph below and labeled Increase in Cost of Gas (Fig.1). Natural gas prices rose by a compounded average growth rate of 17% during this period, with the sharpest rise occurring in the winter of 2005 (most recent winter heating season) where it registered an average price increase of 24% over 2004. The highest price recorded by an LDC during this past winter was $13.31/mcf and lowest $6.73/mcf with $10.70 being the median. While only half the respondents provided natural gas price estimates for 2006, those that did resulted in an average price of $10.71/mcf with $13.87/mcf being the highest, $8.61/mcf being the lowest and $10.59/mcf being the median. Most LDCs expect future natural gas prices to moderate, but the trend is still in an upwards direction and this has been found to be the prime driver for the conservation factor on the part of customers.

Figure 1
Increase in Cost of Gas to LDCs

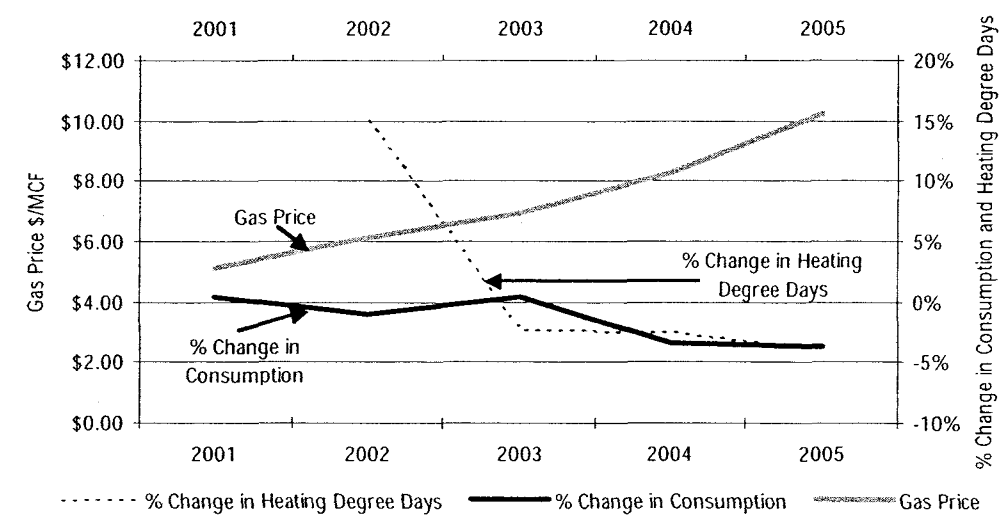


The other noticeable trend is that of falling heating degree days since the winter of 2002 among the responding LDCs. On average, the winter of 2002 appears to have been a fairly cold winter, but the number of heating degree days has since fallen by an average of 3-5% in each of the winter heating seasons since that year. LDCs lacking a WNC or full decoupling mechanism would have suffered in their gas consumption and gross margins when faced with the strong combination of warmer than normal winters and declining gas consumption on account of customer conservation.

Finally, except for a period in 2003 when the average customer consumption increased by .5%, the per customer consumption for residential and commercial users has fallen by 3-4% in each of the last two winter heating seasons on a weather normalized basis, representing that portion of loss in gas consumption resulting from conservation. Changes in gas prices are plotted against percentage changes in per customer consumption and heating degree days in Fig. 2. We note that while the change in per customer consumption on account of conservation has been declining since the 2003 winter heating season at a rate of 3-4% p.a., gas prices have continued to rise much more rapidly.

Figure 2

Gas Price vs. % Change in Consumption and Heating Degree Days



The winter of 2005 saw the most dramatic rise in both natural gas prices and also per customer gas consumption decline on account of conservation (4% average decline). The weather normalized consumption decline for the last winter ranges from 9.1% in the case of one LDC to a gain of 3.1% in another, as it had colder winter weather in 2005 compared with 2004. With the exception of another LDC that had no loss in consumption, all the other respondents had declines in gas consumption. Similarly, except for one LDC which experienced an increase in per customer consumption in 2004 of 1.2%, all others saw declines in per customer consumption from 2003 which ranged from -0.2% to -9.6%.

Impact of Conservation on Losses in Gross Margin

When LDCs were asked how much higher would their gross margins (gas revenues less cost of gas purchased and associated gas taxes) have been had they been fully protected against declines in gas consumption resulting from conservation, all indicated higher gross margins for the last two winter heating seasons. The average gross margins would have increased from a low of $2.4 million in 2003 to a high of $5.2 million in 2004, with one company indicating that they would have gained $18.3 million in 2004 alone and $11.6 million in 2005, where the average company stood to gain an additional $4.6 million in gross margin.

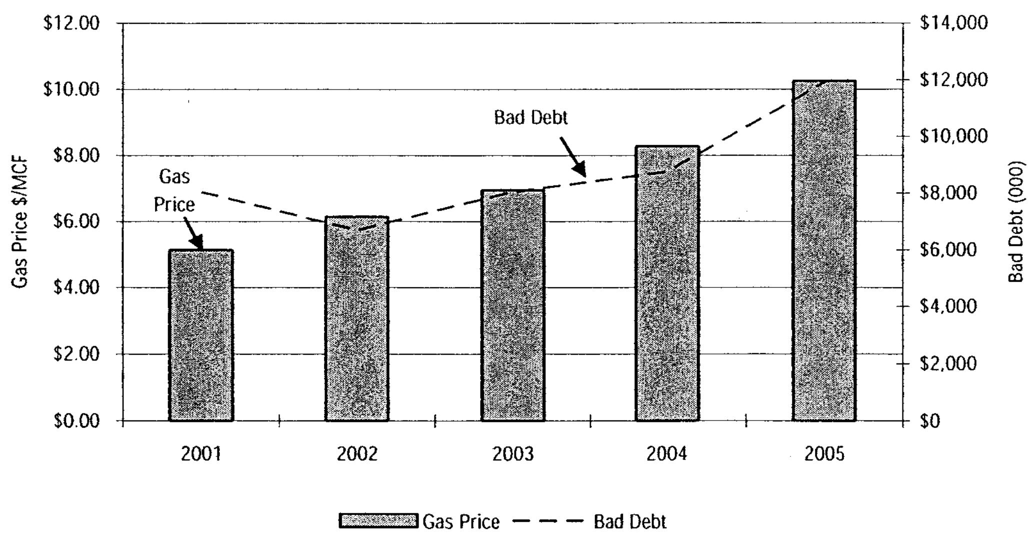
The problem of declining gross margins on account of per customer conservation is explained by the various rate filings and testimonies being offered by consultants on the subject. Symptomatic of the LDC conservation problem is the argument for incorporating a conservation protection design. For example, Questar Gas Company believes that earning its authorized return has been very difficult due to the combination of declining average consumption over time, the use of a historical test year in general rate cases, and the fact that most of its fixed-non-fuel costs are recovered through a volumetric charge. The upshot has been revenues that in normal weather years have fallen short of their own non-gas costs---because average-customer sales in the rate-effective years fell short of the (historical) test-year figures that were used to set rates. Questar would like to decouple its non-gas revenues from year-to-year movements in the per-customer average consumption levels. The mechanics of the decoupling would employ a balancing account to recover non-gas related revenues lost/gained when average consumption drops/rises above the projected average.[1]

In attempting to grapple with the conservation issue, LDCs are in fact, having to dispel the notion that their fixed charges should be recovered from volumetric sales of gas. As the fixed charges appear year in and year out regardless of gas usage, the volumetric approach to cost recovery for operating a gas distribution system is a faulty equation which needs to be rectified in ratemaking. It would appear therefore, that unless and until this anomaly is corrected, the LDC would lack the necessary tools with which to earn its allowed rate of return.

Bad Debt Expense and Increases in Working Capital

One consequence of rising natural gas prices purchased by LDCs and passed onto their customers is the higher level of bad debt expense and increases in working capital that these companies must now contend with. In the winter of 2005 for example, one LDC reported a doubling of their bad debt expense which increased by an average of 17% for all respondents. LDCs in some states such as those located in North Carolina, had the good fortune of being able to recover the gas component of bad debt expense through their purchase gas adjustment (PGA) mechanism, thereby reducing the level of bad debt expense that the company had to absorb on their own. Fig. 3 depicts the close correlation between rising average bad debt expenses and rising gas prices.

Figure 3
Gas Price vs. Bad Debt

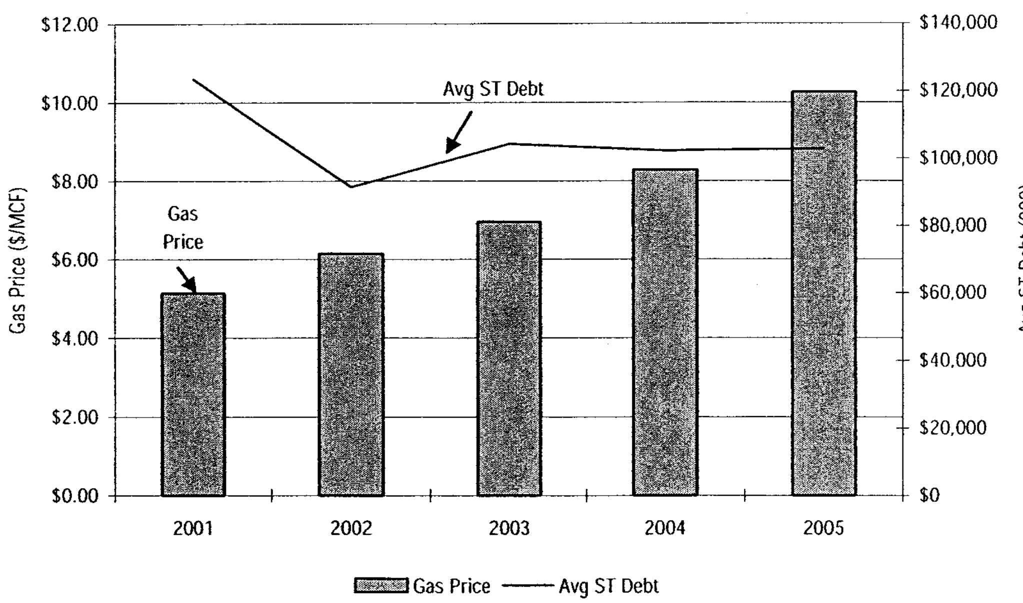


1. *Prefiled Direct Testimony of George R. Compton, Ph.D., for the Division of Public Utilities of the Utah Department of Commerce, Before the Public Service Commission of Utah, January 23, 2006, Docket No. 05-057-T01*

As one would expect, with the higher level of gas commodity prices that customers had to pay and the rise in bad debt expense experienced during the past three winter heating seasons, most LDCs incurred higher levels of working capital. The winter of 2005 witnessed one of the sharpest increases in seasonal working capital on account of accounts receivables and inventory build-ups related to higher natural gas prices, rising 136% over 2004 levels among those LDCs responding to affirmative increases in working capital levels. One large LDC reported a 185% increase in their 2005 working capital level over the prior year. Some companies however, were able to match their increases in accounts receivables and inventory with accounts payable by structuring their gas purchase transactions to more closely match their gas payments for inventory and timing these closer to the anticipated cash receipts from customers, so that they had less working capital to finance.

It is also interesting to note, as depicted in Fig. 4, that on average, LDC short term debt remained relatively flat after 2003 despite the continuing rise in the cost of natural gas prices. Some companies indicated that they were deliberately refinancing short-term debt through medium term notes or through other means of long-term debt by locking in the cost of financing under favorable interest rates, while others were able to contain the increases in their 2005 working capital levels and did not need to borrow as much for their seasonal needs. In fact, approximately half the LDCs indicating having higher levels of working capital in 2005 compared with prior years were able to reduce their short-term debt levels by refinancing via long-term debt or issuance of new equity.

Figure 4
Gas Price Vs. Avg Short Term Debt Outstanding



LDCs Take Varied Approaches in Integrating WNC with RD

It appears that LDCs that already have full RD similar to the "balancing accounts" including revenue normalization adjustments or customer utilization trackers being employed in certain jurisdictions such as California, Maryland and North Carolina, prefer to keep their rate designs intact as they are easily administered and allow for full recovery of their authorized margins. Most other companies that currently have WNC in some of their jurisdictions however, prefer to keep the conservation margin tracker or tariff separate, for the reason that their current WNC provide real time cash flow and earnings adjustments whereas the conservation trackers typically provide after-the-fact cash flow adjustments through deferral accounts that are collected over a subsequent 12-month period.

While some public utility commissions would permit the filing of RD outside the procedural norm of a full rate case, most would clearly prefer a full rate case to be filed in connection with a rate design alteration or at least to review a general rate case after-the-fact in short order. It also appears that the great majority of respondents experiencing customer gas consumption declines on account of conservation would be inclined to file and re-file for some form of RD if denied the first time by their regulators. For many, this is a long but necessary trek to take as a means of curing a rate design deficiency that appears to be increasingly untenable.

Conclusion

In our comment last year, we mentioned several LDCs that had the ability to correct for margin losses on account of conservation or weather variables through their rate design mechanisms, or had RD filing plans or extension plans. Among these, Alabama Gas Corporation (Alagasco) advises that their "rate stabilization and equalization" mechanism will continue through at least 2008 and Southern California Gas Company (SoCal Gas) appears to be satisfied with how their "balancing accounts" have been implemented previously and have requested that the regulatory commission continue with them going forward. Following the completion of an independent study to measure the effectiveness of its conservation mechanism, Northwest Natural Gas Company was able to obtain approval of the Oregon Public Utility Commission in 2005 to continue its conservation tariff for an additional four years through September 30, 2009, and increase the mechanism's coverage from a partial decoupling of 90% of residential and commercial gas usage to a full decoupling of 100%. It also maintains a separate weather normalization mechanism that was extended through September 2008.

In April of 2006, Cascade Natural Gas Corporation in Washington State obtained approval from the Oregon Public Utility Commission to implement a decoupling mechanism to track changes in margin due to conservation (variations in weather-normalized usage) and to track changes in margin due to weather variations from normal for residential and commercial customers. Cascade's RD application for Washington State is still pending.

Piedmont Natural Gas in North Carolina obtained approval for a full RD mechanism for a three-year trial period, with the state's Attorney General appealing the decision in the courts. The appeal has been initiated and the court has taken no action. In the meantime, the company has implemented the mechanism effective November 1 of 2005.

Washington Gas Light Company obtained a full RD (Revenue Normalization Adjustment) in its Maryland jurisdiction which went into effect on October 1, 2005. It has previously attempted to introduce at least partial RD in its Virginia and Washington D.C. jurisdictions.

Southwest Gas Corporation did not fare as well in its Arizona RD application where it generates 54% of its gross margin. The company's credit metrics were already weaker than its Baa utility peers and it badly needed an effective RD mechanism across all its jurisdictions to protect its gross margins. While the Arizona Corporation Commission finally granted it a partial rate increase after over one-year in the application process and brought current recent cost and customer usage factors in Arizona, it denied the company its request for RD through "balancing accounts" as it has in California. The company also lacks RD in its Nevada jurisdiction (37% of gross margins) and the company lost gross margins in 2005 when it experienced one of the 10 warmest years on record, which followed a warm 2003, one of the warmest years in over 100 years. The cumulative effects of this warmer than normal weather continued into the company's quarter ending March 31, 2006 which was mostly responsible for the company's loss of $9 million in operating margin. Moody's took action in May 2006 to downgrade the company's senior unsecured debt to Baa3 from Baa2 where it is currently under stable outlook.

In the meantime, the list of LDCs applying for RD continues to expand with Atmos Energy Corporation attempting to add conservation riders in key jurisdictions where it already has WNC, Indiana Gas Company and Southern Indiana Gas and Electric Company (utility subsidiaries of Vectren Utility Holdings) both applying for conservation margin protection in Indiana to supplement their recently approved WNC, and Questar Gas Corporation seeking a conservation tariff in Utah. New Jersey Natural Gas and South Jersey Gas Company filed for a joint RD application in New Jersey, requesting a full decoupling mechanism. Both of these New Jersey utilities already have WNC.

Moody's believes that the LDCs successful in their RD initiatives will stand a better chance than others in protecting their gross margins and overall credit metrics from the negative impacts of increasing volatility of natural gas prices and climatic changes. Stronger margins and earnings would also serve to cushion the blows inflicted by increases in bad debt expense that tend to accompany rising gas prices. As gas customers step up their conservation efforts in response to these rising commodity prices, it will become increasingly important for LDCs to switch from a gas volumetric cost recovery methodology to one of RD. While RD may have originally begun as a regional concept in certain jurisdictions, it has quickly become a nationwide phenomenon that will challenge regulators and gas utilities alike, as they seek to correct a structural imbalance in their rate design that has become increasingly difficult to ignore.

Related Research

Special Comments:

Impact of Conservation on Gas Margins and Financial Stability in the Gas LDC Sector, June 2005 (92798)

Comparative ROE Attributes of US Local Gas Distribution Companies, July 2004 (87301)

Negative Rating Trend for Local Gas Distribution Companies: Impact of Diversifications and Warm Weather, October 2002 (76344)

To access any of these reports, click on the entry above. Note that these references are current as of the date of publication of this report and that more recent reports may be available. All research may not be available to all clients.

To order reprints of this report (100 copies minimum), please call 1.212.553.1658.
Report Number: 98022

Author	Editor	Associate Analysts	Senior Production Associate
Edward Tan		*Sharon Roberts* *Jacquelyn Ward*	*Charles Ornegri*

UNS Gas, Inc.
Estimate of Contributions in Aid of Construction from New Service Requests

	Actual		Forecast					
	2005	2006	2007	2008	2009	2010	2011	2012
A. Based on UNS Gas Rate Filing								
New Service Lines	**5,568**	**5,443**	**5,700**	**7,100**	**7,500**	**7,300**	**8,000**	**7,200**
Avg. Length of New Service	46.7	42.5	42.5	42.5	42.5	42.5	42.5	42.5
New Service Footage	259,847	231,427	242,250	301,750	318,750	310,250	340,000	306,000
Per Foot Charge	$8.00	$8.00	$12.00	$16.00	$16.00	$16.00	$16.00	$16.00
Contributions Before ICS Allowance	$2,078,776	$1,851,416	$2,907,000	$4,828,000	$5,100,000	$4,964,000	$5,440,000	$4,896,000
ICS Allowance	($351,584)	($449,090)	($726,750)	($1,207,000)	($1,275,000)	($1,241,000)	($1,360,000)	($1,224,000)
Contributions Net of ICS Allowance	**$1,727,192**	**$1,402,326**	**$2,180,250**	**$3,621,000**	**$3,825,000**	**$3,723,000**	**$4,080,000**	**$3,672,000**
ICS Allowance as % of Contribs.	16.9%	24.3%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%
Avg. Contribution per Service Line	**$310**	**$258**	**$383**	**$510**	**$510**	**$510**	**$510**	**$510**
B. Amendment to Reflect Elimination of ICS Allowance								
Net Contributions from Above	$1,727,192	$1,402,326	$2,180,250	$3,621,000	$3,825,000	$3,723,000	$4,080,000	$3,672,000
Elimination of ICS Allowance on Service Lines			$726,750	$1,207,000	$1,275,000	$1,241,000	$1,360,000	$1,224,000
Contributions with Additional Changes			**$2,907,000**	**$4,828,000**	**$5,100,000**	**$4,964,000**	**$5,440,000**	**$4,896,000**
Avg. Contribution per Service Line			**$510**	**$680**	**$680**	**$680**	**$680**	**$680**
C. Amendment to Charge for Excess Flow Valve Installation								
Net Contributions from Above	$1,727,192	$1,402,326	$2,180,250	$3,621,000	$3,825,000	$3,723,000	$4,080,000	$3,672,000
Charge for Excess Flow Valve Installation (1)				$887,500	$1,875,000	$1,825,000	$2,000,000	$1,800,000
Contributions with Additional Changes			**$2,180,250**	**$4,508,500**	**$5,700,000**	**$5,548,000**	**$6,080,000**	**$5,472,000**
Avg. Contribution per Service Line			**$383**	**$635**	**$760**	**$760**	**$760**	**$760**

(1) Assumes average cost of $250 per service line. Installation required beginning July 2008.

SECTION NO. 7
EXTENSION OF LINES
(continued)

2. At its option, the Company may require a performance bond or other surety guaranteeing bona fide operation of the facility for which the extension is requested, in accordance with Applicant's representation in the contract.

3. Master Meter Extensions – If the residential Customers are tenants in a fully improved master-metered mobile home park ("MMP") and the MMP is currently or was formerly served as a master-metered mobile home park, the allowable investment for the MMP will be calculated by the following Incremental Contribution Method and formula:

$$AI = (FR - CR) \times 5$$

where: AI = Allowable Investment

FR = The MMP's estimated future total annual revenue, assuming conversion to individual residential service, using the MMP's average park occupancy for the past two (2) years, less the Company's current average cost of purchased gas.

CR = The MMP's current total annual revenue, under the applicable schedule, averaged for the past two (2) years, less the Company's current average cost of purchased gas. If the MMP is not a current Customer of the Company, the CR will be determined on the basis of engineering estimates of occupancy and usage.

The Company will install that portion of each service in excess of the Allowed Investment subject to a nonrefundable contribution to be paid by the Applicant MMP prior to construction. In no event shall costs above the allowable investment be borne by the Company.

1. Incremental Contribution Method – Gas service line and main line extensions will be made by the Company at its expense for an amount not to exceed the Allowable Investment as calculated by an Incremental Contribution Study ("ICS").

   a. Allowable investment shall mean a determination by the Company that the revenues less the incremental gas cost to serve the Applicant provides a rate of return on the Company's investment no greater than the weighed average cost of capital authorized by the ACC in the Company's most recent general rate case.

   b. <u>All applicants will pay for the entire length of their service lines on their property.</u> ~~If the ICS has an allowable investment that is more than the cost of the main extension, then the excess amount may be applied to reduce the cost of service line installation.~~

EXHIBIT
UNSG 31
admitted

SECTION NO. 7
EXTENSION OF LINES
(continued)

2. At its option, the Company may require a performance bond or other surety guaranteeing bona fide operation of the facility for which the extension is requested, in accordance with Applicant's representation in the contract.

3. Master Meter Extensions – If the residential Customers are tenants in a fully improved master-metered mobile home park ("MMP") and the MMP is currently or was formerly served as a master-metered mobile home park, the allowable investment for the MMP will be calculated by the following Incremental Contribution Method and formula:

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CR = The MMP's current total annual revenue, under the applicable schedule, averaged for the past two (2) years, less the Company's current average cost of purchased gas. If the MMP is not a current Customer of the Company, the CR will be determined on the basis of engineering estimates of occupancy and usage.

The Company will install that portion of each service in excess of the Allowed Investment subject to a nonrefundable contribution to be paid by the Applicant MMP prior to construction. In no event shall costs above the allowable investment be borne by the Company.

1. Incremental Contribution Method – Gas service line and main line extensions will be made by the Company at its expense for an amount not to exceed the Allowable Investment as calculated by an Incremental Contribution Study ("ICS").

   a. Allowable investment shall mean a determination by the Company that the revenues less the incremental gas cost to serve the Applicant provides a rate of return on the Company's investment no greater than the weighed average cost of capital authorized by the ACC in the Company's most recent general rate case.

   b. If the ICS has an allowable investment that is more than the cost of the main extension, then the excess amount may be applied to reduce the cost of service line installation, except that it shall not be used to reduce the cost of excess flow valve installation which shall be paid by the customer.

EXHIBIT
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UNSG-32
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Chaparral City

DOCKET N

UNSG-33

TABLE OF CONTENTS

EXHIBIT
tabbies
UNSG-33
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BEFORE THE ARIZONA CORPORATION COMMISSION

Arizona Corporation Commission
DOCKETED

SEP 30 2005

DOCKETED BY CAR

COMMISSIONERS

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

IN THE MATTER OF THE APPLICATION OF CHAPARRAL CITY WATER COMPANY, AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND FOR INCREASES IN ITS RATES AND CHARGES FOR UTILITY SERVICE BASED THEREON.

DOCKET NO. W-02113A-04-0616

DECISION NO. 68176

OPINION AND ORDER

DATE OF PRE-HEARING CONFERENCE:	May 26,2005
DATE OF HEARING:	May 31, June 1, June 6 and June 8,2005
PLACE OF HEARING:	Phoenix, Arizona
ADMINISTRATIVE LAW JUDGE:	Teena Wolfe
IN ATTENDANCE:	Kristen K. Mayes, Commissioner
APPEARANCES:	Norman D. James and Jay L. Shapiro, FENNEMORE CRAIG, on behalf of Chaparral City Water Company; Daniel Pozefsky, on behalf of the Residential Utility Consumer Office; and David Ronald, Staff Attorney, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

BY THE COMMISSION:

I. INTRODUCTION

A. Procedural History

On August 24, 2004, Chaparral City Water Company ("Chaparral City" or "Company") filed with the Arizona Corporation Commission ("Commission") an application for a determination of the current fair value of its utility plant and property and for increases in its rates and charges for utility service based thereon.

On September 14, 2004, the Residential Utility Consumer Office ("RUCO") filed an Application to Intervene, which was granted.

On September 23, 2004, the Commission's Utilities Division Staff ("Staff") filed a letter stating that the Company's application met the sufficiency requirements set forth in A.A.C. R14-2-103, and classifying the Company as a Class A utility.

On September 28, 2005, a Rate Case Procedural Order was issued setting a hearing date and setting procedural deadlines for public notice, intervention, discovery, and for prefiling direct, rebuttal, surrebuttal and rejoinder testimony.

On February 15,2005, the Company filed a Notice of Publication certifying that public notice was published in *The Fountain Hills Times* on January 26,2005. Public notice of the application and hearing was also mailed to each of the Company's customers in their January 2005 bills. Written public comments in opposition to the rate increase were received as set forth herein. Aside fi-om RUCO, no other party requested intervention.

A hearing was held as scheduled before a duly authorized Administrative Law Judge of the Commission, commencing on May 31, 2005 and continuing on June 1, June 6 and June 8, 2005. Public comment was taken at the commencement of the hearing. The Company, RUCO, and Staff appeared and presented evidence at the hearing. Following the filing of closing briefs on July 6, 2005, and reply briefs on July 20, 2005, the matter was taken under advisement pending the submission of a Recommended Opinion and Order to the Commission. On July 28, 2005, the Company filed a Request for Official Notice of Rate Increases Requested by Arizona Public Service Company and Salt River Project.

B. Rate Application

Chaparral City is an Arizona corporation wholly owned by American States Water Company

("American States"), which is publicly traded on the New York Stock Exchange. American States primary operating subsidiary is Southern California Water Company. In October 2000, as approvec by this Commission in Decision No. 62909 (September 18, 2000), American States purchasec Chaparral City's stock from MCO Properties, Inc. ("MCO"), the real estate developer that owned anc operated the Company. Chaparral City provides water utility service to approximately 12,00C customers located in the northeastern portion of the Phoenix metropolitan area, including the Town oi Fountain Hills and a small portion of the City of Scottsdale. The majority of the Company's approximately 11,340 residential customers during the test year were served by %-inch meters, but approximately 3,000 residential customers have larger meters. During the test year, the Company also provided service to over 300 commercial customers and over 400 irrigation customers.

The application is based on a test year ended December 31,2003. The Company is requesting an increase in revenues of $1,773,091, or 28.59 percent, for a total revenue requirement of $7,795,935. This revenue requirement is lower than that requested in the application due to the Company's adoption of a number of adjustments recommended by Staff and RUCO, and other adjustments the Company made. RUCO is recommending an increase in revenues of $603,988, or).74 percent, for a total revenue requirement of $6,803,753. Staff is recommending a revenue increase of $809,692, or 13.05 percent, for a total revenue requirement of $7,012,536. Based on adjustments to the Company's filing as set forth herein, we authorize an increase in revenues of $1,107,620, an increase of 17.86 percent, for a total revenue requirement of $7,310,464.

I. RATE BASE

A. Plant in Service

The Company is proposing a total of $42,538,338 for plant in service relating to its Original Cost Rate Base ("OCRB") (Bourassa Rj. Sched. B-1). Of that amount, $ 2,979,239 represents plant additions placed in service after the test year: $2,038,443 for the expansion of its Shea Water

Treatment Plant ("Shea WTP"), and $940,979 related to the Fountain Hills Boulevard transmission main (Bourassa Rb. Sched. B-2).

1. Shea Water Treatment Plant Expansion

The Company is requesting rate base treatment of $2,038,442 for the Shea WTP expansion The expansion was begun in 2003 and brought on line in March 2004. The Company has twc facilities that are used to treat its CAP water allocation. The Company's original treatment facility i: a package plant with a current treatment capacity of about 3 million gallons per day ("gpd"). The Shea WTP consists of three separate treatment modules, each module having a treatment capacity oi 5 million gpd. The first module was brought on line in 1996, and the expansion includes the final wo treatment modules. The Company had planned to bring these modules on line before the end oi he 2003 test year but was delayed in obtaining final regulatory approvals. The Company argues on rief that prior to its acquisition of the Chaparral City system, the prior owner had ignored growth nd that as a result, the Company lacked sufficient operational flexibility in its water treatment acilities to perform routine repairs and maintenance or address emergencies. From the years 1995 hrough 2001, no additional treatment capacity was constructed, despite the fact that the Company dded over 4,400 customers, for an average growth rate of ten percent per year (Hanford Rj. at **2,** iting Scott Dt., Exhibit MSJ at 13). During the test year, the Company's peak demand exceeded 10 iillion gpd but it could treat only 8 million gpd of CAP water (Tr. at 63).

RUCO does not oppose the inclusion of the Shea WTP in rate base. According to RUCO's /itness, the full Shea WTP capacity was required for water provisioning to the test year customer ase, and the Company's construction costs were known and measurable, and paid, during the test ear (Moore Dt. at 12). RUCO is recommending that the total actual cost of $2,038,443 be allowed 1 rate base as post-test year plant *(Id.)*.

Staff disagrees with the Company and RUCO, arguing that the Shea WTP is not revenue neutral as it was not needed during the test year (Moe Dt. at 10), and is recommending its exclusion from test year plant in service. Staff asserts that because the Shea WTP expansion increases treatment capacity, increased revenues from water sales are possible, and that no corresponding increase in test year revenues was made to account for this possibility; that the Company was able to meet peak demand in the test year using groundwater as a supplement to its CAP allocation; and that the Company will benefit more than the ratepayers from the additional protection against outages that the increased treatment capacity will provide. However, it appears that if the expansion had been placed in service during the test year, just three months earlier, Staff would have allowed it in rate base (see Bourassa Rj. at Exhibit TJB-2, Staff Data Response 3-17).

As Staff argued on brief in support of its recommendation to include the post-test year Fountain Hills Boulevard transmission main in rate base, inclusion of post-test year plant always causes some mismatch between revenues and expenses, even if post-test year plant is revenue neutral, used and useful, and the value of the additions is known (see Staff Cl. Br. at **2-3)**. Therefore, even though quantification of the inevitable mismatch may not be possible, the significance of the mismatch requires careful consideration (see *id).* Given that ninety percent of the Company's water supply comes from *CAP* water, which must be treated before it can be delivered to customers for potable purposes, the ability of the Company to reliably treat its test year CAP water supply is an important factor that weighs heavily in our consideration of whether to include the Shea WTP expansion in rate base. We find that the weight of the evidence in this proceeding supports the Company's assertion that the Shea WTP expansion, which the Company paid for during the test year, and has been used and useful since March of 2004, allows the Company to reliably meet test year peak demands during the summer months with CAP water, which is a renewable resource we wish to encourage, while retaining the ability to take individual modules off line for repairs and to meet emergency needs. We find credible the Company's assertion that prior to the Shea WTP expansion, the Company had been operating with minimal flexibility for routine maintenance and repairs and had no operating safety margin in the event of a need to shut down some of its treatment facilities. These factors support, in this particular case, treating the Shea WTP expansion, which was paid for during the test year and placed in service within three months following the test year, as if it were actually in service at the end of the test year. We will therefore adopt RUCO's recommendation that the total actual cost of $2,038,443 associated with the Shea WTP be allowed in rate base.

2. Fountain Hills Boulevard Main

The Company also requests inclusion of $940,797 in rate base for the Company's share of the cost of installing the Fountain Hills Boulevard main. The Fountain Hills Boulevard main is a 16-inch water transmission main approximately two miles in length, that was placed in service in November 2004. Because a portion of this main was constructed in connection with new development, part of its cost was paid by the developer.

RUCO objects to including the full amount of the Company's cost associated with the main in rate base. RUCO claims that installation of the main results in operating expense savings due to reduced pumping costs, and that the Company's request does not account for the purported savings (RUCO Cl. Br. at 5-6). RUCO did not calculate the savings it alleges, arguing that the burden is on the Company to establish the plant value, taking into account both the cost and the savings (*Id.*, fn 4).

Staff recommends that the Fountain Hills Boulevard main be included in rate base. Staff states that the main addition provides operational flexibility and improved service to customers (Scott Dt., Exhibit MSJ at 7); that it will assist in providing CAP water flow to blend with the Company's Well Number 10 groundwater source in order to reduce the arsenic concentration in water from that well *(Id.)*; and that any revenues that would potentially come from the transmission line would be incidental (Moe Dt. at 10). Staffs engineering witness testified that there are no pumping cost savings associated with the new main, because its installation does not result in changes in the way the system is operated (Tr. at 635-638).

The Fountain Hills Boulevard transmission main has been used and useful since November 2004, providing operational flexibility and improved service to customers. The weight of the evidence does not demonstrate a reduction in operating costs attributable to its operation that would necessitate a reduction in its cost. Based on the evidence presented, we find that the Company's cost associated with the Fountain Hills Boulevard transmission main, $940,797, should be included in rate base.

3. CAP Hook-Up Fees

In the Company's last rate case, Decision No. 57395 (May 23, 1991), the Commission ordered that a portion of the revenue requirement determined in that case be recovered by means of hook-up fees from new customers due to the unique circumstance that the required revenue increase was due primarily to CAP facilities coming on line (see pages 4-5 of Decision No. 57395). In its current application, the Company proposes that the entirety of its revenue requirement be recovered in accordance with traditional rate making principles, through customers' rates. Chaparral City made an accounting adjustment to remove $220,000 in test year hook-up fees from test year revenues (Kozoman Dt. Sched. H-1). All the parties to this case are in agreement that the hook-up fees should no longer be treated as revenues.

RUCO proposes that an adjustment also be made to increase test year contributions-in-aid of construction ("CIAC") by $220,000, the amount of test year hook-up fees, which would reduce the Company's rate base by $220,000. RUCO argues that this adjustment is necessary in order to recognize that hook-up fees financed $220,000 of plant during the test year. The Company objects to this adjustment, because it does not include a corresponding $220,000 adjustment to the asset side of the balance sheet.

RUCO's proposal assumes that the $220,000 collected during the test year as hook-up fees was used to pay for plant additions. In most circumstances, such an assumption would be correct, because this Commission normally limits the use of hook-up fees to the installation of utility plant. However, as described by the Company's witness (Tr. at 829-832), Decision No. 57395 did not limit the use of the authorized "hook-up fees" to plant investment, but clearly intended that the "hook-up fees" be treated as operating revenues (Decision No. 57395 at 5-6). The $220,000 represents test year revenue and not plant additions. RUCO's proposed adjustment is therefore unnecessary and will not be adopted.

The Company does not have an approved hook-up fee tariff on file at this time. We will require the Company to file a hook-up fee tariff, and to obtain Commission approval of the tariff prior to collecting any hook-up fees on a going-forward basis.

4. Reclassification of Expenses to Plant in Service

RUCO recommends the removal of $5,686 of repairs and maintenance expense associated with water treatment plant. The Company proposes that the expense be reclassified as water treatment plant and Staff agrees. This proposal is reasonable and will be adopted.

Staff recommends that $26,850 from outside services expense be reclassified to meters and pumping equipment. The Company agrees with this recommendation, which is reasonable and will be adopted.

B. Accumulated Depreciation

The Company proposes an adjustment to decrease accumulated depreciation by $11,421, in order to correct for an error in the Company's filing (Co. Rb. Sched. B-2 at 3). Staff proposed additional adjustments to accumulated depreciation associated with the reclassification of expenses to plant in service discussed above, and with the removal of vehicles from plant in service as agreed to by the Company. These adjustments are reasonable and will be adopted, for total accumulated depreciation of $11,980,749.

III. ORIGINAL COST RATE BASE

With the adjustments discussed above, test year plant in service is $42,539,165, and deducting accumulated depreciation results in net plant in service of $30,558,416. As proposed by the Company, test year net CIAC is $258,143, advances in aid of construction ("AIAC") is $10,327,171, customer deposits are $1,070,331, and deferred income tax credits are $1,872,006. Deducting these items from net plant in service results in an adjusted original cost rate base ("OCRB") for ratemaking purposes of $17,030,765.

IV. RECONSTRUCTION COST NEW RATE BASE

Chaparral City submitted schedules reflecting both an OCRB and an estimated reconstruction cost new less depreciation ("RCND") rate base. Staff reviewed the Company's RCN study and agreed with the Company's plant in service values (Scott Dt., Exhibit MSJ at 6). The adjustments discussed above and reflected in our determination of OCRB are equally applicable to the Company's proposed RCND. Based on the foregoing discussion, we therefore adopt an adjusted RCND for ratemaking purposes of $23,649,830.

V. FAIR VALUE RATE BASE

Chaparral City is proposing a FVRB based on the average of its OCRB and RCND. Staff also utilized this approach. RUCO recommends a FVRB equal to its OCRB. We find that the average of the adjusted OCRB and RCND provides a reasonable measurement of the current value of the Company's property dedicated to public service. Based upon a 50/50 weighting of the OCRB and RCND, we find Chaparral City's FVRB at December 31, 2003 to be $20,340,298. The rate of return to be applied to FVRB is discussed in Section VIII below.

VI. OPERATING INCOME

A. Expenses

Several adjustments to operating expenses that Staff and RUCO proposed were either agreed to by the Company prior to the hearing or were not addressed on brief by the Company.[1] We find those proposed adjustments to be reasonable and they will be adopted. Remaining contested operating expense issues are addressed below.

1. Expense Normalization

Staff proposes normalization adjustments in several accounts in which Staff believes test year expenses were not representative of a normal year. The expense accounts to which Staff proposes normalization adjustments are office expenses, outside services, transportation expenses, and miscellaneous expenses. Staff asserts that while operating expenses normally remain fairly stable from year to year, a ratio analysis reveals that the test year expenses in these accounts show a dramatic change from prior years and are not reflective of normal expense levels (Tr. at 731; Moe Sb. at 6). Due to the significant fluctuation in expenses in these accounts, Staff recommends that the actual 2003 test year expense amounts in these accounts be normalized by averaging them with the actual expense amounts incurred in the years 2001 and 2002, in order to mitigate any extenuating circumstances leading to the test year expense levels (Moe Dt. at 14-18; Tr. at 815-16).

Chaparral City advocates for the use of actual test year expenses. The Company claims that Staff's normalization adjustment is not based on known and measurable changes in expenses, and asserts that the averages will produce unrealistic results on a going forward basis (Bourassa Rb. at 33). The Company asserts that 2001 and 2002 expense levels do not reflect current operating expense levels because it took until 2003 for the Company to get its operations up to the current level of system reliability after acquiring the system from MCO in late 2000 (Hanford Rj. at 7-8).

Test year expenses are used to estimate the level of expense that a Company will experience during the period that rates will be in effect. Normalization of expenses is an appropriate ratemaking tool that insures that unusual levels of expense in a test year do not skew expense recovery, and is

[1] The parties were informed that issues not briefed would be assumed waived. See Transcript of Pre-hearing Conference at 11.

used not only in cases where test year expenses are abnormally high, but also in cases where test year expenses are abnormally low. In this case, the evidence presented shows test year expenses in these four accounts to be abnormally high. The 2001 and 2002 expense levels in these accounts are known and measurable. Averaging these known and measurable amounts with the unusually high 2003 test year levels recognize the "across the board increase in expenses" the Company claims has occurred, while producing a realistic estimate of reasonable expenses in these accounts on a going-forward basis. Chaparral City argues that use of year 2004 expenses would have illustrated whether the 2003 expense levels were unusual, or reflect operating expense levels on a going forward basis (Co. Br. at 19). However, because the Company did not provide a comparison of 2004 expenses to test year expenses (Tr. at 732), its argument is speculative. Based on the record evidence, we find it appropriate to normalize the test year level of expenses in these four accounts. Staffs recommendation is reasonable and will be adopted.

2. Legal Expense Related to Purchase from MCO

RUCO recommends that the legal expenses associated with the purchase of the Company from MCO be disallowed from test year outside services expenses because they were unique and not a typical or recurring expense. Chaparral City concedes that the same legal matters resulting in expense during the test year may not reoccur, but that the test year reflects a level of annual legal expenses that a utility of the Company's size is likely to incur in the future (Bourassa Rb. at 35-36; Bourassa Rj. at 22). The legal expenses in question are included in outside services expense, which will be normalized, as discussed above. We find that the normalization of test year outside services expense addresses this issue appropriately and that no further adjustment is necessary.

3. Tank Inspection and Cleaning Expense

The Company proposes to remove operating expenses of $35,400 incurred during the test year for tank inspection and cleaning, and to instead amortize and recover those costs over five years at approximately $7,080 per year (Bourassa Rb. at 31; Rb. Scheds. B-2 at 5 and C-2 at 8). The Company's witness testified that the inspection and cleaning may not be an annual recurring expense, but that it is a prudent and necessary expense incurred in the provision of water services (Bourassa Rb. at 31). RUCO recommends that these costs be disallowed, because they were already recovered through 2003 operating expenses, and the next inspection has not been scheduled (Moore Sb. at 16-17). Staff asserts that its expense normalization adjustment addresses this issue, and recommends that the Company's proposed adjustment not be adopted. We concur with Staff that its normalization adjustment to outside services expense appropriately addresses the issue. Both the disallowance proposed by RUCO and the Company's proposal to amortize this particular expense are therefore unnecessary.

4. Wages and Salaries Expense

The Company, Staff and RUCO proposed that a portion of the Company's wages and salaries expense be capitalized. The capitalization rate for 2003 was 17.46 percent and the 2004 capitalization rate was 17.31 percent (Bourassa Rb. at 30). The Company and Staff both propose the use of the 2004 capitalization rates, which are known and are the most current rates (*Id.*, Bourassa Rj. at 19; Moe Sb. at 14), which results in proposed wages and salaries expense of $991,217. In arriving at its lower recommended wages and salaries expense of $877,231, RUCO uses the capitalization rate that the Company originally provided to it, and does not accept the corrected capitalization rate the Company later provided. (Moore Sb. at 13). The Company asserts that it originally erroneously provided RUCO the Company's payroll system coded default percentages, and not its actual capitalization rate (Bourassa Rb. at 30, Rj. at 19). We agree with the Company and Staffs use of the 2004 capitalization rate of 17.31 percent, as it reflects known and most current rates, and will adopt their recommended wages and salaries expense of $991,217.

5. Purchased Power Expense

The Company proposes that purchased power expense should be adjusted to take into account :ecent rate increases of Salt River Project ("SRP") and Arizona Public Service Company ("APS") Bourassa Rj. at 17). Staff agrees with this adjustment (Moe Sb. at 16). RUCO opposes this ıdjustment claiming that the increases in power rates are too far outside the test year (Moore Sb. at 1 1). The SRP and APS rate increases are known and measurable expenses. The adjustment proposed ›y the Company and Staff is appropriate and will be adopted, for total purchased power expense of $510,947.

6. Property Tax Expense

The Arizona Department of Revenue ("ADOR") determines the value of utility property for ax purposes using a formula that is based on the utility's historical revenues. The Company and ltaff propose to follow recent Commission Decisions[2] to use adjusted test-year revenues in the pplication of the ADOR formula in order to determine allowed property tax expense (Bourassa Rj. t 16; Moe Dt. at 19). RUCO continues to disagree with the Commission's use of adjusted test year ɜvenues in the application of the ADOR formula for estimating property tax expense for ratemaking urposes, and argues that only historical revenues should be used.

In an attempt to support its argument, RUCO compared the results of its methodology, using ıe Company's historical revenues for the years 2001, 2002 and 2003, with the results of the ommission's methodology, using the Company's historical revenues and adjusted test year ›venues, in order to predict the property taxes assessed by ADOR in 2004 (*see* Hearing Exhibit R-2), id asserts that because its methodology more accurately predicted the actual 2004 tax assessment,

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Ξ.g., *Rio Rico Utilities*, Decision No. 67279 (October 5, 2004) (finding that use of only historic revenues understates the pense level); *Arizona Water Company*, Decision No. 64282 (December 28,2001) (accepting Arizona Water Company's operty tax calculation, which included proposed revenues); *Bella Vista Water Company*, Decision No. 65350 lovember 1, 2002) (concluding that "the most logical approach is to use the two most recent historic years' revenues, d the projected revenues under the newly approved rates"); *Arizona American Water Company*, Decision No. 67093 me 30,2004).

that the Commission should adopt its approach (RUCO Br. at 8-9). We do not agree. Exhibit R-: does not, and cannot, include a comparison of results of RUCO's backward-looking methodolog; with results of the Commission's approach for any years beyond 2004, because the actua assessments for the years following 2004 are unknown. What is known is that any revenue increast approved in this proceeding will increase the Company's property taxes, barring the occurrence o: very extraordinary circumstances. ADOR will never again use the inputs of revenues for the year: 2001, 2002 and 2003, the years RUCO advocates using in this proceeding, to determine property tax evels for Chaparral City. RUCO's calculation methodology, which uses only historical revenues. ınfairly and unreasonably understates property tax expense, and is therefore inappropriate for ·atemaking purposes.

As we have repeatedly found, the input of known revenue increases is necessary in order to airly estimate property tax expense for ratemaking purposes. RUCO has not demonstrated in this ıroceeding a basis for departure from our prior determinations on this issue.[3] We will therefore adopt he recommendations of the Company and Staff to follow recent Commission Decisions to use djusted test year revenues in determining property tax expense.

The legislature recently enacted Arizona House Bill 2779, which will gradually lower the ssessment ratio for Class 1 properties, such as utility property, from 25 percent to 20 percent over a en year period, by means of a reduction in the assessment ratio of ½ percent a year. Assessment atios are applied to full cash value to derive an assessed value on which property tax is applied (Tr. t 643). Although the new assessment ratios are known, their actual effect on the amount of property ıxes assessed in the future is unknown, because unlike the assessment ratios which are set by the egislature, actual property tax rates are set by counties and other governmental entities (Tr. at 643, 45). As requested, the parties introduced schedules at the hearing that estimate the impact of HB

RUCO has not appealed prior Commission Decisions rejecting its proposed methodology.

2779 on the Company's property tax expense level (see Hearing Exhibits A-26, R-8, S-15). Th(schedules show that even if property tax rates were to remain constant, the effect of calculating HE 2779's lower assessment ratios into property tax estimates would have a de minimus effect on rates ir this case (see Tr. at 596; 644). No party recommended that its property tax calculation be amended.

Based on the revenue requirement we adopt herein, and utilizing the methodology adopted b) :he Commission in our prior Decisions for the reasons set forth herein, an allowance will be made foı ɔroperty tax expense in the amount of $299,495.

7. Depreciation Expense

The Company's application showed test year depreciation expense of $920,648. The Company did not perform a depreciation study, but chose instead to base its depreciation rates or Staffs developed typical and customary depreciation rates (Bourassa Rb at 2, Rj. at 17). Based on its ɔroposed plant in service amounts, the Company proposed test year adjusted depreciation expense oɪ $1,432,828 (Bourassa Rj. Sched. C-1, p. 1). Staff accepted the Company's use of Staffs developed ypical and customary depreciation rates to calculate its proposed test year adjusted depreciation :xpense of $1,365,295, based on its proposed plant in service (Moe Sb. Sched. JRM-24). RUCO iisagrees with the use of Staffs developed typical and customary depreciation rates and proposes the ıse of a different set of depreciation rates instead, as discussed in Section XI hereinbelow. Using its ›roposed depreciation rates, RUCO proposed test year adjusted depreciation expense of $1,113,339, ›ased on its proposed plant in service amounts (Moore Dt. Sched. RLM-10, p. 1 of 2). Applying RUCO's proposed depreciation rates to the plant in service amounts approved herein would result in est year adjusted depreciation expense of approximately $1,139,194. Consistent with our discussion ›f appropriate depreciation rates in Section XI hereinbelow, we adopt test year adjusted depreciation :xpense of $1,432,828, based on the plant in service amounts authorized herein and using the lepreciation rates proposed by the Company and Staff.

B. Statement of Operating Income

The Company's adjusted test year operating revenues, as agreed by the parties, wer($6,202,844. In accordance with the discussion above, the Company's adjusted test year operatin! expenses for ratemaking purposes total $5,588,597, for an adjusted test year operating income o $614,247.

VII. COST OF CAPITAL

Chaparral City, Staff and RUCO presented cost of capital analyses for purposes o: determining a fair value rate of return in this proceeding. The cost of equity proposed by Chaparra: City's witness, Dr. Thomas Zepp, translates to a recommended overall weighted average cost o1 capital of 8.2 percent if its requested automatic adjustment mechanisms for purchased water and purchased power costs are approved, and 8.6 percent if they are not approved. Staff is recommending, based on the analysis of Staff witness Alejandro Ramirez, a weighted average cost of capital of 7.6 percent. Based on the analysis of its witness William Rigsby, RUCO believes the Commission should adopt RUCO's recommended 7.66 percent weighted average cost of capital.

A. Capital Structure and Cost of Debt

1. Capital Structure

The parties are in agreement that the Company's capital structure as of December 31, 2003 should be used to determine the Company's weighted cost of capital, as follows:

Long Term Debt	$ 8,363,309	41.27%
Common Equity	11,901,727	58.73%
Total Capital	$20,265,036	100.00%

2. Cost of Debt

The parties also agree that the Company's cost of long term debt is 5.1 percent, which results n a weighted cost of debt of 2.11 percent.

B. Cost of Equity

Although the cost of debt can be determined from fixed cost rates, the cost assigned to the equity component of the capital structure can only be estimated. The cost of equity recommendations advocated by the parties are: Chaparral City, 10.4 percent if its requested automatic adjustment mechanisms for purchased water and purchased power costs are approved, and 11.0 percent if they are not approved; RUCO, 9.45 percent; and Staff, 9.3 percent.

1. Chaparral City

Chaparral City's witness, Dr. Zepp, prepared estimates of the cost of equity based on the discounted cash flow ("DCF") model used by the Federal Energy Regulatory Commission ("FERC") and the risk premium method used by the staff of the California Public Utility Commission ("CPUC Staff"). The DCF method of estimating the cost of capital is based on the theory that the present value of a stock is equal to the present value of all expected future dividends or cash flows. The constant growth DCF model assumes that a company will grow at the same rate indefinitely, while the non-constant growth DCF model does not assume that dividends grow at a constant rate over time. The constant-growth DCF formula includes three variables used to estimate the cost of equity: 1) the expected annual dividend; 2) the current stock price; and 3) the expected infinite annual growth rate of dividends ("dividend growth rate"). The constant-growth DCF model calculates a dividend yield by dividing the expected annual dividend by the current stock price, and then adds the resulting dividend yield *to* the expected infinite annual growth rate of dividends. The Company prefers FERC's constant growth DCF method to the constant growth DCF method used by Commission Staff, because the FERC's method eliminates from consideration any individual utility equity cost estimate that is not at least forty basis points above the cost of investment grade bonds (Zepp Dt. at 4, 30). The Company argues that Staffs constant growth methodology, which does not reject such estimates, lowers Staffs average growth inputs for the model and its resulting equity cost estimate

DECISION NO. 68176

(Zepp Rj. at 10-13). The Company also advocates use of the risk premium method used by the CPUC staff to estimate the cost of equity instead of the capital asset pricing model ("CAPM") used by Commission Staff, because the CPUC staffs risk premium approach estimates the risk premiurn by comparing authorized and actual returns on equity ("ROE") with the current yield of investment grade bonds or other debt instruments (Zepp Dt. at 4-5 and 33-34). Using these methods, Dr. Zepp presented updated equity cost estimates in his rejoinder testimony that range from 10.4 percent to 10.9 percent based on the six publicly-traded water utilities included in the sample group.[4] Using the CPUC staffs risk premium approach and interest forecasts, rather than current interest rates, the Company estimated the cost of equity for the water utility sample at 10.5 percent to 10.7 percent (Zepp Rj. at 7-8 and Rejoinder Table 6). Dr. Zepp's analysis included a study of authorized ROEs for the sample group of water utilities, which range from 9.7 percent to 12.7 percent, for an average 10.4 percent, and looked at the returns on equity actually being earned by those water utilities, which averaged 10.0 percent. Dr. Zepp also cited *Value Line,* a source of financial data to which all the parties referred in their analyses, for *Value Line's* projections of returns on common equity of 11.0 percent, 11.5 percent and 12.0 percent for 2005, 2006 and 2008-2010, respectively, for the water utility industry. Dr. Zepp claims that these measures of the cost of equity indicate an equity cost of greater than 10.0 percent for the sample utilities and, he asserts, a higher equity return for Chaparral City, based on his belief that the Company is more risky.

The Company is critical of Staffs implementation of the DCF model, because instead of relying solely on forward-looking estimates of growth, Staff gives a 50 percent weight to historic growth data from 1994-2003, which results in a lower dividend growth rate and a lower equity cost

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[4] The Company and Staff used the same six publicly-traded water utilities as proxies in their analyses: American States Water (Chaparral City's parent), Aqua America, California Water Service, Connecticut Water Services, Middlesex Water Company and SJW Corp. RUCO used the three largest publicly-traded water utilities in this group in its analysis: American States Water, Aqua America and California Water Service. These companies represent the water utilities that are currently analyzed by the *The Value Line Investment Survey Small and Mid Cap Edition* and *The Value Line Investment Survey ("Value Line").*

estimate. The Company also argues that Staffs historic dividend growth rates are extremely low, and produce results that are in some cases below the cost of an investment grade bond (see Hearing Exhibit A-23), and that Staffs application of the average dividend yield to compute its equity cost "masks" this fact. Dr. Zepp advocates the use of future, rather than historic growth rates, based on his belief that forecasts already incorporate the historic information used by Staff (Zepp Dt. at 25). The Company believes that giving 50 percent weight to historic growth rates double counts what has happened in the past, and that investors are more interested in a stock's future performance than its past performance. The Company states that it therefore prefers the forward-looking approach used by the FERC (Co. Br. at 36). In rejoinder testimony, Dr. Zepp restated Staff witness Ramirez' constant growth DCF model estimate, using the average dividend yield (3.3 percent) and an average of Mr. Ramirez' projected growth rates (7.5 percent), and reached a result of 10.8 percent which is virtually identical to Dr. Zepp's updated estimate using the FERC one-step method, 10.9 percent (Zepp Rj. at 10). Dr. Zepp also restated Staffs multi-stage DCF estimate using Staffs data but also including Staff's 8.7 percent estimate of intrinsic growth which Staff used in a different model and also used a different terminal, second stage growth rate. The results of Dr. Zepp's restatement is a cost of equity estimate of 10.1 percent (Zepp Rj. at 14). The Company states that the multi-stage DCF model that Staff uses is similar to the two-step DCF model FERC uses, but is critical of the choices Staff made to implement its model, such as the assumption that average growth will initially be only 3.7 percent, and after 2008, will be 6.5 percent. The Company prefers the assumption in the FERC model that it will take many years before the terminal growth rate will be the same as gross domestic product ("GDP") growth, and the fact that the model therefore gives greater weight to the estimate of near term, stage 1 growth. As for stage 2 growth estimates, the Company also prefers to use the geometric average annual GDP growth rate, which is 6.4 percent, rather than Staffs use of the arithmetic average annual GDP growth rate, which is 6.8 percent. The inputs preferred by Dr. Zepp lead to higher equity cost estimates.

The Company also finds Staffs use of the CAPM model in estimating its equity cos problematic. Dr. Zepp criticizes the Staffs assumption in the CAPM that Chaparral City has the same beta[5] as the average beta of the six publicly traded water utilities in the sample group, 0.68 because, in his opinion, Chaparral City is a more risky operation than the public utilities in the sample group and would have a beta closer to 1.0, which would result in a higher equity cost estimate (Zepp Rb. at 22). Dr. Zepp is also critical of Staffs selection of the average yield on five, seven and ten year Treasury Securities for its risk-free rate, on the basis that most investors hold securities for a five :o ten year period (see Ramirez Dt. at 26-27). The Company argues that the investors' holding period s not relevant, and Staffs choice reduces the equity cost estimate. The Company would instead prefer the use of a long-term Treasury Bond rate as the risk-fi-ee rate (Zepp Rb. at 18-19). The Company further argues that although Staff has used an average of intermediate-term Treasury rates is the risk-free rate, Staff used the long-term Treasury rate to estimate the market risk premium and claims that this creates a mismatch (Zepp Rj. at 15). The Company also argues that recent empirical studies of the CAPM have shown that the returns estimated for low data stocks like the water utility sample group are too low relative to required returns for average risk stocks (Tr. at 245), and quotes an article published last year by Drs. Eugene Fama and Kenneth French which concludes that despite its seductive simplicity, the CAPM's empirical problems probably invalidate its use in pplications."[6] On rejoinder, Dr. Zepp restated Staffs CAPM equity cost estimates using its preferred inputs, and reached an equity cost estimate of 10.2 percent (Zepp Rj. at 15-17). The Company argues that this updated CAPM estimate is conservative for the reasons stated in its riticism of the CAPM.

Beta measures the systematic risk of a company. The market's beta is 1.0; therefore, a security with a beta higher than .0 is riskier than the market, and a security with a beta lower than 1.0 is less risky than the market.

Eugene F. Fama and Kenneth R. French, "The Capital Asset Pricing Model: Theory and Evidence" 18 *Journal of conomic Perspectives* 25-46 (Summer 2004).

While the Company does not disagree regarding the basic formula RUCO used to derive it: Sustainable growth rate to derive its estimate of dividend growth, the Company argues that RUCO'; witness Rigsby's reliance on his personal analysis of *Value Line* forecasts depresses his dividenc growth estimate and reduces the equity cost produced by Mr. Rigsby's DCF model (Zepp Rb. at 31-33; Tr. at 296-99). Dr. Zepp claims that RUCO's dividend growth estimate is flawed in that its external "sv" growth rate includes an understated estimate of the stock financing rate ("s") compared o forecasted stock financing rates (Zepp Rb. at 32, Rebuttal Table 15). Dr. Zepp is also critical of RUCO's estimates of the "v" in its external growth rate, and asserts that that there is no evidence supporting Mr. Rigsby's opinion, based on Dr. Morin's text on regulatory finance *(see* Hearing Exhibit A-16), that the market prices of a utility stock will move toward book value. Using equity cost estimates based on Mr. Rigsby's data, but using different inputs, Dr. Zepp produced a estatement of RUCO's constant growth DCF model in two different ways. Dr. Zepp used RUCO's lividend yields, adjusted RUCO's historical average retention growth rate ("br") growth rate and stock financing ("vs") growth rate estimates to reach an equity cost of 10.7 percent (Zepp Rb. at 31-33 and Rebuttal Tables 15 and 16). Dr. Zepp performed another restatement of RUCO's DCF analysis using forecasts of growth instead of sustainable growth and reached an equity cost estimate of 10.6 percent (Zepp Rj. at 22 and Rejoinder Table 9).

2. Staff

Staffs witness Ramirez prepared estimates of the cost of equity using market-based models: constant-growth DCF model, a multi-stage, or non-constant growth DCF model, and a CAPM nalysis. To calculate dividend yield in its constant-growth DCF calculation, Staff divided the xpected annual dividend as forecasted by *Value Line* by the spot stock price on April 20, 2005. Staff states that it used a spot stock price, rather than a historical average of stock prices, in order to e consistent with the efficient markets hypothesis of finance theory, which holds that the current stock price includes investors' expectations of future returns and is the best indicator of those expectations.[7] Staff then added the resulting dividend yield to its estimate of a dividend growth rate. To reach its dividend growth rate determination, Staff used a combination of historical and projected dividend-per-share ("DPS") growth provided by *Value Line,* and also examined historical and projected growth in earnings-per-share ("EPS") and intrinsic growth. Staffs analysis produced an average of historic and projected growth rates of 5.8 percent, which when added to Staffs dividend yield calculation of 3.3 percent, produced Staffs constant growth DCF estimate of 9.1 percent. Staffs multi-stage DCF model incorporates two growth rates; a near term growth rate and a long-term growth rate to account for the assumption that investors expect dividends to grow at a non-constant rate in the near term (stage 1 growth) and then to grow at a constant rate in the long term (stage 2 growth) (Ramirez Dt. at 23). To calculate stage 1 growth, Staff forecasted four years of dividends for each of the utilities in the sample group using *Value Line's* expected dividends for the first year and projected DPS growth rate for the three subsequent years; and to estimate its stage 2 growth, Staff used the 6.5 percent rate of GDP growth from 1929 to 2003, which Staff believes is appropriate because it assumes that the water industry is expected to grow neither faster nor slower than the overall economy (Ramirez Dt. at 24). Staff reached a multi-stage DCF estimate of 9.5 percent. Staff calculated its overall DCF estimate of 9.3 percent by averaging the results of its constant-growth and multi-stage DCF estimates.

Staff also performed a CAPM analysis using a historical market risk premium estimate, reaching an estimate of 9.1 percent, and a current market risk premium estimate, reaching an estimate of 9.3 percent, to reach its overall CAPM estimate of 9.2 percent (Ramirez Dt. at 25-29). Based on its DCF and CAPM estimates, Staff recommends a cost of equity of 9.3 percent.

[7] Ramirez Dt. at 15. Use of spot market price has been adopted in recent Commission Decisions, including *Arizona Water Company,* Decision No. 66849 (March 19, 2004), and *Arizona-American Water Company,* Decision No. 67093 (June 30, 2004).

Staff disagrees with the Company's use of the FERC DCF analysis because it miscalculates dividend yields and relies only on analysts' forecasts, which are overly optimistic (Ramirez Dt. at 40-41). Staff states that the FERC DCF multi-stage analysis relies more heavily on analysts' forecasts than on GDP growth, and asserts that it is more reasonable to rely on the GDP than on analysts' forecasts, which are known to be overly optimistic (Ramirez Dt. at 42-45). Staff further argues that the FERC multi-stage DCF analysis assumes that the water industry will grow indefinitely at a rate that outpaces the historical GDP growth, which is impossible. Staff also asserts that Dr. Zepp's modification of Staffs multi-stage DCF analysis introduces a supernormal growth stage between stage 1 and stage 2 growth in Staffs model (Ramirez Sb. at 10). Staff addresses Dr. Zepp's criticism of its use of the geometric average, and not the arithmetic average, of GDP growth. Staff states that while the arithmetic mean represents typical performance over single periods, it is more appropriate to use the geometric average because it better represents long-term performance (Ramirez Sb. at 11).

Staff is also critical of Chaparral City's use of the CPUC staffs risk premium analysis to estimate its cost of equity, because the risk premium analysis erroneously assumes that accounting ROEs are equal to the cost of equity. Staff states that this assumption is contrary to the basic proposition in finance that cost of equity is less than the allowed rate of return on equity, and argues that the risk premium analysis used by the CPUC staff is flawed due to its suggestion that investors' actual cost of equity is lower than historical or book ROE. Staff believes that reliance on a risk premium analysis comparing allowed ROEs to the cost of equity is misplaced because it is capital markets, not regulatory commissions, that determine the cost of equity. Staff argues that although certain ROEs may have been allowed in prior regulatory decisions, there are numerous factors which are not always identified in a commission decision that may have influenced the rate of return approved in a particular proceeding; that the particulars behind each case cannot always be known; and that even if the particulars were known, the witnesses who testified in those past cases are not ıvailable for cross-examination in this case (Ramirez Dt. at 51).

Staff is also critical of Dr. Zepp's use of forecasted interest rates, rather than spot market ·ates, to conduct his risk premium analysis. Staff asserts that Dr. Zepp's reliance on forecasts of ten-rear Treasury securities, long-term Treasury securities, and Baa corporate bond rates are biased, and ırgues that the best forecast of tomorrow's yield is simply today's yield (Ramirez Dt. at 47-49). In esponse to Dr. Zepp's argument that the sample water companies Staff used are not representative of Chaparral City because Chaparral City has more systematic risk than the sample companies, Staff rgues that Chaparral City and the sample water companies are in the same business and should have ·n average the same systematic risk, and that no evidence was submitted to support the Company's laim otherwise with regard to potential rate base disallowances, existence of or lack of adjustment iechanisms, or transitions to a multi-tier declining block rate design (Ramirez Dt. at 35-39). Staff rgues that market risk is related to economy-wide perils that affect all businesses, such as inflation, ıterest rates and general business cycles, and that unique risk does not affect the cost of equity, ecause firm-specific risk can be eliminated through shareholder diversification. Staff asserts that its ssumption that all water companies have similar betas is therefore reasonable, and states that even if taff had not performed a CAPM analysis, its cost of equity recommendation would still be 9.3 ercent based on its DCF estimates.

3. **RUCO**

RUCO believes that given the current environment of low inflation and low interest rates, its .45 percent cost of equity estimate is reasonable; that despite the fact that Chaparral City's equity ·vel is slightly higher than the average of the sample companies (59 percent as compared to 56 ercent) RUCO did not make a downward adjustment to its DCF estimates; that its DCF growth rate stimates exceed analysts' growth rates by 49 to 60 basis points; and that its recommended 9.45 ercent cost of equity estimate is extremely close to the 9.50 ROE *Value Line* projection for

American States, Chaparral City's parent, for the 2005 operating period (Rigsby Dt. at 41). RUCO i critical of the Company's reliance on securities analysts' projections alone to arrive at its estimates o growth without attributing any significance to historical data, and points out that Mr. Rigsby': estimates take into account the fact that past projections of *Value Line* analysts have tended to b somewhat higher than the actual returns on the common equity of water utilities. RUCO states tha its methodology for determining the "sv" component of Mr. Rigsby's DCF growth figure, rather thar being subjective, as the Company charges, objectively relies on the work of Dr. Roger A. Morin a well as other academics in the field of finance and the resulting theory that the market price of a utility's common stock will 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 (Rigsby Dt. at 16; Tr. at 318-22; Hearing Exhibit A-16). RUCO points out that while the Company believes Mr. Rigsby's growth estimates are too low, his average "br + sv" growth estimate is 60 basis points higher than the average of *Value Line's* projections on EPS, DPS, and book value per share; that his growth estimate is 185 basis points higher than the average projections of analysts at *Value Line,* and 470 basis points higher than *Value Line's* 5-year average of historical data for the water utilities it follows (Rigsby Dt. at 21).

4. Conclusion

The Company, Staff and RUCO all used a DCF model. The Company's estimates varied ignificantly from Staff and RUCO's estimates due primarily to differences in its dividend growth stimation. We note that while the Company criticized Staff and RUCO for choosing inputs that depressed" their cost of equity estimates, the Company's choices resulted in higher cost of equity stimates. We agree with Staff and RUCO that relying solely on analysts' forecasts of the short-term rowth rate of the water industry may be unreasonable, and believe that averaging past growth rates with growth rate forecasts produces a more reasonable estimate, because analysts' forecasts are nown to be optimistic. We are not convinced that the methodology FERC uses to estimate cost of capital for the energy and gas industry companies it regulates is appropriately applied to monopol\} water utilities. We disagree with the use of a risk premium analysis for cost of equity estimation for the reasons Staff states, as set forth above. We find, after examining the evidence presented, that Staffs DCF methodology provides a more reasonable cost of equity estimate than the Company's. Staff's analysis is based on sound economic principles, and produces a cost of equity estimate that represents a fair and reasonable estimate of Chaparral City's cost of equity for purposes of this proceeding, and will produce a return commensurate with returns on investment in other enterprises with risk corresponding to that of the Company. As described above, Staff arrived at a 9.3 percent cost of equity estimate through application of both the constant growth and multi-stage DCF models and the CAPM.

C. Cost of Capital Summary

	Percentage	Cost	Weighted Cost
Long-Term Debt	41.2%	5.1%	2.1%
Common Equity	58.8%	9.3%	5.5%
Weighted Average Cost of Capital			7.6%

VIII. RATE OF RETURN

Chaparral City advocates that its proposed cost of capital be adopted as a rate of return to be applied to its FVRB to determine required operating income (Bourassa Rb. at 2). Staff recommends that the weighted average cost of capital be used to determine a fair value rate of return in accordance with the Commission's traditional rate of return methodology. As stated earlier, RUCO recommends that its recommended OCRB be adopted as the Company's FVRB without regard to the Company's RCND, and recommends that its proposed weighted average cost of capital be applied to the resulting FVRB.

The Company claims that both Staff and RUCO "ignored FVRB" when they multiplied their recommended rates of return by their recommended OCRBs to determine Chaparral City's operating income, and then divided the operating income by the FVRB to compute a fair value rate of return (Co. Br. at 6-7). The Company claims that this methodology results in rates based solely on origina cost rather than fair value *(Id.)*. The Company further claims that the approach advocated by Staf and RUCO violates the fair value standard (Co. Br. at 10).

RUCO argues that this Commission has historically and consistently averaged a utility's OCRB and RCND to determine a FVRB and then computed a fair value rate of return to apply to FVRB in calculating operating income (RUCO Reply Br. at 3). RUCO asserts that the Company is attempting to persuade the Commission to approve an operating income methodology that considers rate base and rate of return on two different bases, and that its arguments should be rejected, because f rate base and rate of return are not stated on the same basis, operating income will be overstated RUCO Br. at 1-2).

Staff states that in this case, Staff has considered and recommended a finding of fair value and a fair rate of return on that fair value. Staff states that in order to ensure that the Company is given he opportunity to earn a fair rate of return on the fair value of its plant, Staff proposed a cost of apital analysis, and based on its analysis, proposed a weighted average cost of capital which, when pplied to the Company's OCRB, yields just and reasonable rates. Staff further states that its ecommended FVRB similarly provides the Company with an opportunity to earn its cost of capital, nd that allowing a higher rate of return on the Company's FVRB than the return Staff recommends vould provide the utility with an opportunity to earn windfall profits, and would not yield just and easonable rates as required by Article XV, Section 3 of the Arizona Constitution (Staff Br. at 8).

We disagree with the Company's assertion that the rate of return methodology used by this Commission to determine revenue requirement violates the fair value standard. The Company ttempts to equate the weighted average cost of capital to a rate of return, when in fact, this cost of apital estimate is used as a tool to determine a just and reasonable rate of return. The rate of return methodology and resulting revenue increase proposed by Chaparral City would produce an excessive return on FVRB. There has been no legitimate basis presented for departing from the traditional ratemaking methodology of applying a fair value rate of return to the Company's FVRB in this proceeding. For the reasons advocated by Staff and RUCO, we find that applying a fair value rate of return to the FVRB is just, reasonable, and in accord with the mandates of the Arizona Constitution, and will adopt it in this case.

IX. AUTHORIZED INCREASE/DECREASE

With the adjustments adopted herein, the adjusted test year operating income is $614,247. The 7.6 percent cost of capital translates into a 6.36 percent fair value rate of return on FVRB of $20,340,298 as authorized hereinabove. Applying the 6.36 percent rate of return to the FVRB produces required operating income of $1,294,338. This is $680,091 more than the Company's test year adjusted operating income. Multiplying the deficiency by the gross revenue conversion factor of 1.6286 results in an increase in revenues of $1,107,596, or a 17.86 percent net increase over test year adjusted revenues.

X. RATEDESIGN

In its rate application, the Company proposed a two-tier, inverted block rate design, with different breakover points for each size meter based on its cost of service study (Kozoman Dt. at 11-20, Exh. A-14, Sched. G-1 through G-9). In its rebuttal filing, the Company accepted nearly all of the elements of Staffs proposed rate design, including the use of three inverted commodity rate tiers for residential customers on ¾-inch meters, with all other customers having two inverted commodity rate tiers; Staffs recommended breakover points between tiers; elimination of the current additional charge to recover costs for pumping water to elevation zones two and three; elimination of the 1,000 gallons of water in the monthly minimum charge; and the continuation of a single, uniform volume rate for irrigation water service (Kozoman Rj. at 34, Tr. at 771-74). Staffs recommended breakover points for %-inch residential meters are 3,000 gallons and 9,000 gallons; and for %-inch commercia and industrial meters, one breakover point of 9,000 gallons; with increasing single breakover point as meter sizes increase. The Company states that it recognizes the importance of encouraging wate conservation, including the use of rate design to encourage customers to implement conservatioı measures and reduce their water use (Co. Reply Br. at 37). The Company disagrees, however, witl Staffs recommended spread between the commodity rates and also with the commodity rates Staf recommends for irrigation water service.

Chaparral City contends that Staffs recommended inverted tier rate design with its proposec spread between commodity rates may lead to reduced water use by customers, and that if it does, the -ate design will impact its ability to earn its authorized rate of return. The Company believes thai Staff is actually proposing a "lifeline" rate because Staffs recommended commodity rate for the first ier is below the Company's existing commodity rates, and is only applicable to residential customers ›n ¾" meters, and that Staff is using the subsidy of the lower rate for first tier usage to create a larger spread between the tiered commodity rates. The Company asserts that rates should be designed in a vay that accounts for possible reductions in water use (Co. Br. at **54-55)**, and urges that the risk that a ıew rate design may lead to under-recovery of the Company's authorized revenue requirement hould be recognized in the return on equity authorized in this proceeding *(Id.* at 58). Taking the lternative point of view, the Company also argues on brief that if Staffs recommended rate design vill not reduce existing customers' water usage, it should not be required to implement inverted tier ates (Co. Br. at 59).

Staff asserts that its inverted tier rate design was developed to promote long term conservation oals, and includes commodity rates that are spread far enough apart to send appropriate price signals › customers regarding the importance and value of water, which is a limited resource in this state. taff disputes the Company's assertion that its first tier is a "lifeline" rate, because its proposal is not designed according to income level, but instead is focused on sending an appropriate price signa based on customers' meter size and usage (Staff Br. at 4). Staff states that it cannot predict whethei customers will actually decide to use less water in a particular year; that no evidence was presented supporting the Company's claim that there will be a significant short-term change in water use as a result of the implementation of inverted-tier rates; and that the Company's service area still has a rapidly-growing customer base (Staff Reply Br. at 3).

RUCO proposes a rate design that charges each customer the same commodity rate for the same level of usage (RUCO Br. at 14). RUCO's three tier inverted block rate structure has its first breakover point at 8,000 gallons, the present average residential usage, with the second breakover point at 73,000 gallons, which it calculated based on the average of the Company's original proposed graduated breakover points (Moore Dt. at 32). RUCO believes this rate design provides a balanced approach that does not discriminate between classes or meter sizes, and that since its breakover points are based on average customer usage, provides a price incentive against above-average use, which ould result in the conservation of water resources (RUCO Reply Br. at 9).

The Company disagrees with RUCO's rate design because it shifts revenue recovery away rom residential customers, who have smaller meters, and onto commercial and industrial customers, who have larger meters. The Company believes that RUCO's rate design is inequitable to customers on larger sized meters because customers with smaller meters will have a substantial portion of their sage fall into the lower-priced rate block, with little of their usage reaching into the highest price ate block, while customers with larger meters will have the bulk of their usage fall into the higher ers, without regard to whether their water usage is excessive or wasteful.

Of the rate designs presented, we find that Staffs proposal best addresses the goals of onservation, efficient water use, affordability, fairness, and simplicity.[8] We find also that the risk of

Public comment was presented concerning the Company's irrigation rates as originally proposed by the Company. We ste that the irrigation commodity rate we approve herein remains lower than other commodity rates.

revenue instability that the Company fears is sufficiently offset by the current growth in the Company's customer base to allow the implementation of a conservation-oriented rate design at this time. Although the Company provided testimony speculating that Staff's proposed rate design might cause such drastic reductions in water usage that the Company would be unable to recover its authorized revenue requirement, we do not find this conjecture convincing. As Staff's uncontroverted growth analysis demonstrates, the Company still has a growing customer base (*see* Scott Dt., Exhibit MSJ at 5), and new growth will be available to compensate for possible reductions in usage by existing customers, if demand proves to be elastic and existing customers respond to the conservation signals by reducing their usage in response to the new rate design. If, even with customer growth, the Company finds it is not recovering its authorized revenue requirement, it is within the Company's control to file a rate case. After considering the evidence presented, we find hat it is in the public interest for the Company to implement the conservation-oriented rate design ›roposed by Staff.

XI. OTHER ISSUES

A. Automatic Adjustment Mechanisms

The Company requests approval to implement automatic adjustment mechanisms which would allow the Company to directly pass through to its ratepayers increases and decreases in two of :s most significant operating expenses, purchased water and power costs, through a surcharge mechanism.[9] Staff and RUCO recommend against approval of the requested adjustment mechanisms.

Approximately 90 percent of the Company's water supply comes from Central Arizona Project ("CAP") water delivered through the Central Arizona Water Conservation District ("CAWCD") (Hanford Rb. at 3). Under its subcontract with the United States and CAWCD,

9 Adjusted test year purchased water costs are $823,781 and adjusted test year purchased power costs are $510,947.

Chaparral City pays an annual water service capital charge, based on its total CAP allocation, and a separate delivery charge based on the amount of CAP water actually used (Hanford Dt. at 6). Chaparral City is also a member of the Central Arizona Groundwater Replenishment District ("CAGRD") administered by CAWCD. The Company pays fees to the CAGRD for groundwater replenishment services based on the quantity of ground water pumped (Hanford Dt. at 6-7). The Company's witness claims that based on the advisory rates published by CAWCD for the years 2006. 2007 and 2008, purchased water costs will increase over the adjusted test year level by more than $50,000 per year by 2008 and that these increases will amount to over $100,000 of unrecovered water expense over the three year period (Bourassa Rj. at 24).

Chaparral City purchases power from both APS and SRP. The Company projects annual expense increases from SRP and APS of over 5 percent per year over adjusted test year levels (Co. Br. at 24).

Staff agrees that the Company's purchased water costs are significant, but in contrast to the Company's estimate that its purchased water expense will increase by more than $50,000 per year, Staffs analysis of advisory rates showed that the Company's purchased water expense will not increase over test year levels by $50,000 until 2008 (Exh. S-7, Exh. 5). Staff does not believe that the incremental cost level or volatility associated with possible rate increases or decreases associated with the Company's water supply are significant enough to justify a purchased water adjustment mechanism in this case, and recommends denial of the Company's request. Regarding purchased power expense, Staff does not disagree that purchased power expense is a significant cost for Chaparral City, but points out that the issue to be considered in implementing an adjustment mechanism is not merely whether the cost is significant, but whether the incremental cost level, or volatility, associated with possible rate increases or decreases is significant. Staff asserts that the future rate increases the Company projects from SRP and APS do not constitute a level of volatility great enough to warrant the need for a purchased power adjustment mechanism. In particular, Staf differentiates the possible increases in Chaparral City's purchased power expense from the volatility of APS' constantly changing fuel and purchased power costs, which led to the Commission's recen approval of a Power Supply Adjustor for APS.

We do not disagree with the Company that its purchased water and purchased power expense: are significant. However, we agree with Staff and RUCO that these expenses do not constitute a level of volatility that would justify the extraordinary ratemaking treatment that the Company requests. As we stated in Decision No. 56450, there is a danger of piecemeal regulation inherent ir adjustment mechanisms. Because adjustor mechanisms allow automatic increases in rates without a simultaneous review of a Company's unrelated costs, an adjustment mechanism has a built-ir potential of allowing a Company to increase rates based on certain isolated costs when its other costs are declining, or when overall revenues are increasing faster than costs due to customer growth. Such circumstances can result in increases to ratepayers through adjustors even when the Company's level of earnings would not warrant a rate increase, such that the utility's net income is increased outside a rate case. In addition, as we stated in Decision No. 66849 (March 19, 2004), adjustment mechanisms may also provide a disincentive for a utility to obtain the lowest possible cost commodity because the costs are simply passed through to ratepayers. For these reasons, adjustment mechanisms should be implemented only under very special circumstances. Based on the evidence in this proceeding, circumstances do not exist in this case to justify the risks of piecemeal regulation inherent in adjustment mechanisms, and we will not approve the Company's requests.

On July 28, 2005, the Company filed a request that administrative notice be taken of an application filed on July 22, 2005 in Docket No. E-01345A-05-0526 by APS requesting recovery of 100 million in unrecovered fuel and purchased power costs through the Power Supply Adjustor mechanism approved in Decision No. 67744 (April 7,2005). The July 28,2005 filing also requested that administrative notice be taken of SRP's announcement that it intends to increase its residentia and business rates on or about November, 2005. The Company asserts that the APS filing and th€ SRP announcement are relevant to its request for authorization of a purchased power adjustmeni mechanism.

We note that the Commission has not ruled on the APS PSA request, and that the SRP announcement indicated an effective date of November 2005. This means that future changes in SRP's rates, and any changes to APS' rates resulting from its July 22, 2005 filing, will take place nore than one and a half years following the end of the 2003 test year in this case. As explained ıbove, the expenses we approve herein already include an adjustment for known and measurable ›ost-test year changes in the Company's electricity costs. The Company indicated that it is likely to ile another rate case within three to four years (Tr. at 647; Bourassa Dt. at 14). If the Company :xperiences a further increase in costs during 2006 as a result of the anticipated SRP increase, or as a esult of a Decision on the APS filing, it will be appropriate to examine such increases in the context ›f the Company's other concurrent expenses, rather than simply authorizing the Company to pass hose costs through to ratepayers.

B. Depreciation Rates

The Company is proposing to utilize the depreciation rates proposed by Staff on a going orward basis. Staff has developed typical and customary depreciation rates within a range of nticipated equipment life by individual National Association of Regulatory Utility Commissioners "NARUC") category (Scott Dt., Exhibit MSJ at 7, 16). These are the depreciation rates that have een adopted in recent rate cases (See, *e.g.* Decision No. 67279 (October 5,2004) (Rio Rico Utilities, ıc.)). RUCO disagrees with the use of these depreciation rates, which it states are among the highest ates the Commission has recently approved. In the absence of a depreciation study, which would ave provided a definitive set of depreciation rates, RUCO proposes depreciation rates that it states epresent an average of 24 different water systems. The Company criticizes the methodology RUCO ised to develop its proposed depreciation rates, because it mixes composite rates with individual iepreciation rates by plant category in order to calculate average rates, and because the resulting iepreciation rates were not compared with the expected useful lives of the assets to which they would ɔe applied (Tr. at 554-555). We find that the Staff proposal more closely estimates the expected life ɔf the Company's assets than RUCO's proposal, and will order the Company to adopt the typical and customary depreciation rates that Staff has developed as set forth in Mr. Scott's Direct Testimony, Exhibit MSJ at 16.

C. **Cross-Connection and Backflow Prevention Tariff**

Attached to Company witness Mr. Hanford's direct testimony was a proposed cross-connection and backflow prevention tariff. There was no objection or comment on the proposed tariff during this proceeding and the Company requested that it be approved. We will therefore approve it and require that a conforming copy of the tariff be filed along with the tariffs for its new rates.

D. **Water Service Curtailment Tariff**

Also attached to Mr. Hanford's direct testimony was a water service curtailment tariff. In Staffs direct testimony, Staff proposes an alternative form of tariff similar to tariffs approved in the past for Class A water utilities. The Company is in agreement with Staffs proposed form of tariff and requests that it be approved. Staff recommends that the Company be directed to file a copy of a water service curtailment tariff within 45 days of this Decision, for Staffs review and certification. We will therefore direct the Company to file a copy of the tariff in conformance with the form of tariff attached to the direct testimony of Mr. Scott in Exhibit MSJ at 8, within 45 days of this Decision, for Staffs review and certification.

E. Non-Account Water

Staff notes in its direct testimony that Chaparral City's non-account water was over 11 percent, which exceeds Staffs recommendation that non-account water should be 10 percent or less. Staff states that the Company is aware of its non-account water and believes that some of its meters are being under read and that the Company is currently monitoring its meter reading practices. Staff recommends that the Company docket the results of meter monitoring as a compliance item in this case by July 30,2006; that if the reported water loss for the period from June 1,2005 through June 1, 2006 exceeds 10 percent, that the Company be required to prepare either a report containing a detailed analysis and a plan to reduce non-account water to below 10 percent, or to submit a cost-benefit analysis demonstrating that it is not cost-effective to reduce non-account water below 10 percent. The Company did not object to Staffs recommendation. We will adopt Staffs recommendation in this case.

F. Arsenic Issues

As noted above, 90 percent of Chaparral City's water supply consists of treated CAP water. However, the Company has two active wells, Well Number 10 and Well Number 11, which show concentrations of arsenic slightly above the 10 parts per billion maximum contaminant level ("MCL") for arsenic that will become effective in January, 2006 (Scott Dt., Exh. MSJ at 5). Staff notes in its direct testimony that a blend line has already been constructed to Well Number 10 and that the Fountain Hills Boulevard main will be used to blend CAP water with ground water from Well Number 11 *(Id.)*. The Company does not object to Staffs recommendation that the Company be required to submit, by November 30, 2005, a plan describing how the Company will comply with the new arsenic MCL when the CAP canal is out of service. We find this recommendation to be reasonable and will adopt it.

* * * * * * * * * *

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

FINDINGS OF FACT

1. Chaparral City is a public service corporation engaged in providing water utility service to approximately 12,000 customers located in the northeastern portion of the Phoenix metropolitan area, including the Town of Fountain Hills and a small portion of the City of Scottsdale under authority granted by the Commission in Decision No. 41243 (April 20, 1971). The Company's business office is located at 12021 N. Panorama Drive in Fountain Hills, Arizona, 85268.

2. Chaparral City is currently charging rates approved in Decision No. 57395 (May 23, 1991), based on a test year ended December 31, 1988.

3. Chaparral City is an Arizona corporation wholly owned by American States Water Company, which is publicly traded on the New York Stock Exchange. American States' primary operating subsidiary is Southern California Water Company.

4. In October 2000, as approved in Decision No. 62909 (September 18, 2000), American States purchased Chaparral City's stock from MCO Properties, Inc., the real estate developer that owned and operated Chaparral City.

5. On August 24, 2004, Chaparral City filed with the Commission an application requesting an increase in revenues of $1,797,182.

6. On September 14, 2004, RUCO filed an Application to Intervene, which was granted. No other requests for intervention were filed.

7. On September 23, 2004, Staff filed a letter stating that the Company's application met the sufficiency requirements set forth in A.A.C. R14-2-103, and classifying the Company as a Class A utility.

8. On September 28, 2005, a Procedural Order was issued setting this matter for hearing and setting related procedural deadlines.

9. On February 15, 2005, the Company filed a Notice of Publication certifying that public notice was published in *The Fountain Hills Times* on January 26, 2005. Public notice of the

application and hearing was also mailed to each of the Company's customers in their January 200! bills.

10. Written public comments in opposition to the amount of the requested rate increas were received on February 10, February 14, February 28, March 10, March 23, April 8, April 20 April 21, May 24, May 31,[10] and June 14,2005.

11. A hearing was held as scheduled commencing on May 31, 2005 and continuing on une 1, June 6 and June 8,2005.

12. Public comment opposing the proposed increase in irrigation rates was provided on "lay 31, 2005 by Ken Watkins, the golf course superintendent of the FireRock Country Club. Mr. Natkins also filed written public comment in this docket on March 23, 2005 and June 14,2005. Mr. Natkins stated that FireRock would be adversely impacted by the rate increase because even though he golf course uses effluent when possible, it sometimes must rely on potable water.

13. Public comment against the proposed increase in irrigation rates was also provided on hay 31,2005 by Joe Miller, the golf course superintendent of The Golf Club at Eagle Mountain. Mr. hiller also stated that his golf course sometimes must use potable water for irrigation, and that it vould be adversely affected by the proposed rate increase. Mr. Miller also filed written public omment in this docket on April 8,2005 and May 24,2005. Don Rea, the General Manager of The iolf Club at Eagle Mountain also filed a letter dated April 5, 2005 opposing the increase in irrigation ates on April 21,2005 and again May 24,2005.

14. For ratemaking purposes, Chaparral City's OCRB, RCND and FVRB for the test year nded December 31, 2003 are determined to be $17,030,765, $23,649,830, and $20,340,298, espectively.

15. With the adjustments adopted herein, the adjusted test year operating income is 614,247.

16. The 7.6 percent cost of capital translates into a 6.36 percent fair value rate of return on VRB of $20,340,298 as authorized hereinabove. Applying the 6.36 percent rate of return to the

The public comment letter filed on May 31,2005 (the date the hearing commenced) included a request by a customer at a "rate adjustment" made in 2003 be investigated. If the Commission's Consumer Services Section has not already one so, it should promptly contact this customer, and inform the Commission if further action is required.

FVRB produces required operating income of $1,294,338. This is $680,091 more than the Company's test year adjusted operating revenue. Multiplying the deficiency by the gross revenue conversion factor of 1.6286 results in an increase in revenues of $1,107,596, or a 17.86 percent net increase over test year adjusted revenues.

17. The rates set herein result in a monthly increase of $3.83, from $30.49 to $34.32, or 12.57 percent, for the average usage residential customer (9,187 gallons), and a monthly increase of $2.41, from $22.53 to $24.94, or 10.70 percent, for the median usage (5,501 gallons) residential customer.

18. The rate of return methodology and resulting revenue increases proposed by Chaparral City would produce an excessive return on FVRB.

19. It is in the public interest to implement a rate design that promotes long-term conservation goals.

20. The rate design approved herein addresses the goals of conservation, efficient water use, affordability, fairness, simplicity, and revenue stability, and is in the public interest.

21. The methodology adopted herein for estimation of property tax expense fairly estimates property tax expense.

22. Based on the evidence presented, circumstances do not exist in this case to justify the risks of piecemeal regulation inherent in adjustment mechanisms, and Chaparral City's request to implement automatic adjustment surcharge mechanisms for its purchased power and purchased water costs will not be approved.

23. The typical and customary depreciation rates developed by Staff as set forth on page 6 of Exhibit MSJ attached to the Direct Testimony of Staff witness Mr. Scott are just and reasonable and should be used by Chaparral City on a going-forward basis.

24. The cross-connection and backflow prevention tariff attached to the Direct Testimony of Mr. Hanford is reasonable and should be approved. Chaparral City should be required to file a conforming copy of the tariff when it files the tariffs setting forth the new rates we approve herein.

25. Staffs recommendation that the Company be directed to file a copy of a water service curtailment tariff that conforms to the form of tariff attached to the direct testimony of Mr. Scott in

Exhibit MSJ at 8, within 45 days of this Decision, for Staffs review and certification, is reasonable and should be adopted.

26. Staffs recommendation regarding meter monitoring and reporting in relation to Chaparral City's 11 percent test year level of non-account water is reasonable and should be adopted:

27. Staffs recommendation that Chaparral City be required to submit, by November 30, 2005, a plan describing how it will comply with the new arsenic MCL when the CAP canal is out of service, is reasonable and should be adopted.

28. Because an allowance for the property tax expenses of Chaparral City Water Company, Inc. is included in the Company's rates and will be collected from its customers, the Commission seeks assurances from the Company that any taxes collected from ratepayers have been remitted to the appropriate taxing authority. It has come to the Commission's attention that a number of water companies have been unwilling or unable to fulfill their obligation to pay the taxes that were collected from ratepayers, some for as many as twenty years. It is reasonable, therefore, that as a prophylactic measure Chaparral City Water Company, Inc. annually file, as part of its annual report, an affidavit with the Utilities Division attesting that the Company is current in paying its property taxes in Arizona.

29. As discussed herein, it is reasonable to require Chaparral City to cease charging hook-up fees until such time that it has an approved hook-up fee tariff on file.

30. The Maricopa County Environmental Service Department has determined that the Company's system is currently delivering water that meets water quality standards required by Title 18, Chapter 4 of the Arizona Administrative Code.

31. The Company is located in the Phoenix Active Management Area ("AMA") and is therefore subject to the Arizona Department of Water Resources' water use and monitoring requirements. The AMA has reported that the Company is in compliance with its water use and monitoring requirements.

32. The fair value rate base, fair value rate of return, and rates and charges adopted herein are just and reasonable.

CONCLUSIONS OF LAW

1. Chaparral City is a public service corporation within the meaning of Article XV of the Arizona Constitution and A.R.S. Sections 40-250 and 40-241.

2. The Commission has jurisdiction over the Company and the subject matter of the application.

3. Notice of the application was provided in the manner prescribed by law.

ORDER

IT IS THEREFORE ORDERED that Chaparral City Water Company, Inc. is hereby directed to file with the Commission on or before September 30, 2005, the following revised schedules of rates and charges:

MONTHLY USAGE CHARGE:	
(All Zones and Classes)	
¾" Meter	$ 13.60
1" Meter	22.70
1 ½" Meter	45.40
2" Meter	73.00
3" Meter	146.00
4" Meter	227.00
6" Meter	454.00
8" Meter	730.00
10 Meter	1,043.00
12 Meter	1,980.00
Fire Hydrants - Basic Service	No Monthly Usage Charge
Fire Hydrants – Used for Irrigation	$146.00
Commodity Rates Per 1,000 Gallons	
¾" Meter (Residential)	
From 1 to 3,000 Gallons	$1.68
From 3,001 to 9,000 Gallons	2.52
Over 9,000 Gallons	3.03
¾" Meter (Commercial and Industrial)	
From 1 to 9,000 Gallons	2.52
Over 9,000 Gallons	3.03
1" Meter (Residential, Commercial and Industrial)	
From 1 to 24,000 Gallons	2.52
Over 24,000 Gallons	3.03

1 ½" Meter (Residential, Commercial and Industrial)	
From 1 to 60,000 Gallons	2.52
Over 60,000 Gallons	3.03
2" Meter (Residential, Commercial and Industrial)	
From 1 to 100,000 Gallons	2.52
Over 100,000 Gallons	3.03
3" Meter (Residential, Commercial and Industrial)	
From 1 to 225,000 Gallons	2.52
Over 225,000 Gallons	3.03
4" Meter (Residential, Commercial and Industrial)	
From 1 to 350,000 Gallons	2.52
Over 350,000 Gallons	3.03
6" Meter (Residential, Commercial and Industrial)	
From 1 to 725,000 Gallons	2.52
Over 725,000 Gallons	3.03
8" Meter (Residential, Commercial and Industrial)	
From 1 to 1,125,000 Gallons	2.52
Over 1,125,000 Gallons	3.03
10" Meter (Residential, Commercial and Industrial)	
From 1 to 1,500,000 Gallons	2.52
Over 1,500,000 Gallons	3.03
12" Meter (Residential, Commercial and Industrial)	
From 1 to 2,250,000 Gallons	2.52
Over 2,250,000 Gallons	3.03
Irrigation/Bulk (All Meters)	
All Gallons	1.56
Fire Hydrant Irrig./Const. (All Meters)	
All Gallons	1.56
(Standpipe) Fire Hydrants	

All Gallons	2.52
Fire Sprinklers	
All Gallons	2.52

~~Service Line and Meter Installation~~ Charges	Meter		Total
5/8" x ¾" Meter	$135.00	$385.00	$520.00
¾" Meter	215.00	385.00	600.00
1" Meter	255.00	435.00	690.00
1 %"Meter	465.00	470.00	935.00
2" Turbine Meter	965.00	630.00	1,595.00
2" Compound Meter	1,690.00	630.00	2,320.00
3" Turbine Meter	1,470.00	805.00	2,275.00
3" Compound Meter	2,265.00	845.00	3,110.00
4" Turbine Meter	2,350.00	1,170.00	3,520.00
4" Compound Meter	3,245.00	1,230.00	4,475.00
6" Turbine Meter	4,545.00	1,730.00	6,275.00
6" Compound Meter	6,280.00	1,770.00	8,050.00
8" & Larger	At Cost	At Cost	At Cost

Establishment	$25.00
Establishment (After Hours)	35.00
Reconnection (Delinquent)	35.00
Reconnection (Delinquent and After Hours)	50.00
Meter Test	35.00
Deposit Requirement (Residential)	*
Deposit Requirement (Non Residential Meter)	*
Hydrant Meter Deposit	50.00
Deposit Interest	*
Re-establishment (within 12 months)	**
Re-establishment (after hours)	**
NSF Check	25.00
Deferred Payment, per month	1.50%
Meter Re-read	25.00
Charge of moving customer meter- Customer Requested	cost
After hours service charge	Refer to above service charges
Late Charge per month	1.50%

Monthly Service Charge for Fire Sprinkler

4" or smaller	$10.00
6"	10.00
8"	10.00

10"	10.00
Larger than 10"	10.00

*

** Per Commission rule A.A.C. R-14-2-403(B).

Months off system times the monthly minimum per Commission rule A.A.C. R14-2-403(D).

*** 1% of monthly minimum for a comparable size meter connection, but no less than $5.00 per month. The service charge for fire sprinklers is only applicable for service lines separate and distinct for the primary water service line.

In addition to the collection of regular rates, the utility will collect from its customers a proportionate share of any privilege, sales, use and franchise tax, per Commission Rule R14-2-409D(5).

All advances and/or contributions are to include labor, materials, overheads and all applicable taxes, including all gross-up taxes for income taxes, if applicable.

IT IS FURTHER ORDERED that the revised schedule of rates and charges approved herein hall be effective for all service rendered after September 30,2005.

IT IS FURTHER ORDERED that Chaparral City Water Company, Inc. shall notify its ustomers of the revised schedules of rates and charges authorized herein by means of an insert in its ext regularly scheduled billing in a form and manner acceptable to the Commission's Utilities)ivision Staff.

IT IS FURTHER ORDERED that the cross-connection and backflow prevention tariff ttached to the Direct Testimony of Mr. Hanford is hereby approved.

IT IS FURTHER ORDERED that Chaparral City Water Company, Inc., shall file in Docket lontrol, as a compliance item in this case, a conforming copy of the cross-connection and backflow revention tariff approved herein by September 30,2005.

IT IS FURTHER ORDERED that Chaparral City Water Company, Inc. shall file in Docket 'ontrol, as a compliance item in this case, within 45 days, a water service curtailment tariff onforming to the form of tariff attached to the direct testimony of Mr. Scott in Exhibit MSJ at 8. for taffs review and certification.

IT IS FURTHER ORDERED that Chaparral City Water Company, Inc. shall file in Docket 'ontrol, as a compliance item in this case, by November 30, 2005, a plan describing how it will imply with the United States Environmental Protection Agency rule regarding the maximum contaminant level for arsenic when the Central Arizona Project canal from which it takes water delivery is out of service.

IT IS FURTHER ORDERED that in recognition of ongoing drought conditions in Arizona, the Company shall provide the Commission within 1 year of the effective date of this order detailed plans on how the Company's customers could increase the use of effluent and reduce their reliance on groundwater specifically as it pertains to golf courses, ornamental lakes and other aesthetic water features.

IT IS FURTHER ORDERED that Chaparral City Water Company, Inc. shall annually file, as part of its annual report, an affidavit with the Utilities Division attesting that the Company is current in paying its property taxes in Arizona.

IT IS FURTHER ORDERED that Chaparral City Water Company, Inc. shall cease charging hook-up fees until such time that it has an approved off-site facilities hook-up fee tariff on file.

IT IS FURTHER ORDERED that Chaparral City Water Company, Inc. shall adopt the typical and customary depreciation rates developed by Staff as set forth on page 16 of Exhibit MSJ attached to the Direct Testimony of Staff witness Mr. Scott.

IT IS FURTHER ORDERED that Chaparral City Water Company, Inc. shall file in this docket, as a compliance item in this case, by July 30,2006, the results of its meter monitoring for the period from June 1,2005 through June 1,2006. If the reported water loss for the period from June 1, 2005 through June 1, 2006 exceeds 10 percent, Chaparral City Water Company, Inc. shall file, by September 30, 2006, either: 1) a report containing a detailed analysis and a plan to reduce non-account water to below 10 percent, or 2) a cost-benefit analysis demonstrating that it is not cost-effective to reduce non-account water below 10 percent.

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IT IS FURTHER ORDERED that Chaparral City Water Company, Inc.'s requests for approval of automatic adjustment mechanisms for its purchased water costs and purchased power costs are hereby denied.

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

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN

COMMISSIONER

COMMISSIONER

COMMISSIONER

COMMISSIONER

IN WITNESS WHEREOF, I, BRIAN C. McNEIL, Executive Director of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 30th day of Sept., 2005.

BRIAN C. McNEIL
EXECUTIVE DIRECTOR

DISSENT ____________________

DISSENT ____________________

SERVICE LIST FOR: CHAPARRAL CITY WATER COMPANY

DOCKET NO.: W-02113A-04-0616

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And I'll jump around a little bit here because Mr. Maledon covered several subject areas that I was going to get to as well.

Let me ask you to go to your Schedule 7?

A. Sure. I have that.

Q. I just wanted to clarify a couple of things there. The top half of Schedule 7 is obviously identifying the comparison group that you used in your testimony; correct?

A. Right. And how I selected the companies in it, yes.

Q. And it lists various criteria in relation to what you see arrayed along the top of Schedule 7?

A. Yes.

Q. Mr. Parcell, explain to me why you pick a comparison group?

A. The short answer or the long answer?

Q. Give me the short answer. It's deep in the lunch hour.

A. You want a grouping that has similar risk and, therefore, a similar expected cost of capital to the subject company.

Q. And believe me, I'm not going to spend much time on this. But basically those are a couple of the factors that you were talking about back on Page 6 of

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The following is the formula that was used to calculate the ICS rates and was applied using residential average by revenue area.

$$\text{ICS} = \frac{[(\text{Therms} \times .3004\ (\text{margin})] + [\$7 \times 12\ \text{months}] - [\text{O\&M} + \text{Other Taxes} + \text{Depreciation}]}{11.93\%\ \ \text{pre-tax return (see below)}}$$

The following is methodology to determine the O&M, taxes and depreciation (O&M costs) to be applied in the above formula.

Combined AZ Gas Division Cost of Service Study 12 Months Ended December 31, 2001 O&M, Taxes and Depreciation	Residential	Commercial	Industrial	Public Auth.	Irrigation
O&M Expenses	$6,139,908	$613,171	$23,011	$67,317	$443
A&G	986,584	37,840	2,649	6,081	12
Other Taxes	3,303,307	848,473	301,004	286,025	1,506
Depreciation Expense					
380-SERVICES	1,314,025	122,219	888	11,865	84
381-METERS	171,719	23,307	895	2,483	16
General Depreciation Expense	571,075	33196	240	2,372	21
Total COS Expenses	$12,486,618	$1,678,206	$328,686	$376,144	$2,081
Total Number of Customers (end 2001)	108,947	10,088	38	957	7
- cost divided by number of customers					
Incremental O&M Cost per Customer	**$115**	**$166**	**$8,578**	**$393**	**$297**

Effective 1/1/06

System Average Annual Usage

Area	Residential
Flagstaff	717
Sedona	705
Holbrook	655
Winslow	676
Show Low	607
Kingman	503
Lake Havasu	271

Prescott	596
Cottonwood	454
Santa Cruz	481

New ICS Calculation

Area	Residential
Flagstaff	$1,549
Sedona	$1,519
Holbrook	$1,393
Winslow	$1,446
Show Low	$1,272
Kingman	$1,010
Lake Havasu	$426
Prescott	$1,244
Cottonwood	$887
Santa Cruz	$955

Combined AZ Gas Division Cost of Service Study 12 Months Ended December 31, 2001 O&M, Taxes and Depreciation	Residential	Commercial	Industrial	Public Auth.	Irrigation
878-METER EXPENSE	710,142	99,155	3,281	10,535	69
879-CUSTOMER INSTALL EXP	624,065	38,365	66	3,553	28
901-SUPERVISION	$83,141	8,218	141	902	4
902-METER READING EXPENSE	$552,087	47,661	1,617	5,415	28
903-CUST RECORDS & COLLECT	$3,856,901	381,076	3,954	38,082	248
904-UNCOLLECTIBLE ACCOUNTS	$50,595	13,521	13,286	6,205	47
905-MISC CUST ACCTS EXP	$137,540	13,577	621	1,520	11
907-SUPERV. CUSTOMER SERV.	$12,791	1,191	4	111	1
908-CUSTOMER ASSISTANCE	$15,122	1,408	5	131	1
909-INFO & INSTRUCTIONAL ADVERT.	$79,045	7,328	27	693	5
910-MISC. CUST. SERV. & INFO.	$18,480	1,672	10	170	1
O&M Expenses	$6,139,908	$613,171	$23,011	$67,317	$443
A&G	986,584	37,840	2,649	6,081	12
Other Taxes	3,303,307	848,473	301,004	286,025	1,506
Depreciation Expense					
380-SERVICES	1,314,025	122,219	888	11,865	84
381-METERS	171,719	23,307	895	2,483	16
General Depreciation Expense	571,075	33196	240	2,372	21
Total COS Expenses	$12,486,618	$1,678,206	$328,686	$376,144	$2,081
Total Number of Customers (end 2001)	108,947	10,088	38	957	7
Incremental Cost per Customer	$115	$166	$8,578	$393	$297

System Average Annual Usage

Area	Residential	Commercial	Industrial	Public Auth.	Irrigation
Flagstaff	717	3,918	42,519	12,059	
Sedona	705	3,165		3,699	
Holbrook	655	2,831		4,958	2,266
Winslow	676	2,700		12,264	
Show Low	607	2,582	315,997	5,828	

Kingman	503	2,573	141,416	3,067	43,220
Lake Havasu	271	4,063		12,979	
Prescott	596	2,191	162,554	5,201	2,351
Cottonwood	454	1,578		4,084	
Santa Cruz	481	2,390		4,566	

Under Current ICS Calculation

Area	Residential	Commercial	Industrial	Public Auth.	Irrigation
Flagstaff	$2,510	$10,570	$107,767	$31,070	
Sedona	$2,480	$8,673		$10,019	
Holbrook	$2,354	$7,832		$13,190	$6,409
Winslow	$2,407	$7,503		$31,586	
Show Low	$2,233	$7,205	$796,391	$15,379	
Kingman	$1,970	$7,183	$356,792	$8,426	$109,533
Lake Havasu	$1,387	$10,934		$33,384	
Prescott	$2,205	$6,220	$410,017	$13,801	$6,624
Cottonwood	$1,848	$4,678		$10,987	
Santa Cruz	$1,916	$6,722		$12,201	

Under Proposed ICS Calculation

Area	Residential
Flagstaff	$1,549
Sedona	$1,519
Holbrook	$1,393
Winslow	$1,446
Show Low	$1,272
Kingman	$1,010
Lake Havasu	$426
Prescott	$1,244
Cottonwood	$887
Santa Cruz	$955

UNSG-36

fees that are going to finance the plant. And so it is my understanding that they may have to use some of their own funding to cover those shortfalls. So this accounting order is designed to make them whole in the event that that should happen.

Q. So is post in service AFUDC traditional ratemaking?

A. The short answer to that would be no.

Q. Thank you.

Is not recognizing CIAC until a corresponding plant is in service traditional ratemaking?

A. Generally what happens in a situation like that, the contributions are booked at the time that they are received. And then when the company comes in in a general rate case proceeding, the contributions are netted out of the plant in service figure, and of course that gives you a lower rate base figure. Traditionally that's what happens.

Now, in this case, the company is asking for or seeking a diversion from that. And we are in agreement on that, because as Mr. Broderick mentioned the other day, this plant is going to be under construction, and they are probably coming in for some, at least two, rate increases that I think he noted. And so since the plant is still going to be under construction, and if it is

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CWIP, right now the policy is right now it wouldn't be allowed in rate base anyways. We don't have a problem with that arrangement.

Go ahead, I'm sorry.

Q. My question was: Is that traditional ratemaking?

A. That's a tough one, because generally a company is going to wait until a plant is in service until they come in to file. It is not -- you know, granted they would probably book the contributions at the time that they are collected. The company would have to make a decision to make a call on that. They would know, they would probably do a calculation to what their rate would be. If they feel they absolutely have to come in for rates, they would do so. You know, they may make note of the fact that, you know, some of these descriptions are still tied to construction work in progress.

And we might, I am just saying might because I don't know this for sure, but there is a possibility that we may go ahead and say, well, the plant is still under construction and you don't have a perfect match between what they booked in CIAC versus what is actually in service. So we may go ahead and make an adjustment for that, remove that portion of CIAC that isn't attributable to the plant in service.

Q. So by making an adjustment -- well, that's enough on that point.
A. Sure.
Q. Is establishing rates without a fair value finding traditional?
A. No. That's constitutional mandate.
Q. And have you estimated the fair value of Arizona-American's plant in this proceeding?
A. No, we haven't, because this isn't a general rate case proceeding.
Q. And you state on page 5 of your rebuttal that no one can say at this time that the Arizona-American plant is prudent, is that correct?
A. What page was that on?
Q. Page 5 of your rebuttal.
A. And what line was that?
Q. The line?
A. Yes. Could you direct me to that?
Q. It is one line number I didn't write down, Mr. Rigsby, I apologize.
A. Okay. I just want to make sure --
Q. Sure.
A. -- I am reading this correctly.
Q. Okay. Why don't we start on page 4, the last sentence that wraps all the way over and finishes on

American Gas Association

NATURAL GAS Rate Round-Up

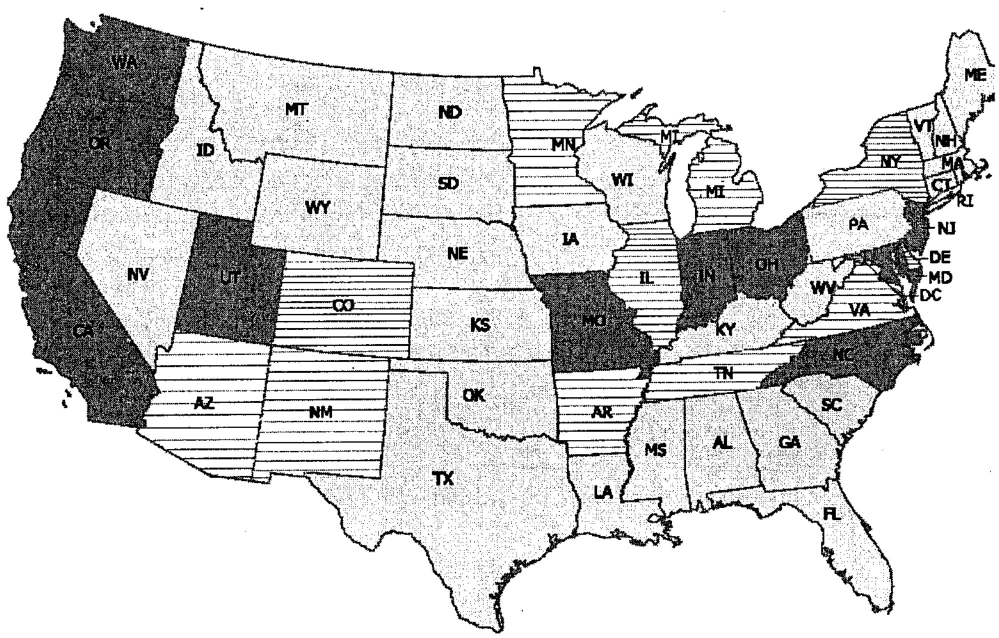
A Periodic Update on Innovative Rate Designs

April 2007

Update on Revenue Decoupling Mechanisms

This Rate Round-Up provides an updated and expanded edition of revenue decoupling reports that AGA issued in 2006 and 2005. Currently, 17 utilities in 10 states have implemented decoupling tariffs that serve 15 million residential customers. Decoupling programs are pending in another 10 states, plus the District of Columbia, potentially serving another 6 million residential customers. Revenue decoupling is a rate design method that allows utilities to actively promote energy efficiency while preventing the erosion of margins that is the usual outcome of customer conservation and utility energy efficiency.

STATES WITH NATURAL GAS REVENUE DECOUPLING TARIFFS



Approved Revenue Decoupling

Pending Revenue Decoupling

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DESCRIPTIONS AND COMPONENTS

Decoupling Rate Design

Natural gas customers and society in general would benefit from greater energy efficiency, and there is general agreement that natural gas utilities are key players in delivering energy efficiency programs and savings to customers. However, natural gas utilities traditionally face a powerful disincentive to promoting increased energy efficiency. The good news is that this disincentive was put in place by utilities and public utility commissions and can be removed. A win-win solution is possible that benefits both customers and utilities, and will lead to far greater energy efficiency.

The problem is simple. Gas utilities are in a fixed-cost business. The costs of the distribution service that they provide do not vary greatly in relation to the amount of gas that the utilities' customers consume. Since this is so, gas utilities should be supportive of customer conservation. However, gas utilities are rate regulated by state public utility commissions and the typical utility rate design in place today penalizes utilities if customers become more energy efficient. Most utilities use a 100-year-old rate design that recovers the fixed costs of a fixed cost business, not on a fixed, per customer basis, but on a volumetric basis. This means that under traditional utility rate design, a utility's earnings and profits will decline if customers conserve.

The solution is also simple. Many states, as well as federal policy makers, now discourage increased natural gas sales and encourage energy efficiency and conservation. Consequently, several states have put in place rate mechanisms that separate, or "decouple", the recovery of fixed distribution system costs from the volume of gas delivered to customers. Revenue decoupling allows the utility to actively promote conservation and energy efficiency without having to sacrifice its financial stability. Revenue decoupling works by adjusting the actual sales volumes to the weather-normalized sales volumes approved during the last rate case. When sales volumes deviate from the level forecasted in the rate case, the true-up mechanism makes a modest adjustment to the distribution charge, which gives the utility an opportunity to recover its authorized fixed costs regardless of fluctuations in energy use.

Energy Efficiency and Conservation Tariffs

The natural gas industry has been a national leader in energy efficiency. Today, the average American home uses about 25 percent less natural gas than it did a quarter century ago. The reduction in per-capita natural gas use has been driven primarily by energy efficiency. Homeowners have conserved by adding storm windows, insulation and weather stripping to their homes. Over the past 25 years, gas appliances have become enormously more efficient. Moreover, new construction, although producing increasingly larger homes, has also produced increasingly energy-efficient homes.

Utility-sponsored customer conservation and energy efficiency mechanisms provide consumers with an incentive to conserve natural gas, or provide education to consumers on how to conserve natural gas. Decoupled rates have been associated with strong energy efficiency programs, and conservation and energy efficiency are being addressed in each decoupling proceeding. Decisions about the inclusion of conservation components and energy efficiency programs within a decoupling program are usually based on the effectiveness of existing energy efficiency programs, the relative satisfaction with existing programs, and the relative desire to push for more aggressive energy efficiency programs—and this all varies by state. Not all decoupling tariffs include a utility-sponsored conservation component.

Not all utility-sponsored conservation and energy efficiency programs include a decoupling mechanism. At least 29 natural gas utilities have energy efficiency tariffs or conservation provisions that allow recovery of conservation and demand-side management program costs, as well as recovery of lost net revenues caused by the reduction in sales. The programs differ in what costs are allowed recovery (e.g., program costs, administrative costs, lost margin costs), and who administers the program (e.g., company, state, or charitable organization). One example is NW Natural, which includes a conservation component in its current decoupling mechanism that is administered by an outside charitable foundation. Another example is Vermont Gas, which does not have a decoupling program, but does have a Demand Side Management and Energy Efficiency program, in which the utility funds a portion of customers' costs of purchasing new, more energy-efficient appliances. Vermont Gas defers the costs of the program until its next rate case, subsequently amortizes the costs over a three-year period, and charges the costs to all ratepayers.

Computing the Adjustment and Accounting for Increases in Customer Count

There are several options for calculating the revenue adjustment, or true-up, and while the results are approximately the same, the different options help companies meet unique regulatory preferences and circumstances. The use-per-customer basis makes a rate adjustment that is based on changes in average use per customer, and then applies that adjustment factor against unit margins by customer class. The margin-per-customer rate adjustment is based on the change in baseline marginal revenue per customer compared to the actual marginal revenue per customer. The total margin revenue adjustment is based on comparison of total baseline marginal revenues to actual marginal revenues.

In order to remove the financial disincentive to promoting energy efficiency and conservation, marginal revenues from new customers are retained by the utility. The rate case level of fixed costs has been based on expenses and return on rate base that matches the rate case number of customers, and those costs do not reflect the additional operating costs and return on rate base arising from the addition of new customers to the utility. The fixed costs from those customers can only be recovered through the margins generated by sales to those new customers. Therefore, prior to determining the revenue adjustment, the amount of actual revenue is adjusted by the level of marginal revenue from new customers.

Return on Equity Considerations

Decoupling is a fair and efficient means to design utility rates from the customer's perspective. The change in rate design decouples the recovery of the utility's return on equity from the volumes of natural gas commodity consumed by the utility's customers. The symmetrical nature of decoupling prevents the utility from increasing its earnings by increasing its delivered volumes because any additional distribution charges collected by the utility in that event are refunded to customers. Moreover, decoupling does not shelter the utility from the impact of increased costs and/or provide a guarantee that the utility will achieve its authorized return.

Return on equity is established at a level that allows the utility to compete for the attraction of capital with other companies of similar risk profile, and to pay investors a fair return on their investment. Factors that are considered in equity return determinations have seldom, if ever, included rate design, and prior to the advent of innovative rates, rate designs seldom, if ever, included a premium for their possibly risky rate designs. The utility's peer group that is used for the return on equity determination may already include companies whose rate designs are all or partially non-volumetric in design. Decoupling is not incentive regulation and it does not provide a bonus or an incentive that can be earned or awarded to the company.

Similar Non-Volumetric Rate Design Mechanisms

More than one rate design method exists that will break the link between volumes of gas consumed and cost recovery for the utility. Fixed variable rate design places all of the utility's fixed costs, including a regulated profit on the value of the utility's investment in plant and equipment used to provide service to the customer, into a fixed monthly charge called a service charge or a demand charge. This charge is similar to the monthly fee charged by cable TV companies and is unrelated to the amount of gas (or number of TV programs) used by the customer. Utilities in four states currently utilize a fixed charge type of rate design for recovery of their costs. AGA discussed this rate design mechanism in the June 2006 Rate Round-Up http://www.aga.org/Template.cfm?Section=Rate_Roundup&Template=/MembersOnly.cfm&ContentID=20563.

Rate stabilization is another rate design mechanism that decouples a utility's profits from its gas throughput. The mechanism works by adjusting the utility's monthly revenues up or down to meet pre-established revenue and return targets. The amount calculated is added to or subtracted from the commodity charge of the utility in the next month, and the utility files a revised rate schedule with the regulator. Natural gas utilities in six states have received approval for these mechanisms. The December 2006 Rate Round-Up at http://www.aga.org/Template.cfm?Section=Rate_Roundup&Template=/MembersOnly.cfm&ContentID=20563 discussed these mechanisms in more detail.

Conclusions

While decoupling imposes no additional costs to the customer beyond those approved in the rate case, the mechanism leads to reduced customer bill variability from stabilized fixed cost recovery. Most important, since the biggest portion of a customer's gas utility bill is the cost of natural gas, greater energy efficiency and conservation lead to significantly lower utility bills. Lower bills also lead to lower bad debt expense, which is a system cost paid by all customers. Finally, reduced overall gas demand could lead to lower natural gas prices.

An independent evaluation of one decoupling tariff[1] found the program to be worthwhile and in the public interest. Among the conclusions of the evaluators were that the mechanism is effective in reducing the variability of utility revenues; the mechanism removes disincentives to promote energy efficiency; decoupling changes the company focus from sales advertising to conservation advertising; the mechanism does not reduce the incentive for good customer service; public purpose funding established in conjunction with the conservation component is beneficial to consumers; and the mechanism does not shift risk to customers.

While traditional rate designs contain a financial disincentive that prevents utilities from aggressively promoting energy efficiency and conservation, revenue decoupling breaks the link between a utility's earnings and energy consumption of its customers without adding any additional customer charges beyond what was approved by regulators. States should energetically consider implementing this innovative rate design.

[1]A Review of Distribution Margin Normalization as Approved by the Oregon Public Utility Commission for Northwest Natural, Christensen Associates Energy Consulting, LLC, March 2005.

CURRENT REVENUE DECOUPLING PROGRAMS

✦ APPROVED

1. CA – Pacific Gas and Electric
2. CA - San Diego Gas and Elec.
3. CA – Southern California Gas
4. CA – Southwest Gas
5. IN – Vectren Indiana
6. MD – Baltimore Gas and Elec.
7. MD – Washington Gas
8. NJ – NJ Natural Gas
9. NJ – South Jersey Gas
10. MO – Atmos Energy
11. OH – Vectren Ohio
12. OR – Cascade Natural Gas
13. OR – NW Natural Gas
14. NC - Piedmont Natural Gas
15. UT – Questar Gas
16. WA – Avista Corp.
17. WA – Cascade Natural Gas

✦ PENDING

1. AR – CenterPoint Energy
2. AZ – UNS Gas
3. CO – PSC of Colorado
4. DC – Washington Gas
5. IL – Peoples Gas/Integrys
6. MI – CMS Energy
7. MN – Xcel Energy
8. NM – Public Service Co. of NM
9. NY – National Fuel Gas Distribution
10. TN – Chattanooga Gas
11. VA – Washington Gas Light

California - Pacific Gas and Electric

The only state that has adopted decoupling for both natural gas and electric utilities is California. With the goal of encouraging conservation and with broad stakeholder support at the time, Pacific Gas and Electric (PG&E) decoupled natural gas sales in 1978 and electric sales in 1982. In the 1970s, the California PUC mandated inverted block rate design (increasing levels of consumption are charged higher rates) to encourage customer conservation. However, an inverted rate structure magnifies the impact on revenues of weather, conservation, price elasticity and other sales changes. Decoupling allows pricing signals to customers without revenue loss or gain to the company. The revenue decoupling mechanism is paired with an annual attrition mechanism that adjusts annually for customer growth, inflation, and replacement of aging infrastructure facilities. To address the huge escalation of natural gas costs in the winter after Hurricane Katrina, PG&E deployed several initiatives that encouraged conservation but that reduced its natural gas transportation revenues by $47 million. Without decoupling, the conservation program would have had a negative impact on PG&E's financial performance and very likely would not have been proposed. Today, nearly all of PG&E's revenues are decoupled, with only about 4 percent of natural gas revenues at risk, and support continues to be widespread among stakeholders throughout the state.

California - Southwest Gas

California has had some variation of a decoupling program in place for most of its utilities for nearly 30 years. The impetus for the program was the enactment of lifeline rates legislation, gas supply constraints, and the adoption of demand side management programs by the state. In its most recent general rate case order, effective April 15, 2004, Southwest Gas was granted authority to implement a decoupling mechanism for all customer classes. The decoupling mechanism utilizes a balancing account to protect customers if base revenues exceed authorized levels, and to protect stockholders if base revenues are less than authorized levels. The program is firmly established and utilizes a long-standing regulatory construct that does not recognize an explicit reduction to ROE.

Future test year system annual revenue requirement (margin) is established in a rate case as a fixed dollar amount on a monthly and annual basis. The difference between billed margins and authorized margins, plus carrying costs, is recorded monthly in a deferred account. The account balance is amortized annually through a uniform cents-per-therm rate applicable to all schedules, except special contracts. The test year margin amount increases each January 1 (between rate cases) according to an established formula.

California - Southern California Gas and San Diego Gas and Electric
The decoupling programs at Southern California Gas and at San Diego Gas and Electric are similar to the programs at Southwest Gas and at Pacific Gas and Electric. The decoupling programs at the California utilities apply to all customer classes, including industrial customers.

Indiana - Vectren
Vectren Energy Delivery's decoupling mechanism consists of two interrelated components: the conservation funding rider, and the decoupling mechanism. The company filed a petition rather than a new rate case for the conservation program and settled the filing in 2006. The Energy Efficiency Funding Component is assessed to residential and general service (commercial, small industrial) customers, although Vectren is financing a few items itself.

Maryland - Baltimore Gas and Electric and Washington Gas Light
BG&E's decoupling program began as part of a 1998 base rate case and is a "full decoupling" program, in that it is designed to recover multiple sources of margin loss, including weather and price elasticity, as well as losses caused by customers' conservation and energy efficiency. The Maryland decoupling mechanism utilizes a balancing account that returns to customers excess margin when revenues exceed authorized levels. A conservation component is separate from the decoupling mechanism, which applies to residential and general service firm customers.

BG&E makes adjustments to the delivery price of gas under the applicable schedules to reflect test year base rate revenues established in the latest base rate proceeding, after adjustment to recognize the subsequent change in the number of customers from the test year level. Test year average use per customer is multiplied by the net number of customers added since the like-month during the test year. The product is added to test year revenue to restate test year revenues for the month to include the revised values. Actual revenues collected for the month are compared to the restated test year revenues, and any difference is divided by estimated sales for the second succeeding month to obtain the adjustment to the applicable delivery price. Any difference between actual and estimated sales is reconciled in the determination of the adjustment for a future month. Details of the calculation of the billing adjustment are filed monthly with the public service commission.

In October of 2005, Washington Gas Light implemented a decoupling mechanism outside of a rate case that is similar in design to the decoupling program of Baltimore Gas and Electric. The Washington Gas program applies to all firm customer classes and does not have a conservation component as part of the mechanism.

Missouri - Atmos Energy
The Missouri Public Service Commission issued an order on February 22, 2007, in the base rate case of Atmos Energy Co., and adopted the commission staff's recommended revenue decoupling rate design. Atmos had filed for weather normalization rather than for decoupling. The new rates will apply to residential and small commercial customers with less than 2,000 Ccf annual consumption. The mechanism includes a requirement to spend 1 percent of annual gross non-gas cost revenues on conservation initiatives including energy audits. A collaborative

approach among company, staff, and the public counsel will be used to develop the conservation programs, which are scheduled to be implemented on August 31. The new rates took effect on April 1, 2007.

New Jersey - New Jersey Natural Gas and South Jersey Gas

On October 12, 2006, the New Jersey Board of Public Utilities (BPU) approved requests by New Jersey Natural Gas Co. and South Jersey Gas Co. to replace their existing weather normalization clauses (WNC) with a conservation incentive program (CIP) that would capture gross margin variations related to both weather and customer usage. The three-year pilot programs, which were initiated outside of a base rate case, apply to residential and most commercial customers, who will be segregated in distinct groups to avoid any cross subsidization. The decoupling mechanisms include new conservation programs that will be funded by the company, with additional programs expected to be added during the three year pilot. New Jersey Natural will spend at least $2 million on the new customer conservation efforts, and South Jersey Gas will spend at least $1.2 million.

As with the old WNC calculation, gross margin deficiencies attributable to conservation and other non-weather-related factors will be recovered from customers in the subsequent year through the CIP Rider. However, annual recoveries based on those deficiencies will be limited to a level of agreed-upon gas supply savings. For New Jersey Natural, the initial level of agreed upon savings will be $10.6 million for each year of the pilot. This amount has been realized by releasing capacity, with BPU approval, from New Jersey Natural Gs to NJR Energy Services, the wholesale energy services subsidiary of New Jersey Resources.

The new decoupling program features a return on equity test that prevents New Jersey Natural from recovering any portion of a CIP deficiency charge that would cause the company to earn in excess of its authorized return during the pilot period. The company will have an independent third-party provide a comprehensive evaluation of the effectiveness of the initial two years of the program and will file a report with the BPU no later than April 1, 2009. The BPU may extend, modify or terminate the program at the end of the three-year pilot and if the program is not extended, the WNC program would be reinstated. The program at South Jersey is nearly identical to the New Jersey Natural decoupling program.

North Carolina - Piedmont Natural Gas

This decoupling tariff, approved by the North Carolina Utilities Commission in the company's November 2005 rate case, gave Piedmont Natural Gas permission to implement a Customer Utilization Tracker (CUT). The mechanism was approved as an experimental, provisional tariff for a period of no more than three years and will automatically terminate on November 1, 2008, unless renewed in a general rate case. During the life of the CUT, Piedmont has agreed to contribute $500,000 per year toward conservation programs. Adoption of the CUT also resulted in the elimination of the company's existing weather normalization adjustment mechanism. In the 2005 ruling, the commission established an approved margin per customer per month for each residential and commercial rate class. Differences between the approved levels and the actual recovery are tracked monthly in a deferred account and trued-up twice a year. The mechanism applies to residential and commercial customers.

The North Carolina attorney general appealed to the state Supreme Court to overturn the commission action. In July of 2006, Piedmont negotiated a settlement with the attorney general in which the company agreed to an additional contribution of up to $1,500,000 per year, dependent upon the level of conservation related revenues received by the company through the CUT mechanism. The (up to) $1,500,000 will be split 50/50 between a direct reduction in customer rates and further contributions to conservation programs, over and above the $500,000 per year contribution to conservation agreed to in the tariff.

Ohio - Vectren

In September 2006, Vectren Energy Delivery received approval from the Ohio Public Utility Commission to implement a conservation tracking mechanism that is designed to provide customers with tools and information to assist them in reducing their energy costs from the level of costs that would otherwise exist absent the program. The program will operate for a minimum of two years and will receive funds from the utility, gas supply portfolio management proceeds, and reduced customer arrearages. The decoupled sales component will recover the difference between actual revenues and revenues approved in the last rate case. The company's most recent rate case came 10 months before the filing, which was settled in April of 2006. The mechanism is assessed to residential and general service (commercial, small industrial) customers.

Oregon - NW Natural

The Public Utility Commission of Oregon approved a decoupling tariff for NW Natural in September of 2002. The PUC said the tariff was designed "to break the link between an energy utility's sales and its profitability, so that the utility can assist its customers with energy efficiency without conflict." The tariff was a partial decoupling mechanism that allowed NW Natural to defer and then amortize 90 percent of the margin differentials for the residential and commercial customer groups. The mechanism contained two components: 1) a "price elasticity" factor that adjusted for increases or decreases in consumption attributable to annual changes in commodity costs or periodic changes in the company's general rates; and 2) a decoupling adjustment calculated on a monthly basis that accounted for deviations in expected volumes. Weather related risks were not covered by the mechanism. The additional company revenues or credits to customers produced by the mechanism were booked to a deferral account that was reconciled as part of the company's annual purchased gas adjustment.

The NW Natural decoupling tariff was put in place for three years on a pilot basis and had a sunset date of September 30, 2005, unless extended by the PUC. In March of 2005, NW Natural asked the PUC to investigate whether the decoupling tariff should continue. As part of the petition, NW Natural submitted the results of an independent study that had been required under the original order.

In August 2005, the Oregon PUC extended NW Natural's partial decoupling mechanism for an additional four years. NW Natural revised the decoupling schedule to provide for 100 percent deferral and amortization of the margin differentials. This change eliminated the non-weather related margin variability related to distribution fixed costs. In addition to the decoupling provisions, NW Natural currently has in effect a weather-adjusted rate mechanism (WARM) that was adopted in an earlier rate case and that lasts until September 30, 2008. The WARM covers all residential and small commercial customers, unless the customers opt out. The 2005 decoupling case dictates that public purpose funding and low-income assistance programs will remain in effect throughout the life of the decoupling program. In addition, industrial customers will not be charged or be eligible for any of the assistance programs.

NW Natural has a conservation component to its decoupling program that provides an indirect efficiency incentive to its customers. The company collects from all of its residential and commercial customers a "public purpose" surcharge of 1.5 percent of their total monthly bills. The funds are then passed on to an independent, non-profit organization, the Energy Trust of

Oregon. The Energy Trust, which also receives funding from public purposes surcharges from all of Oregon's electric utilities, then provides grants to promote energy efficiency and renewable resources among homes and businesses.

The Energy Trust of Oregon disburses approximately $6 million each year to encourage more efficient use of natural gas. Incentives include: $450 - $825 per unit to builders of new home construction if natural gas service is installed; rebates for high-efficiency gas furnaces, water heaters (including tankless units) and other appliances in existing homes; rebates on insulation, new windows and other efforts to reduce home energy use; and rebates on the installation of tankless water heaters, efficient boilers, etc., in commercial buildings.

Oregon - Cascade Natural Gas
Cascade Natural Gas' decoupling mechanism was approved by the Oregon Public Utility Commission on April 19, 2006. The mechanism, which was implemented outside of a rate case, applies to residential and commercial customers, and mitigates demand reduction caused by conservation. The mechanism also adjusts symmetrically for deviations from normal weather. The Conservation Alliance Plan consists of two deferral accounts, one that tracks monthly weather-normalized usage impacts on margins, and another that tracks monthly non-weather related changes in usage on margin. The deferral accounts will be maintained as regulatory assets or regulatory liabilities and will be amortized over the following year as increments to the commodity charge. The Cascade decoupling program includes a 0.75 percent public purpose surcharge to customers and a 0.75 percent of revenue contribution from the company to fund conservation programs for customers.

The Cascade Natural Gas decoupling mechanism imposes service quality requirements, and includes a penalty provision for failing to perform below specified ratios on customer complaints. While there was no reduction to allowed ROE, Cascade's current earnings sharing mechanism was modified to reduce the threshold amount for earnings sharing from baseline ROE plus 300 basis points, to baseline ROE plus 175 basis points. If requested by the commission, the company must file a general rate case in 2008. The plan will remain in effect until September of 2010 and an independent evaluation of the program will be conducted for the parties.

Utah - Questar Gas
Questar Gas received approval for a Conservation Enabling Tariff on October 6, 2006. The three-year pilot program was the result of a four-year process that included numerous task forces and stakeholder groups. The program applies only to the general service class (residential and small commercial) customers and requires the company to aggressively pursue demand side management goals and to fund low-income weatherization programs. The company was granted full decoupling and also kept its previously authorized weather normalization adjustment clause. The program was implemented outside of a rate case.

Washington - Avista
On February 1, 2007, Avista received approval from the Washington Utilities and Transportation Commission to implement a partial decoupling mechanism on a three-year pilot basis. The program, which does not include losses related to weather, will apply to residential and small commercial customers, and rate increases from the program will be capped at 2 percent per year. The company had recently completed a rate case when it filed its petition.

Avista is to defer 90 percent of the non-weather-related margin difference (positive or negative), which is to be recovered from or returned to customers. The recovery of any deferred costs is subject to both an earnings test that would prohibit collection if Avista is earning above its authorized 9.11 percent rate of return, and a demand-side management (DSM) test that would prohibit collection if specific conservation targets are not achieved. Funds not recovered due to the earnings and/or DSM tests may not to be carried over to the next period. Also, the commission prohibits Avista from earning interest on deferrals until the deferrals are approved for recovery.

Avista must submit an evaluation of the mechanism and any proposed modifications if it wishes to continue the program after three years. The commission stated that the mechanism will be evaluated, and extension granted, only if there is a demonstration that the mechanism led to cost-effective enhanced conservation.

Washington - Cascade Natural Gas
On January 12, 2007, the Washington Utilities and Transportation Commission authorized Cascade Natural Gas to implement a partial decoupling mechanism on a pilot basis for a three-year period. The mechanism, which will apply to residential and general service commercial customers, would defer non-weather-related margin variances (e.g., changes in usage related to conservation and energy efficiency improvements). In connection with the decoupling mechanism, the settlement called for Cascade to submit a conservation plan, which would be filed after the settlement was approved and an advisory group was convened to review an outside consultant's assessment of the energy efficiency potential in the company's service territory. The settlement specified that the plan would contain targets and benchmarks based on recommendations from the advisory group, and opportunities for penalties and/or incentives. Cascade's program includes paying for customer incentives on rebates for cost-effective demand side management programs, such as high efficiency appliances, insulation and consumer education programs. The decoupling program will be subject to commission approval of a conservation plan, with earnings capped at the authorized 8.85 percent overall rate of return, and will include penalties for failure to meet conservation targets and benchmarks. The pilot program will be evaluated regardless of whether the company seeks to continue the program after the three-year period expires.

This case was a follow up to the company's previous proposal before the Washington commission. In May 2005, the commission issued a proposal to decouple utilities' gas volume sales from their recovery of fixed costs. As part of the proceeding, the commission considered a decoupling petition by Cascade Natural Gas that was outside of a rate case. The commission ultimately denied the petition and said that the issues were better considered within a rate case.

PENDING DECOUPLING MECHANISMS

Arizona – UNS
UNS Gas has asked the Arizona Corporation Commission to design rates to recover a greater share of the company's fixed costs through a higher fixed customer charge, establish a decoupling mechanism, and approve a new demand side management (DSM) program, plus a charge to fund the DSM mechanism. UNS serves customers in a geographically diverse region, and the current rate design provides a subsidy from ratepayers in colder areas to ratepayers in warmer areas. The higher fixed customer charge component will reduce this inequity, while the decoupling mechanism will true-up the remaining volumetric charges to levels anticipated by test-year usage.

Arkansas – CenterPoint Energy
[On January 16, 2007, CenterPoint Energy Arkansas Gas filed a base rate case and proposed to implement a Trial Billing Determinant Adjustment Clause (TBDAC) Rider, to mitigate the impact of reduced customer natural gas usage on company revenues. While the company supports the Arkansas commission's efforts to implement energy efficiency program guidelines for the state's utilities, CenterPoint feels that the current rate design creates a very strong economic disincentive for the company to support those energy efficiency programs. A final PSC decision is expected in mid-November.

Colorado – Public Service Co. of Colorado (a Unit of Xcel Energy)
As part of a rate case, Public Service Co. of Colorado has proposed to implement a partial decoupling rate adjustment (PDRA) clause to reflect the annual non-weather related effect of the change in average actual use per customer from the average use per customer used in the company's last rate case. The PDRA is a per therm rate adjustment for residential customers and has been proposed as a three year pilot program. No conservation component has been proposed as part of the pending rider, however, pending legislation in Colorado would mandate gas demand side management. A decision is expected in August of 2007.

District of Columbia – Washington Gas Light
Washington Gas filed a rate case on December 15, 2006, in which it proposed to implement a revenue normalization adjustment mechanism similar to its decoupling program in Maryland. That program is designed to recover multiple sources of margin loss, including weather and price elasticity, as well as losses caused by customers' conservation and energy efficiency. The decoupling mechanism will utilize a balancing account that returns to customers excess margin when revenues exceed authorized levels. An energy efficiency communication component has been proposed as part of the rate case and not specifically part of the decoupling mechanism, which applies to firm and interruptible customers. A decision is expected in September of 2007.

Illinois – Peoples Gas and North Shore Gas (Units of Integrys Energy Group)
On March 9, Peoples Gas Light & Coke and North Shore Gas filed a base rate case with the Illinois Commerce Commission and asked for approval of a decoupling mechanism under which rates would be adjusted to exclude the impact on margin of variations in weather, customer participation in conservation programs, and other factors. The companies are also proposing separate energy efficiency programs, to be funded at a level of $7.5 million and recovered through a rider.

Michigan – CMS Energy
On February 9, 2007, Consumers Energy filed a request with the Michigan Public Service Commission for a revenue decoupling mechanism for the recovery of fixed costs that do not vary with throughput, a residential energy efficiency and conservation program, and an annual true-up mechanism for uncollectible expenses.

Minnesota - Northern States Power (a Unit of Xcel Energy)
Northern States Power has proposed to implement a partial decoupling mechanism to reflect the annual non-weather related effect of the change in average actual use per customer from the average use per customer used in the company's last rate case. The mechanism is a per therm rate adjustment for residential customers and has been proposed as a three year pilot program. Northern States will continue to participate in Minnesota's state-wide conservation program. The Minnesota Department of Commerce recommends that the commission deny the company's decoupling proposal and consider opening a generic docket on decoupling. A decision is expected in December of 2007. In addition, a bill is pending at the Minnesota state

legislature that includes language allowing one or more utilities to file a decoupling pilot program.

New Mexico – Public Service Company of New Mexico
On May 30, 2006, Public Service Company of New Mexico filed a rate case in which it requested a decoupling mechanism that would be adjusted monthly, with an annual true-up, to allow the company to recover revenue lost due to conservation efforts. The monthly adjustment would be shown on the customer bill as a separate line item.

New York – National Fuel Gas Distribution Co.
On January 29, 2007, National Fuel Gas Distribution Co. filed a rate case in its New York jurisdiction in which it requested a decoupling mechanism. Beginning in 2009, the mechanism would allow the company to implement a surcharge and credit mechanism, through which it would be able to recover lost margin associated with conservation savings generated during the 2008 test year. As part of that decoupling proposal, National Fuel seeks to establish a Conservation Incentive Program with three main components: (1) a low income usage reduction program that would provide insulation and efficient appliances for qualified low income customers; (2) a high efficiency appliance rebate program for residential and small non-residential customers; and (3) a general customer conservation education and outreach effort with a specific low-income customer component that recognizes that low income customers are among the highest consuming residential customers.

The decoupling mechanism would apply to residential and small consumption (less than 5000 Mcf annual) customers. The company has requested that if the decoupling mechanism is not approved, that its ROE be increased. National Fuel states that most members of the proxy group used to calculate the company's ROE already have a revenue decoupling program, and the company assumed that it would receive approval for decoupling when it supported its ROE request.

Tennessee – Chattanooga Gas
On November 20, 2006, Chattanooga Gas Co. settled its base rate case in which it proposed to implement an energy conservation program, a conservation and usage adjustment mechanism, and a bare steel and cast iron pipeline replacement program. The company dropped its request for the pipeline replacement tracking mechanism, and the company and the commission agreed to consider separately, in Phase II of the case, the conservation and usage adjustment and the energy conservation program. A final decision about a decoupling mechanism is expected in April of 2007.

Virginia – Washington Gas Light
Washington Gas Light (WGL) initiated a base rate case on September 15, 2006, in which it proposes to implement a revenue normalization adjustment designed to eliminate the effect on revenue collections of deviations in customer usage caused by variations in weather from normal levels and conservation programs.

STATEWIDE INVESTIGATIONS

Arkansas
On January 11, 2007, the Arkansas Public Service Commission adopted energy efficiency rules in a proceeding in which the commission investigated the adequacy of existing efficiency programs for the state's electric and natural gas distribution utilities. According to the adopted rules: (1) the utilities must file for commission approval of a portfolio of initial energy efficiency

programs by July 1, 2007, that are to remain in place from October 1, 2007-December 31, 2009; (2) the utilities are to demonstrate the cost savings expected to be achieved through these programs; (3) these programs may include incentives to encourage efficiency investments by customers; (4) all programs filed with the commission should be "fuel neutral"; (5) the utilities are permitted to request cost recovery of efficiency programs through a separate surcharge; (6) subsequent efficiency programs are to remain in place for terms of up to three years; and (7) the utilities are required to annually submit to the commission a report that addresses the performance of their energy efficiency programs.

Delaware
In March 2007, Delmarva Natural Gas settled its gas base rate case with the Delaware Public Service Commission and the parties agreed to investigate the development of a decoupling mechanism through a statewide process with all parties reserving all rights to argue that a ROE adjustment or some other adjustment may or may not be appropriate if a decoupling mechanism is adopted. While the rate case did not propose a conservation component, as part of the company's recent, "Blueprint For the Future" filing, the company did include rebate programs for DSM and energy conservation programs for gas and electric customers in Delaware.

Indiana
In 2006, the Indiana Utility Regulatory Commission decided two case-specific decoupling proposals, one in favor of Vectren and one opposed to Citizens Gas. The commission noted the variation that fits underneath the broad umbrella of decoupling, and because of the importance of the decoupling mechanisms in promoting utility stability and conservation benefits to customers, the commission initiated a formal inquiry into rate design alternatives and energy efficiency measure for natural gas utilities. The inquiry will address standardization of decoupling mechanisms as well as information to be filed with the commission; the benefits of decoupling to both the utility and the consumer; whether decoupling should include conservation or normal temperature adjustments; and the impact of implementing decoupling mechanisms for both the utility and the consumer. A series of technical conferences will be held to discuss the issues.

Iowa
On February 9, 2006, the Iowa Utilities Board initiated an inquiry into the effect of reduced natural gas usage resulting from increased energy efficiency and other factors on the non-gas revenues of the state's natural gas utilities. In its last rate case, Aquila asked the commission for a rate mechanism that would have decoupled a portion of its rates. While the Iowa Utilities Board denied Aquila's request, it stated that it is open to other decoupling proposals

New York
The state of New York is investigating the potential gas delivery rate disincentives against the promotion of energy efficiency, renewable technologies and distributed generation.

Pennsylvania
On October 11, 2006, the Pennsylvania Public Utility Commission opened an investigation of conservation, energy efficiency activities, and demand side response by energy utilities and ratemaking mechanisms to promote such efforts. There are three main components to the investigation: (1) what are energy utilities' current efforts to assist their customers to reduce usage, increase energy efficiency, and implement demand side response programs (including implementation of time-based rates), and whether additional cost effective and reasonable steps can be taken to increase those efforts materially (and, if so, the nature of those activities and the costs that the utility or other entity and customers would incur to implement them); (2) whether

advanced metering infrastructure should be developed by Pennsylvania utilities, and, if so, the timeline and standards that should be established for the implementation of these systems for the various customer classes and the methods of sharing this information with customers, competitive energy suppliers, and other customer representatives; and (3) whether revenue decoupling or other similar mechanisms are necessary or appropriate to assure that energy utilities, and in particular natural gas utilities, aggressively encourage and implement conservation and energy efficiency in their service territories, and whether such mechanisms are fair to customers and otherwise in the public interest. A report expected on or before May 15, 2007.

RESOURCES: COMPANIES, RATE ORDERS, WEBSITES, CONTACTS, ETC.

Arkansas – Generic Investigation Opened, Docket No. 06-004-R, January 12, 2006

Atmos Energy – Missouri – Approved – Missouri Case No. Feb. 22, 2007, Contact Pat Childers at 615-771-5877

Avista Corp. – Washington – Approved – Docket No. UG-060518, January 2007; Contact Kelly Norwood @ 509-495-4267

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Contact Laurie Duhan @ 410-265-4031

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CenterPoint – Arkansas – Petition Pending – Arkansas Docket No. 06-161- U; Contact Chuck Harder at 713-207-7273

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CMS – Michigan – Petition Pending – Michigan Case No. U-15190, February 7, 2007; Contact Lisa Johnson at 517-482-6744

Delmarva – Maryland – Statewide Investigation Pending – Regulatory Docket No. 59; Contact Bill Moore at 302-354-1811 or at bill.moore@pepcoholdings.com

Indiana Utility Regulatory Commission – Generic Investigation Opened – December 1, 2006, Cause No. 43180

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New Jersey Natural Gas – New Jersey – Approved – October 12, 2006, Docket No. GR05121020; http://www2.njresources.com/news/trans/newsrpt.asp?Year=2005; Contact Annemarie Peracchio @ 732-938-1129

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Pacific Gas and Electric Co. – California – Approved – December 30, 1981, California Decision No.93887

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Piedmont Natural Gas – North Carolina – Approved – Dockets G-9, Sub 499, G-21 Sub 461, G-44 Sub 15, November 3, 2005; http://ncuc.commerce.state.nc.us/docksrch.html, Contact: David Carpenter @ 704-364-4242

Public Service Company of Colorado – Colorado – Petition Pending – Docket No. 06-656G, December 1, 2006; Contact Ron Darnell at 303-294-2180 or ron.darnell@xcelenergy.com

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South Jersey Gas – New Jersey – Approved – Docket No. GR05121020, October 12, 2006; Contact Sam Pignatelli @ 609-561-9000 x4204

Southwest Gas – California – Approved – California Application No. 02-02-012, Decision No. 04-03-034; Contact Roger Montgomery @ 702-876-7321

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Washington Gas Light –District of Columbia – Petition Pending –Case No. 1054, December 21; 2006, Contact Paul Buckley @ 703-750-5260

Washington Gas Light –Maryland – Approved – Maryland Case No. 8990, October 1, 2005, http://webapp.psc.state.md.us/Intranet/maillog/orders.cfm Contact Paul Buckley @ 703-750-5260

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Xcel Energy – Minnesota – Petition Pending; Minnesota Docket No. G002/GR06-1429, November 9, 2006; Contact Amy Liberkowski @ amy.a.Liberkowski@xcelenergy.com

ADDITIONAL INFORMATION

If you would like more information about a particular program or would like to speak to another AGA member regarding the details of the program, please contact: Cynthia Marple, AGA director of rates and regulatory affairs, cmarple@aga.org or 202-824-7228.

Coming Up
The next edition of the AGA Rate Roundup will cover weather normalization adjustment clauses. If your company offers such a program, please contact Cynthia Marple.

Previous Editions
The December 2006 Rate Round-Up on Revenue Stabilization Mechanisms can be found at: http://www.aga.org/Template.cfm?Section=Rate_Roundup&Template=/MembersOnly.cfm&ContentID=20563.

The June 2006 Rate Round-Up focused on Innovative Rate Designs for Fixed Cost Recovery. Find this Round-Up at:
http://www.aga.org/Template.cfm?Section=Rate_Roundup&Template=/MembersOnly.cfm&ContentID=20563.