ORIGINAL

NEW APPLICATION

0000012802

SOUTHWEST GAS CORPORATION

Docket No. G-01551A-04-0876

Arizona Corporation Commission
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2004
ARIZONA
GENERAL RATE CASE

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APPLICATION
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Volume I

2004
ARIZONA
GENERAL RATE CASE

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ANNUAL REPORT
TARIFF SHEETS

Volume I

Application

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

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

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-01551A-04-

APPLICATION
AND
REQUEST FOR IMPLEMENTATION OF NEW RATES BY NOVEMBER 1, 2005

Southwest Gas Corporation (Southwest) respectfully states and represents as follows:

Applicant

Southwest, a corporation organized and existing under the laws of the state of California, is engaged in the business of purchasing, transporting, and distributing natural gas in service territories located throughout the states of Arizona, California and Nevada.

Southwest is a public service corporation subject to the jurisdiction of the Arizona Corporation Commission (Commission) by virtue of Article XV of Arizona's Constitution and applicable provisions of Title 40 of Arizona Revised Statutes (A.R.S.).

Southwest's certificated service territories in Arizona are located in portions of the counties of Cochise, Gila, Graham, Greenlee, La Paz, Maricopa, Mohave, Pima, Pinal and Yuma. For operational purposes, Southwest's Central Arizona Division is headquartered in Phoenix, Arizona, and Southwest's Southern Arizona Division is headquartered in Tucson, Arizona. Approximately 55 percent of Southwest's customers are located in Arizona.

Corporate Headquarters; Communications

Southwest's corporate headquarters is located at 5241 Spring Mountain Road in Las Vegas, Nevada. Southwest's mailing address is P. O. Box 98510, Las Vegas, Nevada 89193-8510, and Southwest's telephone number in Las Vegas is (702) 876-7163.

Communications regarding this Application should be directed to the attention of Debra Jacobson, Director/Government & State Regulatory Affairs, at the above Las Vegas address and telephone number and Andrew W. Bettwy, Assistant General Counsel, at the above Las Vegas address and telephone number (702) 876-7107.

Statutory Authority

This Application is made pursuant to Sections 3 and 14 of Article XV of Arizona's Constitution, A.R.S. §§ 40-250 and 40-

251 and other applicable provisions of Title 40 of A.R.S. and Sections R14-2-102 and R14-2-103 of the Arizona Administrative Code (A.A.C.).

Supporting Documentation

Southwest is a Class A utility within the contemplation of A.A.C. R14-2-103; accordingly, the schedules required by that Rule are a part of this Application. Also accompanying this Application is a copy of Southwest's 2003 Annual Report to Shareholders. Additionally, accompanying this Application is the testimony and exhibits which Southwest submits in support of this Application.

Nature of Relief Sought by Southwest

Southwest seeks the establishment of rates and charges for the provision of natural gas service in Arizona at just and reasonable levels in order to provide Southwest with the opportunity to earn a fair and reasonable rate of return on the fair value of Southwest's properties devoted to its Arizona operations.

Circumstances Justifying Relief

Southwest's primary reason for filing this Application, which is based on the historical test year ended August 31, 2004, is that current rates and charges are not sufficient to provide Southwest with a reasonable opportunity to earn a fair and reasonable rate of return on its investment in order to attract the capital necessary to ensure the continuation of a reliable service to present and future customers. The historical test year in Southwest's last general rate case was the twelve-month period ended December 31, 1999.

For the 12-month test year ended August 31, 2004, as adjusted, the rate of return associated with Southwest's Arizona properties is 4.78 percent. Southwest is proposing a rate of return of 9.40 percent and, accordingly, an annual margin increase approximating $70.8 million is needed to achieve the proposed rate of return.

The testimony and exhibits accompanying this Application reflect that approximately $15.2 million of the deficiency is attributable to Southwest not achieving the margin levels authorized by the Commission in Southwest's last general rate case due to circumstances beyond the control of Southwest -- e.g., declining average residential usage due to better-insulated homes and more efficient appliances.

Although Southwest has been successful in its efforts to control costs and to improve productivity since Southwest's last general rate case, the strains on Southwest's financial resources have been extraordinary. Southwest's capital expenditures for its Arizona operations from December 31, 1999, the end of the test year in its last general rate case, through August 31, 2004, the end of the test year in this general rate case, exceeded $500 million. Southwest was able to fund only 38 percent of its capital expenditures with cash flows from its gas operations. The remainder, over $300 million, had to be raised from external financing sources. With unprecedented customer growth expected to continue for the foreseeable future, Southwest's need to access the financial markets to fund a substantial portion of its capital expenditures will be reduced if the relief requested in this general rate case is granted.

During this period of unprecedented customer growth, Southwest's customer-to-employee ratio, a key measure of productivity, has continued to improve substantially. On December 31, 1999, the test year ending date in Southwest's last general rate case, Southwest was serving approximately 645 customers per employee, and on August 31, 2004, the test year ending date in this general rate case, Southwest was serving approximately 745 customers per employee. Despite this significant increase in its customer-to-employee ratio, Southwest was ranked in 2003 by J.D. Power & Associates as the best gas utility in the western region of the United States in terms of customer satisfaction. Southwest has been successful controlling costs while, at the same time, not compromising Southwest's commitment to customer satisfaction.

The best interests of Southwest's customers are served by ensuring that Southwest is sufficiently strong financially to be able to make the expenditures necessary to enable Southwest to continue to provide safe and reliable natural gas service throughout its Arizona service territories. Existing rates are unjust and unreasonable and their continuance threatens Southwest's financial integrity.

The Overall Theme

The overall theme of Southwest's Application is to seek ratemaking treatment which recognizes that declining average residential usage and significant growth in a historical test year jurisdiction place an enormous financial strain on Southwest's ability to earn its authorized return and, as a consequence, to compete effectively for capital at a reasonable cost.

In his direct testimony, Chief Executive Officer Jeffrey Shaw explains from a broad policy perspective why it is critical that Southwest be provided with a reasonable opportunity to actually earn the rate of return authorized by the Commission in this proceeding. Among other things, Mr. Shaw stresses the importance of designing a rate structure that addresses the phenomena associated with a continued decline in average residential usage due, *inter alia*, to conservation and increased efficiencies in housing stock. Exhibit No. ________ (RAM-1) demonstrates that Southwest has been unable to earn the rate of return authorized by the Commission since 1994, except for the year 1998, a year in which the weather in Arizona was 28 percent colder than normal. The associated schedules show that, over the approximately eleven-year period, the total earnings shortfall from Southwest's Arizona operations approximates $145.6 million.

Consistent with the overall theme, a central focus of this Application is the need for Southwest to have the ability to compete effectively in the financial markets to secure the capital required to meet the growth demands in one of the fastest growing states in the country. In this Application, Southwest advances proposals which are designed to improve Southwest's financial strength over time and to achieve parity with comparable natural gas distribution companies in the competitive financial marketplace.

Southwest is confident that, if the Commission adopts Southwest's proposals addressing the obstacles hindering Southwest's ability to earn the rate of return authorized by the Commission, Southwest would have a reasonable opportunity to earn its authorized rate of return and, over time, to improve its capital structure and, in turn, its credit ratings -- which reasonably could be expected to lower the overall cost of debt for the benefit of Southwest's customers.

Conservation Margin Tracker

Southwest is proposing aggressive programs to further promote conservation and energy efficiencies. Successful programs necessarily erode Southwest's opportunity to earn the rate of return authorized by the Commission so long as a portion of Southwest's revenue requirement is placed at risk through a rate design which relies on volumetric throughput to recover Southwest's fixed costs.

Southwest urges the Commission to adopt the proposed conservation margin tracker (CMT) as a means to address the phenomenon of declining average residential usage, thereby removing the inherent disincentive to aggressively promote conservation and energy efficiency. Whether average residential usage turns out to be higher or lower than the consumption level recognized in this proceeding [due to weather variations, conservation or other factors], neither Southwest nor its customers would either benefit or be disadvantaged.

The proposed CMT is consistent with the July 2004 Joint Statement of the American Gas Association, the Natural Resources Defense Council and the American Council for an Energy-Efficient Economy, and the Joint Statement garnered the support of the National Association of Regulatory Utility Commissioners (NARUC) during NARUC's 2004 Summer Meetings.

A real benefit to both Southwest and its customers would be that, with such a mechanism in place, an element of risk which influences credit ratings would be eliminated -- and that reasonably could be expected to impact positively on Southwest's ability to improve its earnings, compete for the capital necessary to continue to provide both current and future customers with safe and reliable natural gas service and fund infrastructure investments. Approval of the proposed CMT further benefits customers, as it results in a reduction of the proposed common equity cost rate.

Line Extension Policy and Practices

In Southwest's last general rate case, the Commission directed Southwest to address in this proceeding the manner in which Southwest determines the magnitude of allowances associated with extending facilities to provide service to new customers. In his direct testimony, Southwest witness Robert Mashas details the methodology employed by Southwest to calculate the allowances. Mr. Mashas also demonstrates that the analyses conducted by Southwest include a consideration of the incremental revenues, expenses and investment required to serve new customers and that new customers generate a sufficient revenue stream for Southwest to earn from the new customers at or above the authorized rate of return.

Southern Arizona Pipe Replacements

Southwest is proposing a modification to the settlement agreement (Agreement) which was approved by the Commission in the general rate case in Docket No. U-1551-93-272. Essentially, Southwest seeks the establishment of a sunset date for the write-offs associated with certain pipe replacement activities. Throughout the decade following the Commission's decision in Docket No. U-1551-93-272, the magnitude of pipe replacement activities has been reduced substantially, and pipe that is subject to the write-off provisions of the Agreement continues to be utilized to provide service to Southwest's customers even though the pipe has reached the end of its normal, estimated service life.

Witness Testimony

A complete and accurate explanation of the circumstances and conditions relied upon by Southwest as justification for the proposed adjustments in rates and charges and the changes in other tariff provisions proposed in this Application is embodied in the following accompanying testimony:

Jeff Shaw, Chief Executive Officer [policy and general rate case overview]

Chris Palacios, Senior Vice President/Southern Arizona Division [safety, cost control, productivity and customer service]

Robert Mashas [revenue deficiency, line extension policy, transmission integrity management program and southern Arizona pipe replacements]

Randi Aldridge [rate base, expenses and allocations]

Theodore Wood [overall rate of return, capital structure, and cost of debt and preferred equity]

Frank Hanley [cost of common equity]

James Cattanach [weather normalization, decline in average residential usage and price elasticity]

Christy Berger [class cost of service studies]

Steve Fetter [regulatory policy related to conservation margin tracker and credit rating impacts]

Edward Gieseking [rate design policy and conservation margin tracker]

Brooks Congdon [billing determinants, revenue allocation, rate design and related tariff revisions]

Vivian Scott [demand-side management, conservation and energy efficiency programs]

Request for Implementation of New Rates by November 1, 2005

Southwest requests that this Application be processed under a schedule which contemplates the implementation of new rates by November 1, 2005, the beginning of the winter heating season. Mr. Shaw, has provided assurance to the Commission that all Southwest personnel are dedicated to making every effort possible to facilitate a process which results in a final decision as soon as practicable.

Southwest proposes the following timetable and, in particular, Southwest seeks the support of the Commission Staff and the Residential Utility Consumer Office for such a schedule:

January 7, 2005	-	Staff Notice of Sufficiency
January 14, 2005	-	Procedural Conference
June 3, 2005	-	Filing of Staff & Intervenor Direct
July 1, 2005	-	Filing of Rebuttal
July 11, 2005	-	Filing of Surrebuttal
July 21, 2005	-	Filing of Rejoinder
July 22, 2005	-	Prehearing Conference
July 25 – August 5, 2005	-	Conduct Hearing
November 1, 2005	-	Effective Date of New Rates

As indicated above, the rate of return experienced by Southwest from its Arizona operations for the test year ended August 31, 2004, was 4.78 percent. It is inevitable that, by November 1, 2005 [fourteen months after the end of the test year], Southwest's earnings from its Arizona operations will have continued to erode.

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WHEREFORE, Southwest respectfully requests that the Commission issue a special order pursuant to A.A.C. R14-3-101.C to establish notice, filing, discovery and hearing procedures.

Southwest requests further that, upon conclusion of the hearing, the Commission issue its Decision determining the fair value of Southwest's Arizona properties, authorizing a just and reasonable rate of return thereon and establishing rates and charges designed to realize the authorized rate of return.

RESPECTFULLY SUBMITTED this 8th day of December, 2004.

SOUTHWEST GAS CORPORATION

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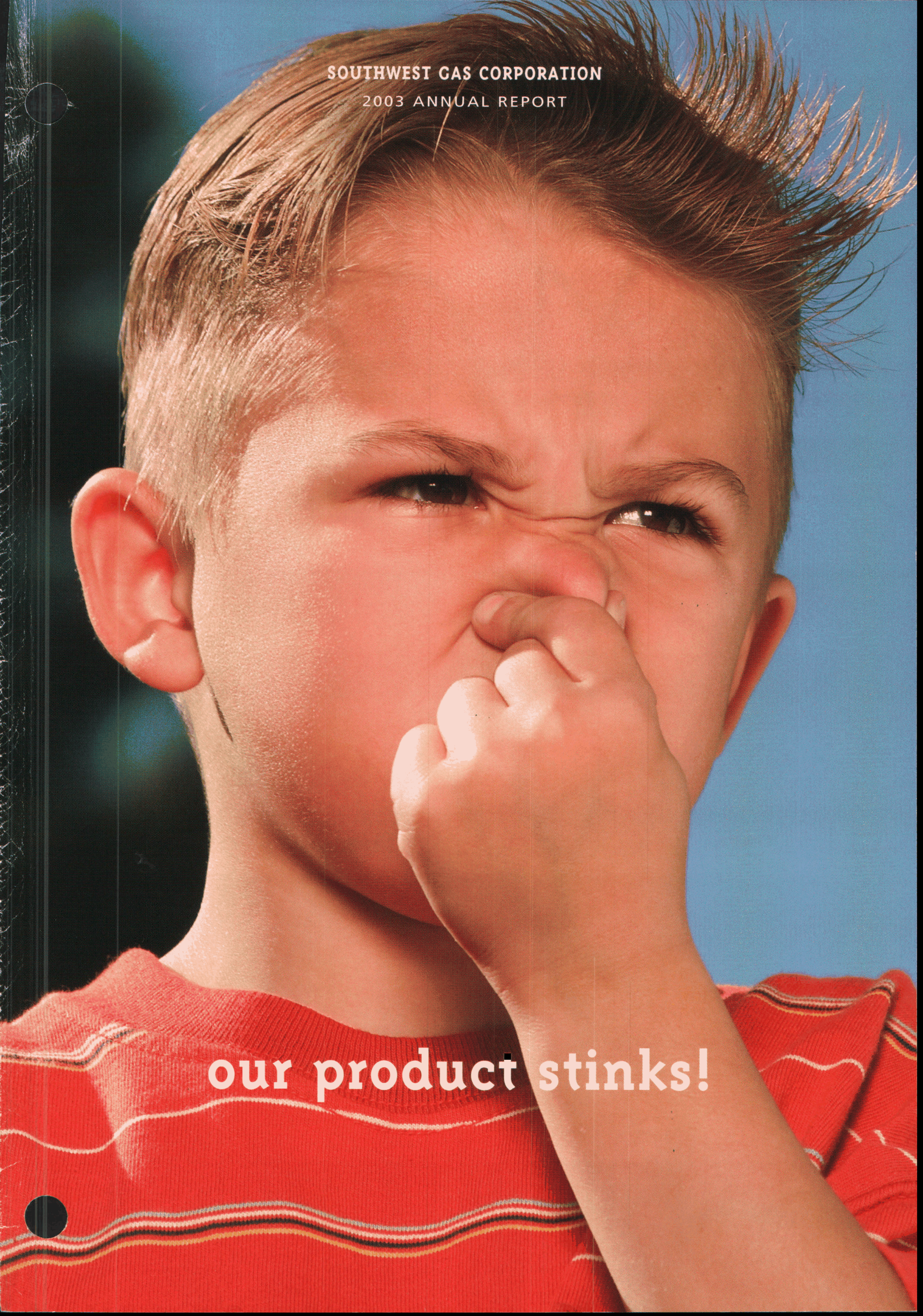
Annual Report


SOUTHWEST GAS CORPORATION
2003 ANNUAL REPORT
our product stinks!

but we made
it smell bad for
a good reason

We make it stink! Nothing is more important to Southwest Gas than the safety of our customers and the communities we serve. Because natural gas is odorless, a harmless additive that smells like rotten eggs is used to help detect its presence. That's why we encourage customers, and non-customers alike, to call us when they smell that rotten-egg odor.

Safety of our customers is serious business at Southwest Gas. From pipe replacement programs and annual leak inspections to safety communications and appliance checks for new customers, Southwest Gas spends millions of dollars to ensure the system remains safe, and that our customers know what to do if there's a leak.

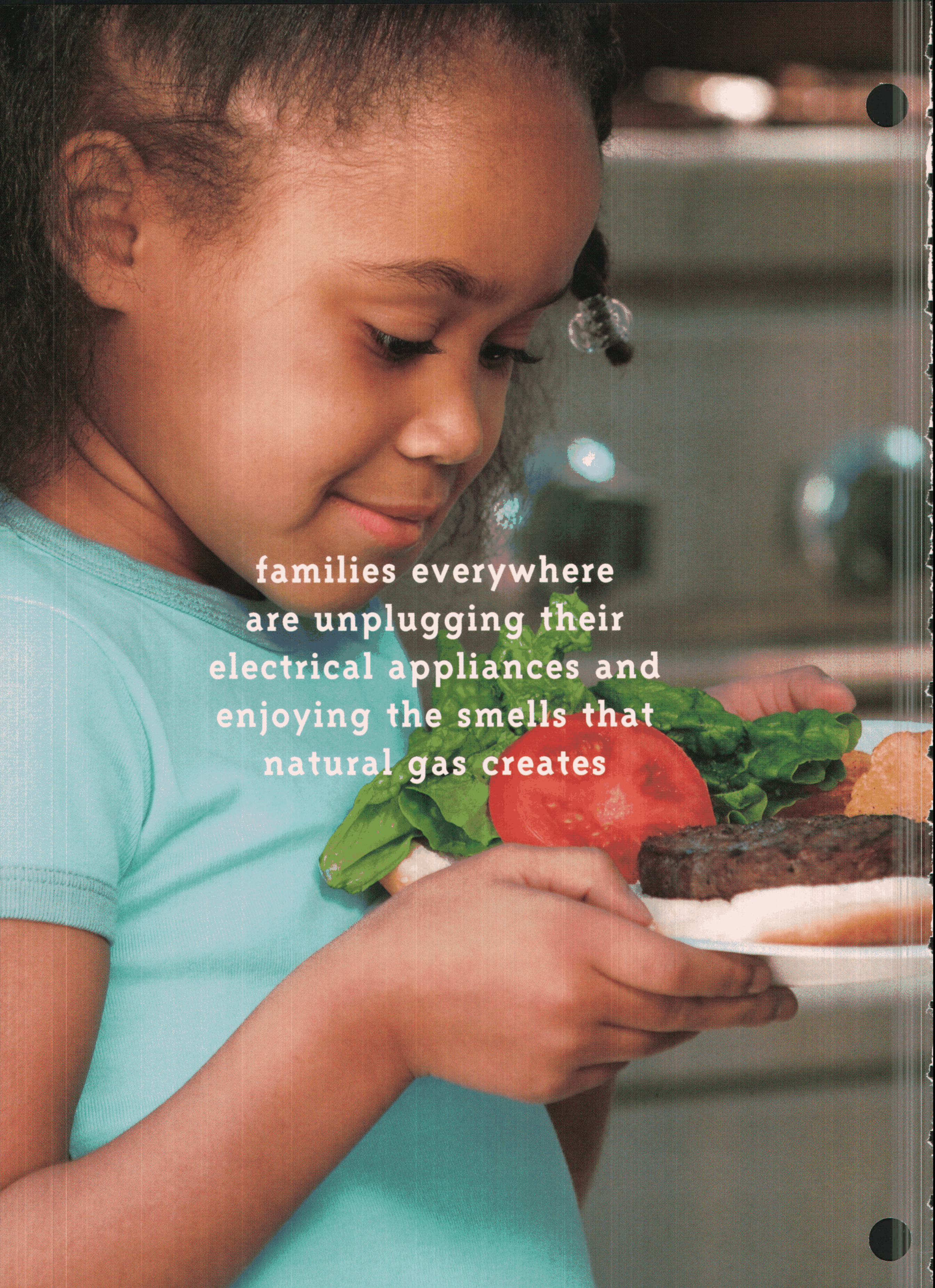
But natural gas does provide some good smells, too. There's nothing better than the aroma of fresh-baked cookies directly from the oven, or what could be better than the great smell of sauce-smothered ribs simmering on a natural gas barbecue? Our mouths water just thinking about it.

Natural gas helps create other pleasant smells, too—fresh towels coming directly from a natural gas dryer, and relaxing scents from a hot bubble bath.

our "stink" helps create the amazing smells of home

cookies bring out the kid in all of us

Warm! Delicious! Chocolate chip, oatmeal, sugar cookies right from the oven. Natural gas ovens can fill the kitchen with delectable smells that bring squeals of delight. ❋ The combined range and oven is one appliance that's used almost daily, and cooking with natural gas makes baking even easier. It's efficient. It's economical. Customers know they can depend on Southwest Gas to help make those cookies mouth watering. The J.D. Power survey of natural gas utilities ranked Southwest Gas as the best in customer service in the western United States in 2003. ❋ When it comes to baking cookies, it's hard to deny that the first cookie out of the oven is worth the wait. ❋ A glass of milk anyone?

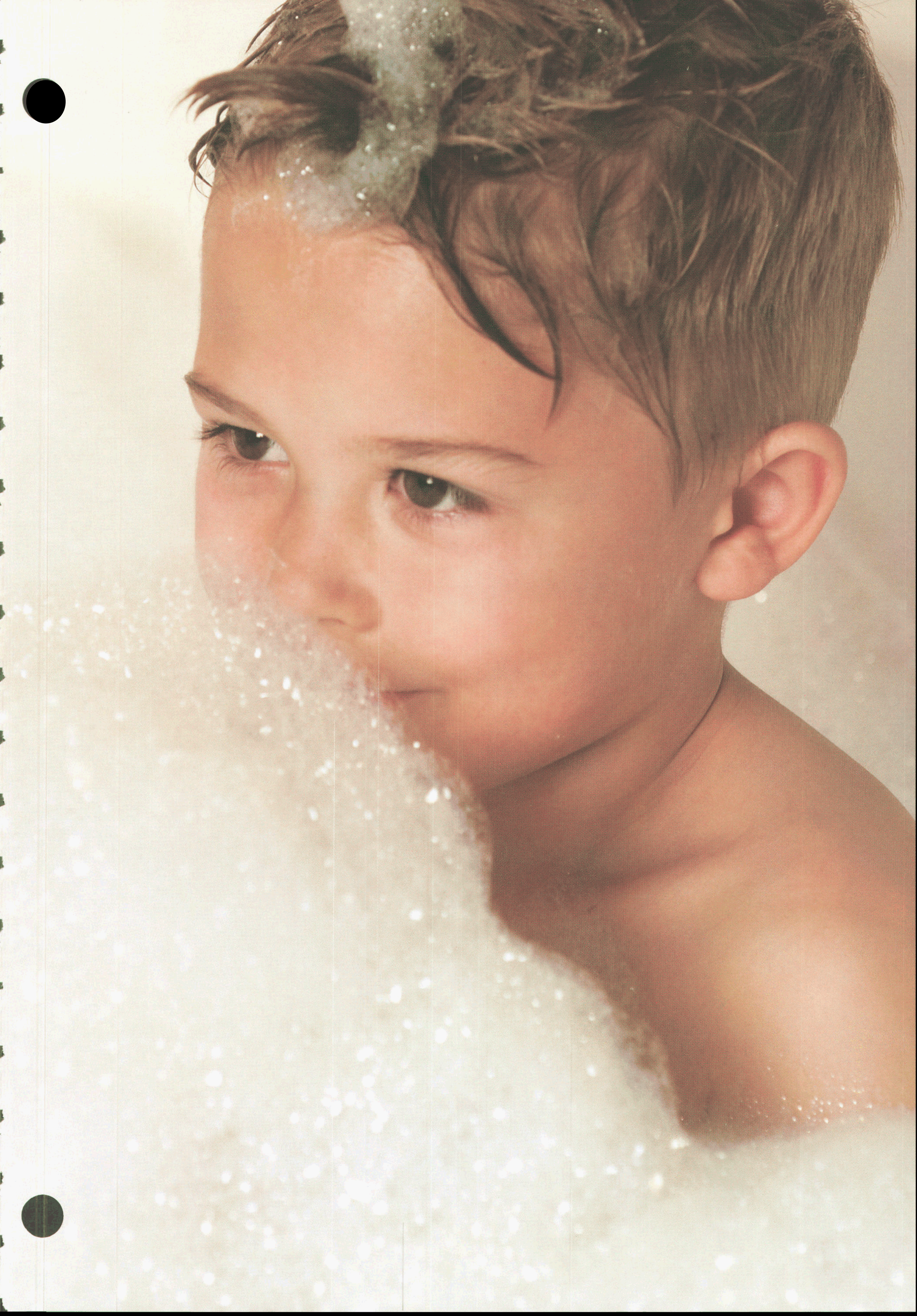

families everywhere
are unplugging their
electrical appliances and
enjoying the smells that
natural gas creates

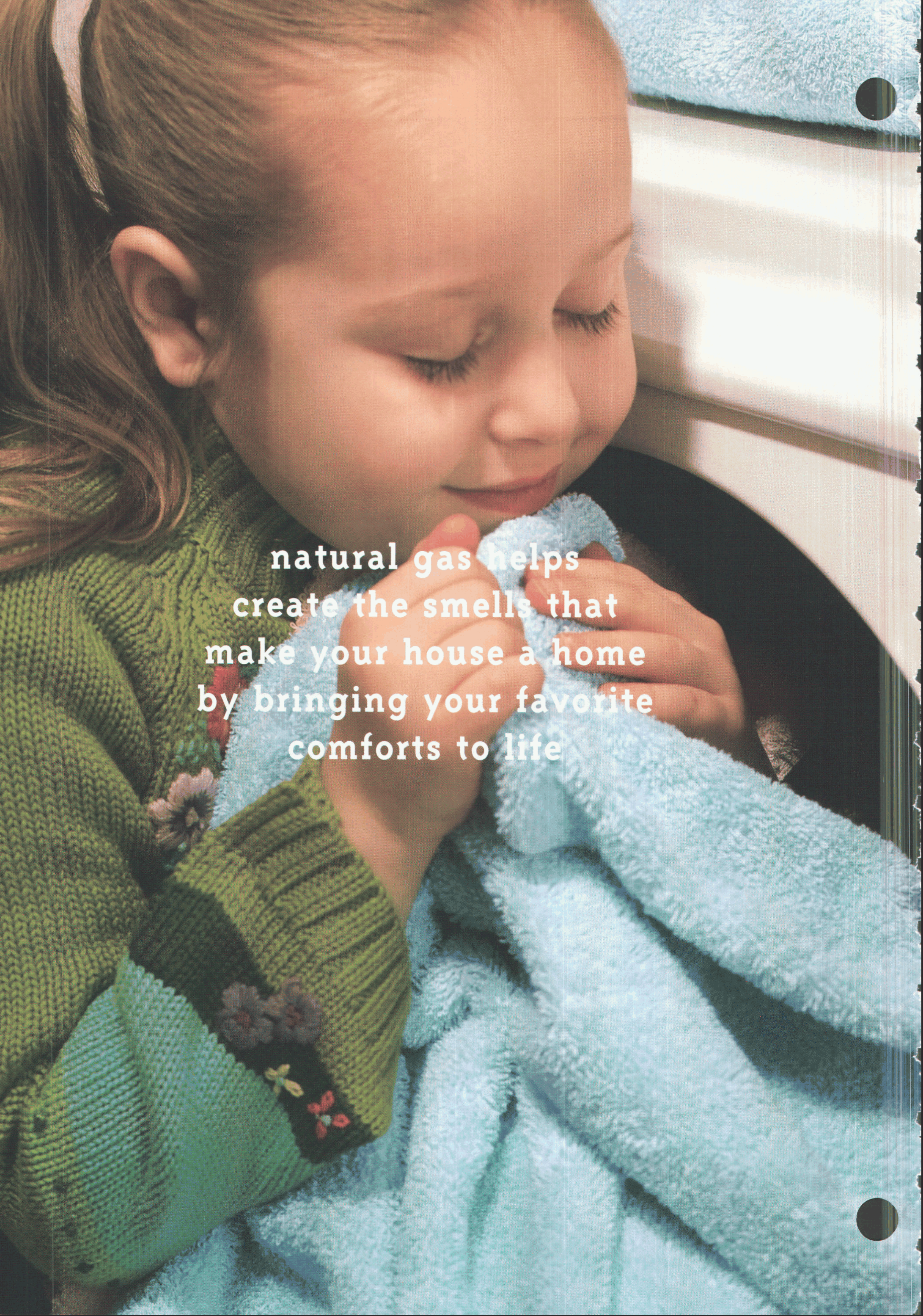
grill of our dreams

The aromas from burgers and ribs to shish kebabs make the short wait almost unbearable. Today's natural gas barbecues have helped transform the outdoor patio into an extension of the house. ❋ Natural gas grills are ready when you are. No waiting for charcoal to heat up or scrambling to refill a propane tank. Precise temperature-controlled cooking and a flame that never goes out until you turn it off are what every outdoor chef loves about natural gas grills. ❋ There's virtually no special setup… you get to grill without charcoal dust on your hands and smoke in your eyes. ❋ The record-setting 66,000 new residential customers that joined the Southwest Gas system in 2003 know life is good with a natural gas grill!

hot bubble bath soothes the senses

There's nothing quite as relaxing as a hot bubble bath. Having enough hot water to indulge in this luxury is essential to the experience. ※ With a natural gas hot water heater you will have adequate hot water when you want it-and need it most. ※ Just sit back and relax. With a natural gas hot water heater you have the best source for heating that bubble bath. And to think, it only took 10 million feet of new pipe this year to assure customers that the hot water would be there when they want it. ※ Hey, where's the rubber ducky?




natural gas helps
create the smells that
make your house a home
by bringing your favorite
comforts to life

aah. soft, fluffy, fresh-smelling towels

Better yet, hot, soft, fluffy fresh-smelling towels... ❋ Better still, hot, soft, fluffy towels quickly. Nothing feels better or smells as fresh as a towel just out of your natural gas dryer. ❋ There are added benefits, too. A natural gas clothes dryer saves time and money for the things you really want to do. There's no lengthy warm-up, and because natural gas is instant on and off, you have complete temperature and drying control. As an added bonus, newer models dry clothes with lower temperatures that are gentler on clothes. Enjoy soft and wrinkle-free clothing with every load. ❋ About the only thing natural gas dryers won't do to towels is fold them.

gas has never smelled so good

to our shareholders

"Our product stinks"...but J.D. Power & Associates still ranked Southwest Gas the best natural gas utility in the western United States in 2003 and 67,000 new customers followed the "Guide to the Southwest Territories" (last year's annual report theme), positively answering the question posed "Do you have gas?" (2001's annual report theme) with a resounding YES. Southwest Gas remains one of the fastest growing natural gas distribution companies in the nation (if not the fastest growing) for the 10th year running.

"Our product stinks"...and unfortunately so did earnings in 2003. The whole year ended...much as it began...warmer than normal. In fact, 2003 was the 2nd warmest year in Nevada and 5th warmest year in Arizona overall in the last 109 years. Good weather for the tourism industry throughout our service territories, but not so good for the gas business. To complete the whining...earnings per share were $1.14 in 2003 compared to $1.33 in 2002. Weather, or lack thereof, robbed us of nearly 60¢ per share in 2003!

"We're Cooking," our annual report theme for 2000, was chosen at the time to not only focus on one of the most pleasurable uses for our product but to describe the robust growth environment and construction activities in our service territories. "We're Still Cooking" could easily have been the theme of this year's annual report because nothing better encapsulates the level of the Company's activities for 2003.

2003 established an all-time high of 67,000 new customer additions...a five percent increase overall. An additional 9,000 customers joined the Southwest ranks with the acquisition of Black Mountain Gas in October 2003. Our southern Nevada division (Las Vegas) led the Company with over 29,000 (six percent) new customer hook-ups. We ended the year with 1,531,000 customers. Whatever slowdown in activity that was experienced in various segments of the economy in other parts of the country, and in our own service territories, just never translated into a slowdown in the housing markets in Nevada and Arizona. As we begin 2004, we keep a watchful eye, but don't yet see any signs of construction activities tapering off.

If record new customer growth wasn't enough to keep our folks busy, a record amount of new government regulations did. Southwest Gas, as well as the rest of the industry, had to contend with extraordinary new and complex pipeline safety mandates from governmental agencies. As is often the case in America today, the innocent are punished with the guilty. These new rules will cost pipeline operators more than $5 billion to prove that existing tried and true operating practices are as good as a century's worth of experience has proven them to be.

These false alarms remind thoughtful people that reactionary government creates distrust in institutions by insinuating that the "sky is falling" and the only protection is more and more costly rules and regulations. There is no such thing as an accident anymore. Someone must be blamed and guilt by association is now the rule of the day. Despite proclamations that "this type of incident must never happen again," the reality of course is accidents will happen again regardless of increased rules and regulations.

As has every publicly traded company in 2003, the Board and senior management spent an inordinate amount of time implementing new regulations associated with the Sarbanes-Oxley federal legislation adopted in July of 2002 and the various implementation phases expected to occur through the year 2005 as promulgated by the Securities and Exchange Commission. For Southwest Gas very little has changed in terms of the overall quality of corporate governance. However, the Board and management have spent a great deal of time working through the new regulations. The efforts have been more of an exercise of "rearranging the deck chairs," while "killing a lot of trees" in the process. Our Board believes the Company's overall corporate governance practices have always been among the very best, and this is confirmed by our recent Institutional Shareholder Services (ISS) index ranking of over 99%. This ranking indicates that Southwest Gas outperformed over 99% of the companies in the S&P 600 Index in terms of corporate governance issues.

Aside from the ever increasing burdens of new regulations, our greatest concern to the Company and for the industry in general is the level and volatility of commodity prices. Gas markets have dramatically changed over the past few years. Prices are higher generally and the associated volatility is historically unprecedented.

Elevated natural gas prices are the result of the accumulated impact of years of incongruent regulatory policy and the continued failure of Congress and the last two Presidential administrations to develop balanced national energy use and resource development legislation and regulation. For over a decade, environmentalists, federal regulators and in some cases, the natural gas industry itself, have promoted the use of natural gas as a more environmentally friendly way to meet the growing demand for additional electricity generation.

The increased use of natural gas to generate more electricity, when combined with incompatible regulations for limiting access to new natural gas supply, is creating a growing natural gas supply/demand imbalance. One set of environmental policies is driving up the demand for natural gas, while other environmental policies are simultaneously severely limiting development of adequate natural gas supplies. The resulting impact is clear. Not only does this negatively impact our customers' pocketbooks, but it creates serious regulatory and customer relations problems for the LDC's who are caught in the middle.

We have continued to pursue those key elements we believe have made us successful:

- remaining focused on core competencies
- continuing to maximize efficiency and productivity
- continuing to be aggressive in managing growth
- striving to exceed our customers' expectations

Yet, we believe we remain watchful and positioned to seize strategic growth opportunities.

As mentioned above, Southwest Gas is very proud to be designated the best natural gas utility in the western United States by J.D. Power & Associates. This is quite a tribute to our 2,500 employees who, despite phenomenal growth, volatile energy prices and ever changing regulations and requirements, manage to create and maintain a customer centric-environment. Congratulations to all of you!

2004 will see a significant transition in membership of our Board of Directors and management. Due to mandatory Board retirement age or change in personal circumstances, Michael Jager, Len Judd, David Gunning and Mark Feldman are not seeking re-election to the Board this year.

The Board wishes to express its deepest gratitude to these gentlemen for their years of service... their leadership and friendship.

In 2003 and in anticipation of the above noted changes, LeRoy C. Hanneman, Jr., Chairman and Chief Executive Officer, Element Homes, LLC located in Phoenix, was added to the Board. In addition, Richard M. Gardner, Retired Partner, Deloitte & Touche and who resides in Phoenix, and Thomas E. Chestnut, Owner, President and CEO, Chestnut Construction Company located in Tucson have been nominated for election to the Board at the Shareholders' meeting in May.

Lastly, we need to comment on Mike Maffie's intention to retire as CEO in the summer of this year. One of the Board's (any Board's) most significant responsibilities is to determine who runs the Company. To that end, the Board went through an extensive and lengthy process over the past several years planning for this eventuality. In July 2003, Jeff Shaw was made the president of the Company and it is the Board's intention that he will become chief executive officer in June.

Certainly, Mike's leadership and experience will be missed. However, the Board is confident Southwest will continue to flourish under Jeff's leadership with the help of its 2,500 outstanding employees.

Sincerely,

Thomas Y. Hartley	Michael O. Maffie
Chairman of the Board	Chief Executive Officer

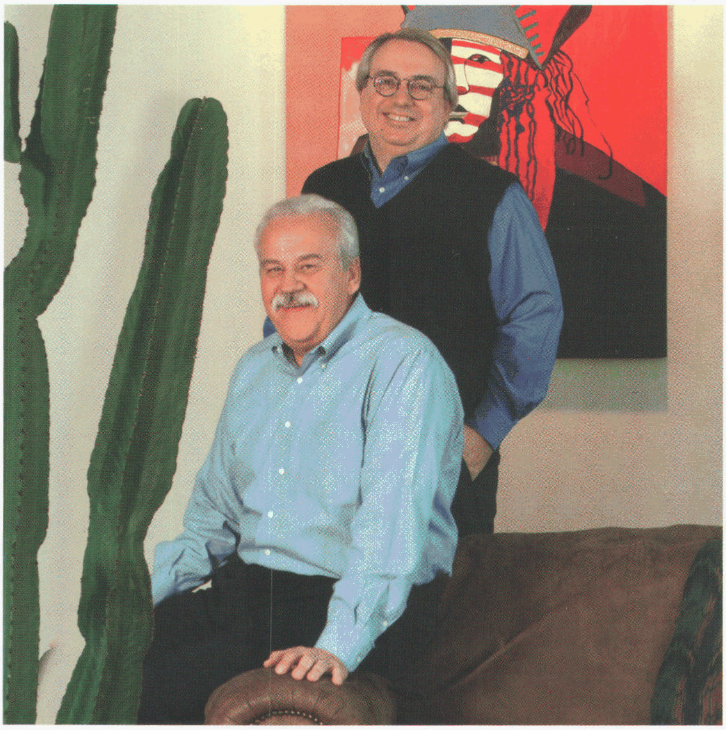
a brief farewell

Ed and I both came to Southwest Gas in the fall of 1978. Southwest was a small natural gas distribution company with just over 160,000 customers spread throughout three states. The Company had recently contracted to purchase the natural gas business in Tucson from Tucson Gas & Electric, which would double its size. In 1984, the Company doubled its size again, acquiring the natural gas business in Phoenix from Arizona Public Service. At a time in history when many doubted the industry's long-term viability, these acquisitions created the footprint for the Company to take advantage of the phenomenal opportunities in the southwest over the next 20 years...resulting in a company today with over 1.5 million customers. Growth and change became ingrained parts of our corporate culture, and we and all Southwesters flourished.

Exciting, challenging, exasperating and many other things. After more than 25 years, we've decided it's time that the "next generation" has their turn and we're confident they're up to the task. We couldn't have asked to spend 25 plus years of our careers with a better company. Southwesters are a unique bunch...they're the best!

Michael O. Maffie
Chief Executive Officer

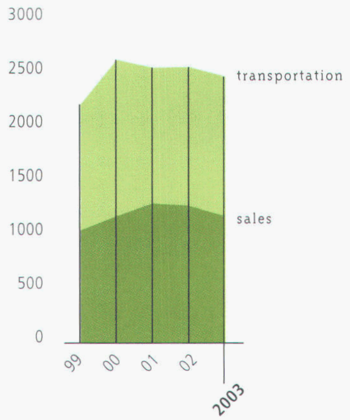
**after over 25 years at southwest gas,
mike and ed are retiring**



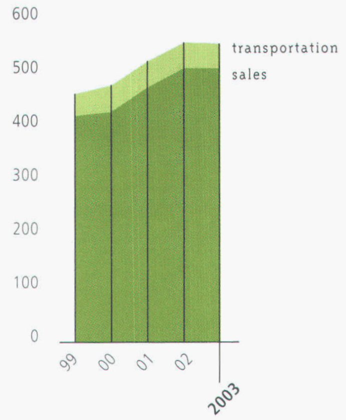
Edward S. Zub
Executive Vice President/Consumer Resources and Energy Services (front)

Michael O. Maffie
Chief Executive Officer (back)

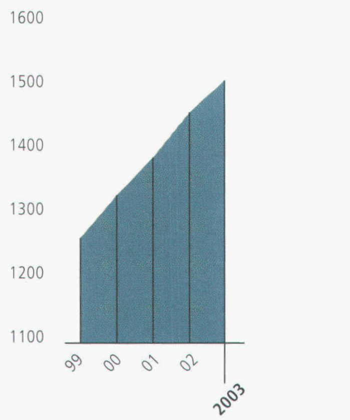
Throughput
(in millions of therms)



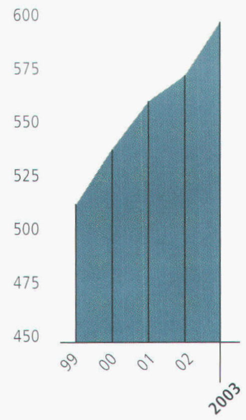
Margin
(in millions of dollars)



Number of Gas Customers
(in thousands)

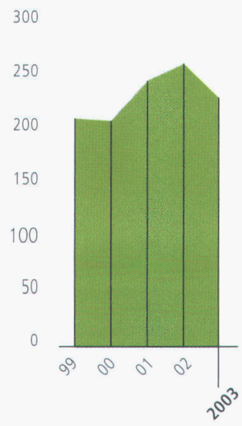


Customers per Employee

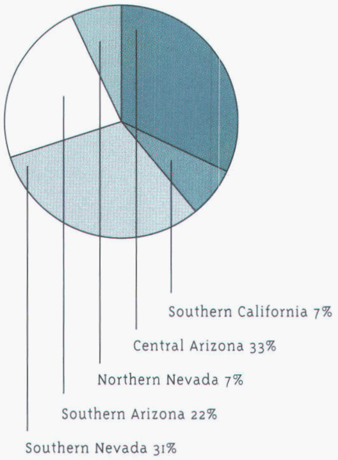


Market Price Relative to Book Value
(in dollars)

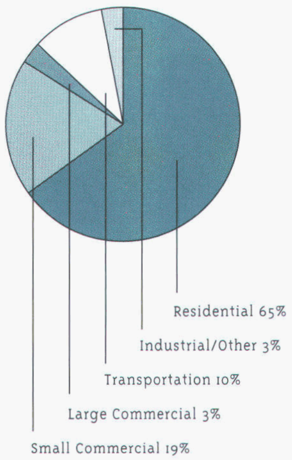
Construction Expenditures Gas Segment
(in millions of dollars)



Customers by Division
(December 31, 2003)

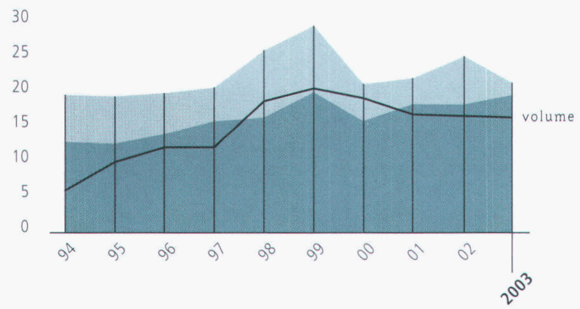


Margin by Customer Class
(2003)



Stock Prices & Trading Volume per Year

(stock prices in dollars, volume in millions)



consolidated selected financial statistics

(thousands of dollars, except per share amounts)

YEAR ENDED DECEMBER 31,	2003	2002	2001	2000	1999
Operating revenues	$ 1,231,004	$ 1,320,909	$ 1,396,688	$ 1,034,087	$ 936,866
Operating expenses	1,095,899	1,174,410	1,262,705	905,457	805,654
Operating income	$ 135,105	$ 146,499	$ 133,983	$ 128,630	$ 131,212
Net income	$ 38,502	$ 43,965	$ 37,156	$ 38,311	$ 39,310
Total assets at year end	$ 2,608,106	$ 2,432,928	$ 2,369,612	$ 2,232,337	$ 1,923,442

CAPITALIZATION AT YEAR END

Common equity	$ 630,467	$ 596,167	$ 561,200	$ 533,467	$ 505,425
Mandatorily redeemable preferred trust securities	—	60,000	60,000	60,000	60,000
Subordinated debentures	100,000	—	—	—	—
Long-term debt	1,121,164	1,092,148	796,351	896,417	859,291
	$ 1,851,631	$ 1,748,315	$ 1,417,551	$ 1,489,884	$ 1,424,716

COMMON STOCK DATA

Return on average common equity	6.3%	7.5%	6.8%	7.4%	8.0%
Earnings per share	$ 1.14	$ 1.33	$ 1.16	$ 1.22	$ 1.28
Diluted earnings per share	$ 1.13	$ 1.32	$ 1.15	$ 1.21	$ 1.27
Dividends paid per share	$ 0.82	$ 0.82	$ 0.82	$ 0.82	$ 0.82
Payout ratio	72%	62%	71%	67%	64%
Book value per share at year end	$ 18.42	$ 17.91	$ 17.27	$ 16.82	$ 16.31
Market value per share at year end	$ 22.45	$ 23.45	$ 22.35	$ 21.88	$ 23.00
Market value per share to book value per share	122%	131%	129%	130%	141%
Common shares outstanding at year end (000)	34,232	33,289	32,493	31,710	30,985
Number of common shareholders at year end	22,616	22,119	23,243	24,092	22,989
Ratio of earnings to fixed charges	1.60	1.68	1.59	1.60	1.78

natural gas operations

(thousands of dollars)

YEAR ENDED DECEMBER 31,	2003	2002	2001	2000	1999
Sales	$ 984,966	$ 1,069,917	$ 1,149,918	$ 816,358	$ 740,900
Transportation	49,387	45,983	43,184	54,353	50,255
Operating revenue	1,034,353	1,115,900	1,193,102	870,711	791,155
Net cost of gas sold	482,503	563,379	677,547	394,711	330,031
Operating margin	551,850	552,521	515,555	476,000	461,124
EXPENSES					
Operations and maintenance	266,862	264,188	253,026	231,175	221,258
Depreciation and amortization	120,791	115,175	104,498	94,689	88,254
Taxes other than income taxes	35,910	34,565	32,780	29,819	27,610
Operating income	$ 128,287	$ 138,593	$ 125,251	$ 120,317	$ 124,002
Contribution to consolidated net income	$ 34,211	$ 39,228	$ 32,626	$ 33,908	$ 35,473
Total assets at year end	$ 2,528,332	$ 2,345,407	$ 2,289,111	$ 2,154,641	$ 1,855,114
Net gas plant at year end	$ 2,175,736	$ 2,034,459	$ 1,825,571	$ 1,686,082	$ 1,581,102
Construction expenditures and property additions	$ 228,288	$ 263,576	$ 248,352	$ 205,161	$ 207,773
CASH FLOW, NET					
From operating activities	$ 187,122	$ 281,329	$ 103,848	$ 109,872	$ 165,220
From investing activities	(249,300)	(243,373)	(246,462)	(203,325)	(207,024)
From financing activities	60,815	(49,187)	154,727	95,481	40,674
Net change in cash	$ (1,363)	$ (11,231)	$ 12,113	$ 2,028	$ (1,130)
(thousands of therms)					
TOTAL THROUGHPUT					
Residential	593,048	588,215	589,943	571,378	554,507
Small commercial	279,154	280,271	279,965	272,673	266,030
Large commercial	100,422	121,500	107,583	63,908	62,566
Industrial/Other	157,305	224,055	283,772	199,715	154,306
Transportation	1,336,901	1,325,149	1,268,203	1,482,700	1,186,859
Total throughput	2,466,830	2,539,190	2,529,466	2,590,374	2,224,268
Weighted average cost of gas purchased ($/therm)	$ 0.46	$ 0.38	$ 0.55	$ 0.42	$ 0.28
Customers at year end	1,531,000	1,455,000	1,397,000	1,337,000	1,274,000
Employees at year end	2,550	2,546	2,507	2,491	2,482
Degree days – actual	1,772	1,912	1,963	1,938	1,928
Degree days – ten-year average	1,931	1,963	1,970	1,991	2,031

management's discussion and analysis of financial condition and results of operations

EXECUTIVE SUMMARY

The following discussion of Southwest Gas Corporation and subsidiaries (the "Company") includes information related to regulated natural gas transmission and distribution activities and non-regulated activities.

The Company is comprised of two business segments: natural gas operations ("Southwest" or the "natural gas operations" segment) and construction services. Southwest is engaged in the business of purchasing, transporting, and distributing natural gas in portions of Arizona, Nevada, and California. Southwest is the largest distributor in Arizona, selling and transporting natural gas in most of central and southern Arizona, including the Phoenix and Tucson metropolitan areas. Southwest is also the largest distributor and transporter of natural gas in Nevada, serving the Las Vegas metropolitan area and northern Nevada. In addition, Southwest distributes and transports natural gas in portions of California, including the Lake Tahoe area and the high desert and mountain areas in San Bernardino County.

Northern Pipeline Construction Co. ("NPL" or the "construction services" segment), a wholly owned subsidiary, is a full-service underground piping contractor that provides utility companies with trenching and installation, replacement, and maintenance services for energy distribution systems.

consolidated results of operations

(thousands of dollars, except per share amounts)

YEAR ENDED DECEMBER 31,	2003	2002	2001
CONTRIBUTION TO NET INCOME			
Natural gas operations	$ 34,211	$ 39,228	$ 32,626
Construction services	4,291	4,737	4,530
Net income	$ 38,502	$ 43,965	$ 37,156
EARNINGS PER SHARE			
Natural gas operations	$ 1.01	$ 1.19	$ 1.02
Construction services	0.13	0.14	0.14
Consolidated	$ 1.14	$ 1.33	$ 1.16

See separate discussions at **Results of Natural Gas Operations** and **Results of Construction Services**. Average shares outstanding increased by 807,000 between 2003 and 2002, and 831,000 between 2002 and 2001, primarily resulting from continuing issuances under the Dividend Reinvestment and Stock Purchase Plan ("DRSPP").

As reflected in the table above, the natural gas operations segment accounted for an average of 89 percent of consolidated net income over the past three years. As such, management's main focus is on that segment.

Southwest's operating revenues are recognized from the distribution and transportation of natural gas (and related services) billed to customers. An estimate of the amount of natural gas distributed, but not yet billed, to residential and commercial customers from the latest meter reading date to the end of the reporting period is also recognized in revenues.

Margin is the measure of utility revenues less the net cost of gas sold. Management uses margin as a main benchmark in comparing operating results from period to period. The three principal factors affecting utility margin are general rate relief, weather, and customer growth.

management's discussion and analysis of financial condition and results of operations

Rates charged to customers vary according to customer class and rate jurisdiction and are set by the individual state and federal regulatory commissions that govern Southwest's service territories. Southwest makes periodic filings for rate adjustments as the costs of providing service (including the cost of natural gas purchased) change and as additional investments in new or replacement pipeline and related facilities are made. (See the section on Rates and Regulatory Proceedings for additional information). Rates are intended to provide for recovery of all prudently incurred costs and provide a reasonable return on investment. The mix of fixed and variable components in rates assigned to various customer classes (rate design) can significantly impact the operating margin actually realized by Southwest.

Weather is a significant driver of natural gas volumes used by residential and small commercial customers and is the main reason for volatility in margin. Space heating-related volumes are the primary component of billings for these customer classes and are concentrated in the months of November to April for the majority of the Company's customers. Variances in temperatures from normal levels, especially during these months, have a significant impact on the margin and associated net income of the Company.

Customer growth, excluding acquisitions, has averaged five percent annually over the past 10 years and over four percent annually during the past three years. Incremental margin has accompanied this customer growth, but the costs associated with creating and maintaining the infrastructure needed to accommodate these customers also have been significant. The timing of including these costs in rates is often delayed (regulatory lag) and results in a reduction of current-period earnings.

Management has attempted to mitigate the regulatory lag by being judicious in its staffing levels through the effective use of technology. During the past decade while adding nearly 600,000 customers, Southwest only increased staffing levels by 232. During this same period, Southwest's customer to employee ratio has climbed from 402/1 to 600/1, one of the best in the industry. It has accomplished this without sacrificing service quality. Examples of technological improvements over the last few years include electronic order routing, an electronic mapping system and, most recently, a work management system.

The results of the natural gas operations segment and the overall results of the Company are heavily dependent upon the three components noted previously (general rate relief, weather, and customer growth). Significant changes in these components (primarily weather) have contributed to somewhat volatile earnings. Management continues to work with its regulatory commissions in designing rate structures that provide affordable and reliable service to its customers while mitigating the volatility in prices to customers and stabilizing returns to investors.

As of December 31, 2003, Southwest had 1,531,000 residential, commercial, industrial, and other natural gas customers, of which 851,000 customers were located in Arizona, 542,000 in Nevada, and 138,000 in California. Residential and commercial customers represented over 99 percent of the total customer base. During 2003, Southwest added 67,000 customers (excluding 9,000 associated with the acquisition of Black Mountain Gas Company ("BMG") in October 2003), a five percent increase, of which 30,000 customers were added in Arizona, 31,000 in Nevada, and 6,000 in California. These additions are largely attributed to population growth in the service areas. Based on current commitments from builders, customer growth is expected to be between four and five percent in 2004. During 2003, 56 percent of operating margin was earned in Arizona, 36 percent in Nevada, and 8 percent in California. During this same period, Southwest earned 84 percent of operating margin from residential and small commercial customers, 6 percent from other sales customers, and 10 percent from transportation customers. These patterns are expected to continue.

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RESULTS OF NATURAL GAS OPERATIONS

(thousands of dollars)

YEAR ENDED DECEMBER 31,	2003	2002	2001
Gas operating revenues	$ 1,034,353	$ 1,115,900	$ 1,193,102
Net cost of gas sold	482,503	563,379	677,547
Operating margin	551,850	552,521	515,555
Operations and maintenance expense	266,862	264,188	253,026
Depreciation and amortization	120,791	115,175	104,498
Taxes other than income taxes	35,910	34,565	32,780
Operating income	128,287	138,593	125,251
Other income (expense)	2,955	3,108	7,694
Net interest deductions	76,251	78,505	78,746
Net interest deductions on subordinated debentures	2,680	—	—
Preferred securities distributions	4,180	5,475	5,475
Income before income taxes	48,131	57,721	48,724
Income tax expense	13,920	18,493	16,098
Contribution to consolidated net income	$ 34,211	$ 39,228	$ 32,626

2003 vs. 2002

Contribution from natural gas operations declined $5 million in 2003 compared to 2002. The decrease was principally the result of lower operating margin and increased operating expenses, partially offset by decreased financing costs.

Operating margin decreased $671,000 in 2003 as compared to 2002. Approximately 67,000 customers were added during the last 12 months, a growth rate of five percent. Another 9,000 customers were added in October 2003 with the acquisition of Black Mountain Gas Company. New customers contributed $16 million in incremental margin. Differences in heating demand caused by weather variations between years resulted in a $13 million margin decrease as warmer-than-normal temperatures were experienced during both years. During 2003, operating margin was negatively impacted $32 million by the weather, while in 2002 the negative impact was $19 million. Conservation, energy efficiency and other factors accounted for the remainder of the decline.

Operations and maintenance expense increased $2.7 million, or one percent, compared to 2002. The impacts of general cost increases and costs associated with the continued expansion and upgrading of the gas system to accommodate customer growth were offset by cost-curbing management initiatives begun in the fourth quarter of 2002. Going forward, operations and maintenance expenses overall are expected to trend upward corresponding to the customer growth rate and inflation. The costs of additional regulation, social programs, medical costs and pensions are some of the primary factors responsible for this trend.

Depreciation expense and general taxes increased $7 million, or five percent, as a result of construction activities. Average gas plant in service increased $231 million, or nine percent, as compared to 2002. The increase reflects ongoing capital expenditures for the upgrade of existing operating facilities and the expansion of the system to accommodate continued customer growth.

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Other income (expense) decreased $153,000 between years. The prior year included income of $2.2 million related to several non-recurring items. Interest income (primarily on purchased gas adjustment ("PGA") balances) declined $1.6 million between years. Improvements in returns on long-term investments substantially offset the negative factors.

Net financing costs declined $869,000 between years primarily due to lower interest rates on variable-rate debt and interest savings generated from the refinancing of industrial development revenue bonds and preferred securities instruments in 2003. Interest costs are expected to trend upward in 2004 as the Company finances the infrastructure associated with customer growth.

During 2003, Southwest recognized $2 million of income tax benefits associated with plant-related items. In 2002, Southwest recognized $2.7 million of income tax benefits associated with state taxes, plant, and non-plant related items.

2002 vs. 2001

The gas segment contribution to consolidated net income for 2002 increased $6.6 million from 2001. Growth in operating margin was partially offset by higher operating costs and a decline in other income (expense).

Operating margin increased $37 million, or seven percent, in 2002 as compared to 2001. The increase was a result of rate relief and customer growth, partially offset by the impacts of warm weather between periods. General rate relief granted during the fourth quarter of 2001, in both Arizona and Nevada, increased operating margin by $33 million. Southwest added 58,000 customers during 2002, an increase of four percent. New customers contributed $20 million in incremental margin. Differences in heating demand caused by weather variations between periods and conservation resulted in a $16 million margin decrease. Warmer-than-normal temperatures were experienced during the second and fourth quarters of 2002, whereas during 2001, temperatures were relatively normal.

Operations and maintenance expense increased $11.2 million, or four percent, reflecting general increases in labor and maintenance costs, and incremental costs associated with servicing additional customers. Uncollectible expenses in 2002 were slightly below the amounts recorded in 2001 as natural gas prices declined, lowering average customer bills.

Depreciation expense and general taxes increased $12.5 million, or nine percent, as a result of construction activities. Average gas plant in service increased $207 million, or eight percent, compared to the prior year. This was attributed to the continued expansion and upgrading of the gas system to accommodate customer growth.

Other income (expense) declined $4.6 million between years principally because of a $5 million decrease in interest income earned on the balance of deferred purchased gas costs. Significant components of the 2002 balance included: an $8.9 million gain on the sale of undeveloped property, $4 million of net merger-related litigation costs, and $2.7 million of charges associated with the settlement of a regulatory issue in California.

Net interest deductions declined $241,000 between years. Strong cash flows during the first half of 2002, from the recovery of previously deferred purchased gas costs and general rate relief, mitigated the amount of incremental borrowings needed to finance construction expenditures. Declining interest rates on variable-rate debt instruments were also a contributing favorable factor.

During 2002, Southwest recognized $2.7 million of income tax benefits associated with state taxes, plant, and non-plant related items. In 2001, the resolution of state income tax issues resulted in a $2.5 million income tax benefit.

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RATES AND REGULATORY PROCEEDINGS

Arizona General Rate Case. In May 2000, Southwest last filed a general rate application with the Arizona Corporation Commission ("ACC") for its Arizona rate jurisdiction. The ACC authorized a general rate increase of $21.6 million effective November 2001. Management has not determined the timing of filing its next general rate case in Arizona.

Nevada General Rate Cases. In March 2004, Southwest filed general rate applications with the Public Utilities Commission of Nevada ("PUCN"), which included annual increases of $8.6 million for northern Nevada and $18.9 million in southern Nevada. A PUCN decision is expected in the third quarter of 2004.

In July 2001, Southwest filed general rate applications with the PUCN for its southern Nevada and northern Nevada rate jurisdictions. The PUCN authorized general rate increases of $13.5 million in southern Nevada and $5.9 million in northern Nevada effective December 2001.

California General Rate Cases. In February 2002, Southwest filed general rate applications with the California Public Utilities Commission ("CPUC") for its northern and southern California jurisdictions. The applications sought annual increases over a five-year rate case cycle with a cumulative total of $6.3 million in northern California and $17.2 million in southern California. The last general rate increases received in California were January 1998 in northern California and January 1995 in southern California.

In July 2002, the Office of Ratepayer Advocates ("ORA") filed testimony in the rate case recommending significant reductions to the rate increases sought by Southwest. The ORA concurred with the majority of the Southwest rate design proposals including a margin tracking mechanism to mitigate weather-related and other usage variations. At the hearing that was held in August 2002, Southwest modified its proposal from a five-year to a three-year rate case cycle and accordingly reduced its cumulative request to $4.8 million in northern California and $10.7 million in southern California. For 2003, the amounts requested were $2.6 million in northern California and $5.7 million in southern California. The final general rate case decision, originally anticipated to have an effective date of January 2003, was delayed due to the reassignment of the Administrative Law Judge ("ALJ") assigned to the case. As a result of this delay, Southwest filed a motion during the first quarter of 2003 requesting authorization to establish a memorandum account to track the related revenue shortfall between the existing and proposed rates in the general rate case filing. This motion was approved, effective May 2003. In October 2003, the ALJ rendered a draft decision ("proposed decision" or "PD") on the general rate case. The PD was modified in February 2004. If approved as modified, the PD would increase rates by about 60 percent of the 2003 amount filed for and provide for attrition increases beginning in 2004. Southwest filed comments largely in support of the PD. In January 2004, an alternate decision ("AD") from one of the commissioners was received, reducing the rate increase in southern California as proposed in the PD by $2 million, with no significant change to northern California. In addition, the AD proposed a disallowance of $12.2 million in gas costs. Southwest filed comments vehemently opposed to the AD. The general rate case is on the agenda for mid-March; however, management can not determine which, if any, of the proposed or alternate decisions will be approved.

FERC Jurisdiction. In July 1996, Paiute Pipeline Company, a wholly owned subsidiary of the Company, filed its most recent general rate case with the Federal Energy Regulatory Commission ("FERC"). The FERC authorized a general rate increase effective January 1997. The timing of Paiute's next general rate case filing has not been determined.

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PGA FILINGS

The rate schedules in all of the service territories contain PGA clauses, which permit adjustments to rates as the cost of purchased gas changes. In Arizona, Southwest adjusts rates monthly for changes in purchased gas costs, within pre-established limits. In California, a monthly gas cost adjustment based on forecasted monthly prices is utilized. Monthly adjustments are designed to provide a more timely recovery of gas costs and to send appropriate pricing signals to customers. In Nevada, tariffs provide for annual adjustment dates for changes in purchased gas costs. In addition, Southwest may request to adjust rates more often, if conditions warrant. Filings to change rates in accordance with PGA clauses are subject to audit by state regulatory commission staffs. PGA changes impact cash flows but have no direct impact on profit margin. Southwest had the following outstanding PGA balances receivable/(payable) at the end of its two most recent fiscal years (millions of dollars):

	2003	2002
Arizona	$ (5.8)	$ (24.0)
Northern Nevada	1.7	8.3
Southern Nevada	5.1	(21.9)
California	8.2	10.9
	$ 9.2	$ (26.7)

Nevada PGA Filings. In June 2003, Southwest made its annual PGA filing with the PUCN. Southwest requested a change to a monthly PGA mechanism, rather than annual, to reduce volatility in rate changes. Effective in December 2003, the PUCN approved an increase of $25.5 million, or 12.3 percent, for customers in southern Nevada and a decrease of $8.6 million, or 10.2 percent, in northern Nevada. The monthly adjustment mechanism proposed in the annual filing was not adopted. As a result of increases in gas costs experienced since the annual filing in June 2003 (in addition to projected continued increases), an out-of-cycle filing was made in December 2003. This filing requested increases of $59.8 million, or 25.5 percent, in southern Nevada and $16.7 million, or 22.1 percent, in northern Nevada. In January 2004, the PUCN approved the elimination of a credit surcharge, resulting in an interim increase of 5.5 percent in southern Nevada and 4.8 percent in northern Nevada beginning in February 2004. A final decision on the PGA filing is expected in the second quarter of 2004.

OTHER FILINGS

Since November 1999, the Federal Energy Regulatory Commission has been examining capacity allocation issues on the El Paso system in several proceedings. This examination resulted in a series of orders by the FERC in which all of the major full requirements transportation service agreements on the El Paso system, including the agreement by which Southwest obtained the transportation of gas supplies to its Arizona service areas, were converted to contract demand-type service agreements, with fixed maximum service limits, effective September 2003. At that time, all of the transportation capacity on the system was allocated among the shippers. In order to help ensure that the converting full requirements shippers would have adequate capacity to meet their needs, El Paso was authorized to expand the capacity on its system by adding compression.

The FERC is continuing to examine issues related to the implementation of the full requirements conversion. Petitions for judicial review of the FERC's orders mandating the conversion have been filed.

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Management believes that it is difficult to predict the ultimate outcome of the proceedings or the impact of the FERC action on Southwest. Southwest has had adequate capacity for its customers needs during the 2003/2004 heating season to date and management believes adequate capacity exists for the remainder of the heating season. Additional costs may be incurred to acquire capacity in the future as a result of the FERC order. However, it is anticipated that any additional costs will be collected from customers through the PGA mechanism.

CAPITAL RESOURCES AND LIQUIDITY

The capital requirements and resources of the Company generally are determined independently for the natural gas operations and construction services segments. Each business activity is generally responsible for securing its own financing sources. The capital requirements and resources of the construction services segment are not material to the overall capital requirements and resources of the Company.

Southwest continues to experience significant customer growth. This growth has required significant capital outlays for new transmission and distribution plant, to keep up with consumer demand. During the three-year period ended December 31, 2003, total gas plant increased from $2.4 billion to $3 billion, or at an annual rate of nine percent. Customer growth was the primary reason for the plant increase as Southwest added 194,000 net new customers (including BMG) during the three-year period.

During 2003, capital expenditures for the natural gas operations segment were $228 million. Approximately 72 percent of these current-period expenditures represented new construction and the balance represented costs associated with routine replacement of existing transmission, distribution, and general plant. Cash flows from operating activities of Southwest (net of dividends) provided $159 million of the required capital resources pertaining to total construction expenditures in 2003. The remainder was provided from external financing activities.

asset purchases

In October 2003, the Company completed the purchase of BMG, a gas utility serving portions of Carefree, North Scottsdale, North Phoenix, Cave Creek, and Page, Arizona. The Company paid approximately $24 million for BMG. BMG has approximately 9,000 natural gas customers in a rapidly growing area north of Phoenix and about 2,500 propane customers. The Company plans to sell the propane operations.

2003 financing activity

In March 2003, the Company issued several series of Clark County, Nevada Industrial Development Revenue Bonds ("IDRBs") totaling $165 million, due 2038. Of this total, variable-rate IDRBs ($50 million 2003 Series A and $50 million 2003 Series B) were used to refinance the $100 million 7.50% 1992 Series B, fixed-rate IDRBs due 2032. At December 31, 2003, the effective interest rate including all fees on the new Series A and Series B IDRBs was 2.66%. The $30 million 7.30% 1992 Series A, fixed-rate IDRBs due 2027 was refinanced with $30 million 5.45% 2003 Series C fixed-rate IDRBs. An incremental $35 million ($20 million 3.35% 2003 Series D and $15 million 5.80% Series E fixed-rate IDRBs) was used to finance construction expenditures in southern Nevada during the first and second quarters of 2003. The Series C and Series E were set with an initial interest rate period of 10 years, while the Series D has an initial interest rate period of 18 months. After the initial interest rate periods, the Series C, D, and E interest rates will be reset at then prevailing market rates for periods not to exceed the maturity date of March 1, 2038.

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The 2003 Series A and Series B IDRBs described above are supported by two letters of credit totaling $101.7 million, which expire in March 2006. These IDRBs are set at weekly rates and the letters of credit support the payment of principal or a portion of the purchase price corresponding to the principal of the IDRBs while in the weekly rate mode.

In June 2003, the Company filed a registration statement on Form S-3 for an incremental $100 million of various securities with the Securities and Exchange Commission ("SEC") and to revise $200 million of securities previously registered to provide additional flexibility in the types of securities available for issuance. After the issuance of the preferred securities described in the following paragraph, the Company has a total of $200 million in securities registered with the SEC which are available for future financing needs.

In August 2003, Southwest Gas Capital II, a wholly owned subsidiary and financing trust, issued $100 million of 7.70% Preferred Trust Securities. A portion of the net proceeds from the issuance of the Preferred Trust Securities was used to complete the redemption of the 9.125% Trust Originated Preferred Securities effective September 2003 at a redemption price of $25 per Preferred Security, totaling $60 million plus accrued interest of $1.3 million. For more information, including the accounting treatment, see **Note 5 – Preferred Securities**.

In October 2003, a $55.3 million letter of credit, which supports the City of Big Bear $50 million tax-exempt Series A IDRBs, due 2028, was renewed for a three-year period expiring in October 2006.

In July 2003, the Company registered 1.5 million shares of common stock with the SEC for issuance under the Southwest Gas Corporation 2002 Stock Incentive Plan. In December 2003, the Company registered 600,000 shares of common stock with the SEC for issuance under the Southwest Gas Corporation Employees' Investment Plan.

2004 construction expenditures and financing

In March 2002, the Job Creation and Worker Assistance Act of 2002 ("2002 Act") was signed into law. The 2002 Act provided a three-year, 30 percent bonus depreciation deduction for businesses. The Jobs and Growth Tax Relief Reconciliation Act of 2003 ("2003 Act"), signed into law in May 2003, provides for enhanced and extended bonus tax depreciation. The 2003 Act increased the bonus depreciation rate to 50 percent for qualifying property placed in service after May 2003 and, generally, before January 2005. Southwest estimates the 2002 and 2003 Acts bonus depreciation deductions will defer the payment of $35 million of federal income taxes during 2004.

Southwest estimates construction expenditures during the three-year period ending December 31, 2006 will be approximately $690 million. Of this amount, $233 million are expected to be incurred in 2004. During the three-year period, cash flow from operating activities including the impacts of the Acts (net of dividends) is estimated to fund approximately 80 percent of the gas operations' total construction expenditures. The Company expects to raise $50 million to $55 million from its Dividend Reinvestment and Stock Purchase Plan ("DRSPP"). The remaining cash requirements are expected to be provided by other external financing sources. The timing, types, and amounts of these additional external financings will be dependent on a number of factors, including conditions in the capital markets, timing and amounts of rate relief, growth levels in Southwest service areas, and earnings. These external financings may include the issuance of both debt and equity securities, bank and other short-term borrowings, and other forms of financing.

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off balance sheet arrangements

All Company debt is recorded on its balance sheets. The Company has long-term operating leases, which are described in **Note 2 – Utility Plant** of the Notes to Consolidated Financial Statements. No debt instruments have credit triggers or other clauses that result in default if Company bond ratings are lowered by rating agencies. Certain Company debt instruments contain customary leverage, net worth and other covenants, and securities ratings covenants that, if set in motion, would increase financing costs. To date, the Company has not incurred any increased financing costs as a result of these covenants.

Southwest has fixed-price gas purchase contracts, which are considered normal purchases occurring in the ordinary course of business. These gas purchase contracts are entered into annually to mitigate market price volatility. The Company does not currently utilize other stand-alone derivative instruments for speculative purposes or for hedging and does not have foreign currency exposure. None of the Company's long-term financial instruments or other contracts are derivatives that are marked to market, or contain embedded derivatives with significant mark-to-market value.

contractual obligations

Obligations under long-term debt, gas purchase obligations and non-cancelable operating leases at December 31, 2003 were as follows:

CONTRACTUAL OBLIGATIONS

(millions of dollars)		PAYMENTS DUE BY PERIOD			
	TOTAL	2004	2005-2006	2007-2008	THEREAFTER
Short-term debt (Note 7)	$ 52	$ 52	$ —	$ —	$ —
Subordinated debentures to Southwest Gas Capital II (Note 5)	103	—	—	—	103
Long-term debt (Note 6)	1,121	6	204	43	868
Operating leases (Note 2)	47	8	10	8	21
Gas purchase obligations (a)	218	170	48	—	—
Pipeline capacity (b)	551	69	137	132	213
Other commitments	8	4	4	—	—
Total	$ 2,100	$ 309	$ 403	$ 183	$ 1,205

(a) Includes fixed price and variable rate gas purchase contracts covering approximately 99 million dekatherms. Fixed price contracts range in price from $3.70 to $5.84 per dekatherm. Variable price contracts reflect minimum contractual obligations.

(b) Southwest has pipeline capacity contracts for firm transportation service, both on a short- and long-term basis, with several companies (primarily El Paso Natural Gas Company and Kern River Gas Transmission Company) for all of its service territories. Southwest also has interruptible contracts in place that allow additional capacity to be acquired should an unforeseen need arise. Costs associated with these pipeline capacity contracts are a component of the cost of gas sold and are recovered from customers primarily through the PGA mechanism.

Estimated pension funding for 2004 is $14 million.

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liquidity

Liquidity refers to the ability of an enterprise to generate adequate amounts of cash to meet its cash requirements. Several general factors that could significantly affect capital resources and liquidity in future years include inflation, growth in the economy, changes in income tax laws, changes in the ratemaking policies of regulatory commissions, interest rates, variability of natural gas prices, and the level of Company earnings.

Since the winter of 2000-2001, the price of natural gas has varied widely. Southwest customers have benefited from the fixed prices associated with term contracts in place during 2003. These contracts are generally of short duration (less than one year) and cover about half of Southwest's supply needs. Southwest enters into new contracts annually to replace those that are expiring to help mitigate price volatility. Remaining needs will be covered with the purchase of natural gas on the spot market and are subject to market fluctuations. Over the next few years, continued strong growth in natural gas demand and limited supply increases indicate prices for natural gas will remain volatile. Southwest continues to pursue all available sources to maintain the balance between a low cost and reliable supply of natural gas for its customers. All incremental costs are expected to be included in the PGA mechanism for recovery from customers in each rate jurisdiction.

The rate schedules in all of the service territories of Southwest contain PGA clauses which permit adjustments to rates as the cost of purchased gas changes. The PGA mechanism allows Southwest to change the gas cost component of the rates charged to its customers to reflect increases or decreases in the price expected to be paid to its suppliers and companies providing interstate pipeline transportation service. On an interim basis, Southwest generally defers over or under collections of gas costs to PGA balancing accounts. In addition, Southwest uses this mechanism to either refund amounts over-collected or recoup amounts under-collected as compared to the price paid for natural gas during the period since the last PGA rate change went into effect. At December 31, 2003, the combined balances in PGA accounts totaled an under-collection of \$9.2 million versus an over-collection of \$27 million at December 31, 2002. See **PGA Filings** for more information on recent regulatory filings. Southwest utilizes short-term borrowings to temporarily finance under-collected PGA balances. Southwest has a total short-term borrowing capacity of \$150 million (with \$98 million available at December 31, 2003), which the Company believes is adequate to meet anticipated needs.

PGA changes affect cash flows but have no direct impact on profit margin. In addition, since Southwest is permitted to accrue interest on PGA balances, the cost of incremental, PGA-related short-term borrowings will be offset, and there should be no material negative impact to earnings. However, gas cost deferrals and recoveries can impact comparisons between periods of individual income statement components. These include Gas operating revenues, Net cost of gas sold, Net interest deductions and Other income (deductions).

The Company has a common stock dividend policy which states that common stock dividends will be paid at a prudent level that is within the normal dividend payout range for its respective businesses, and that the dividend will be established at a level considered sustainable in order to minimize business risk and maintain a strong capital structure throughout all economic cycles. The quarterly common stock dividend was 20.5 cents per share throughout 2003. The dividend of 20.5 cents per share has been paid quarterly since September 1994.

security ratings

Securities ratings issued by nationally recognized ratings agencies provide a method for determining the credit worthiness of an issuer. Company debt ratings are important because long-term debt constitutes a significant portion of total capitalization. These debt ratings are a factor considered by lenders when determining the cost of debt for the Company (i.e., the better the rating, the lower the cost to borrow funds).

management's discussion and analysis of financial condition and results of operations

Since January 1997, Moody's Investors Service, Inc. ("Moody's") has rated Company unsecured long-term debt at Baa2. Moody's debt ratings range from Aaa (best quality) to C (lowest quality). Moody's applies a Baa2 rating to obligations which are considered medium grade obligations (i.e., they are neither highly protected nor poorly secured).

The Company's unsecured long-term debt rating from Fitch, Inc. ("Fitch") is BBB. Fitch debt ratings range from AAA (highest credit quality) to D (defaulted debt obligation). The Fitch rating of BBB indicates a credit quality that is considered prudent for investment.

The Company's unsecured long-term debt rating from Standard and Poor's Ratings Services ("S&P") is BBB-. S&P debt ratings range from AAA (highest rating possible) to D (obligation is in default). The S&P rating of BBB- indicates the debt is regarded as having an adequate capacity to pay interest and repay principal.

A securities rating is not a recommendation to buy, sell, or hold a security and is subject to change or withdrawal at any time by the rating agency.

inflation

Results of operations are impacted by inflation. Natural gas, labor, and construction costs are the categories most significantly impacted by inflation. Changes to cost of gas are generally recovered through PGA mechanisms and do not significantly impact net earnings. Labor is a component of the cost of service, and construction costs are the primary component of rate base. In order to recover increased costs, and earn a fair return on rate base, general rate cases are filed by Southwest, when deemed necessary, for review and approval by regulatory authorities. Regulatory lag, that is, the time between the date increased costs are incurred and the time such increases are recovered through the ratemaking process, can impact earnings. See **Rates and Regulatory Proceedings** for a discussion of recent rate case proceedings.

RESULTS OF CONSTRUCTION SERVICES

(thousands of dollars)

YEAR ENDED DECEMBER 31,	2003	2002	2001
Construction revenues	$ 196,651	$ 205,009	$ 203,586
Cost of construction	184,290	191,561	189,429
Gross profit	12,361	13,448	14,157
General and administrative expenses	5,543	5,542	5,026
Operating income	6,818	7,906	9,131
Other income (expense)	1,290	1,221	871
Interest expense	855	1,466	1,985
Income before income taxes	7,253	7,661	8,017
Income tax expense	2,962	2,924	3,487
Contribution to consolidated net income	$ 4,291	$ 4,737	$ 4,530

2003 vs. 2002

The 2003 contribution to consolidated net income from construction services decreased $446,000 from the prior year. The decrease was primarily due to a decline in construction revenues and an insurance settlement, partially offset by lower interest expense.

management's discussion and analysis of financial condition and results of operations

Revenues decreased $8.4 million due to a reduced workload in some operating areas, the completion of certain projects, and the non-renewal of two long-term contracts. Cost of construction includes a one-time $1.3 million charge for an unfavorable insurance settlement. Interest expense declined $611,000 as a result of the refinancing of long-term debt to take advantage of lower interest rates.

2002 vs. 2001

The 2002 contribution to consolidated net income from construction services increased $207,000 from the prior year. The increase was primarily due to a decline in Income tax expense and an increase in Other income. Revenues remained relatively constant, while the gross profit margin percentage decreased slightly.

Gross profit decreased $709,000 because of the absorption of significant increases in insurance costs. Other income in 2001 included $400,000 of goodwill amortization that was not included in 2002 due to the adoption of a new accounting pronouncement. General and administrative expenses increased by $516,000 due to increased labor costs and additional depreciation related to a new computer system. Interest expense declined as a result of the refinancing of long-term debt to take advantage of lower interest rates. Income tax expense decreased largely as a result of a $274,000 tax credit in the state of Arizona.

RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

In January 2003, the Financial Accounting Standards Board ("FASB") issued Interpretation No. 46 "Consolidation of Variable Interest Entities – an Interpretation of ARB No. 51" ("FIN 46") effective July 2003. This Interpretation of Accounting Research Bulletin No. 51 "Consolidated Financial Statements," addresses consolidation by business enterprises of variable interest entities. FIN 46 explains how to identify variable interest entities and how an enterprise assesses its interests in a variable interest entity to decide whether to consolidate that entity. Southwest Gas Capital II ("Trust II"), a wholly owned subsidiary, was created by the Company to issue preferred trust securities for the benefit of the Company. (See Note 5 of the Notes to Consolidated Financial Statements for additional information.) Trust II, the issuer of the preferred trust securities, meets the definition of a variable interest entity.

Although the Company owns 100 percent of the common voting securities of Trust II, under current interpretation of FIN 46, the Company is not considered the primary beneficiary of this trust and therefore Trust II is not consolidated. The adoption of FIN 46 results in the Company reflecting a liability to Trust II, which under the prior accounting treatment would have been eliminated in consolidation, instead of to the holders of the preferred trust securities. As a result, payments and amortizations associated with the liability are classified on the consolidated statements of income as Net interest deductions on subordinated debentures.

APPLICATION OF CRITICAL ACCOUNTING POLICIES

A critical accounting policy is one which is very important to the portrayal of the financial condition and results of a company, and requires the most difficult, subjective, or complex judgments of management. The need to make estimates about the effect of items that are uncertain is what makes these judgments difficult, subjective, and/or complex. Management makes subjective judgments about the accounting and regulatory treatment of many items. The following are examples of accounting policies that are critical to the financial statements of the Company. For more information regarding the significant accounting policies of the Company, see **Note 1 – Summary of Significant Accounting Policies**.

- Natural gas operations are subject to the regulation of the Arizona Corporation Commission, the Public Utilities Commission of Nevada, the California Public Utilities Commission, and the Federal Energy Regulatory Commission. The

management's discussion and analysis of financial condition and results of operations

accounting policies of the Company conform to generally accepted accounting principles applicable to rate-regulated enterprises (including SFAS No. 71 "Accounting for the Effects of Certain Types of Regulation") and reflect the effects of the ratemaking process. As such, the Company is allowed to defer as regulatory assets, costs that otherwise would be expensed if it is probable that future recovery from customers will occur. If rate recovery is no longer probable, due to competition or the actions of regulators, the Company is required to write-off the related regulatory asset. Refer to **Note 4 – Regulatory Assets and Liabilities** for a list of regulatory assets.

- The income tax calculations of the Company require estimates due to regulatory differences between the multiple states in which the Company operates, and future tax rate changes. The Company uses the asset and liability method of accounting for income taxes. Under the asset and liability method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. A change in the regulatory treatment or significant changes in tax-related estimates, assumptions, or enacted tax rates could have a material impact on the financial position and results of operations of the Company.
- Depreciation is computed at composite rates considered sufficient to amortize costs over the estimated remaining lives of assets, and includes adjustments for the cost of removal, and salvage value. Depreciation studies are performed periodically and prospective changes in rates are estimated to make up for past differences. These studies are reviewed and approved by the appropriate regulatory agency. Changes in estimates of depreciable lives or changes in depreciation rates mandated by regulations could affect the results of operations of the Company in periods subsequent to the change.
- In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations," which was effective for fiscal years beginning after June 15, 2002. SFAS No. 143 establishes accounting standards for recognition and measurement of liabilities for asset retirement obligations and the associated asset retirement costs. The Company adopted the provisions of SFAS No. 143 as of January 1, 2003.

  In accordance with approved regulatory practices, the depreciation expense for Southwest includes a component to recover removal costs associated with utility plant retirements. In accordance with the SEC's position on presentation of these amounts, management has reclassified $68 million and $55 million, as of December 31, 2003 and 2002, respectively, of estimated removal costs from accumulated depreciation to accumulated removal costs (in the liabilities section of the balance sheet).

  Under utility accounting, all plant is assumed to be fully depreciated upon retirement. However, retirements often occur earlier than the average service life of the plant group. Accumulated depreciation has a historical mix of credits (depreciation amounts designed to recover plant investment and net removal costs) and debits (charges for retirements and actual costs of removal). The actual amount of net removal costs recorded as credits has never been tracked by the Company. The estimate of the calculated cost of removal embedded in accumulated depreciation employed various assumptions including average service lives and historical depreciation rates. Variations in the assumptions utilized would result in a range of accumulated removal costs that would vary significantly from the amount estimated above.

Management believes that regulation and the effects of regulatory accounting have the most significant impact on the financial statements. When Southwest files rate cases, capital assets, costs, and gas purchasing practices are subject to review, and disallowances can occur. Regulatory disallowances in the past have not been frequent but have on occasion been significant to the operating results of the Company.

FORWARD-LOOKING STATEMENTS

This annual report contains statements which constitute "forward-looking statements" within the meaning of the Securities Litigation Reform Act of 1995 ("Reform Act"). All statements other than statements of historical fact included or incorporated by reference in this annual report are forward-looking statements, including, without limitation, statements regarding the Company's plans, objectives, goals, projections, strategies, future events or performance, and underlying assumptions. The words "may," "will," "should," "could," "expect," "plan," "anticipate," "believe," "estimate," "predict," "continue," and similar words and expressions are generally used and intended to identify forward-looking statements. All forward-looking statements are intended to be subject to the safe harbor protection provided by the Reform Act.

management's discussion and analysis of financial condition and results of operations

A number of important factors affecting the business and financial results of the Company could cause actual results to differ materially from those stated in the forward-looking statements. These factors include, but are not limited to, the impact of weather variations on customer usage, customer growth rates, changes in natural gas prices, our ability to recover costs through our PGA mechanism, the effects of regulation/deregulation, the timing and amount of rate relief, changes in gas procurement practices, changes in capital requirements and funding, the impact of conditions in the capital markets on financing costs, changes in construction expenditures and financing, changes in operations and maintenance expenses, changes in pipeline capacity for the transportation of gas and related costs, acquisitions and management's plans related thereto, competition and our ability to raise capital in external financings or through our DRSPP. In addition, the Company can provide no assurance that its discussions regarding certain trends relating to its financing, operations and maintenance expenses will continue in future periods. For additional information on the risks associated with the Company's business, see **Item 1. Business – Company Risk Factors** in the Company's Annual Report on Form 10-K for the year ended December 31, 2003.

All forward-looking statements in this annual report are made as of the date hereof, based on information available to the Company as of the date hereof, and the Company assumes no obligation to update or revise any of its forward-looking statements even if experience or future changes show that the indicated results or events will not be realized. We caution you not to unduly rely on any forward-looking statement(s).

COMMON STOCK PRICE AND DIVIDEND INFORMATION

	2003		2002		DIVIDENDS PAID	
	HIGH	LOW	HIGH	LOW	2003	2002
First quarter	$ 23.64	$ 19.30	$ 25.35	$ 21.80	$ 0.205	$ 0.205
Second quarter	22.45	19.74	24.99	22.60	0.205	0.205
Third quarter	23.49	20.14	24.75	18.10	0.205	0.205
Fourth quarter	23.48	22.04	23.63	19.82	0.205	0.205
					$ 0.820	$ 0.820

The principal markets on which the common stock of the Company is traded are the New York Stock Exchange and the Pacific Exchange. At March 1, 2004, there were 23,259 holders of record of common stock and the market price of the common stock was $23.45.

southwest gas corporation
consolidated balance sheets

(thousands of dollars, except par value)

DECEMBER 31,	2003	2002
ASSETS		
UTILITY PLANT:		
Gas plant	$ 3,035,969	$ 2,779,960
Less: accumulated depreciation	(896,309)	(814,908)
Acquisition adjustments, net	2,533	2,714
Construction work in progress	33,543	66,693
Net utility plant (Note 2)	2,175,736	2,034,459
Other property and investments	87,443	87,391
CURRENT ASSETS:		
Cash and cash equivalents	17,183	19,392
Accounts receivable, net of allowances (Note 3)	126,783	130,695
Accrued utility revenue	66,700	65,073
Deferred income taxes (Note 10)	6,914	3,084
Deferred purchased gas costs (Note 4)	9,151	—
Prepaids and other current assets (Note 4)	54,356	43,524
Total current assets	281,087	261,768
Deferred charges and other assets (Note 4)	63,840	49,310
Total assets	$ 2,608,106	$ 2,432,928

southwest gas corporation
consolidated balance sheets

(thousands of dollars, except par value)

DECEMBER 31,	2003	2002
CAPITALIZATION AND LIABILITIES		
CAPITALIZATION:		
Common stock, $1 par (authorized – 45,000,000 shares; issued and outstanding – 34,232,098 and 33,289,015 shares)	$ 35,862	$ 34,919
Additional paid-in capital	510,521	487,788
Retained earnings	84,084	73,460
Total equity	630,467	596,167
Mandatorily redeemable preferred trust securities (Note 5)	—	60,000
Subordinated debentures due to Southwest Gas Capital II (Note 5)	100,000	—
Long-term debt, less current maturities (Note 6)	1,121,164	1,092,148
Total capitalization	1,851,631	1,748,315
Commitments and contingencies (Note 8)		
CURRENT LIABILITIES:		
Current maturities of long-term debt (Note 6)	6,435	8,705
Short-term debt (Note 7)	52,000	53,000
Accounts payable	110,114	88,309
Customer deposits	44,290	34,313
Income taxes payable, net	—	10,969
Accrued general taxes	32,466	28,400
Accrued interest	19,665	21,137
Deferred purchased gas costs (Note 4)	—	26,718
Other current liabilities	45,442	41,630
Total current liabilities	310,412	313,181
DEFERRED INCOME TAXES AND OTHER CREDITS:		
Deferred income taxes and investment tax credits (Note 10)	277,332	229,358
Taxes payable	6,661	—
Accumulated removal costs (Note 4)	68,000	55,000
Other deferred credits (Note 4)	94,070	87,074
Total deferred income taxes and other credits	446,063	371,432
Total capitalization and liabilities	$ 2,608,106	$ 2,432,928

The accompanying notes are an integral part of these statements.

southwest gas corporation
consolidated statements of income

(in thousands, except per share amounts)

YEAR ENDED DECEMBER 31,	2003	2002	2001
OPERATING REVENUES:			
Gas operating revenues	$ 1,034,353	$ 1,115,900	$ 1,193,102
Construction revenues	196,651	205,009	203,586
Total operating revenues	1,231,004	1,320,909	1,396,688
OPERATING EXPENSES:			
Net cost of gas sold	482,503	563,379	677,547
Operations and maintenance	266,862	264,188	253,026
Depreciation and amortization	136,439	130,210	118,448
Taxes other than income taxes	35,910	34,565	32,780
Construction expenses	174,185	182,068	180,904
Total operating expenses	1,095,899	1,174,410	1,262,705
Operating income	135,105	146,499	133,983
OTHER INCOME AND (EXPENSES):			
Net interest deductions	(77,106)	(79,971)	(80,731)
Net interest deductions on subordinated debentures (Note 5)	(2,680)	—	—
Preferred securities distributions (Note 5)	(4,180)	(5,475)	(5,475)
Other income (deductions)	4,245	4,329	8,964
Total other income and (expenses)	(79,721)	(81,117)	(77,242)
Income before income taxes	55,384	65,382	56,741
Income tax expense (Note 10)	16,882	21,417	19,585
Net income	$ 38,502	$ 43,965	$ 37,156
Basic earnings per share (Note 12)	$ 1.14	$ 1.33	$ 1.16
Diluted earnings per share (Note 12)	$ 1.13	$ 1.32	$ 1.15
Average number of common shares outstanding	33,760	32,953	32,122
Average shares outstanding (assuming dilution)	34,041	33,233	32,398

The accompanying notes are an integral part of these statements.

southwest gas corporation
consolidated statements of cash flows

(thousands of dollars)

YEAR ENDED DECEMBER 31,	2003	2002	2001
CASH FLOW FROM OPERATING ACTIVITIES:			
Net income	$ 38,502	$ 43,965	$ 37,156
ADJUSTMENTS TO RECONCILE NET INCOME TO NET CASH PROVIDED BY OPERATING ACTIVITIES:			
Depreciation and amortization	136,439	130,210	118,448
Deferred income taxes	44,144	(15,684)	(11,175)
CHANGES IN CURRENT ASSETS AND LIABILITIES:			
Accounts receivable, net of allowances	4,416	24,687	(19,773)
Accrued utility revenue	(1,627)	(1,300)	(5,900)
Deferred purchased gas costs	(35,981)	110,219	8,563
Accounts payable	21,586	(20,858)	(85,512)
Accrued taxes	(386)	33,997	18,766
Other current assets and liabilities	1,692	4,763	34,051
Other	(1,009)	(11,525)	28,128
Net cash provided by operating activities	207,776	298,474	122,752
CASH FLOW FROM INVESTING ACTIVITIES:			
Construction expenditures and property additions	(240,671)	(282,851)	(265,580)
Other (Note 14)	(18,215)	23,985	4,318
Net cash used in investing activities	(258,886)	(258,866)	(261,262)
CASH FLOW FROM FINANCING ACTIVITIES:			
Issuance of common stock, net	21,290	18,174	17,061
Dividends paid	(27,685)	(27,009)	(26,323)
Issuance of subordinated debentures, net	96,312	—	—
Issuance of long-term debt, net	159,997	206,161	213,026
Retirement of long-term debt, net	(140,013)	(210,028)	(14,723)
Retirement of preferred securities	(60,000)	—	—
Change in short-term debt	(1,000)	(40,000)	(38,000)
Net cash provided by (used in) financing activities	48,901	(52,702)	151,041
Change in cash and cash equivalents	(2,209)	(13,094)	12,531
Cash at beginning of period	19,392	32,486	19,955
Cash at end of period	$ 17,183	$ 19,392	$ 32,486
SUPPLEMENTAL INFORMATION:			
Interest paid, net of amounts capitalized	$ 78,561	$ 76,867	$ 74,032
Income taxes paid (received), net	$ (26,733)	$ 1,797	$ 13,186

The accompanying notes are an integral part of these statements.

southwest gas corporation
consolidated statements of stockholders' equity

(in thousands, except per share amounts)

	COMMON STOCK		ADDITIONAL		
	SHARES	AMOUNT	PAID-IN CAPITAL	RETAINED EARNINGS	TOTAL
DECEMBER 31, 2000	31,710	$ 33,340	$ 454,132	$ 45,995	$ 533,467
Common stock issuances	783	783	16,278		17,061
Net income				37,156	37,156
Dividends declared					
Common: $0.82 per share				(26,484)	(26,484)
DECEMBER 31, 2001	32,493	34,123	470,410	56,667	561,200
Common stock issuances	796	796	17,378		18,174
Net income				43,965	43,965
Dividends declared					
Common: $0.82 per share				(27,172)	(27,172)
DECEMBER 31, 2002	33,289	34,919	487,788	73,460	596,167
Common stock issuances	943	943	20,347		21,290
Net income				38,502	38,502
Other			2,386		2,386
Dividends declared					
Common: $0.82 per share				(27,878)	(27,878)
DECEMBER 31, 2003	34,232*	$ 35,862	$ 510,521	$ 84,084	$ 630,467

* At December 31, 2003, 882,000 common shares were registered and available for issuance under provisions of the Employee Investment Plan and the Dividend Reinvestment and Stock Purchase Plan. In addition, 2.5 million common shares are registered for issuance upon the exercise of options granted under the Stock Incentive Plan (see Note 9).

The accompanying notes are an integral part of these statements.

notes to consolidated financial statements

NOTE 1
summary of significant accounting policies

Nature of Operations. Southwest Gas Corporation (the "Company") is comprised of two segments: natural gas operations ("Southwest" or the "natural gas operations" segment) and construction services. Southwest purchases, transports, and distributes natural gas to customers in portions of Arizona, Nevada, and California. The public utility rates, practices, facilities, and service territories of Southwest are subject to regulatory oversight. The timing and amount of rate relief can materially impact results of operations. Natural gas sales are seasonal, peaking during the winter months. Variability in weather from normal temperatures can materially impact results of operations. Natural gas purchases and the timing of related recoveries can materially impact liquidity. Northern Pipeline Construction Co. ("NPL" or the "construction services" segment), a wholly owned subsidiary, is a full-service underground piping contractor that provides utility companies with trenching and installation, replacement, and maintenance services for energy distribution systems.

Basis of Presentation. The Company follows generally accepted accounting principles ("GAAP") in accounting for all of its businesses. Accounting for the natural gas utility operations conforms with GAAP as applied to regulated companies and as prescribed by federal agencies and the commissions of the various states in which the utility operates. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Consolidation. The accompanying financial statements are presented on a consolidated basis and include the accounts of Southwest Gas Corporation and all subsidiaries, except for Southwest Gas Capital II (see Note 5). All significant intercompany balances and transactions have been eliminated with the exception of transactions between Southwest and NPL in accordance with Statement of Financial Accounting Standards ("SFAS") No. 71, "Accounting for the Effects of Certain Types of Regulation."

Net Utility Plant. Net utility plant includes gas plant at original cost, less the accumulated provision for depreciation and amortization, plus the unamortized balance of acquisition adjustments. Original cost includes contracted services, material, payroll and related costs such as taxes and benefits, general and administrative expenses, and an allowance for funds used during construction less contributions in aid of construction.

Deferred Purchased Gas Costs. The various regulatory commissions have established procedures to enable Southwest to adjust its billing rates for changes in the cost of gas purchased. The difference between the current cost of gas purchased and the cost of gas recovered in billed rates is deferred. Generally, these deferred amounts are recovered or refunded within one year.

Income Taxes. The Company uses the asset and liability method of accounting for income taxes. Under the asset and liability method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the period that includes the enactment date.

For regulatory and financial reporting purposes, investment tax credits ("ITC") related to gas utility operations are deferred and amortized over the life of related fixed assets.

notes to consolidated financial statements

Gas Operating Revenues. Revenues are recorded when customers are billed. Customer billings are based on monthly meter reads and are calculated in accordance with applicable tariffs. Southwest also recognizes accrued utility revenues for the estimated amount of services rendered between the meter-reading dates in a particular month and the end of such month.

Construction Revenues. The majority of the NPL contracts are performed under unit price contracts. These contracts state prices per unit of installation. Revenues are recorded as installations are completed. Fixed-price contracts use the percentage-of-completion method of accounting and, therefore, take into account the cost, estimated earnings, and revenue to date on contracts not yet completed. The amount of revenue recognized is based on costs expended to date relative to anticipated final contract costs. Revisions in estimates of costs and earnings during the course of the work are reflected in the accounting period in which the facts requiring revision become known. If a loss on a contract becomes known or is anticipated, the entire amount of the estimated ultimate loss is recognized at that time in the financial statements.

Asset Retirement Obligations. In June 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 143, "Accounting for Asset Retirement Obligations," which was effective for fiscal years beginning after June 15, 2002. SFAS No. 143 establishes accounting standards for recognition and measurement of liabilities for asset retirement obligations and the associated asset retirement costs. The Company adopted the provisions of SFAS No. 143 as of January 1, 2003.

In accordance with approved regulatory practices, the depreciation expense for Southwest includes a component to recover removal costs associated with utility plant retirements. In accordance with the SEC's position on presentation of these amounts, management has reclassified $68 million and $55 million, as of December 31, 2003 and 2002, respectively, of estimated removal costs from accumulated depreciation to accumulated removal costs (in the liabilities section of the balance sheet).

Depreciation and Amortization. Utility plant depreciation is computed on the straight-line remaining life method at composite rates considered sufficient to amortize costs over estimated service lives, including components which compensate for salvage value, removal costs and retirements, as approved by the appropriate regulatory agency. When plant is retired from service, the original cost of plant, including cost of removal, less salvage, is charged to the accumulated provision for depreciation. Acquisition adjustments are amortized, as ordered by regulators, over periods which approximate the remaining estimated life of the acquired properties. Costs related to refunding utility debt and debt issuance expenses are deferred and amortized over the weighted-average lives of the new issues. Other regulatory assets, when appropriate, are amortized over time periods authorized by regulators. Nonutility property and equipment are depreciated on a straight-line method based on the estimated useful lives of the related assets. Goodwill amortization for the year 2001 was $400,000. Pursuant to SFAS No. 142, "Goodwill and Other Intangible Assets," goodwill amortization was eliminated as of January 2002.

Allowance for Funds Used During Construction ("AFUDC"). AFUDC represents the cost of both debt and equity funds used to finance utility construction. AFUDC is capitalized as part of the cost of utility plant. The Company capitalized $2.6 million in 2003, $3.1 million in 2002, and $2.5 million in 2001 of AFUDC related to natural gas utility operations. The debt portion of AFUDC is reported in the consolidated statements of income as an offset to net interest deductions and the equity portion is reported as other income. Utility plant construction costs, including AFUDC, are recovered in authorized rates through depreciation when completed projects are placed into operation, and general rate relief is requested and granted.

notes to consolidated financial statements

Earnings Per Share. Basic earnings per share ("EPS") are calculated by dividing net income by the weighted-average number of shares outstanding during the period. Diluted EPS includes the effect of additional weighted-average common stock equivalents (stock options and performance shares). Unless otherwise noted, the term "Earnings Per Share" refers to Basic EPS. A reconciliation of the shares used in the Basic and Diluted EPS calculations is shown in the following table. Net income was the same for Basic and Diluted EPS calculations.

(in thousands)

	2003	2002	2001
Average basic shares	33,760	32,953	32,122
EFFECT OF DILUTIVE SECURITIES:			
Stock options	73	94	122
Performance shares	208	186	154
Average diluted shares	34,041	33,233	32,398

Cash and Cash Equivalents. For purposes of reporting consolidated cash flows, cash and cash equivalents include cash on hand and financial instruments with a maturity of three months or less, but exclude funds held in trust from the issuance of industrial development revenue bonds ("IDRB").

Reclassifications. Certain reclassifications have been made to the prior year's financial information to present it on a basis comparable with the current year's presentation.

Recently Issued Accounting Pronouncements. In January 2003, the FASB issued Interpretation No. 46 "Consolidation of Variable Interest Entities – an Interpretation of ARB No. 51" ("FIN 46") effective July 2003. See **Note 5 – Preferred Securities** for additional information.

In April 2003, the FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities," which was effective for contracts entered into or modified after September 30, 2003 with exceptions for certain types of securities. SFAS No. 149 clarifies the definition and characteristics of a derivative and amends other existing pronouncements for consistency. Southwest has fixed-price gas purchase contracts, which are considered normal purchases occurring in the ordinary course of business. The Company does not currently utilize stand-alone derivative instruments for speculative purposes and does not have foreign currency exposure. None of the Company's long term financial instruments or other contracts are derivatives that are marked to market, or contain embedded derivatives with significant mark-to-market value. The adoption of the standard did not have a material impact on the financial position or results of operations of the Company.

In May 2003, the FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity," which is effective for all financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. SFAS No. 150 addresses the accounting for certain financial instruments with characteristics of both liabilities and equity that, under previous guidance, issuers could account for as equity. SFAS No. 150 requires those instruments be classified as liabilities in statements of financial position. The adoption of the standard did not have a material impact on the financial position or results of operations of the Company.

notes to consolidated financial statements

Stock-Based Compensation. At December 31, 2003, the Company had two stock-based compensation plans, which are described more fully in **Note 9 – Employee Benefits**. These plans are accounted for in accordance with Accounting Principles Board ("APB") Opinion No. 25 "Accounting for Stock Issued to Employees" and related interpretations. The following table illustrates the effect on net income and earnings per share if the Company had applied the fair value recognition provision of SFAS No. 123 "Accounting for Stock-Based Compensation" to its stock-based employee compensation:

(thousands of dollars, except per share amounts)

	2003	2002	2001
Net income, as reported	$ 38,502	$ 43,965	$ 37,156
Add: Stock-based employee compensation expense included in reported net income, net of related tax benefits	2,438	1,783	1,879
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax benefits	(2,920)	(2,024)	(2,222)
Pro forma net income	$ 38,020	$ 43,724	$ 36,813
EARNINGS PER SHARE:			
Basic – as reported	$ 1.14	$ 1.33	$ 1.16
Basic – pro forma	1.13	1.33	1.15
Diluted – as reported	1.13	1.32	1.15
Diluted – pro forma	1.12	1.32	1.14

NOTE 2
utility plant

Net utility plant as of December 31, 2003 and 2002 was as follows:

(thousands of dollars)

DECEMBER 31,	2003	2002
GAS PLANT:		
Storage	$ 4,158	$ 4,213
Transmission	215,907	196,997
Distribution	2,496,708	2,293,655
General	197,693	198,093
Other	121,503	87,002
	3,035,969	2,779,960
Less: accumulated depreciation	(896,309)	(814,908)
Acquisition adjustments, net	2,533	2,714
Construction work in progress	33,543	66,693
Net utility plant	$ 2,175,736	$ 2,034,459

Depreciation and amortization expense on gas plant was $118 million in 2003, $113 million in 2002, and $102 million in 2001.

notes to consolidated financial statements

Leases and Rentals. Southwest leases the liquefied natural gas ("LNG") facilities on its northern Nevada system, a portion of its corporate headquarters office complex in Las Vegas, and its administrative offices in Phoenix. The leases provide for current terms which expire in 2005, 2017, and 2009, respectively, with optional renewal terms available at the expiration dates. The rental payments for the LNG facilities are $3.3 million for 2004 and $1.7 million in 2005, when the lease expires in June. The rental payments for the corporate headquarters office complex are $2 million in each of the years 2004 through 2008 and $18.3 million cumulatively thereafter. The rental payments for the Phoenix administrative offices are $1.4 million in 2004, $1.5 million for each of the years 2005 through 2008, and $1 million in 2009 when the lease expires. In addition to the above, the Company leases certain office and construction equipment. The majority of these leases are short-term. These leases are accounted for as operating leases, and for the gas segment are treated as such for regulatory purposes. Rentals included in operating expenses for all operating leases were $20 million in 2003, $26.5 million in 2002, and $28 million in 2001. These amounts include NPL lease expenses of approximately $9.6 million in 2003, $12.3 million in 2002, and $12.6 million in 2001 for various short-term leases of equipment and temporary office sites.

The following is a schedule of future minimum lease payments for noncancellable operating leases (with initial or remaining terms in excess of one year) as of December 31, 2003:

(thousands of dollars)

YEAR ENDING DECEMBER 31,	
2004	$ 8,408
2005	5,991
2006	4,130
2007	3,967
2008	3,997
Thereafter	20,543
Total minimum lease payments	$ 47,036

notes to consolidated financial statements

NOTE 3
receivables and related allowances

Business activity with respect to gas utility operations is conducted with customers located within the three-state region of Arizona, Nevada, and California. At December 31, 2003, the gas utility customer accounts receivable balance was $102 million. Approximately 56 percent of the gas utility customers were in Arizona, 35 percent in Nevada, and 9 percent in California. Although the Company seeks to minimize its credit risk related to utility operations by requiring security deposits from new customers, imposing late fees, and actively pursuing collection on overdue accounts, some accounts are ultimately not collected. Provisions for uncollectible accounts are recorded monthly, as needed, and are included in the ratemaking process as a cost of service. Activity in the allowance for uncollectibles is summarized as follows:

(thousands of dollars)

	ALLOWANCE FOR UNCOLLECTIBLES
Balance, December 31, 2000	$ 1,564
Additions charged to expense	3,874
Accounts written off, less recoveries	(3,567)
Balance, December 31, 2001	1,871
Additions charged to expense	3,824
Accounts written off, less recoveries	(3,870)
Balance, December 31, 2002	1,825
Additions charged to expense	2,523
Accounts written off, less recoveries	(2,102)
Balance, December 31, 2003	$ 2,246

NOTE 4
regulatory assets and liabilities

Natural gas operations are subject to the regulation of the Arizona Corporation Commission ("ACC"), the Public Utilities Commission of Nevada ("PUCN"), the California Public Utilities Commission ("CPUC"), and the Federal Energy Regulatory Commission ("FERC"). Company accounting policies conform to generally accepted accounting principles applicable to rate-regulated enterprises, principally SFAS No. 71, and reflect the effects of the ratemaking process. SFAS No. 71 allows for the deferral as regulatory assets, costs that otherwise would be expensed if it is probable future recovery from customers will occur. If rate recovery is no longer probable, due to competition or the actions of regulators, Southwest is required to write off the related regulatory asset.

notes to consolidated financial statements

The following table represents existing regulatory assets and liabilities:

(thousands of dollars)

DECEMBER 31,	2003	2002
REGULATORY ASSETS:		
Deferred purchased gas costs	$ 9,151	$ —
Accrued purchased gas costs *	8,800	—
SFAS No. 109 – income taxes, net	3,700	5,035
Unamortized premium on reacquired debt	18,560	12,614
Other	28,095	27,873
	68,306	45,522
REGULATORY LIABILITIES:		
Deferred purchased gas costs	—	(26,718)
Accumulated removal costs	(68,000)	(55,000)
Other	(425)	(422)
Net regulatory assets (liabilities)	$ (119)	$(36,618)

* Included in Prepaids and other current assets on the Consolidated Balance Sheet.

Other regulatory assets include deferred costs associated with rate cases, regulatory studies, and state mandated public purpose programs (including low income and conservation programs), as well as amounts associated with accrued absence time and accrued post-retirement benefits other than pensions.

NOTE 5
preferred securities

In October 1995, Southwest Gas Capital I (the "Trust"), a consolidated wholly owned subsidiary of the Company, issued $60 million of 9.125% Trust Originated Preferred Securities (the "Preferred Securities"). In connection with the Trust issuance of the Preferred Securities and the related purchase by the Company of all of the trust common securities, the Company issued to the Trust $61.8 million principal amount of its 9.125% Subordinated Deferrable Interest Notes, due 2025.

In June 2003, the Company created Southwest Gas Capital II ("Trust II"), a wholly owned subsidiary, as a financing trust for the sole purpose of issuing preferred trust securities for the benefit of the Company. In August 2003, Trust II publicly issued $100 million of 7.70% Preferred Trust Securities ("Preferred Trust Securities"). In connection with the Trust II issuance of the Preferred Trust Securities and the related purchase by the Company for $3.1 million of all of the Trust II common securities ("Common Securities"), the Company issued $103.1 million principal amount of its 7.70% Junior Subordinated Debentures, due 2043 ("Subordinated Debentures") to Trust II. The sole assets of Trust II are and will be the Subordinated Debentures. The interest and other payment dates on the Subordinated Debentures correspond to the distribution and other payment dates on the Preferred Trust Securities and Common Securities. Under certain circumstances, the Subordinated Debentures may be distributed to the holders of the Preferred Trust Securities and holders of the Common Securities in liquidation of Trust II. The Subordinated Debentures are redeemable at the option of the Company after August 2008 at a redemption price of $25 per Subordinated Debenture plus accrued and unpaid interest. In the event that the Subordinated Debentures are repaid, the Preferred Trust Securities and the Common Securities will be redeemed on a pro rata basis at $25 (par value) per Preferred Trust Security and Common Security plus accumulated and unpaid distributions. Company obligations under the Subordinated Debentures, the Trust Agreement (the agreement under which

notes to consolidated financial statements

Trust II was formed), the guarantee of payment of certain distributions, redemption payments and liquidation payments with respect to the Preferred Trust Securities to the extent Trust II has funds available therefore and the indenture governing the Subordinated Debentures, including the Company agreement pursuant to such indenture to pay all fees and expenses of Trust II, other than with respect to the Preferred Trust Securities and Common Securities, taken together, constitute a full and unconditional guarantee on a subordinated basis by the Company of payments due on the Preferred Trust Securities. As of December 31, 2003, 4.1 million Preferred Trust Securities were outstanding.

The Company has the right to defer payments of interest on the Subordinated Debentures by extending the interest payment period at any time for up to 20 consecutive quarters (each, an "Extension Period"). If interest payments are so deferred, distributions to Preferred Trust Securities holders will also be deferred. During such Extension Period, distributions will continue to accrue with interest thereon (to the extent permitted by applicable law) at an annual rate of 7.70% per annum compounded quarterly. There could be multiple Extension Periods of varying lengths throughout the term of the Subordinated Debentures. If the Company exercises the right to extend an interest payment period, the Company shall not during such Extension Period (i) declare or pay dividends on, or make a distribution with respect to, or redeem, purchase or acquire or make a liquidation payment with respect to, any of its capital stock, or (ii) make any payment of interest, principal, or premium, if any, on or repay, repurchase, or redeem any debt securities issued by the Company that rank equal with or junior to the Subordinated Debentures; provided, however, that restriction (i) above does not apply to any stock dividends paid by the Company where the dividend stock is the same as that on which the dividend is being paid. The Company has no present intention of exercising its right to extend the interest payment period on the Subordinated Debentures.

A portion of the net proceeds from the issuance of the Preferred Trust Securities was used to complete the redemption of the 9.125% Trust Originated Preferred Securities effective September 2003 at a redemption price of $25 per Preferred Security, totaling $60 million plus accrued interest of $1.3 million.

In January 2003, the FASB issued Interpretation No. 46 "Consolidation of Variable Interest Entities – an Interpretation of ARB No. 51" ("FIN 46") effective July 2003. This Interpretation of Accounting Research Bulletin No. 51 "Consolidated Financial Statements," addresses consolidation by business enterprises of variable interest entities. FIN 46 explains how to identify variable interest entities and how an enterprise assesses its interests in a variable interest entity to decide whether to consolidate that entity. Trust II, the issuer of the preferred trust securities, meets the definition of a variable interest entity.

Although the Company owns 100 percent of the common voting securities of Trust II, under current interpretation of FIN 46, the Company is not considered the primary beneficiary of this trust and therefore Trust II is not consolidated. The adoption of FIN 46 results in the Company reflecting a liability to Trust II (which under the prior accounting treatment would have been eliminated in consolidation) instead of to the holders of the preferred trust securities. As a result, payments and amortizations associated with the liability are classified on the consolidated statements of income as Net interest deductions on subordinated debentures. The $103.1 million Subordinated Debentures are shown on the balance sheet of the Company net of the $3.1 million Common Securities as Subordinated debentures due to Southwest Gas Capital II.

notes to consolidated financial statements

NOTE 6
long-term debt

(thousands of dollars)

	2003		2002	
DECEMBER 31,	CARRYING AMOUNT	MARKET VALUE	CARRYING AMOUNT	MARKET VALUE
DEBENTURES:				
7½% Series, due 2006	$ 75,000	$ 83,149	$ 75,000	$ 81,889
Notes, 8.375%, due 2011	200,000	241,155	200,000	226,128
Notes, 7.625%, due 2012	200,000	232,198	200,000	218,166
8% Series, due 2026	75,000	88,240	75,000	79,017
Medium-term notes, 7.75% series, due 2005	25,000	27,198	25,000	27,342
Medium-term notes, 6.89% series, due 2007	17,500	19,443	17,500	18,781
Medium-term notes, 6.27% series, due 2008	25,000	27,219	25,000	25,946
Medium-term notes, 7.59% series, due 2017	25,000	29,217	25,000	26,711
Medium-term notes, 7.78% series, due 2022	25,000	29,076	25,000	25,725
Medium-term notes, 7.92% series, due 2027	25,000	29,220	25,000	26,134
Medium-term notes, 6.76% series, due 2027	7,500	7,725	7,500	6,870
Unamortized discount	(5,957)	—	(6,534)	—
	694,043		693,466	
Revolving credit facility and commercial paper	100,000	100,000	100,000	100,000
INDUSTRIAL DEVELOPMENT REVENUE BONDS:				
VARIABLE-RATE BONDS:				
Tax-exempt Series A, due 2028	50,000	50,000	50,000	50,000
2003 Series A, due 2038	50,000	50,000	—	—
2003 Series B, due 2038	50,000	50,000	—	—
FIXED-RATE BONDS:				
7.30% 1992 Series A, due 2027	—	—	30,000	30,600
7.50% 1992 Series B, due 2032	—	—	100,000	102,000
6.50% 1993 Series A, due 2033	75,000	76,500	75,000	75,000
6.10% 1999 Series A, due 2038	12,410	12,596	12,410	13,744
5.95% 1999 Series C, due 2038	14,320	15,811	14,320	15,322
5.55% 1999 Series D, due 2038	8,270	9,014	8,270	8,332
5.45% 2003 Series C, due 2038	30,000	32,826	—	—
3.35% 2003 Series D, due 2038	20,000	20,000	—	—
5.80% 2003 Series E, due 2038	15,000	16,809	—	—
Unamortized discount	(1,986)	—	(3,169)	—
	323,014		286,831	
Other	10,542	—	20,556	—
	1,127,599		1,100,853	
Less: current maturities	(6,435)		(8,705)	
Long-term debt, less current maturities	$ 1,121,164		$ 1,092,148	

notes to consolidated financial statements

In May 2002, the Company replaced a $350 million revolving credit facility that was to expire in June 2002 with a $125 million three-year facility and a $125 million 364-day facility. Interest rates for the new facility are calculated at either the London Interbank Offering Rate ("LIBOR") plus or minus a competitive margin, or the greater of the prime rate or one half of one percent plus the Federal Funds rate. The Company has designated $100 million of the total facility as long-term debt and uses the remaining $150 million for working capital purposes and has designated the related outstanding amounts as short-term debt.

In October 2002, the Company entered into a $50 million commercial paper program. Any issuance under the commercial paper program is supported by the Company's current revolving credit facility and, therefore, does not represent new borrowing capacity. Interest rates for the new program are calculated at the then current commercial paper rate. At December 31, 2003, $50 million was outstanding on the commercial paper program.

In March 2003, the Company issued several series of Clark County, Nevada Industrial Development Revenue Bonds ("IDRBs") totaling $165 million, due 2038. Of this total, variable-rate IDRBs ($50 million 2003 Series A and $50 million 2003 Series B) were used to refinance the $100 million 7.50% 1992 Series B, fixed-rate IDRBs due 2032. At December 31, 2003, the effective interest rate including all fees on the new Series A and Series B IDRBs was 2.66%. The $30 million 7.30% 1992 Series A, fixed-rate IDRBs due 2027 was refinanced with a $30 million 5.45% 2003 Series C fixed-rate IDRBs. An incremental $35 million ($20 million 3.35% 2003 Series D and $15 million 5.80% Series E fixed-rate IDRBs) was used to finance construction expenditures in southern Nevada during the first and second quarters of 2003. The Series C and Series E were set with an initial interest rate period of 10 years, while the Series D has an initial interest rate period of 18 months. After the initial interest rate periods, the Series C, D, and E interest rates will be reset at then prevailing market rates for periods not to exceed the maturity date of March 1, 2038.

The 2003 Series A and Series B IDRBs are supported by two letters of credit totaling $101.7 million, which expire in March 2006. These IDRBs are set at weekly rates and the letters of credit support the payment of principal or a portion of the purchase price corresponding to the principal of the IDRBs (while in the weekly rate mode).

The Company's Revolving Credit Facilities contain financial covenants including a maximum leverage ratio of 70 percent (debt to capitalization as defined) and a minimum net worth calculation of $450 million (adjusted for sales of securities after May 31, 2002). In October 2003, a $55.3 million letter of credit, which supports the City of Big Bear $50 million tax-exempt Series A IDRBs, due 2028, was renewed for a three-year period expiring in October 2006. This letter of credit has a maximum leverage ratio of 70 percent (debt to capitalization as defined) and a minimum net worth calculation of $450 million (adjusted for sales of equity securities after July 1, 2003). If the Company were not in compliance with these covenants, an event of default would occur, which if not cured could cause the amounts outstanding to become due and payable. This would also trigger cross-default provisions in substantially all other outstanding indebtedness of the Company. At December 31, 2003, the Company was in compliance with the applicable covenants.

The interest rate on the tax-exempt variable-rate IDRBs averaged 2.73 percent in 2003 and 2.82 percent in 2002. The rates for the variable-rate IDRBs are established on a weekly basis. The Company has the option to convert from the current weekly rates to daily rates, term rates, or variable-term rates.

The fair value of the revolving credit facility approximates carrying value. Market values for the debentures and fixed-rate IDRBs were determined based on dealer quotes using trading records for December 31, 2003 and 2002, as applicable, and other secondary sources which are customarily consulted for data of this kind. The carrying values of variable-rate IDRBs were used as estimates of fair value based upon the variable interest rates of the bonds.

notes to consolidated financial statements

Estimated maturities of long-term debt for the next five years are $6.4 million, $128.1 million, $76 million, $17.5 million, and $25 million, respectively.

The $7.5 million medium-term notes, 6.76% series, due 2027 contains a put feature at the discretion of the bondholder on one date only in 2007. If the bondholder does not exercise the put on that date, the notes will reach maturity in 2027. If the bondholder exercises the put, the maturities of long-term debt for 2007 will total $25 million.

NOTE 7
short-term debt

As discussed in Note 6, Southwest has a $250 million credit facility consisting of a $125 million three-year facility and a $125 million 364-day facility. Effective May 2003, the Company renewed the $125 million 364-day facility for an additional year with no significant changes in rates or terms. Short-term borrowings were $52 million and $53 million at December 31, 2003 and 2002, respectively. The weighted-average interest rates on these borrowings were 2.04 percent at December 31, 2003 and 2.35 percent at December 31, 2002.

NOTE 8
commitments and contingencies

California General Rate Cases. In February 2002, Southwest filed general rate applications with the California Public Utilities Commission ("CPUC") for its northern and southern California jurisdictions. The applications sought annual increases over a five-year rate case cycle with a cumulative total of $6.3 million in northern California and $17.2 million in southern California. The last general rate increases received in California were January 1998 in northern California and January 1995 in southern California.

In July 2002, the Office of Ratepayer Advocates ("ORA") filed testimony in the rate case recommending significant reductions to the rate increases sought by Southwest. The ORA concurred with the majority of the Southwest rate design proposals including a margin tracking mechanism to mitigate weather-related and other usage variations. At the hearing that was held in August 2002, Southwest modified its proposal from a five-year to a three-year rate case cycle and accordingly reduced its cumulative request to $4.8 million in northern California and $10.7 million in southern California. For 2003, the amounts requested were $2.6 million in northern California and $5.7 million in southern California. The final general rate case decision, originally anticipated to have an effective date of January 2003, was delayed due to the reassignment of the Administrative Law Judge ("ALJ") assigned to the case. As a result of this delay, Southwest filed a motion during the first quarter of 2003 requesting authorization to establish a memorandum account to track the related revenue shortfall between the existing and proposed rates in the general rate case filing. This motion was approved, effective May 2003. In October 2003, the ALJ rendered a draft decision ("proposed decision" or "PD") on the general rate case. The PD was modified in February 2004. If approved as modified, the PD would increase rates by about 60 percent of the 2003 amount filed for and provide for attrition increases beginning in 2004. Southwest filed comments largely in support of the PD. In January 2004, an alternate decision ("AD") from one of the commissioners was received, reducing the rate increase in southern California as proposed in the PD by $2 million, with no significant change to northern California. In addition, the AD proposed a disallowance of $12.2 million in gas costs. Southwest filed comments vehemently opposed to the AD. The general rate case is on the agenda for mid-March; however, management can not determine which, if any, of the proposed or alternate decisions will be approved.

Legal and Regulatory Proceedings. The Company is a defendant in miscellaneous legal proceedings. The Company is also a party to various regulatory proceedings. The ultimate dispositions of these proceedings are not presently determinable; however, it is the opinion of management that no litigation or regulatory proceeding to which the Company is subject will have a material adverse impact on its financial position or results of operations.

NOTE 9
employee benefits

Southwest has a noncontributory qualified retirement plan with defined benefits covering substantially all employees. Southwest also provides postretirement benefits other than pensions ("PBOP") to its qualified retirees for health care, dental, and life insurance benefits.

In December 2003, the FASB issued SFAS No. 132 (revised 2003), "Employers' Disclosures about Pensions and Other Postretirement Benefits" expanding financial statement disclosure requirements for defined benefit plans. The following disclosures reflect the new requirements. In addition to expanded annual disclosures, various elements of pension and other postretirement benefit costs are required to be reported on a quarterly basis.

In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 ("Medicare Act") was signed into law. The Medicare Act includes a prescription drug benefit under Medicare as well as a federal subsidy to sponsors of retiree health care benefit plans which have a benefit at least actuarially equivalent to that included in the Medicare Act. The Company makes fixed contributions for health care benefits of employees who retire after 1988, but pays up to 100 percent of covered health care costs for employees who retired prior to 1989. A prescription drug benefit is provided for the approximately 100 pre-1989 retirees. The Company is electing to defer recognizing the effects of the Medicare Act until authoritative guidance on the accounting for the federal subsidy is issued. The following disclosures of APBO and net periodic benefit cost do not reflect the effects of the Medicare Act. When authoritative guidance is issued, previously reported information may change.

Investment objectives and strategies for the retirement plan are developed and approved by the Pension Plan Investment Committee of the Board of Directors of the Company. They are designed to preserve capital, maintain minimum liquidity required for retirement plan operations and effectively manage pension assets.

A target portfolio of investments in the retirement plan is developed by the Pension Plan Investment Committee and is reevaluated periodically. Rate of return assumptions are determined by evaluating performance expectations of the target portfolio. Projected benefit obligations are estimated using actuarial assumptions and Company benefit policy. A target mix of assets is then determined based on acceptable risk versus estimated returns in order to fund the benefit obligation. The current percentage ranges of the target portfolio are:

Type of Investment	Percentage Range
Equity securities	55 to 67
Debt securities	32 to 38
Other	1 to 7

The Company's pension and related benefits plans utilize various assumptions which impact the expense and funding levels of these plans. The Company is lowering the expected rate of return on plan assets assumption for these plans from 8.95% to 8.75% for 2004. The lower rate of return reflects anticipated investment returns on a long-term basis considering asset mix, projected and historical investment returns. This change, coupled with a 25 basis point reduction in the discount rate, will result in a $2.3 million increase in pension expense for 2004.

notes to consolidated financial statements

The following tables set forth the retirement plan and PBOP funded status and amounts recognized on the Consolidated Balance Sheets and Statements of Income.

(thousands of dollars)

	QUALIFIED RETIREMENT PLAN		PBOP	
	2003	2002	2003	2002
CHANGE IN BENEFIT OBLIGATIONS				
Benefit obligation for service rendered to date at beginning of year (PBO/APBO)	$ 319,404	$ 288,046	$ 31,307	$ 28,204
Service cost	12,267	11,585	675	595
Interest cost	21,243	20,568	2,095	1,992
Actuarial loss (gain)	25,580	7,905	1,850	1,966
Benefits paid	(9,400)	(8,700)	(1,560)	(1,450)
Benefit obligation at end of year (PBO/APBO)	$ 369,094	$ 319,404	$ 34,367	$ 31,307
CHANGE IN PLAN ASSETS				
Market value of plan assets at beginning of year	$ 242,159	$ 274,103	$ 12,912	$ 12,402
Actual return on plan assets	49,464	(28,344)	1,477	(647)
Employer contributions	11,213	5,100	1,465	1,157
Benefits paid	(9,400)	(8,700)	—	—
Market value of plan assets at end of year	$ 293,436	$ 242,159	$ 15,854	$ 12,912
Funded status	$ (75,658)	$ (77,245)	$ (18,513)	$ (18,395)
Unrecognized net actuarial loss (gain)	56,649	52,936	6,741	6,760
Unrecognized transition obligation (2004/2012)	—	795	7,802	8,669
Unrecognized prior service cost	9	66	—	—
Prepaid (accrued) benefit cost	$ (19,000)	$ (23,448)	$ (3,970)	$ (2,966)
WEIGHTED-AVERAGE ASSUMPTIONS (BENEFIT OBLIGATION)				
Discount rate	6.50%	6.75%	6.50%	6.75%
Rate of compensation increase	4.25%	4.25%	4.25%	4.25%
ASSET ALLOCATION				
Equity securities	64%	55%	35%	28%
Debt securities	30%	39%	16%	20%
Other	6%	6%	49%	52%
Total	100%	100%	100%	100%

notes to consolidated financial statements

The measurement date used to determine pension and other postretirement benefit measurements was December 31, 2003. Estimated funding for the plans above during 2004 is approximately $14 million. The accumulated benefit obligation for the retirement plan was $289 million and $249 million at December 31, 2003 and 2002, respectively.

For PBOP measurement purposes, the per capita cost of covered health care benefits is assumed to increase five percent annually. The Company makes fixed contributions for health care benefits of employees who retire after 1988, but pays up to 100 percent of covered health care costs for employees who retired prior to 1989. The assumed annual rate of increase noted above applies to the benefit obligations of pre-1989 retirees only.

components of net periodic benefit cost:

(thousands of dollars)

	QUALIFIED RETIREMENT PLAN			PBOP		
	2003	2002	2001	2003	2002	2001
Service cost	$ 12,267	$ 11,585	$ 11,057	$ 675	$ 595	$ 591
Interest cost	21,243	20,568	18,805	2,095	1,992	1,856
Expected return on plan assets	(27,217)	(27,178)	(25,383)	(1,205)	(1,184)	(1,073)
Amortization of prior service costs	57	57	57	—	—	—
Amortization of unrecognized transition obligation	795	837	837	867	867	867
Amortization of net (gain) loss	—	(207)	(568)	257	—	—
Net periodic benefit cost	$ 7,145	$ 5,662	$ 4,805	$ 2,689	$ 2,270	$ 2,241
WEIGHTED-AVERAGE ASSUMPTIONS (NET BENEFIT COST)						
Discount rate	6.75%	7.25%	7.25%	6.75%	7.25%	7.25%
Expected return on plan assets	8.95%	9.25%	9.25%	8.95%	9.25%	9.25%
Rate of compensation increase	4.25%	4.75%	4.75%	4.25%	4.75%	4.75%

In addition to the retirement plan, Southwest has a separate unfunded supplemental retirement plan which is limited to officers. The plan is noncontributory with defined benefits. Plan costs were $2.7 million in 2003, $3 million in 2002, and $2.9 million in 2001. The accumulated benefit obligation of the plan was $24 million at December 31, 2003.

The Employees' Investment Plan provides for purchases of various mutual fund investments and Company common stock by eligible Southwest employees through deductions of a percentage of base compensation, subject to IRS limitations. Southwest matches one-half of amounts deferred. The maximum matching contribution is three percent of an employee's annual compensation. The cost of the plan was $3.3 million in 2003, $3.1 million in 2002, and $3 million in 2001. NPL has a separate plan, the cost and liability for which are not significant.

Southwest has a deferred compensation plan for all officers and members of the Board of Directors. The plan provides the opportunity to defer up to 100 percent of annual cash compensation. Southwest matches one-half of amounts deferred by officers. The maximum matching contribution is three percent of an officer's annual salary. Payments of compensation deferred, plus interest, are made in equal monthly installments over 10, 15, or 20 years, as elected by the participant. Directors have an additional option to receive such payments over a five-year period. Deferred compensation earns interest at a rate determined each January. The interest rate equals 150 percent of Moody's Seasoned Corporate Bond Rate Index.

notes to consolidated financial statements

At December 31, 2003, the Company had two stock-based compensation plans. These plans are accounted for in accordance with APB Opinion No. 25 "Accounting for Stock Issued to Employees." In connection with the stock-based compensation plans, the Company recognized compensation expense of $4.1 million in 2003, $3 million in 2002, and $3.1 million in 2001.

Under one plan, the Company may grant options to purchase shares of common stock to key employees and outside directors. Each option has an exercise price equal to the market price of Company common stock on the date of grant and a maximum term of ten years. The options vest 40 percent at the end of year one and 30 percent at the end of years two and three. The grant date fair value of the options was estimated using the extended binomial option pricing model. The following assumptions were used in the valuation calculation:

	2003	2002	2001
Dividend yield	3.94%	3.64%	3.60%
Risk-free interest rate range	1.06 to 2.17%	1.70 to 2.63%	2.17 to 3.82%
Expected volatility range	16 to 25%	23 to 31%	22 to 27%
Expected life	1 to 3 years	1 to 3 years	1 to 3 years

The following tables summarize Company stock option plan activity and related information:

(thousands of options)

	2003		2002		2001	
	NUMBER OF OPTIONS	WEIGHTED-AVERAGE EXERCISE PRICE	NUMBER OF OPTIONS	WEIGHTED-AVERAGE EXERCISE PRICE	NUMBER OF OPTIONS	WEIGHTED-AVERAGE EXERCISE PRICE
Outstanding at the beginning of the year	1,260	$ 21.66	1,123	$ 20.79	990	$ 18.94
Granted during the year	348	21.05	320	21.97	317	23.23
Exercised during the year	(106)	17.18	(183)	16.95	(184)	15.07
Forfeited during the year	—	—	—	—	—	—
Expired during the year	—	—	—	—	—	—
Outstanding at year end	1,502	$ 21.83	1,260	$ 21.66	1,123	$ 20.79
Exercisable at year end	868	$ 21.96	677	$ 21.46	597	$ 21.00

The weighted-average grant-date fair value of options granted was $1.90 for 2003, $2.69 for 2002, and $2.81 for 2001. The following table summarizes information about stock options outstanding at December 31, 2003:

(thousands of options)

	OPTIONS OUTSTANDING			OPTIONS EXERCISABLE	
RANGE OF EXERCISE PRICE	NUMBER OUTSTANDING	WEIGHTED-AVERAGE REMAINING CONTRACTUAL LIFE	WEIGHTED-AVERAGE EXERCISE PRICE	NUMBER EXERCISABLE	WEIGHTED-AVERAGE EXERCISE PRICE
$15.00 to $19.13	285	5.1 Years	$ 17.64	285	$ 17.64
$20.49 to $24.50	1,099	8.1 Years	$ 22.16	465	$ 22.84
$28.75 to $28.94	118	5.5 Years	$ 28.91	118	$ 28.91

notes to consolidated financial statements

In addition to the option plan, the Company may issue restricted stock in the form of performance shares to encourage key employees to remain in its employment to achieve short-term and long-term performance goals. Plan participants are eligible to receive a cash bonus (i.e., short-term incentive) and performance shares (i.e., long-term incentive). The performance shares vest after three years from issuance and are subject to a final adjustment as determined by the Board of Directors. The following table summarizes the activity of this plan:

(thousands of shares)

YEAR ENDED DECEMBER 31,	2003	2002	2001
Nonvested performance shares at beginning of year	345	314	237
Performance shares granted	147	122	142
Performance shares forfeited	—	—	—
Shares vested and issued	(111)	(91)	(65)
Nonvested performance shares at end of year	381	345	314
Average grant date fair value of award	$ 22.21	$ 22.35	$ 19.91

NOTE 10
income taxes

Income tax expense (benefit) consists of the following:

(thousands of dollars)

YEAR ENDED DECEMBER 31,	2003	2002	2001
CURRENT:			
Federal	$ (24,176)	$ 5,546	$ 27,750
State	(4,421)	3,462	2,078
	(28,597)	9,008	29,828
DEFERRED:			
Federal	41,474	14,819	(9,902)
State	4,005	(2,410)	(341)
	45,479	12,409	(10,243)
Total income tax expense	$ 16,882	$ 21,417	$ 19,585

Deferred income tax expense (benefit) consists of the following significant components:

(thousands of dollars)

YEAR ENDED DECEMBER 31,	2003	2002	2001
DEFERRED FEDERAL AND STATE:			
Property-related items	$ 46,808	$ 44,491	$ 19,560
Purchased gas cost adjustments	1,030	(29,087)	(26,975)
Employee benefits	(1,767)	(5,113)	(2,121)
All other deferred	276	2,986	161
Total deferred federal and state	46,347	13,277	(9,375)
Deferred ITC, net	(868)	(868)	(868)
Total deferred income tax expense	$ 45,479	$ 12,409	$ (10,243)

notes to consolidated financial statements

The consolidated effective income tax rate for the period ended December 31, 2003 and the two prior periods differs from the federal statutory income tax rate. The sources of these differences and the effect of each are summarized as follows:

YEAR ENDED DECEMBER 31,	2003	2002	2001
Federal statutory income tax rate	35.0%	35.0%	35.0%
Net state tax liability	2.4	1.0	3.2
Property-related items	1.3	—	1.5
Effect of closed tax years and resolved issues	(3.6)	—	(4.4)
Tax credits	(1.6)	(1.3)	(1.5)
Corporate owned life insurance	(2.3)	—	(0.5)
All other differences	(0.7)	(1.9)	1.2
Consolidated effective income tax rate	30.5%	32.8%	34.5%

Deferred tax assets and liabilities consist of the following:

(thousands of dollars)

DECEMBER 31,	2003	2002
DEFERRED TAX ASSETS:		
Deferred income taxes for future amortization of ITC	$ 8,037	$ 8,574
Employee benefits	27,416	25,650
Alternative minimum tax	36,681	23,874
Net operating losses & credits	24,200	—
Other	6,076	4,195
Valuation allowance	—	—
	102,410	62,293
DEFERRED TAX LIABILITIES:		
Property-related items, including accelerated depreciation	331,770	247,954
Regulatory balancing accounts	5,379	4,349
Property-related items previously flowed through	11,737	13,609
Unamortized ITC	12,933	13,801
Debt-related costs	5,777	4,378
Other	5,232	4,476
	372,828	288,567
Net deferred tax liabilities	$ 270,418	$ 226,274
Current	$ (6,914)	$ (3,084)
Noncurrent	277,332	229,358
Net deferred tax liabilities	$ 270,418	$ 226,274

At December 31, 2003, the Company has a federal net operating loss carryforward of $64.7 million which expires in 2022 to 2023 and a federal general business credit carryforward of $1.4 million which expires in 2011 to 2022. The Company also has an Arizona net operating loss carryforward of $33.1 million which expires in 2005 to 2007 and an Arizona tax credit carryforward of $826,000 which expires in 2004 to 2007.

notes to consolidated financial statements

NOTE 11
segment information

Company operating segments are determined based on the nature of their activities. The natural gas operations segment is engaged in the business of purchasing, transporting, and distributing natural gas. Revenues are generated from the sale and transportation of natural gas. The construction services segment is engaged in the business of providing utility companies with trenching and installation, replacement, and maintenance services for energy distribution systems.

The accounting policies of the reported segments are the same as those described within **Note 1 – Summary of Significant Accounting Policies**. NPL accounts for the services provided to Southwest at contractual (market) prices. At December 31, 2003 and 2002, consolidated accounts receivable included $5.8 million and $6 million, respectively, which were not eliminated during consolidation.

The financial information pertaining to the natural gas operations and construction services segments for each of the three years in the period ended December 31, 2003 is as follows:

(thousands of dollars)

2003	GAS OPERATIONS	CONSTRUCTION SERVICES	ADJUSTMENTS	TOTAL
Revenues from unaffiliated customers	$ 1,034,353	$ 137,717		$ 1,172,070
Intersegment sales	—	58,934		58,934
Total	$ 1,034,353	$ 196,651		$ 1,231,004
Interest expense	$ 78,931	$ 855		$ 79,786
Depreciation and amortization	$ 120,791	$ 15,648		$ 136,439
Income tax expense	$ 13,920	$ 2,962		$ 16,882
Segment income	$ 34,211	$ 4,291		$ 38,502
Segment assets	$ 2,528,332	$ 79,774		$ 2,608,106
Capital expenditures	$ 228,288	$ 12,383		$ 240,671

2002	GAS OPERATIONS	CONSTRUCTION SERVICES	ADJUSTMENTS	TOTAL
Revenues from unaffiliated customers	$ 1,115,900	$ 134,625		$ 1,250,525
Intersegment sales	—	70,384		70,384
Total	$ 1,115,900	$ 205,009		$ 1,320,909
Interest expense	$ 78,505	$ 1,466		$ 79,971
Depreciation and amortization	$ 115,175	$ 15,035		$ 130,210
Income tax expense	$ 18,493	$ 2,924		$ 21,417
Segment income	$ 39,228	$ 4,737		$ 43,965
Segment assets	$ 2,345,407	$ 87,521		$ 2,432,928
Capital expenditures	$ 263,576	$ 19,275		$ 282,851

notes to consolidated financial statements

(thousands of dollars)

2001	GAS OPERATIONS	CONSTRUCTION SERVICES	ADJUSTMENTS	TOTAL
Revenues from unaffiliated customers	$ 1,193,102	$ 135,655		$ 1,328,757
Intersegment sales	—	67,931		67,931
Total	$ 1,193,102	$ 203,586		$ 1,396,688
Interest expense	$ 78,746	$ 1,985		$ 80,731
Depreciation and amortization	$ 104,498	$ 13,950		$ 118,448
Income tax expense	$ 16,098	$ 3,487		$ 19,585
Segment income	$ 32,626	$ 4,530		$ 37,156
Segment assets	$ 2,289,111	$ 83,228	$ (2,727)	$ 2,369,612
Capital expenditures	$ 248,352	$ 17,228		$ 265,580

Construction services segment assets include deferred tax assets of $2.5 million in 2001, which were netted against gas operations segment deferred tax liabilities during consolidation. Construction services segment liabilities include taxes payable of $204,000 in 2001, which were netted against gas operations segment tax receivable during consolidation.

NOTE 12
quarterly financial data (unaudited)

(thousands of dollars, except per share amounts)

	QUARTER ENDED			
	MARCH 31	JUNE 30	SEPTEMBER 30	DECEMBER 31
2003				
Operating revenues	$ 403,285	$ 255,852	$ 220,162	$ 351,705
Operating income (loss)	62,314	11,789	(8,285)	69,287
Net income (loss)	25,539	(4,104)	(17,407)	34,474
Basic earnings (loss) per common share*	0.76	(0.12)	(0.51)	1.01
Diluted earnings (loss) per common share*	0.76	(0.12)	(0.51)	1.00
2002				
Operating revenues	$ 499,501	$ 261,123	$ 223,863	$ 336,422
Operating income (loss)	80,317	7,044	(3,337)	62,475
Net income (loss)	42,896	(20,610)	(16,136)	37,815
Basic earnings (loss) per common share*	1.32	(0.63)	(0.49)	1.14
Diluted earnings (loss) per common share*	1.30	(0.63)	(0.49)	1.13
2001				
Operating revenues	$ 487,498	$ 278,960	$ 246,094	$ 384,136
Operating income (loss)	74,106	1,111	(4,597)	63,363
Net income (loss)	33,809	(11,140)	(16,488)	30,975
Basic earnings (loss) per common share*	1.06	(0.35)	(0.51)	0.96
Diluted earnings (loss) per common share*	1.05	(0.35)	(0.51)	0.95

* The sum of quarterly earnings (loss) per average common share may not equal the annual earnings (loss) per share due to the ongoing change in the weighted average number of common shares outstanding.

notes to consolidated financial statements

The demand for natural gas is seasonal, and it is the opinion of management that comparisons of earnings for the interim periods do not reliably reflect overall trends and changes in the operations of the Company. Also, the timing of general rate relief can have a significant impact on earnings for interim periods. See Management's Discussion and Analysis for additional discussion of operating results.

NOTE 13
merger-related litigation settlements

Litigation related to the now terminated acquisition of the Company by ONEOK, Inc. ("ONEOK") and the rejection of competing offers from Southern Union Company ("Southern Union") was resolved during 2002. In August 2002, the Company reached final settlements with both Southern Union and ONEOK related to this litigation. The Company paid Southern Union $17.5 million to resolve all remaining Southern Union claims against the Company and its officers. ONEOK paid the Company $3 million to resolve all claims between the Company and ONEOK. The net after-tax impact of the settlements was a $9 million charge and was reflected in the second quarter 2002 financial statements. The Company and one of its insurance providers were in dispute over whether the insurance coverage applied to the Southern Union settlement and related litigation defense costs. Because of the dispute, the Company did not recognize any benefit for potential insurance recoveries related to the Southern Union settlement in the second quarter of 2002.

In December 2002, the Company negotiated a $16.25 million settlement with the insurance provider related to the coverage dispute. Income from the settlement was recognized in the fourth quarter of 2002 and amounted to $9 million after-tax.

NOTE 14
acquisition of black mountain gas company

In October 2003, the Company acquired all of the outstanding stock of Black Mountain Gas Company.

The assets acquired and the liabilities assumed at the acquisition date were as follows:

(thousands of dollars)

Gas plant	$ 23,974
Less: accumulated depreciation	(5,992)
Net utility plant	17,982
Other property and investments	1,500
Accounts receivable, net of allowances	504
Prepaids and other current assets	163
Deferred charges and other assets (includes goodwill of $5,445)	5,610
Total assets acquired	25,759
Accounts payable	219
Customer deposits	55
Deferred purchased gas costs	112
Accrued general taxes	144
Other deferred credits	1,229
Total liabilities assumed	1,759
Cash acquisition price	$ 24,000

report of independent auditors

To the Shareholders of
Southwest Gas Corporation:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, of stockholders' equity and of cash flows present fairly, in all material respects, the financial position of Southwest Gas Corporation and its subsidiaries at December 31, 2003 and 2002, and the results of their operations and their cash flows for the years ended December 31, 2003 and 2002 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audits of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion. The financial statements of the Company as of December 31, 2001 were audited by other independent accountants who have ceased operations. Those independent accountants expressed an unqualified opinion on those statements in their report dated February 8, 2002.

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it accounts for asset retirement obligations as of January 1, 2003, financial instruments with characteristics of both debt and equity and certain variable interest entities as of July 1, 2003.

PricewaterhouseCoopers LLP

Los Angeles, California
March 11, 2004

report of independent public accountants

To the Shareholders of
Southwest Gas Corporation:

We have audited the accompanying consolidated balance sheets of Southwest Gas Corporation (a California corporation) and its subsidiaries (the Company) as of December 31, 2001 and 2000, and the related consolidated statements of income, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Southwest Gas Corporation and its subsidiaries as of December 31, 2001 and 2000, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2001 in conformity with accounting principles generally accepted in the United States.

ARTHUR ANDERSEN LLP

Las Vegas, Nevada
February 8, 2002

The aforementioned report on the consolidated balance sheets of Southwest Gas Corporation and its subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of income, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2001 is a copy of a previously issued Arthur Andersen LLP report. Arthur Andersen LLP has not reissued this report.

shareholder information

STOCK LISTING INFORMATION
Southwest Gas Corporation's common stock is listed on the New York Stock Exchange under the ticker symbol "SWX." Quotes may be obtained in daily financial newspapers or some local newspapers where it is listed under "SoWestGas."

ANNUAL MEETING
The Annual Meeting of Shareholders will be held on May 6, 2004 at 10:00 a.m. at the Rio Suites Hotel and Casino, I-15 and Flamingo Road, Las Vegas, Nevada.

DIVIDEND REINVESTMENT AND STOCK PURCHASE PLAN
The Southwest Gas Corporation Dividend Reinvestment and Stock Purchase Plan (DRSPP) provides its shareholders, natural gas customers, employees and residents of Arizona, California and Nevada with a simple and convenient method of investing cash dividends in additional shares of the Company's stock without payment of any brokerage commission.

the DRSPP features include:
Initial investments of $100, up to $100,000 annually
Automatic investing
No commissions on purchases
Safekeeping for common stock certificates

for more information contact:
Shareholder Services
Southwest Gas Corporation
P.O. Box 98511, Las Vegas, NV 89193-8511
or call (800) 331-1119.

DIVIDENDS
Dividends on common stock are declared quarterly by the Board of Directors. As a general rule, they are payable on the first day of March, June, September and December.

INVESTOR RELATIONS
Southwest Gas Corporation is committed to providing relevant and complete investment information to shareholders, individual investors and members of the investment community. Additional copies of the Company's 2003 Annual Report on Form 10-K, without exhibits, as filed with the Securities and Exchange Commission may be obtained upon request free of charge. Additional financial information may be obtained by contacting Kenneth J. Kenny, Investor Relations, Southwest Gas Corporation, P.O. Box 98510, Las Vegas, NV 89193-8510 or by calling (702) 876-7237.

Southwest Gas Corporation information is also available on the Internet at www.swgas.com. For non-financial information, please call (702) 876-7011.

TRANSFER AGENT
Shareholder Services
Southwest Gas Corporation
P.O. Box 98511
Las Vegas, NV 89193-8511

REGISTRAR
Southwest Gas Corporation
P.O. Box 98510
Las Vegas, NV 89193-8510

AUDITORS
PricewaterhouseCoopers LLP
350 S. Grand Avenue
Los Angeles, CA 90071

Board of Directors and Officers

DIRECTORS

GEORGE C. BIEHL
Las Vegas, Nevada
Executive Vice President/
Chief Financial Officer
and Corporate Secretary
Southwest Gas Corporation

MANUEL J. CORTEZ
Las Vegas, Nevada
President and Chief Executive Officer
Las Vegas Convention
and Visitors Authority

MARK M. FELDMAN
New York, New York
President and Chief Executive Officer
Cold Spring Group, Inc.

DAVID H. GUNNING
Cleveland, Ohio
Vice Chairman
Cleveland-Cliffs, Inc.

LEROY C. HANNEMAN, JR.
Phoenix, Arizona
Chairman and Chief
Executive Officer
Element Homes, LLC

THOMAS Y. HARTLEY
Las Vegas, Nevada
Chairman of the Board of Directors
Southwest Gas Corporation

MICHAEL B. JAGER
Newport Beach, California
Private Investor

LEONARD R. JUDD
Scottsdale, Arizona
Former President, Chief
Operating Officer and Director
Phelps Dodge Corporation

JAMES J. KROPID
Las Vegas, Nevada
President
James J. Kropid Investments

MICHAEL O. MAFFIE
Las Vegas, Nevada
Chief Executive Officer
Southwest Gas Corporation

CAROLYN M. SPARKS
Las Vegas, Nevada
President
International Insurance
Services, Ltd.

TERRENCE L. WRIGHT
Las Vegas, Nevada
Owner/Chairman of
the Board of Directors
Nevada Title Insurance Company

OFFICERS

MICHAEL O. MAFFIE
Chief Executive Officer

JEFFREY W. SHAW
President

GEORGE C. BIEHL
Executive Vice President/
Chief Financial Officer and
Corporate Secretary

JAMES P. KANE
Executive Vice President/
Operations

EDWARD S. ZUB
Executive Vice President/Consumer
Resources and Energy Services

JAMES F. LOWMAN
Senior Vice President/
Central Arizona Division

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Legal Affairs and General Counsel

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Senior Vice President/
Chief Knowledge and
Technology Officer

THOMAS J ARMSTRONG
Vice President/Gas Resources
and Energy Services

ROY R. CENTRELLA
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Chief Accounting Officer

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Vice President/
Southern Nevada Division

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JOHN P. HESTER
Vice President/Regulatory
Affairs & Systems Planning

EDWARD A. JANOV
Vice President/Finance

KENNETH J. KENNY
Treasurer

ROGER C. MONTGOMERY
Vice President/Pricing

CHRISTINA A. PALACIOS
Vice President/
Southern Arizona Division

DENNIS REDMOND
Vice President/
Northern Nevada Division

ANITA M. ROMERO
Vice President/
Southern California Division

ROBERT J. WEAVER
Vice President/
Information Services

JAMES F. WUNDERLIN
Vice President/Engineering

SOUTHWEST GAS CORPORATION

5241 SPRING MOUNTAIN ROAD
LAS VEGAS, NEVADA 89150

Southwest Gas Corporation is a natural gas utility based in Las Vegas, Nevada. Southwest provides natural gas service to approximately 1,531,000 residential, commercial and industrial customers in Arizona and Nevada, and parts of northeastern and southeastern California. During 2003, the Company added 67,000 new customers, maintaining its status as one of the fastest-growing natural gas distribution companies in the United States (excluding mergers and acquisitions). Another 9,000 customers were added in October 2003 with the acquisition of Black Mountain Gas Company.

Proposed Tariff Sheets

SOUTHWEST GAS CORPORATION
PROPOSED ARIZONA TARIFF REVISIONS

DESCRIPTION	PROPOSED CHANGE
Table of Contents	Reflect proposed changes to rate schedules, Special Supplementary Tariff provisions and the deletion of schedules related to the old Black Mountain Gas Company.
Statement of Rates	Change rates to reflect Southwest's proposed rate design changes and new rate schedules. Include footnotes on Sheet No. 13 describing rates applicable to customers receiving transportation service and remove currently effective tariff sheet reflecting applicable transportation service rates.
Other Service Charges	Revise Sheet No. 15 to reflect proposed changes to rates and service conditions. Include monthly margin per customer amounts applicable to the Conservation Margin Tracker.
Residential Gas Service	Implement a new schedule applicable to residential customers residing in multi-family dwellings, eliminate current Low-Income Rate Schedule No. G-10 and incorporate low-income discount into Southwest's proposed single-family and multi-family residential rate schedules.
General Gas Service	Change the volume threshold for Southwest's current Small General Gas Service rate schedule. Change the title of the current Large General Gas Service rate schedule to Transportation Eligible General Gas Service rate schedule and revise the billing demand calculation.
Optional Gas Service	Clarify the applicability provisions of the rate schedule.
Air-Conditioning Gas Service	De-link the Basic Service Charge from the "customer's otherwise applicable rate schedule" and implement a basic service charge specific to the air-conditioning rate schedule.
Street Lighting Gas Service	Clarify the billing of stand-alone gas light customers.

SOUTHWEST GAS CORPORATION
PROPOSED ARIZONA TARIFF REVISIONS
(Continued)

Cogeneration Gas Service	Expand the applicability to include all electric generation and change the schedule title to Electric Generation. Require customers with installed facilities exceeding 5 megawatts in nameplate capacity to take transportation service or execute a Special Procurement Agreement if qualified. Include schedule in Southwest's Special Supplementary Tariff Purchased Gas Adjustment Provision.
Small Essential Agricultural	Close the schedule to new customers.
Transportation Gas Service	Revise Section 3.1 Rates to reflect revisions to transportation rates on Statement of Effective Rates and change other references to rates to be consistent. Delete Form of Service Agreement from transportation tariff to allow service agreements to be individually customized.
Special Supplementary Tariff	Include Rate Schedule No. G-60 in the Purchased Gas Adjustment Provision. Eliminate Title Assignment Service and change the title of Southwest's currently effective Interstate Pipeline Capacity Service Provision. Include new language implementing Southwest's proposed Conservation Margin Tracker.
Rule No. 1, Definitions	Clarify that customer Agents may not be billed directly by the Utility. Clarify that same-day service may not always be possible. Exclude electric generation as an Industrial use of natural gas. Include definitions for Multi-Family and Single-Family residential customers, and Residential Dwelling. Change summer and winter season definitions.
Rule No. 3, Est. of Service	Limit cash deposits to amounts less than $5,000 and require another form of deposit for amounts exceeding $5,000 and add language protecting the Utility in customer bankruptcies.

TABLE OF CONTENTS

The following listed sheets contain all of the effective rules and regulations affecting rates and service and information relating thereto in effect on and after the date indicated thereon:

SOUTHWEST GAS CORPORATION
P.O. Box 98510
Las Vegas, Nevada 89193-8510
Arizona Gas Tariff No. 7
Arizona Division

PROPOSED TARIFF SHEET

Fifth Revised A.C.C. Sheet No. 3
Canceling Fourth Revised A.C.C. Sheet No. 3

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Issued On ____________
Docket No. ____________

Issued by
John P. Hester
Vice President

Effective ____________
Decision No. ____________

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SOUTHWEST GAS CORPORATION
P.O. Box 98510
Las Vegas, Nevada 89193-8510
Arizona Gas Tariff No. 7
Arizona Division

PROPOSED TARIFF SHEET

Sixty-Second Revised A.C.C. Sheet No. 11
Canceling Sixty-First Revised A.C.C. Sheet No. 11

STATEMENT OF RATES
EFFECTIVE SALES RATES APPLICABLE TO ARIZONA SCHEDULES [1/] [2/] C

Description	Base Tariff Rate Margin	Base Tariff Rate Gas Cost	3/ Rate Adjustment	Monthly Gas Cost Adjustment	Currently Effective Tariff Rate	C
G-5 – Single-Family Residential Gas Service						
Basic Service Charge per Month	$ 12.00				$ 12.00	I
Commodity Charge per Therm:						
Summer (April–November):						C
First 8 Therms	$ .84286	$ .53436	$ .01971	$ .00000	$ 1.39693	
Over 8 Therms	.25000	.53436	.01971	.00000	.80407	
Winter (December–March):						
First 30 Therms	$ .84286	$ .53436	$ .01971	$ .00000	$ 1.39693	
Over 30 Therms	.25000	.53436	.01971	.00000	.80407	C/D
G-6 – Multi-Family Residential Gas Service						N
Basic Service Charge per Month	$ 11.00				$ 11.00	
Commodity Charge per Therm:						
Summer (April–November):						
First 7 Therms	$ .84286	$ .53436	$ .01971	$ .00000	$ 1.39693	
Over 7 Therms	.25000	.53436	.01971	.00000	.80407	
Winter (December–March):						
First 18 Therms	$ .84286	$ .53436	$ .01971	$ .00000	$ 1.39693	
Over 18 Therms	.25000	.53436	.01971	.00000	.80407	N
						D
G-20 – Master-Metered Mobile Home Park Gas Service						
Basic Service Charge per Month	$100.00				$100.00	I
Commodity Charge per Therm:						
All Usage	$ .32271	$ .53436	$ .01971	$ .00000	$ .87678	I
G-25 – General Gas Service						
Basic Service Charge per Month:						
Small	$ 25.00				$ 25.00	I
Medium	35.00				$ 35.00	I
Large	150.00				$150.00	I
Transportation Eligible	750.00				$750.00	N
Commodity Charge per Therm:						
Small, All Usage	$ .69076	$ .53436	$ .00000	$ .00000	$ 1.22512	I
Medium, All Usage	.40089	.53436	.00000	.00000	.93525	I
Large, All Usage	.27399	.53436	.00000	.00000	.80835	I
Transportation Eligible	.09262	.53436	.00000	.00000	.62698	N
Demand Charge per Month:						
Transportation Eligible						
Demand Charge 4/	$ .062645				$ .062645	C/N

Issued On ____________________
Docket No. ____________________

Issued by
John P. Hester
Vice President

Effective ____________________
Decision No. ____________________

STATEMENT OF RATES
EFFECTIVE SALES RATES APPLICABLE TO ARIZONA SCHEDULES [1/] [2/] C
(Continued)

Description	Base Tariff Rate Margin	Base Tariff Rate Gas Cost	3/ Rate Adjustment	Monthly Gas Cost Adjustment	Currently Effective Tariff Rate	C
G-30 – Optional Gas Serivce						
Basic Service Charge per Month	As specified on A.C.C. Sheet No. 27.					
Commodity Charge per Therm:						
All Usage	As specified on A.C.C. Sheet No. 28.					
						D
G-40 – Air-Conditioning Gas Service						
Basic Service Charge per Month	$ 25.00				$ 25.00	C
Commodity Charge per Therm:						
All Usage	$ .10208	$ .53436	$ .00000	$ .00000	$ .63644	I
G-45 – Street Lighting Gas Service						
Commodity Charge per Therm of Rated Capacity:						
All Usage	$ .54644	$ .53436	$ .00000	$ .00000	$ 1.08080	I
G-55 – Gas Service for Compression on Customer's Premises 5/						
Basic Service Charge per Month:						
Small	$ 25.00				$ 25.00	I
Large	350.00				350.00	I
Residential	12.00				12.00	I
Commodity Charge per Therm:						
All Usage	$ .13669	$ .53436	$ .00000	$ .00000	$ .67105	C/I D
G-60 – Electric Generation Gas Service						C/N
Basic Service Charge per Month	As specified on A.C.C. Sheet No. 40.					
Commodity Charge per Therm:						
All Usage	$ .10188	$ .53436	$ .00000	$ .00000	$ .63624	R
G-75 – Small Essential Agricultural User Gas Service						
Basic Service Charge per Month	$150.00				$150.00	I
Commodity Charge per Therm:						
All Usage	$ .22186	$ .53436	$ .00000	$ .00000	$ .75622	I
G-80 – Natural Gas Engine Gas Service 6/						C
Basic Service Charge per Month:						
Off-Peak Season (October–March)	$ 0.00				$ 0.00	
Peak Season (April–September)	100.00				100.00	I
Commodity Charge per Therm:						
All Usage	$ .15848	$ .43742	$ .00000	$ .00000	$ .59590	R

STATEMENT OF RATES
EFFECTIVE SALES RATES APPLICABLE TO ARIZONA SCHEDULES 1/ 2/ C
(Continued)

1/ All charges are subject to adjustment for any applicable taxes or governmental impositions.

2/ Customers taking transportation service will pay the Basic Service Charge, the Margin, LIRA and DSM components of the commodity charge per therm, and Demand Charge, if applicable, of the Currently Effective Tariff Rate for each meter included in the transportation service agreement, plus an amount of $.00475 per therm for distribution system shrinkage as defined in Rule No. 1 of this Arizona Gas Tariff. The shrinkage charge shall be updated annually effective May 1. For customers converting from sales service, an additional amount equal to the currently effective Gas Cost Balancing Account Adjustment will be assessed for a period of 12 months. N

3/ (a) For Schedule Nos. G-5, G-6 and G-20, the Rate Adjustment includes $.01247 per therm to recover LIRA program costs. L/C

(b) For all rate schedules, the Rate Adjustment includes $.00724 per therm to recover DSM Program costs. This charge shall be updated annually effective May 1. C/D N N

(c) For Schedule Nos. G-5, G-6 and G-20, the Rate Adjustment includes $.00000 per therm to recover/refund CMT under- or over-collections. N N

4/ The total monthly demand charge is equal to the unit rate shown multiplied by the customer's billing determinant. L

5/ The charges for Schedule No. G-55 are subject to adjustment for applicable state and federal taxes on fuel used in motor vehicles.

6/ The gas cost for this rate schedule shall be updated seasonally, April 1 and October 1 of each year. L

Margin per Customer Balancing Provision Average Margin per Customer per Month N

	G-5	G-6	G-20
January	$ 46.66	$ 34.25	$ 330.91
February	41.78	31.46	254.39
March	38.55	29.12	232.19
April	23.77	20.63	213.12
May	21.03	18.78	213.84
June	19.52	17.68	239.06
July	18.76	17.17	387.47
August	18.26	16.80	766.25
September	18.40	16.97	913.96
October	18.89	17.42	753.71
November	21.11	19.39	615.01
December	40.01	30.71	467.66

N

HELD FOR FUTURE USE D/N

STATEMENT OF RATES
OTHER SERVICE CHARGES [1/]

Description	Reference	Amount	D/C
Service Establishment Charge			
Schedule No. G-5 and G-6 [2/]			C
Normal Service	Rule 3D	$ 35.00	I
Expedited Service	Rule 3D	50.00	R
All Other Rate Schedules [3/]			C
Normal Service	Rule 3D	$ 60.00	I
Expedited Service	Rule 3D	85.00	R
Customer Requested Meter Tests			
First Test	Rule 8C	$ 25.00	C
Subsequent Tests [4/]		$ 25.00	N
Returned Item Charge			
Per Item	Rule 9J	$ 14.00	I
Re-Read Charge			
Per Read	Rule 8B	$ 10.00	
Late Charge			
Each Delinquent Bill	Rule 9E	1.5% of the delinquent amount.	
Field Collection Fee			
Each Field Collection	Rule 9E	$ 20.00	

1/ Subject to adjustment for any applicable taxes or governmental impositions.

2/ The Service Establishment Charge for low income customers served under Rate Schedule Nos. G-5 & G-6 will be discounted by fifteen-percent from the above amounts. N

3/ For customers whose annual usage exceeds 180,000 therms per year, the Utility may, at its sole discretion, charge the customer the costs actually incurred by the Utility in establishing service.

4/ For customers whose annual usage exceeds 180,000 therms per year, the Utility may, at its sole discretion, charge the customer the costs actually incurred by the Utility to perform the meter test. N

Schedule No. G-5

SINGLE-FAMILY RESIDENTIAL GAS SERVICE C

APPLICABILITY

Applicable to gas service to customers which consists of direct domestic gas usage in a single-family residential dwelling for space heating, clothes drying, cooking, water heating, and other residential uses. C

TERRITORY

Throughout the certificated area served by the Utility in the communities as set forth on A.C.C. Sheet No. 8 of this Arizona Gas Tariff.

RATES

The basic service charge and commodity charge are set forth in the currently effective Statement of Rates of this Arizona Gas Tariff and are incorporated herein by reference.

MINIMUM CHARGE

The minimum charge per meter per month is the basic service charge.

SPECIAL CONDITIONS

The charges specified for this schedule are subject to adjustment for the applicable proportionate part of any taxes or governmental impositions which are assessed on the basis of the gross revenues of the Utility.

PURCHASED GAS ADJUSTMENT CLAUSE

The rates specified for this schedule are subject to increases or decreases in the cost of gas purchased in accordance with those provisions set forth in the "Special Supplementary Tariff, Purchased Gas Cost Adjustment Provision," contained in this Arizona Tariff.

RULES AND REGULATIONS

The standard Rules and Regulations of the Utility as authorized by the Commission shall apply where consistent with this schedule.

N

Schedule No. G-5

SINGLE-FAMILY RESIDENTIAL GAS SERVICE
(Continued)

LOW INCOME DISCOUNT

1. Eligibility requirements for the Low Income Residential Gas Service Discount are set forth on the Utility's Application and Declaration of Eligibility for Low Income Ratepayer Assistance form. Customers must have an approved application form on file with the utility. Recertification will be required prior to November 1 every two years and whenever a customer moves to a new residence within the Utility's service area.
2. Eligible customers will pay a discounted Basic Service Charge of $7.00 per month, and the commodity charges for low income customers will be discounted by fifteen-percent from the Rate Schedule No. G-5 Currently Effective Tariff Rate commencing with the next regularly scheduled billing period after the Utility has received the customer's properly completed application form or recertification.
3. Eligibility information provided by the customer on the application form may be subject to verification by the Utility. Refusal or failure of a customer to provide current documentation of eligibility acceptable to the Utility, upon request of the Utility, shall result in removal from or ineligibility for this discount.
4. Customers who wrongfully declare eligibility or fail to notify the Utility when they no longer meet the eligibility requirements may be rebilled for the period of ineligibility under their otherwise applicable residential schedule.
5. It is the responsibility of the customer to notify the Utility within 30 days of any changes in the customer's eligibility status.
6. Customers with connected service to pools, spas or hot tubs are eligible for this discount, only if usage is prescribed, in writing, by a licensed physician.
7. All monetary discounts will be tracked through a balancing account established by the Utility and recovered through the Utility's Low Income Ratepayer Assistance (LIRA) surcharge. N

D

N

Schedule No. G-6

MULTI-FAMILY RESIDENTIAL GAS SERVICE

APPLICABILITY

Applicable to gas service to customers which consists of direct domestic gas usage in a multi-family residential dwelling for space heating, clothes drying, cooking, water heating, and other residential uses.

TERRITORY

Throughout the certificated area served by the Utility in the communities as set forth on A.C.C. Sheet No. 8 of this Arizona Gas Tariff.

RATES

The basic service charge and commodity charge are set forth in the currently effective Statement of Rates of this Arizona Gas Tariff and are incorporated herein by reference.

MINIMUM CHARGE

The minimum charge per meter per month is the basic service charge.

SPECIAL CONDITIONS

The charges specified for this schedule are subject to adjustment for the applicable proportionate part of any taxes or governmental impositions which are assessed on the basis of the gross revenues of the Utility.

PURCHASED GAS ADJUSTMENT CLAUSE

The rates specified for this schedule are subject to increases or decreases in the cost of gas purchased in accordance with those provisions set forth in the “Special Supplementary Tariff, Purchased Gas Cost Adjustment Provision,” contained in this Arizona Tariff.

RULES AND REGULATIONS

The standard Rules and Regulations of the Utility as authorized by the Commission shall apply where consistent with this schedule. N

Schedule No. G-6 N

MULTI-FAMILY RESIDENTIAL GAS SERVICE
(Continued)

LOW INCOME DISCOUNT

1. Eligibility requirements for the Low Income Residential Gas Service Discount are set forth on the Utility's Application and Declaration of Eligibility for Low Income Ratepayer Assistance form. Customers must have an approved application form on file with the utility. Recertification will be required prior to November 1 every two years and whenever a customer moves to a new residence within the Utility's service area.
2. Eligible customers will pay a discounted Basic Service Charge of $7.00 per month, and the commodity rates for low income customers will be discounted by fifteen-percent from the Rate Schedule No. G-6 Currently Effective Tariff Rate, commencing with the next regularly scheduled billing period after the Utility has received the customer's properly completed application form or recertification.
3. Eligibility information provided by the customer on the application form may be subject to verification by the Utility. Refusal or failure of a customer to provide current documentation of eligibility acceptable to the Utility, upon request of the Utility, shall result in removal from or ineligibility for this discount.
4. Customers who wrongfully declare eligibility or fail to notify the Utility when they no longer meet the eligibility requirements may be rebilled for the period of ineligibility under their otherwise applicable residential schedule.
5. It is the responsibility of the customer to notify the Utility within 30 days of any changes in the customer's eligibility status.
6. Customers with connected service to pools, spas or hot tubs are eligible for this discount, only if usage is prescribed, in writing, by a licensed physician.
7. All monetary discounts will be tracked through a balancing account established by the Utility and recovered through the Utility's Low Income Ratepayer Assistance (LIRA) surcharge. N

D

SOUTHWEST GAS CORPORATION
P.O. Box 98510
Las Vegas, Nevada 89193-8510
Arizona Gas Tariff No. 7
Arizona Division

PROPOSED TARIFF SHEET

First Revised A.C.C. Sheet No. 19-22B
Canceling Original A.C.C. Sheet No. 19-22B

HELD FOR FUTURE USE D/N

Issued On ______
Docket No. ______

Issued by
John P. Hester
Vice President

Effective ______ T
Decision No. ______ T

Schedule No. G-25

GENERAL GAS SERVICE

APPLICABILITY

Applicable to commercial, industrial, United States Armed Forces, and essential agricultural customers as defined in Rule No. 1 of this Arizona Gas Tariff. Small general gas service customers are defined as those whose average monthly requirements on an annual basis are less than or equal to 50 therms per month. Medium general gas service customers are those whose average monthly requirements on an annual basis are greater than 50 therms, but less than or equal to 600 therms per month. Large general gas service customers are those whose average monthly requirements on an annual basis are greater than 600 therms per month, but less than or equal to 15,000 therms per month. Transportation-eligible gas service customers are those whose average monthly requirements on an annual basis are greater than 15, 000 therms per month. T C C

TERRITORY

Throughout the certificated area served by the Utility in the communities as set forth on A.C.C. Sheet No. 8 of this Arizona Gas Tariff.

RATES

1. Small, Medium, and Large General Gas Service C

The basic service charge and commodity charge are set forth in the currently effective Statement of Rates of this Arizona Gas Tariff and are incorporated herein by reference.

The minimum charge per meter per month is the basic service charge.

2. Transportation-Eligible General Gas Service C

The basic service charge, the demand charge and the commodity charge are set forth in the currently effective Statement of Rates of this Arizona Gas Tariff and are incorporated herein by reference.

The monthly demand charge shall be the product of the demand charge rate multiplied by the customer's billing determinant. The billing determinant shall be equal to each customer's highest monthly throughput during the most recent 12-month period, ending the month prior to the current billing period. For new customers, the initial billing determinant shall be calculated by multiplying the customer's estimated average daily use by the number of days in the billing period. D/C D/C C C

Schedule No. G-30

OPTIONAL GAS SERVICE

APPLICABILITY

Applicable to natural gas use by customers that qualify for service under this schedule according to either Applicability Provision (1), (2) or (3) below:

1. Customers whose average monthly requirements on an annual basis are greater than 11,000 therms per month and who have installed facilities capable of burning alternate fuels or energy.
2. Customers whose average monthly requirements on an annual basis are greater than 11,000 therms per month and who can demonstrate to the Utility sufficient evidence of economic hardship under the customer's otherwise applicable sales tariff schedule.
3. Customers whose requirements may be served by other natural gas suppliers at rates lower than the customer's otherwise applicable gas sales tariff schedule. As a condition precedent to qualifying for service under this applicability provision, the customer must qualify for transportation service under Schedule No. T-1 and T establish that bypass is economically, operationally and physically feasible and imminent.

This optional schedule is not available for partial requirements gas service where gas is used in combination with alternate fuels or energy, or with natural gas provided by other suppliers. Any gas service rendered to customers not in conformance with the provisions of this schedule shall be billed under the otherwise applicable gas sales tariff schedule.

TERRITORY

Throughout the certificated area served by the Utility in the communities as set forth on A.C.C. Sheet No. 8 of this Arizona Gas Tariff.

RATES

The basic service charge is the charge per meter set as set forth in the customer's otherwise applicable gas sales tariff schedule and is set forth in the currently effective Statement of Rates of this Arizona Gas Tariff or the charge as set forth in the customer's service agreement.

HELD FOR FUTURE USE D/N

Schedule No. G-40

AIR-CONDITIONING GAS SERVICE

APPLICABILITY

Applicable to gas service to commercial or industrial customers as defined in Rule No. 1 of this Arizona Gas Tariff who qualify for service under Schedule No. G-25 and who have installed and regularly operate a gas-fired air-conditioning system which meets the Utility's specifications and approval.

All of the provisions of the customer's otherwise applicable gas sales tariff schedule shall apply to this service unless specifically modified within this schedule.

The volume of gas used for air-conditioning only purposes shall be determined by metering equipment installed by the Utility, unless, a written agreement is executed by the customer and the Utility that sets forth the estimated gas volumes or the methodology to determine the volumes to be billed under this schedule.

Service for any end use of gas other than for air-conditioning purposes, such as space heating, water heating, processing or boiler fuel use, is not permitted under this schedule and shall be billed under the otherwise applicable gas sales tariff schedule. Volumes billed under this schedule may not be used for purposes of establishing the customer's average monthly requirements under Schedule No. G-25.

TERRITORY

Throughout the certificated area served by the Utility in the communities as set forth on A.C.C. Sheet No. 8 of this Arizona Gas Tariff.

RATES

The basic service charge and commodity charge are set forth in the currently effective T
Statement of Rates of this Arizona Gas Tariff and are incorporated herein by reference. T

MINIMUM CHARGE

The minimum charge per meter per month is the basic service charge as set forth in the customer's otherwise applicable gas sales tariff schedule.

Schedule No. G-45

STREET LIGHTING GAS SERVICE

APPLICABILITY

Applicable to gas service for continuous street or outdoor lighting in lighting devices approved by the Utility. Service under this schedule is conditional upon arrangements mutually satisfactory to the customer and the Utility for connection of customer's lighting devices to Utility's facilities.

TERRITORY

Throughout the certificated area served by the Utility in the communities as set forth on A.C.C. Sheet No. 8 of this Arizona Gas Tariff.

RATES

D

The charge per month is the product of the therms per month per mantle and the commodity rate as set forth in the currently effective Statement of Rates of this Arizona D
Gas Tariff, and such commodity rate is incorporated herein by reference.

D

SPECIAL CONDITIONS

1. At its sole option, the Utility may reduce the maximum rated capacity to reflect use of automatic dimmer devices or adjustment of the lamps to operate at less than maximum rated capacity.

2. The charges specified for this schedule are subject to adjustment for the applicable proportionate part of any taxes or governmental impositions which are assessed on the basis of the gross revenues of the Utility.

Schedule No. G-60

ELECTRIC GENERATION GAS SERVICE C/N

APPLICABILITY

Applicable to gas service to electric generation customers. This schedule is available for only the electric generation portion of the customer's gas purchases. C/D

TERRITORY

Throughout the certificated area served by the Utility in the communities as set forth on A.C.C. Sheet No. 8 of this Arizona Gas Tariff.

RATES

The basic service charge is the charge under the customer's otherwise applicable gas sales tariff schedule. The basic service charge and the commodity charge are set forth in the currently effective Statement of Rates of this Arizona Gas Tariff and are incorporated herein by reference.

MINIMUM CHARGE

The minimum charge per meter is the basic service charge.

SPECIAL CONDITIONS

1. Gas service under this schedule is not available unless accompanied by a signed contract for a minimum of one year as the precedent to service under this schedule, and said contract shall continue in force and effect from year to year thereafter until either the Utility or the customer shall give the other written notice of a desire to terminate the same at least 30 days prior to the expiration of any such year. If the customer permanently ceases operation, such contract shall not thereafter continue in force.

2. Gas service under this schedule is not available for "standby" or occasional temporary service.

3. Customers initiating service after __________ (the effective date of rates in this case) whose installed facilities exceed 5 megawatts in name plate capacity will be required to take transportation service or, if qualified, enter into a Special Procurement Agreement under Rate Schedule No. G-30. N
N

Schedule No. G-60

ELECTRIC GENERATION GAS SERVICE C/N
(Continued)

SPECIAL CONDITIONS *(Continued)*

4. The charges specified for this schedule are subject to adjustment for the applicable proportionate part of any taxes or governmental impositions which are assessed on the basis of the gross revenues of the Utility. T

PURCHASED GAS ADJUSTMENT CLAUSE

The charges specified for this schedule are subject to increases or decreases in the cost of gas purchased by the Utility. Such change shall be reflected in the commodity charge of the currently effective tariff rates as shown on A.C.C. Sheet No. 12 of this Arizona Gas Tariff.

RULES AND REGULATIONS

The standard Rules and Regulations of the Utility as authorized by the Commission shall apply where consistent with this schedule. Gas service under this schedule is not available for “standby” or occasional temporary service.

Schedule No. G-75

SMALL ESSENTIAL AGRICULTURAL USER GAS SERVICE C/N
(Continued)

APPLICABILITY

Applicable to gas service to customers whose gas use is certified by the Secretary of Agriculture as an "essential agricultural use" and whose maximum annual requirements are estimated by the Utility to be less than 125,000 dekatherms. This Schedule is closed T
to new Installations. T

TERRITORY

Throughout the certificated area served by the Utility in the communities as set forth on A.C.C. Sheet No. 8 of this Arizona Gas Tariff.

RATES

The basic service charge and commodity charge are set forth in the currently effective Statement of Rates of this Arizona Gas Tariff and are incorporated herein by reference.

MINIMUM CHARGE

The minimum charge per meter per month is the basic service charge.

SPECIAL CONDITIONS

1. Any customer who uses or who is estimated to use in excess of 50 dekatherms in any one month may be required to sign a contract for one year as the precedent to service under this schedule, and said contract shall continue in force and effect from year to year thereafter until either the Utility or the customer shall give the other written notice of a desire to terminate the same at least 30 days prior to the expiration of any such year. If the customer permanently ceases operation, such contract shall not thereafter continue in force.

2. The charges specified for this schedule are subject to adjustment for the applicable proportionate part of any taxes or governmental impositions which are assessed on the basis of the gross revenues of the Utility.

HELD FOR FUTURE USE D/N

Schedule No. T-1

TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS

1. AVAILABILITY

This schedule is available to any customer for transportation of natural gas by the Utility from any existing interconnection between the Utility and EL Paso Natural Gas Company (herein called Receipt Point) to the Delivery Point(s) on the Utility's system under the following conditions:

1.1 The Utility has available capacity to render the requested service without construction of any additional facilities, except as provided by Section 8 hereof;

1.2 The customer has demonstrated to the Utility's satisfaction in accordance with Section 6.8(d) hereof, the assurance of natural gas supplies and third-party transportation agreements with quantities and for a term compatible with the service being requested from the Utility. Except for customers otherwise served under Schedule No. G-55, service under this schedule is limited to: (a) customers whose average monthly requirements at one of the customer's premises on an annual basis are no less than 15,000 therms, and (b) customers whose average monthly requirements at one of the customer's premises during the months of May through September are no less than 15,000 therms. Projected transportation quantities for customers otherwise served under Schedule No. G-55 shall not be less than 50,000 therms annually at one of the customer's premises.

1.3 The customer and the Utility have executed a service agreement for service under this schedule. A single service agreement may provide for service to any or all of the customer's separate premises, provided that all of the premises are under common ownership. D

2. APPLICABILITY AND CHARACTER OF SERVICE

This schedule shall apply to gas transported by the Utility for customer pursuant to the executed service agreement.

2.1 The basic transportation service rendered under this schedule shall consist of:

(a) The receipt by the Utility for the account of the customer of the customer's gas at the Receipt Point;

Schedule No. T-1

TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS
(Continued)

3. RATES

3.1 The customer shall pay the Utility monthly the sum of the following charges:

(a) Basic Service Charge. The basic service charge as set forth in the currently effective Statement of Rates of this Arizona Gas Tariff for each meter included in the transportation service agreement. Customers receiving service under contract rates shall pay the basic service charge as set forth in the customer's service agreement. C

(b) Demand Charge. The monthly demand charge, if applicable, shall be the product of the demand charge rate set forth in the currently effective Statement of Rates of this Arizona Gas Tariff, multiplied by the customer's billing determinant. The billing determinant shall be equal to the customer's highest monthly throughput during the most recent 12-month period, ending the month prior to the current billing period. For new customers, the initial billing determinant shall be calculated by multiplying the customer's estimated average daily use by the number of days in the billing period. C

(c) Volume Charge: The LIRA and DSM margin components of the commodity charge per therm as set forth in the currently effective Statement of Rates of this Arizona Gas Tariff for each meter included in the transportation service agreement, plus an amount for distribution system shrinkage as defined in Rule No. 1 and set forth in the Statement of Rates, Sheet No. 13 of this Arizona Gas Tariff. The amount collected for distribution system shrinkage shall be recorded in the Gas Cost Balancing Account. C

Schedule No. T-1

TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS
(Continued)

3. RATES *(Continued)*

(d) Gas Cost Balancing Account Adjustment: For customers converting from sales service, an additional amount equal to the currently effective Gas Cost Balancing Account Adjustment to amortize the Gas Cost Balancing Account for a period of 12 months. D

(e) Any applicable imbalance charges as specified in Section 7 of this schedule.

The Utility may adjust from time to time the applicable unit transportation rate to any individual customer, provided, however, that such adjusted rate shall not exceed the applicable charges as specified in Section 3.1 above. C/D

In addition to the basic service charge, demand charge (if applicable), volume charge and any applicable imbalance charges, the Utility shall include as a surcharge on the customer's bill any charges from upstream pipeline transporters or suppliers which have been incurred by the Utility because of the transportation service rendered for the customer under this schedule.

Schedule No. T-1

TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS
(Continued)

3. RATES *(Continued)*

3.3 The charges specified for this schedule are subject to adjustment for the applicable proportionate part of any taxes, assessments or governmental impositions assessed on the Utility. D

4. MINIMUM CHARGE

The minimum charge per month is the basic service charge per month per meter and the demand charge per month per meter, if applicable.

5. FORCE MAJEURE

5.1 Relief From Liability: Neither party shall be liable in damages to the other on account of "force majeure" occasioned by any act, omission or circumstances occasioned by or in consequence of any act of God, strikes, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrests and restraints of rulers and people, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, depletion of or temporary failure of gas supply, the binding order of any court or governmental authority which has been resisted in good faith by all reasonable legal means, and any other cause, whether of the kind herein enumerated or not, and not within the control of the party claiming suspension and which by the exercise of due diligence such party is unable to prevent or overcome. Failure to settle or prevent any strikes or other 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 party claiming suspension.

5.2 Liabilities Not Relieved: Neither the customer nor the Utility shall be relieved from liability in the event of its concurring negligence or failure on its part to use due diligence to remedy the force majeure and remove the cause with all reasonable dispatch, nor shall such causes or contingencies affecting performance of any agreement relieve either party from its obligations to make payments when due in respect of gas theretofore delivered.

Schedule No. T-1

TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS
(Continued)

7. TRANSPORTATION IMBALANCE SERVICE *(Continued)*

(g) If, as the result of a billing error, metering error, or adjustments of scheduled supply, a customer trades an incorrect imbalance quantity based on notification by the Utility, the Utility will not be liable for any financial losses or damages incurred by customer nor will the Utility be financially liable to any of the customer's imbalance trading partners. If, as a result of such error, the Utility overbills the customer, the Utility shall refund the difference without interest. If the Utility underbills the customer, the customer shall be liable for the undercharge, including any associated excess imbalance charges. For purposes of determining imbalances and any applicable charges hereunder, the Utility will include billing adjustments to the volume in prior periods as part of the current month's activity. Trades occurring in prior periods will not be affected by such billing adjustments. T

7.2 Payment for Excess Imbalances

Customers will be assessed imbalance charges if, an imbalance exists in excess of applicable daily or monthly operating windows set forth in Section 6.9 hereof. (Monthly imbalances will be adjusted to reflect imbalance trading activity before assessing any imbalance charge.) The customer's daily imbalance is defined as the difference between the customer's daily metered quantities and the sum of the customer's daily scheduled transportation quantity plus any Utility-approved daily imbalance adjustment quantity. The customer's monthly imbalance is defined as the difference between the customer's total monthly metered quantity, including the effect of any adjustment for cycle billing of the customer's meters and the customer's total monthly scheduled transportation quantity. The portion of any imbalance quantity established by a customer in excess of the applicable monthly operating window is defined as an excess imbalance quantity. In addition to the charges payable under this schedule and the customer's otherwise applicable sales schedule, any monthly excess imbalance quantity shall be billed as follows:

Schedule No. T-1

TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS
(Continued)

7. TRANSPORTATION IMBALANCE SERVICE *(Continued)*

(ii) The weighted average cost of gas for the highest incremental purchases during the same month. The average will be determined by first weighting the highest priced gas purchased by the Utility during the month by the number of therms purchased at that price. The total therms to be allocated in this manner are equivalent to the total number of negative excess imbalance therms to be cashed out for the month. The weighted average cost of gas will also include any applicable upstream interstate transportation charges, such as fuel and variable transportation charges. A charge equal to the Utility's monthly average interstate transportation reservation cost is also included in the weighted average cost of gas.

7.3 Subject to mitigation through imbalance trading, if a customer is assessed an imbalance charge based on Utility billing information that is later determined to be in error, the portion of the imbalance charge not assessable based on the corrected billing information shall be reversed on the customer's bill without interest. If a customer is not assessed an imbalance charge based on Utility billing information that is later determined to be in error, the customer shall be billed for any applicable imbalance charges determined to be assessable based on the revised billing information. The original negative imbalance charge rate that is calculated for the applicable month will be used in any subsequent billings.

7.4 Should a customer elect to discontinue taking service under this schedule and change to a sales service schedule, the Utility may allow, in its sole good faith judgment, any remaining imbalance within the applicable operating window to be cleared as follows:

(a) The Utility shall credit the customer for any positive imbalance quantity at a price equal to the lowest incremental cost of gas purchased by the Utility during the prior month for gas delivered to the Utility within the state of Arizona.

(b) For any remaining negative imbalance quantity, the customer shall pay the Utility for the imbalance quantity at the otherwise applicable gas sales tariff rate adjusted C
to exclude the gas cost balancing account adjustment. C

(c) The customer may trade any remaining imbalance pursuant to this section; however, if a customer does not enter into a trade for any remaining imbalance quantity, the Utility will clear the remaining imbalance by utilizing paragraph (a) or (b) above, as applicable.

HELD FOR FUTURE USE D/N

SPECIAL SUPPLEMENTARY TARIFF
PURCHASED GAS COST ADJUSTMENT PROVISION

APPLICABILITY

This Purchased Gas Cost Adjustment Provision ("PGA") shall apply to all schedules except for Schedule Nos. G-30 and G-80 of this Arizona Gas Tariff. D

CHANGE IN RATES

Sales rate schedules covered by this provision include a base cost of gas ("BCOG") of $.53436 per therm. In accordance with Decision Nos. 61225 and 61711, a monthly adjustment to the BCOG will be made through a change in the Purchased Gas Adjustment ("PGA") rate that is based upon the rolling twelve-month average of actual purchased gas costs and sales. In accordance with Decision No. 62994, the PGA rate calculated for the month cannot be more than $.10 per therm different than any PGA rate in effect during the preceding twelve months. C

BANK BALANCE

The Utility shall establish and maintain a Gas Cost Balancing Account, if necessary, for the schedules subject to this provision. Entries shall be made to this account each month, if appropriate, as follows:

1. A debit or credit entry equal to the difference between (a) the actual purchased gas cost for the month and (b) an amount determined by multiplying the average purchased gas cost included in the sum of the Base Tariff Rate Gas Cost and the Monthly Gas Cost Adjustment as set forth on Sheet Nos. 11 and 12 of this Arizona Gas Tariff by the therms billed during the month under the applicable schedules of this Arizona Gas Tariff.

2. A debit or credit entry equal to the therms billed during the month under the applicable schedules of this Arizona Gas Tariff, multiplied by the Gas Cost Balancing Account Adjustment, if any, reflected in the rates charged during the month.

3. A debit or credit entry for refunds or payments authorized by the Commission.

4. A debit or credit entry for interest to be applied to over- and under-collected bank balances based on the non-financial three-month commercial paper rate for each month contained in the Federal Reserve Statistical Release, G-13, or its successor publication.

HELD FOR FUTURE USE D/N

SPECIAL SUPPLEMENTARY TARIFF
INTERSTATE PIPELINE CAPACITY RELEASE SERVICE PROVISION T

D

A. APPLICABILITY

The purpose of this Capacity Release Service Provision is to govern the release of interstate pipeline capacity in excess of the requirements of the Utility's Title Assignment and Priority 1 and 2 customers. The Utility shall identify and offer for release any available interstate pipeline capacity reserved to serve such customers for the purpose of minimizing the overall cost of upstream interstate pipeline capacity.

1. Capacity released pursuant to this provision shall be made available on a non-discriminatory basis. As a condition precedent to obtaining released capacity under this provision, on-system transportation customers of the Utility must execute a transportation service agreement pursuant to Schedule No. T-1, Transportation of Customer-Secured Gas, and must comply with all applicable terms and conditions contained in this Arizona Gas Tariff.

2. In order to acquire any of the Utility's firm interstate pipeline capacity released under this provision, acquiring shippers must demonstrate to the Utility that they have met the creditworthiness and other requirements of the applicable interstate pipeline(s) and such other credit standards that the Utility may deem appropriate.

3. Capacity release pursuant to this provision is subject to all FERC rules and regulations and the specific terms and conditions governing capacity release on the interstate pipeline system(s). L | L

SPECIAL SUPPLEMENTARY TARIFF
INTERSTATE PIPELINE CAPACITY RELEASE SERVICE PROVISION T
(Continued)

B. RATES AND BIDDING PROCEDURES

1. The Utility shall identify excess interstate pipeline capacity available for release on a monthly basis and from time-to-time more frequently thereafter as necessary to pre-arrange the release of any remaining available capacity. The Utility reserves the right to not release capacity if market conditions so warrant, or if the Utility is seeking to reduce its billing determinant or contract demand on the upstream interstate pipeline(s).

2. The Utility shall determine the minimum acceptable bid price for released capacity. The minimum acceptable bid represents the floor price for the Utility's consideration of any particular bid. The minimum acceptable bid shall be the greater of a., b. or c. below:

   a. The Utility's best determination of the current market value for such released capacity, based on a comparison of the price of completed bids of a like nature and term posted to the applicable interstate pipeline's electronic bulletin board.

   b. When an interruptible transportation crediting mechanism exists on the upstream interstate pipeline and, therefore, interruptible transportation credits could be earned if such capacity was not released, a bid price equal to the current market rate for interruptible transportation service.

   c. If the Utility is able to determine the cost allocation methodology that will be utilized by the upstream pipeline to develop future interstate pipeline charges, the Utility reserves the right to adjust the minimum acceptable bid price to protect the interests of its Priority 1 and Priority 2 gas sales customers.

SPECIAL SUPPLEMENTARY TARIFF
INTERSTATE PIPELINE CAPACITY RELEASE SERVICE PROVISION T
(Continued)

B. RATES AND BIDDING PROCEDURES *(Continued)* T

3. The release of interstate pipeline capacity for a term of more than one month shall be accomplished according to the following procedures.

   a. The Utility shall offer to prearrange the release of interstate pipeline capacity at rates greater than or equal to the minimum acceptable bid for the release period being considered. All bids below the minimum acceptable bid floor shall be rejected. Bids for prearranged capacity release shall be accepted based on the highest price offered. If more than one bid is received at the same price, bids shall be accepted based on the longest term offered. Bids of an identical price and term shall be accepted on a pro rata basis up to the amount of capacity available for release.

   b. Successful prearranged bids shall then be submitted to the applicable interstate pipeline for posting on its electronic bulletin board.

      (1) Unless the bid price is equal to the interstate pipeline's full "as-billed" rate, other eligible parties will be allowed by the pipeline to submit bids higher than that of the prearranged shipper. If prearranged bids are outbid by another party, the prearranged bidder shall have the right of first refusal to match the higher bid and thereby acquire the released capacity.

      (2) If the higher bid is not matched, the award shall be made to the higher bidder(s) pursuant to the established bid evaluation and (or) "tie breaker" procedures of the interstate pipeline.

   c. Any remaining capacity available for release shall then be posted for open bidding to the applicable interstate pipeline electronic bulletin board at the minimum acceptable bid price determined according to Section B.2 above.

SPECIAL SUPPLEMENTARY TARIFF
INTERSTATE PIPELINE CAPACITY RELEASE SERVICE PROVISION T
(Continued)

B. RATES AND BIDDING PROCEDURES *(Continued)* T

4. The Utility reserves the right to prearrange from time-to-time the release of excess capacity for a term of one month or less. Capacity released for a term of one month or less shall be subject to all FERC and interstate pipeline rules and regulations governing such releases, and shall be at rates greater than or equal to the minimum acceptable bid.

C. BILLING

Billing for released capacity shall be made by the interstate pipeline directly to acquiring customers and shippers. Shippers acquiring released capacity shall be billed by the pipeline at the accepted bid price plus applicable usage charges and surcharges. The Utility will receive credit from the interstate pipeline for the payment of reservation charges and reservation surcharges due from the acquiring shipper.

D. RECALL OF RELEASED CAPACITY

Capacity released by the Utility shall be recallable over the term of the release under the following conditions:

1. Force majeure situations occurring on the upstream pipeline system; or

2. To protect service to Priority 1 and Priority 2 customers; or

3. When the Utility's core demand for upstream pipeline capacity is greater than the Utility's current billing determinant or contract demand on the applicable interstate pipeline(s); or

4. If the acquiring shipper fails to remit payment for services rendered to the interstate pipeline when such amounts are due.

E. ACCOUNTING FOR CAPACITY RELEASE CREDITS

All capacity release credits received by the Utility shall be credited to Account No. 191, Unrecovered Purchased Gas Costs.

N

SPECIAL SUPPLEMENTARY TARIFF
CONSERVATION MARGIN TRACKER

APPLICABILITY

The Conservation Margin Tracker (CMT) applies to residential Rate Schedule Nos. G-5, G-6, and G-20 included in this Arizona Gas Tariff. It specifies the procedures to be utilized to decouple non-gas revenue (margin) per customer from customer consumption by comparing authorized margin-per-customer to actual billed margin-per-customer on a monthly basis. The CMT specifies the accounting procedures and rate setting adjustments necessary to assure the Utility neither over-recovers, nor under-recovers, the margin-per-customer authorized in its most recent general rate case proceeding.

TEST PERIOD

The Test Period shall be the first full 12-month period following the implementation of the most recently authorized general rates, and each 12-month period thereafter.

RATE ADJUSTMENT

The Rate Adjustment applicable to each schedule subject to this provision shall be revised annually to reflect the difference between the margin-per-customer authorized in the general rate case and the billed margin-per-customer during the Test Period. The Rate Adjustment revisions will be accomplished by increasing or decreasing the Conservation Margin Tracker Balancing Account (CMTBA) Adjustment. The CMTBA Adjustment will be calculated by dividing the CMTBA at the end of the Test Period by the recorded sales volume for the Test Period.

N

SPECIAL SUPPLEMENTARY TARIFF
CONSERVATION MARGIN TRACKER
(Continued

N

CONSERVATION MARGIN TRACKING BALANCING ACCOUNT

The Utility shall maintain accounting records that accumulate the difference between authorized and actual billed margin-per-customer. Entries shall be recorded to the CMTBA each month as follows:

1. A debit or credit entry equal to the difference between authorized margin and actual billed margin for each rate schedule subject to this provision. Authorized margin is the product of the monthly margin-per-customer authorized in the Utility's last general rate case, as stated on Sheet No. 13 of this Arizona Gas Tariff, and the actual number of customers during the month.

2. A debit or credit entry equal to the therms billed during the month under the schedules subject to this provision, multiplied by the applicable CMTBA Adjustment.

3. A debit or credit entry for carrying charges equal to the previous month's ending balance in the account, multiplied by a carrying charge rate based on the non-financial three-month commercial paper rate for each month contained in the Federal Reserve Statistical Release, G-13, or its successor publication.

TIMING AND MANNER OF FILING

The Utility shall file its CMTBA annually with the Commission in accordance with all statutory and regulatory requirements.

N

HELD FOR FUTURE USE D/N

RULE NO. 1

DEFINITIONS

For the purpose of these Tariffs, the terms and expressions listed below shall have the meanings set forth opposite:

Advance in Aid of Construction:	Funds provided to the Utility by an applicant for service under the terms of a main extension agreement, the amount of which may be refundable.
Agent:	Any party a customer may contract with for purposes of administering the customer's service agreement with the Utility excluding the right for the Agent to be billed directly by the Utility. An Agent has only those rights designated in writing by such customer for the effective time period, N
Alternate Fuel Capability:	A situation where an alternate fuel can be utilized whether or not the facilities for such use have actually been installed.
Applicant:	A person requesting the Utility to supply natural gas service.
Application:	A request to the Utility for natural gas service, as distinguished from an inquiry as to the availability or charges for such service.
Arizona Corporation Commission:	The regulatory authority of the State of Arizona having jurisdiction over the public service corporations operating in Arizona.
Average Month:	30.4 days.
Base Gas Supply:	Natural gas purchased by the Utility from its primary supplier.
Basic Service Charge:	A fixed amount a customer must pay the Utility for the availability of gas service, independent of consumption, as specified in the Utility's tariffs.
Billing Month:	The period between any two regular readings of the Utility's meters at intervals of approximately 30 days.
Billing Period:	The time interval between two consecutive meter readings that are taken for billing purposes.

RULE NO. 1

DEFINITIONS
(Continued)

Electronic Billing Service Provider:	An agent of the Utility that provides electronic bill presentment and payment service for the Utility and serves as a common link between the Utility and the customer.
Electronic Transfer:	Paperless exchange of data and/or funds.
Essential Agricultural Use:	Any use of natural gas which is certified by the Secretary of Agriculture as an "essential agricultural use."
Essential Industrial Process and Feedstock Uses:	Any use of natural gas by an industrial customer as "process gas" or as feedstock, or gas used for human comfort to protect health and hygiene in an industrial installation.
Excess Flow Valve:	A device designed to restrict the flow of gas in a customer's natural gas service line by automatically closing in the event of a service line break, thus mitigating the consequences of service line failures.
Expedited Service:	Service that is generally performed on the same workday the request for service is made. There may be instances where Company scheduling will not permit same day service. Service is considered to be expedited when an order is scheduled any day prior to the next available work date. D/T
Farm Tap:	A service connection from a company distribution or transmission line operating at higher than normal distribution pressure, thereby requiring regulation and/or pressure limiting devices before the customer can be served.
Feedstock Gas:	Natural gas used as a raw material for its chemical properties in creating an end product.

RULE NO. 1

DEFINITIONS
(Continued)

Inability to Pay	Circumstances where a residential customer: 1. Is not gainfully employed and unable to pay, or 2. Qualifies for government welfare assistance, but has not begun to receive assistance on the date that he receives his bill and can obtain verification from the government welfare assistance agency, or 3. Has an annual income below the published federal poverty level and can produce evidence of this, and 4. Signs a declaration verifying that he meets one of the above criteria and is either elderly, handicapped, or suffers from an illness.
Industrial Boiler Fuel:	Natural gas used in a boiler as a fuel for the generation of steam or electricity.
Industrial Customer:	A customer who is engaged primarily in a process which creates or changes raw or unfinished materials into another form or product, excluding electric power generation. C
Intra-day Nomination:	A Nomination submitted after the nominating deadline for Daily and Standing Nominations specified in Section 6.1 of Schedule T-1 which has an effective time no earlier than the beginning of the next Gas Day, and which has an ending time no later than the end of that Gas Day.

RULE NO. 1

DEFINITIONS
(Continued)

Meter:	The instrument for measuring and recording the volume of natural gas that has passed through it.
Meter Tampering:	A situation where a meter or meter piping has been illegally altered. Common examples are meter bypassing and other unauthorized connections.
Minimum Charge:	The amount the customer must pay for the availability of gas service as specified in the Utility's tariffs.
Mobile Home:	A residential unit designed and built to be towed on its own chassis. It is without a permanent foundation and is designed for year-round living.
Monthly Operating Window:	A transportation operating constraint governing the allowable monthly difference between the customer's metered quantities and the sum of the customer's scheduled transportation quantities, plus any Utility-approved imbalance adjustment quantity. The Monthly Operating Window requires such difference to be within plus or minus 5 percent (±5%) of the month's total of daily scheduled transportation quantities, plus any Utility-approved imbalance adjustment quantity, or 1,500 therms, whichever is greater.
Mountain Clock Time (MCT):	Mountain Standard Time or Mountain Daylight Time, whichever is currently in effect in the majority of the Mountain Time Zone, regardless of which time the State of Arizona is operating under.
Multi-Family Residential:	Any structure where more than one permanent residential dwelling receives the benefits of natural gas service through individual meters. N | N
Off-Peak Irrigation Season:	The six-month period beginning October 1 and ending March 31.
Operating Day:	The 24-hour period beginning 7:00 a.m. Mountain Standard Time.

L

RULE NO. 1

DEFINITIONS
(Continued)

Ownership:	The legal right of possession or proprietorship of the premise(s) where service is established. L
Peak Day:	Maximum daily consumption as determined by the best practical method available. L
Peak Irrigation Season:	The six-month period beginning April 1 and ending September 30.
Permanent Customer:	A customer who is a tenant or owner of a service location who applies for and receives natural gas service in a status other than transient, temporary or agent.
Permanent Service:	Natural gas service which, in the opinion of the Utility, is of a permanent and established character. The use of gas may be continuous, intermittent or seasonal in nature.
Person:	Any individual, partnership, corporation, governmental agency, or other organization operating as a single entity.
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.
Point of Delivery:	The point where pipes owned, leased, or under license by a customer and which are subject to inspection by the appropriate city, county or state authority connect to the Utility's pipes or at the outlet side of the meter.

RULE NO. 1

DEFINITIONS
(Continued)

Police Protection Uses:	Natural gas used by law enforcement agencies in the performance of their appointed duties.
Preemption of Gas Supply:	An emergency condition where the Utility may, under specified conditions, utilize the customer-owned gas supplies of low priority transportation customers to serve the requirements of higher priority transportation and sales customers.
Premises:	All of the real property and apparatus employed in a single enterprise on an integral parcel of land undivided by public streets, alleys or railways.
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 purpose of this definition, propane and other gaseous fuels shall not be considered alternate fuels.
Regular Working Hours:	Except for Utility observed holidays, the period from 8 a.m. to 5 p.m., Monday through Friday.
Residential Dwelling:	A house, apartment, townhouse or any other permanent residential unit that is used as a permanent home. N N
Residential Subdivision:	Any tract of land which has been divided into four or more contiguous lots for use for the construction of residential buildings or permanent mobile homes for either single or multiple occupancy.
Residential Use:	Service to customers using natural 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.

RULE NO. 1

DEFINITIONS
(Continued)

Service Line:	A natural gas pipe that transports gas from a common source of supply (normally a distribution main) to the customer's point of delivery.
Service Line Extension:	Consists of a service line provided for a new customer at a premise not heretofore served, in accordance with the service line extension rule.
Service Establishment Charge:	A charge as specified in the Utility's tariffs for establishing a new account.
Service Reconnect Charge:	A charge as specified in the Utility's tariffs which must be paid by the customer prior to reconnection of natural gas service each time the service is disconnected for nonpayment or whenever service is discontinued for failure to comply with the Utility's tariffs.
Service Reestablishment Charge:	A charge as specified in the Utility's tariffs for service at the same location where the same customer had ordered a service disconnection within the preceding 12-month period.
Shrinkage:	The cost of the gas volumes lost, unaccounted for, or used as company fuel in the transportation process and represented by the differential between the cost of gas on a sales basis and the cost of gas on a purchased basis. D
Single-Family Residential:	A detached house or any other permanent single-family residential dwelling that receives the benefits of natural gas service through an individual meter. C | C
Southwest Vista:	An Electronic Bulletin Board service for subscribing users with computers and modems to dial up over telephone lines and access the many features available. The bulletin board is a communication tool that can support many users simultaneously.

RULE NO. 1

DEFINITIONS
(Continued)

Standard Delivery Pressure:	0.25 pounds per square inch gauge at the meter or point of delivery.
Standard Mantle:	A mantle which consumes a maximum of 2.6 cubic feet of gas per hour.
Standing Nomination:	A Daily Nomination which is effective for multiple Gas Days. Standing Nominations cannot exceed the term of the customer's Transportation Service Agreement. A Standing Nomination can be replaced by a new Daily Nomination or Intra-day Nomination; however, upon the expiration of such replacement Nomination, the Standing Nomination becomes effective again.
Storage Injection Gas:	Natural gas injected by a distributor into storage for later use.
Subdivision:	An area for single family dwellings which may be identified by filed subdivision plans.
Summer Season:	The eight-month period beginning April 1 and ending November 30. C C
Supplemental Gas Supply:	Natural gas purchased by the Utility from all sources other than the base gas supply.
Supply Curtailment:	A condition occurring when the demand for natural gas exceeds the available supply of gas. This condition can occur due to supply failure or upstream pipeline capacity curtailment.
Tariffs:	The documents filed with and approved by the Commission which list the rules, regulations, services and products offered by the Utility and which set forth the terms and conditions and a schedule of the rates and charges for those services and products.
Tariff Sheets:	The individual sheets included in the tariff.

RULE NO. 1

DEFINITIONS
(Continued)

Utility's Operating Convenience:	This term refers to the utilization, under certain circumstances, of facilities or practices not ordinarily employed which contribute to the overall efficiency of the Utility's operations. It does not refer to customer convenience nor to the use of facilities or adoption of practices required to comply with applicable laws, ordinances, rules or regulations, or similar requirements of public authorities.
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, indicates that the temperature will not exceed 32 degrees Fahrenheit for the next day's forecast. The Commission may determine that other weather conditions are especially dangerous to health as the need arises.
Winter Season:	The four-month period beginning December 1 and ending March 31. C C
Workday:	The time period between 8 a.m. and 5 p.m., Monday through Friday, excluding holidays.

Rule No. 3

ESTABLISHMENT OF SERVICE

A. INFORMATION FROM APPLICANTS

1. The Utility may request the following minimum information from each new applicant for service:

   a. Name or names of applicant(s), including information regarding co-applicant (s). D/T

   b. Identification that is acceptable to the Utility. T

   c. Service address or location and telephone number.

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

   e. Address where service was provided previously.

   f. Date applicant will be ready for service.

   g. Indication of whether premises have previously been supplied with the Utility's service.

   h. Purpose for which service is to be used.

   i. Indication of whether applicant is owner or tenant of or agent for the premises.

   j. Information concerning the natural gas usage and demand requirements of the customers so as to determine which tariff schedule is applicable.

   k. Type and kind of life-support equipment, if any, used by the customer.

   l. Third party notification. If an applicant or customer who is elderly and/or handicapped lists a third party whom they wish notified in the event that their service is scheduled for discontinuance in accordance with Rule No. 10, such third party's name, address and telephone number shall be noted on the application for service.

Rule No. 3

ESTABLISHMENT OF SERVICE
(Continued)

B. ESTABLISHMENT AND REESTABLISHMENT OF CREDIT/DEPOSITS *(Continued)*

a. Residential *(Continued)*

(2) When credit cannot be established to the satisfaction of the Utility, the applicant will be required to:

(a) Pay the deposit amount billed by the date specified on the bill or make acceptable payment arrangements, or

(b) Place a deposit utilizing cash or an acceptable credit card to secure payment of bills for service as prescribed herein, or

(c) Provide a surety bond acceptable to the Utility in an amount equal to the required deposit.

b. Nonresidential

(1) The Utility shall not require a deposit from a new applicant for nonresidential service if the applicant has had service of a comparable nature within the preceding 24 months at another service location with Southwest Gas and a satisfactory payment history was established.

(2) When a deposit is required from a new applicant for nonresidential service, the applicant will be required to:

(a) Pay the deposit amount billed by the date specified on the bill or make acceptable payment arrangements, or

(b) For amounts not exceeding five thousand dollars ($5,000), place a deposit utilizing cash or an acceptable credit card to secure payment of bills for service as prescribed herein, or N

(c) Furnishes a surety bond, letter of credit, or other means acceptable to the Utility for payment to the Utility in an amount equal to the required deposit. N

2. Reestablishment of Credit

a. Former Customers with an Outstanding Balance

Rule No. 3

ESTABLISHMENT OF SERVICE
(Continued)

B. ESTABLISHMENT AND REESTABLISHMENT OF CREDIT/DEPOSITS *(Continued)*

3. Deposits *(Continued)*

(1) Residential customer deposits shall not exceed two times the customer's estimated average monthly bill.

(2) Nonresidential customer deposits shall not exceed two and one-half times the customer's estimated maximum monthly bill.

b. The Utility may bill the customer for any required deposit amount provided that credit and payment arrangements have been made according to the Utility's policy and procedures.

c. Applicability to Unpaid Accounts

Deposits and interest prescribed herein will be applied to unpaid bills owing to the Utility when service is discontinued or terminated, or in the event the customer declares bankruptcy or becomes otherwise insolvent. N | N

d. Refund of Deposits

(1) Upon discontinuance of service, the Utility will refund any balance of the deposit, plus applicable interest, in excess of unpaid bills. The Utility will return any credit balance by check to the last known customer address.

(2) After a residential customer has, for 24 consecutive months, paid all bills without being delinquent more than twice, the Utility shall refund the deposit with earned interest within 30 days. C

(3) After a nonresidential customer has, for 24 consecutive months, paid all bills prior to the next regular billing, the Utility shall refund the deposit with earned interest within 30 days.

(4) In the case of refunding a deposit which has been made by an agency from the Utility Assistance Fund (Fund) established by A.R.S. 46-731 to provide assistance for eligible customers, such deposit shall be refunded to the Fund. The standard Rules and Regulations of the Utility as authorized by the Arizona Corporation Commission shall apply to these refunds.

Rule No. 3

ESTABLISHMENT OF SERVICE
(Continued)

B. ESTABLISHMENT AND REESTABLISHMENT OF CREDIT/DEPOSITS *(Continued)*

1. Deposits *(Continued)*

a. Interest on Deposits

The Utility will pay 3 percent interest on deposits from the date of deposit until the date of settlement or withdrawal of deposit. Where such deposit remains for a period of one year or more and the person making the deposit continues to be a customer, the interest on the deposit at the end of the year shall be applied to the customer's account. C

b. The Utility may review the customer's usage after service has been connected and adjust the deposit amount based upon the customer's actual usage.

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

d. The Utility shall issue a non-negotiable receipt to the applicant for the deposit. The inability of the customer to produce such a receipt shall in no way impair his right to receive a refund of the deposit which is reflected on the Utility's records.

C. GROUNDS FOR REFUSAL OF SERVICE

1. The Utility may refuse to establish service if any of the following conditions exists:

a. The applicant has an outstanding amount due for the same class of service with the Utility and the applicant is unwilling to make satisfactory arrangements with the Utility for payment.

b. A condition exists which in the Utility's judgment is unsafe or hazardous to the applicant, the general population, or the Utility's personnel or facilities.

c. Refusal by the applicant to provide the Utility with a deposit when the customer has failed to meet the credit criteria for waiver of deposit requirements.

Rule No. 3

ESTABLISHMENT OF SERVICE
(Continued)

C. GROUNDS FOR REFUSAL OF SERVICE *(Continued)*

d. Customer is known to be in violation of the Utility's tariffs filed with and approved by the Commission.

e. Failure of the customer to furnish such funds, service, equipment, and/or rights-of-way necessary to serve the customer and which have been specified by the Utility as a condition for providing service.

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

g. Where service has been discontinued for fraudulent use, in which case Rule No. 11 will apply.

h. If the intended use of the service is for any restricted apparatus or prohibited use.

2. Notification to Applicants or Customers

When an applicant or customer is refused service or service has been discontinued under the provisions of this rule, the Utility will notify the applicant or customer of the reasons for the refusal to serve and of the right of applicant or customer to appeal the Utility's decision to the Commission.

D. SERVICE ESTABLISHMENT, REESTABLISHMENT OR RECONNECTION

1. To recover the operating and clerical costs, the Utility shall collect a service charge whenever service is established, reestablished or reconnected as set forth and referred to as "Service Establishment Charge" in the currently effective Statement of Rates, A.C.C. Sheet No. 15 of this Arizona Gas Tariff. This charge will be applicable for (1) establishing a new account, (2) reestablishing service at the same location where the same customer had ordered a service disconnection, or (3) reconnecting service after having been discontinued for nonpayment of bills or for failure to otherwise comply with filed rules or tariff schedules. T T T

RULE NO. 9

BILLING AND COLLECTION
(Continued)

K. EQUAL PAYMENT PLAN

1. The Equal Payment Plan (EPP) is available to all residential customers receiving (or applicants qualifying and applying to receive) natural gas service provided that the customer (applicant) has established credit to the satisfaction of the Utility.

2. Participation in the EPP is subject to approval by the Utility.

3. Customers may sign up for the EPP at any time of year. The EPP amount will be based on the annual estimated bill divided into 12 equal monthly payments.

4. The Utility will render its regular monthly billing statement showing both the amount for actual usage for the period and the designated EPP amount. The customer will pay his designated EPP amount, plus any additional amount shown on the bill for materials, parts, labor or other charges.

5. The settlement month will be the customer's anniversary date, 12 months from the time the customer entered the EPP. The settlement amount is the difference between the EPP payments made and the amount actually owing based on actual usage during the period the customer was billed under the EPP. All debit amounts are due and payable in the settlement month. However, debit amounts of $50 or less may be carried forward and added to the total annual estimated bill for the next EPP year. Credit amounts of $50 or C
less will be carried forward and applied against the first billing or billings due in the next EPP year. Credit amounts over $50 will be refunded by check. C

6. The EPP amount may be adjusted quarterly to reduce the likelihood of an excessive debit or credit balance in the settlement month for changes in rates due to Commission-approved rate increases or decreases greater than 5 percent, or when estimates indicate that an overpayment or undercollection of $50 or more may occur by the end of the plan year.

7. The Utility may remove from the EPP and place on regular billing any customer who fails to make timely payments according to his EPP obligation. Such a customer will then be subject to termination of service in accordance with Rule No. 10 for nonpayment of a bill.

Current Tariff Sheets

TABLE OF CONTENTS

The following listed sheets contain all of the effective rules and regulations affecting rates and service and information relating thereto in effect on and after the date indicated thereon:

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STATEMENT OF RATES
EFFECTIVE SALES RATES APPLICABLE TO ARIZONA SCHEDULES 1/

Description	Base Tariff Rate Margin	Base Tariff Rate Gas Cost	2/ Rate Adjustment	Monthly Gas Cost Adjustment	Currently Effective Tariff Rate
G-5 – Residential Gas Service					
Basic Service Charge per Month	$ 8.00				$ 8.00
Commodity Charge per Therm:					
Summer (May–October):					
First 20 Therms	$ .48762	$ .37034	$ .01073	$ .16402	$ 1.03271
Over 20 Therms	.40344	.37034	.01073	.16402	.94853
Winter (November–April):					
First 40 Therms	$ .48762	$ .37034	$ .01073	$ .16402	$ 1.03271
Over 40 Therms	.40344	.37034	.01073	.16402	.94853
G-10 – Low-Income Residential Gas Service					
Basic Service Charge per Month	$ 7.00				$ 7.00
Commodity Charge per Therm:					
Summer (May–October):					
First 20 Therms	$ .48762	$ .37034	$ .00486	$ .16402	$ 1.02684
Over 20 Therms	.40344	.37034	.00486	.16402	.94266
Winter (November–April):					
First 40 Therms	$ .28225	$ .37034	$ .00486	$ .16402	$ .82147
Next 110 Therms	.21491	.37034	.00486	.16402	.75413
Over 150 Therms	.40344	.37034	.00486	.16402	.94266
G-15 – Special Residential Gas Service for Air Conditioning					
Basic Service Charge per Month	$ 8.00				$ 8.00
Commodity Charge per Therm:					
Summer (May–October):					
First 20 Therms	$ .48762	$ .37034	$ .00486	$ .16402	$ 1.02684
Over 20 Therms	.19125	.37034	.00486	.16402	.73047
Winter (November–April):					
First 40 Therms	$ .48762	$ .37034	$ .00486	$ .16402	$ 1.02684
Over 40 Therms	.40344	.37034	.00486	.16402	.94266
G-16 – Special Residential Gas Service for Electric Generation					
Basic Service Charge per Month	$ 8.00				$ 8.00
Commodity Charge per Therm:					
Summer (May–October):					
First 20 Therms	$ .48762	$ .37034	$ .00486	$ .16402	$ 1.02684
Over 20 Therms	.19125	.37034	.00486	.16402	.73047
Winter (November–April):					
First 40 Therms	$ .48762	$ .37034	$ .00486	$ .16402	$ 1.02684
Over 40 Therms	.40344	.37034	.00486	.16402	.94266
G-20 – Master-Metered Mobile Home Park Gas Service					
Basic Service Charge per Month	$ 50.00				$ 50.00
Commodity Charge per Therm:					
All Usage	$ .31415	$ .37034	$ .01073	$ .16402	$ .85924
G-25 – General Gas Service					
Basic Service Charge per Month:					
Small	$ 20.00				$ 20.00
Medium	90.00				$ 90.00
Large	500.00				$500.00
Commodity Charge per Therm:					
Small, All Usage	$ .38024	$ .37034	$ .00000	$ .16402	$ .91460
Medium, All Usage	.27211	.37034	.00000	.16402	.80647
Large, All Usage	.08548	.37034	.00000	.16402	.61984
Demand Charge per Month–Large:					
Demand Charge 3/	$ .072695				$ .072695

SOUTHWEST GAS CORPORATION
P.O. Box 98510
Las Vegas, Nevada 89193-8510
Arizona Gas Tariff No. 7
Arizona Division

CURRENT TARIFF SHEET

Fifty- Eighth Revised A.C.C. Sheet No. 12
Canceling Fifty-Seventh Revised A.C.C. Sheet No. 12

STATEMENT OF RATES
EFFECTIVE SALES RATES APPLICABLE TO ARIZONA SCHEDULES 1/
(Continued)

Description	Base Tariff Rate: Margin	Base Tariff Rate: Gas Cost	2/ Rate Adjustment	Monthly Gas Cost Adjustment	Currently Effective Tariff Rate
G-30 – Optional Gas Serivce					
Basic Service Charge per Month	As specified on A.C.C. Sheet No. 27.				
Commodity Charge per Therm:					
All Usage	As specified on A.C.C. Sheet No. 28.				
G-35 – Gas Service to Armed Forces					
Basic Service Charge per Month	$350.00				$350.00
Commodity Charge per Therm:					
All Usage	$ .18966	$ .37034	$ .00000	$ .16402	$ .72402
G-40 – Air-Conditioning Gas Service					
Basic Service Charge per Month	As specified on A.C.C. Sheet No. 32.				
Commodity Charge per Therm:					
All Usage	$ .07613	$ .37034	$ .00000	$ .16402	$ .61049
G-45 – Street Lighting Gas Service					
Commodity Charge per Therm of Rated Capacity:					
All Usage	$ .47648	$ .37034	$ .00000	$ .16402	$ 1.01084
G-55 – Gas Service for Compression on Customer's Premises 5/					
Basic Service Charge per Month:					
Small	$ 20.00				$ 20.00
Large	170.00				170.00
Residential	8.00				8.00
Commodity Charge per Therm:					
Small, All Usage	$ .13305	$ .37034	$ .00000	$ .16402	$ .66741
Large, All Usage	.13305	.37034	.00000	.16402	.66741
G-60 – Cogeneration Gas Service 4/					
Basic Service Charge per Month	As specified on A.C.C. Sheet No. 40.				
Commodity Charge per Therm:					
All Usage	$ .08934	$ .43742			$ .52676
G-75 – Small Essential Agricultural User Gas Service					
Basic Service Charge per Month	$ 75.00				$ 75.00
Commodity Charge per Therm:					
All Usage	$ .19468	$ .37034	$ .00000	$ .16402	$ .72904
G-80 – Natural Gas Engine Gas Service 4/					
Basic Service Charge per Month:					
Off-Peak Season (October–March)	$ 0.00				$ 0.00
Peak Season (April–September)	80.00				80.00
Commodity Charge per Therm:					
All Usage	$ .16189	$ .43742			$ .59931
G-95 – Resale Gas Service					
Basic Service Charge per Month					
Commodity Charge per Therm:					
All Usage					

Issued On August 18, 2004
Docket No. G-01551A-01-0060

Issued by
John P. Hester
Vice President

Effective August 27, 2004
Decision No. 63598

STATEMENT OF RATES

EFFECTIVE SALES RATES APPLICABLE TO ARIZONA SCHEDULES 1/

(Continued)

1/ All charges are subject to adjustment for any applicable taxes or governmental impositions.

2/ (a) For Schedule Nos. G-5 and G-20, the Rate Adjustment includes $.00587 per therm to recover LIRA program costs.

(b) For Schedule Nos. G-5, G-10, G-15, G-16 and G-20, the Rate Adjustment includes $.00486 per therm to recover DSM Program costs.

3/ The total monthly demand charge is equal to the unit rate shown multiplied by the customer's billing determinant.

4/ The gas cost for this rate schedule shall be updated seasonally, April 1 and October 1 of each year.

5/ The charges for Schedule No. G-55 are subject to adjustment for applicable state and federal taxes on fuel used in motor vehicles.

STATEMENT OF RATES
EFFECTIVE TRANSPORTATION RATES APPLICABLE TO ARIZONA SCHEDULES 1/ 2/

The maximum charges are listed below. The volume charge is intended to cover both margin and variable costs. In no event will the minimum charge be less than the variable cost. The volume charges are stated in dollars per therm.

Customer Class	Basic Service Charge per Month per Meter 3/	Demand Charge	Volumetric Charges: Margin	Volumetric Charges: Shrinkage 5/
General, Small	$ 20.00	N/A	$ .38024	$ .00475
General, Medium	$ 90.00	N/A	$ .27211	$ .00475
General, Large	$ 500.00	$.072695 4/	$ .08548	$ .00475
Armed Forces	$ 350.00	N/A	$ .18966	$ .00475
Air Conditioning	Varies	N/A	$ .07613	$ .00475
Compression on Customer's Premises:				
Small	$ 20.00	N/A	$ .13305	$ .00475
Large	$ 170.00	N/A	$ .13305	$ .00475
Cogeneration	Varies	N/A	$ .08934	$ .00475
Small Essential Agricultural	$ 75.00	N/A	$ .19468	$ .00475
Natural Gas Engine	$ 80.00 6/	N/A	$ .16189	$ .00475
Resale	$ 800.00	N/A	$ .02479	$ .00475

1/ The charges shown above are subject to adjustment for the applicable proportionate part of any taxes or governmental impositions which are assessed on the basis of the gross revenues of the Utility.

2/ For customers electing to assign title of its customer-secured gas to the Utility for transportation in upstream pipelines, the customer shall reimburse the Utility for the cost of such customer-secured gas, all incremental costs incurred by the Utility in transporting such customer-secured gas through upstream pipelines and up to 100 percent of upstream pipeline fixed reservation charges set forth in the applicable pipeline's firm transportation rates, in addition to any applicable charges under Schedule No. T-1. Revenues resulting from the pass-through of upstream pipeline fixed reservation and usage charges which are in excess of the incremental costs incurred by the Utility in transporting such customer-secured gas through upstream pipelines shall be credited to the Gas Cost Balancing Account.

3/ Where transportation service is rendered in combination with an applicable gas sales tariff schedule, the customer shall not be billed for more than one basic service charge per month per meter.

4/ The total monthly demand charge for Large General Gas Service is equal to the unit rate shown multiplied by the customer's billing determinant.

5/ This charge shall be updated annually effective May 1.

6/ Applicable during Peak Season (April–September).

STATEMENT OF RATES
OTHER SERVICE CHARGES 1/

Description	Reference	Service Supplied Under Schedules G-5 thru G-80 T-1 and B-1
Service Establishment Charge		
Schedule No. G-10		
Normal Service	Rule 3D	$ 24.00
Expedited Service	Rule 3D	32.00
All Other Schedules		
Normal Service	Rule 3D	$ 30.00
Expedited Service	Rule 3D	40.00
Customer Requested Meter Tests		
Per Test	Rule 8C	$ 25.00
Returned Item Charge		
Per Item	Rule 9J	$ 10.00
Re-Read Charge		
Per Read	Rule 8B	$ 10.00
Late Charge		
Each Delinquent Bill	Rule 9E	1.5% of the delinquent amount.
Field Collection Fee		
Each Field Collection	Rule 9E	$ 20.00

1/ Subject to adjustment for any applicable taxes or governmental impositions.

Schedule No. G- 5

RESIDENTIAL GAS SERVICE

APPLICABILITY

Applicable to gas service to customers which consists of direct domestic gas usage in a residential dwelling for space heating, clothes drying, cooking, water heating and other residential uses.

TERRITORY

Throughout the certificated area served by the Utility in the communities as set forth on A.C.C. Sheet No. 8 of this Arizona Gas Tariff.

RATES

The basic service charge and commodity charge are set forth in the currently effective Statement of Rates of this Arizona Gas Tariff and are incorporated herein by reference.

MINIMUM CHARGE

The minimum charge per meter per month is the basic service charge.

SPECIAL CONDITIONS

The charges specified for this schedule are subject to adjustment for the applicable proportionate part of any taxes or governmental impositions which are assessed on the basis of the gross revenues of the Utility.

PURCHASED GAS ADJUSTMENT CLAUSE

The rates specified for this schedule are subject to increases or decreases in the cost of gas purchased in accordance with those provisions set forth in the "Special Supplementary Tariff, Purchased Gas Cost Adjustment Provision," contained in this Arizona Gas Tariff.

RULES AND REGULATIONS

The standard Rules and Regulations of the Utility as authorized by the Commission shall apply where consistent with this schedule.

Schedule No. G-10

LOW INCOME RESIDENTIAL GAS SERVICE

APPLICABILITY

Applicable to gas service to the primary residences of low income residential customers who would otherwise be provided service under Schedule No. G-5 and who meet the criterion which establishes that a qualifying customer' s household income must not exceed 150 percent of the Federal poverty level.

TERRITORY

Throughout the certificated area served by the Utility in the communities as set forth on A.C.C. Sheet No. 8 of this Arizona Gas Tariff.

RATES

The basic service charge is set forth in the currently effective Statement of Rates of this Arizona Gas Tariff and is incorporated herein by reference. The commodity charge applicable to the first 150 therms per month during the winter season (November through April) delivered under this schedule shall reflect a 20 percent reduction from the commodity charge (excluding the LIRA surcharge) applicable to Schedule No. G-5, the customer' s otherwise applicable gas sales tariff schedule.

MINIMUM CHARGE

The minimum charge per meter per month is the basic service charge.

SPECIAL CONDITIONS

1. Eligibility requirements for the Low Income Residential Gas Service are set forth on the Utility' s Application and Declaration of Eligibility for Low Income Ratepayer Assistance form. Customers must have an approved application form on file with the Utility. Recertification will be required prior to November 1 every two years and whenever a customer moves to a new residence within the Utility' s service area.

Schedule No. G-10

LOW INCOME RESIDENTIAL GAS SERVICE
(Continued)

SPECIAL CONDITIONS *(Continued)*

2. Eligible customers shall be billed under this schedule during the winter season commencing with the next regularly scheduled billing period after the Utility has received the customer's properly completed application form or recertification.

3. Eligibility information provided by the customer on the application form may be subject to verification by the Utility. Refusal or failure of a customer to provide current documentation of eligibility acceptable to the Utility, upon request of the Utility, shall result in removal from or ineligibility for this schedule.

4. Customers who wrongfully declare eligibility or fail to notify the Utility when they no longer meet the eligibility requirements may be rebilled for the period of ineligibility under their otherwise applicable residential schedule.

5. It is the responsibility of the customer to notify the Utility within 30 days of any changes in the customer's eligibility status.

6. Customers with connected service to pools, spas or hot tubs are eligible for this schedule, only if usage is prescribed, in writing, by a licensed physician.

7. All monetary discounts will be tracked through a balancing account established by the Utility and recovered through the Utility's Low Income Ratepayer Assistance (LIRA) surcharge.

8. The charges specified for this schedule are subject to adjustment for the applicable proportionate part of any taxes or governmental impositions which are assessed on the basis of the gross revenues of the Utility.

PURCHASED GAS ADJUSTMENT CLAUSE

The rates specified for this schedule are subject to increases or decreases in the cost of gas purchased in accordance with those provisions set forth in the "Special Supplementary Tariff, Purchased Gas Cost Adjustment Provision," contained in this Arizona Gas Tariff.

RULES AND REGULATIONS

The standard Rules and Regulations of the Utility as authorized by the Commission shall apply where consistent with this schedule.

Schedule No. G-15

SPECIAL RESIDENTIAL GAS SERVICE FOR AIR CONDITIONING

APPLICABILITY

Applicable to gas service to residential customers formerly served under Schedule Nos. AG-15 and PG-15 as of August 31, 1993 and to residential customers with installed gas air conditioning.

TERRITORY

Throughout the certificated area served by the Utility in the communities as set forth on A.C.C. Sheet No. 8 of this Arizona Gas Tariff.

RATES

The basic service charge and commodity charges are set forth in the currently effective Statement of Rates of this Arizona Gas Tariff and are incorporated herein by reference.

MINIMUM CHARGE

The minimum charge per meter per month is the basic service charge.

SPECIAL CONDITIONS

1. A customer under this schedule may not elect service under a different applicable schedule unless service has been rendered under this schedule for a period of 12 or more months, or until a new or revised schedule is established.

2. The charges specified for this schedule are subject to adjustment for the applicable proportionate part of any taxes or governmental impositions which are assessed on the basis of the gross revenues of the Utility.

Schedule No. G-15

SPECIAL RESIDENTIAL GAS SERVICE
FOR AIR CONDITIONING
(Continued)

PURCHASED GAS ADJUSTMENT CLAUSE

The rates specified for this schedule are subject to increases or decreases in the cost of gas purchased in accordance with those provisions set forth in the " Special Supplementary Tariff, Purchased Gas Cost Adjustment Provision," contained in this Arizona Gas Tariff.

RULES AND REGULATIONS

The standard Rules and Regulations of the Utility as authorized by the Commission shall apply where consistent with this schedule.

Schedule No. G-16

SPECIAL RESIDENTIAL GAS SERVICE FOR ELECTRIC GENERATION

APPLICABILITY

Applicable to gas service to residential customers with installed natural gas-fired electric generation facilities.

TERRITORY

Throughout the certificated area served by the Utility in the communities as set forth on A.C.C. Sheet No. 8 of this Arizona Gas Tariff.

RATES

The basic service charge and commodity charges are set forth in the currently effective Statement of Rates of this Arizona Gas Tariff and are incorporated herein by reference.

MINIMUM CHARGE

The minimum charge per meter per month is the basic service charge.

SPECIAL CONDITIONS

1. A customer under this schedule may not elect service under a different applicable schedule unless service has been rendered under this schedule for a period of 12 or more months, or until a new or revised schedule is established.

2. The charges specified for this schedule are subject to adjustment for the applicable proportionate part of any taxes or governmental impositions which are assessed on the basis of the gross revenues of the Utility.

Schedule No. G-16

SPECIAL RESIDENTIAL GAS SERVICE
FOR ELECTRIC GENERATION
(Continued)

PURCHASED GAS ADJUSTMENT CLAUSE

The rates specified for this schedule are subject to increases or decreases in the cost of gas purchased in accordance with those provisions set forth in the " Special Supplementary Tariff, Purchased Gas Cost Adjustment Provision," contained in this Arizona Gas Tariff.

RULES AND REGULATIONS

The standard Rules and Regulations of the Utility as authorized by the Commission shall apply where consistent with this schedule.

Schedule No. G-25

GENERAL GAS SERVICE

APPLICABILITY

Applicable to commercial, industrial and essential agricultural customers as defined in Rule No. 1 of this Arizona Gas Tariff. Small general gas service customers are defined as those whose average monthly requirements on an annual basis are less than or equal to 600 therms per month. Medium general gas service customers are those whose average monthly requirements on an annual basis are greater than 600 therms, but less than or equal to 15,000 therms per month. Large general gas service customers are those whose average monthly requirements on an annual basis are greater than 15,000 therms per month.

TERRITORY

Throughout the certificated area served by the Utility in the communities as set forth on A.C.C. Sheet No. 8 of this Arizona Gas Tariff.

RATES

1. Small and Medium General Gas Service

   The basic service charge and commodity charge are set forth in the currently effective Statement of Rates of this Arizona Gas Tariff and are incorporated herein by reference.

   The minimum charge per meter per month is the basic service charge.

2. Large General Gas Service

   The basic service charge, the demand charge and the commodity charge are set forth in the currently effective Statement of Rates of this Arizona Gas Tariff and are incorporated herein by reference.

   The monthly demand charge shall be the product of the demand charge rate multiplied by the customer's billing determinant. The billing determinant shall be equal to each customer's throughput during the month in which the Utility's peak demand is established. Each customer's billing determinant shall be revised annually following the conclusion of each Winter Season (March) and shall be used with billings beginning May 1 of each year. For new customers or customers without a monthly consumption history, the initial billing determinant shall be the customer's estimated average monthly throughput.

Schedule No. G-30

OPTIONAL GAS SERVICE

APPLICABILITY

Applicable to natural gas use by customers that qualify for service under this schedule according to either Applicability Provision (1), (2) or (3) below:

1. Customers whose average monthly requirements on an annual basis are greater than 11,000 therms per month and who have installed facilities capable of burning alternate fuels or energy.

2. Customers whose average monthly requirements on an annual basis are greater than 11,000 therms per month and who can demonstrate to the Utility sufficient evidence of economic hardship under the customer's otherwise applicable sales tariff schedule.

3. Customers whose requirements may be served by other natural gas suppliers at rates lower than the customer's otherwise applicable gas sales tariff schedule. As a condition precedent to qualifying for service under this applicability provision, the customer must either qualify for transportation service under Schedule No. T-1 or establish that bypass is economically, operationally and physically feasible and imminent.

This optional schedule is not available for partial requirements gas service where gas is used in combination with alternate fuels or energy, or with natural gas provided by other suppliers. Any gas service rendered to customers not in conformance with the provisions of this schedule shall be billed under the otherwise applicable gas sales tariff schedule.

TERRITORY

Throughout the certificated area served by the Utility in the communities as set forth on A.C.C. Sheet No. 8 of this Arizona Gas Tariff.

RATES

The basic service charge is the charge per meter set as set forth in the customer's otherwise applicable gas sales tariff schedule and is set forth in the currently effective Statement of Rates of this Arizona Gas Tariff or the charge as set forth in the customer's service agreement.

Schedule No. G-35

GAS SERVICE TO ARMED FORCES

APPLICABILITY

Applicable to gas service to the United States Armed Forces, including housing facilities owned by the United States Government and operated by and as a part of the contiguous facilities described above.

TERRITORY

Throughout the certificated area served by the Utility in the communities as set forth on A.C.C. Sheet No. 8 of this Arizona Gas Tariff.

RATES

The basic service charge and commodity charge are set forth in the currently effective Statement of Rates of this Arizona Gas Tariff and are incorporated herein by reference.

MINIMUM CHARGE

The minimum charge per month is the basic service charge.

SPECIAL CONDITIONS

The charges specified for this schedule are subject to adjustment for the applicable proportionate part of any taxes or governmental impositions which are assessed on the basis of the gross revenues of the Utility.

PURCHASED GAS ADJUSTMENT CLAUSE

The rates specified for this schedule are subject to increases or decreases in the cost of gas purchased in accordance with those provisions set forth in the "Special Supplementary Tariff, Purchased Gas Cost Adjustment Provision," contained in this Arizona Gas Tariff.

RULES AND REGULATIONS

The standard Rules and Regulations of the Utility as authorized by the Commission shall apply where consistent with this schedule.

Schedule No. G-40

AIR-CONDITIONING GAS SERVICE

APPLICABILITY

Applicable to gas service to commercial or industrial customers as defined in Rule No. 1 of this Arizona Gas Tariff who qualify for service under Schedule No. G-25 and who have installed and regularly operate a gas-fired air-conditioning system which meets the Utility's specifications and approval.

All of the provisions of the customer's otherwise applicable gas sales tariff schedule shall apply to this service unless specifically modified within this schedule.

The volume of gas used for air-conditioning only purposes shall be determined by metering equipment installed by the Utility, unless, a written agreement is executed by the customer and the Utility that sets forth the estimated gas volumes or the methodology to determine the volumes to be billed under this schedule.

Service for any end use of gas other than for air-conditioning purposes, such as space heating, water heating, processing or boiler fuel use, is not permitted under this schedule and shall be billed under the otherwise applicable gas sales tariff schedule. Volumes billed under this schedule may not be used for purposes of establishing the customer's average monthly requirements under Schedule No. G-25.

TERRITORY

Throughout the certificated area served by the Utility in the communities as set forth on A.C.C. Sheet No. 8 of this Arizona Gas Tariff.

RATES

The basic service charge is set forth under the customer's otherwise applicable gas sales tariff schedule in the currently effective Statement of Rates of this Arizona Gas Tariff. The commodity charge is set forth in the currently effective Statement of Rates, A.C.C. Sheet No. 12 of this Arizona Gas Tariff. The basic service charge and commodity charge are incorporated herein by reference.

MINIMUM CHARGE

The minimum charge per meter per month is the basic service charge as set forth in the customer's otherwise applicable gas sales tariff schedule.

Schedule No. G-45

STREET LIGHTING GAS SERVICE

APPLICABILITY

Applicable to gas service for continuous street or outdoor lighting in lighting devices approved by the Utility. Service under this schedule is conditional upon arrangements mutually satisfactory to the customer and the Utility for connection of customer' s lighting devices to Utility' s facilities.

TERRITORY

Throughout the certificated area served by the Utility in the communities as set forth on A.C.C. Sheet No. 8 of this Arizona Gas Tariff.

RATES

Rate " X" – Lighting Only Service

The charge per month is the product of the therms per month per mantle and the commodity rate as set forth in the currently effective Statement of Rates, Sheet No. 12 of this Arizona Gas Tariff, and such commodity rate is incorporated herein by reference.

Rate " Y" – Lighting in Combination With Other Usage

The charge per month is the product of the therms per month per mantle and the commodity rate for the customer' s otherwise applicable sales schedule as set forth in the currently effective Statement of Rates of this Arizona Gas Tariff, and such commodity rate is incorporated herein by reference.

SPECIAL CONDITIONS

1. At its sole option, the Utility may reduce the maximum rated capacity to reflect use of automatic dimmer devices or adjustment of the lamps to operate at less than maximum rated capacity.

2. The charges specified for this schedule are subject to adjustment for the applicable proportionate part of any taxes or governmental impositions which are assessed on the basis of the gross revenues of the Utility.

Schedule No. G-60

COGENERATION GAS SERVICE

APPLICABILITY

Applicable to gas service where natural gas is used in a cogeneration facility that meets the efficiency standards outlined in Title 18, Code of Federal Regulation, Part 292, Subparts A and B, and where the customer's generators and load are located at the same premise. This schedule is available for only the cogeneration portion of the customer's gas purchases.

TERRITORY

Throughout the certificated area served by the Utility in the communities as set forth on A.C.C. Sheet No. 8 of this Arizona Gas Tariff.

RATES

The basic service charge is the charge under the customer's otherwise applicable gas sales tariff schedule. The basic service charge and the commodity charge are set forth in the currently effective Statement of Rates of this Arizona Gas Tariff and are incorporated herein by reference.

MINIMUM CHARGE

The minimum charge per meter per month is the basic service charge.

SPECIAL CONDITIONS

1. Gas service under this schedule is not available unless accompanied by a signed contract for a minimum of one year as the precedent to service under this schedule, and said contract shall continue in force and effect from year to year thereafter until either the Utility or the customer shall give the other written notice of a desire to terminate the same at least 30 days prior to the expiration of any such year. If the customer permanently ceases operation, such contract shall not thereafter continue in force.

2. Gas service under this schedule is not available for "standby" or occasional temporary service.

Schedule No. G-60

COGENERATION GAS SERVICE
(Continued)

SPECIAL CONDITIONS *(Continued)*

3. The charges specified for this schedule are subject to adjustment for the applicable proportionate part of any taxes or governmental impositions which are assessed on the basis of the gross revenues of the Utility.

PURCHASED GAS ADJUSTMENT CLAUSE

The charges specified for this schedule are subject to increases or decreases in the cost of gas purchased by the Utility. Such change shall be reflected in the commodity charge of the currently effective tariff rates as shown on A.C.C. Sheet No. 12 of this Arizona Gas Tariff.

RULES AND REGULATIONS

The standard Rules and Regulations of the Utility as authorized by the Commission shall apply where consistent with this schedule.

Schedule No. G-75

SMALL ESSENTIAL AGRICULTURAL USER GAS SERVICE

APPLICABILITY

Applicable to gas service to customers whose gas use is certified by the Secretary of Agriculture as an "essential agricultural use" and whose maximum annual requirements are estimated by the Utility to be less than 125,000 dekatherms.

TERRITORY

Throughout the certificated area served by the Utility in the communities as set forth on A.C.C. Sheet No. 8 of this Arizona Gas Tariff.

RATES

The basic service charge and commodity charge are set forth in the currently effective Statement of Rates of this Arizona Gas Tariff and are incorporated herein by reference.

MINIMUM CHARGE

The minimum charge per meter per month is the basic service charge.

SPECIAL CONDITIONS

1. Any customer who uses or who is estimated to use in excess of 50 dekatherms in any one month may be required to sign a contract for one year as the precedent to service under this schedule, and said contract shall continue in force and effect from year to year thereafter until either the Utility or the customer shall give the other written notice of a desire to terminate the same at least 30 days prior to the expiration of any such year. If the customer permanently ceases operation, such contract shall not thereafter continue in force.

2. The charges specified for this schedule are subject to adjustment for the applicable proportionate part of any taxes or governmental impositions which are assessed on the basis of the gross revenues of the Utility.

Schedule No. R-1

RESIDENTIAL GAS SERVICE

APPLICABILITY

Applicable to gas service to customers located in the service area formerly served by Black Mountain Gas Company which consists of direct domestic gas usage in a residential dwelling for space heating, clothes drying, cooking, water heating, and other residential uses.

TERRITORY

Throughout the certificated area formerly served by Black Mountain Gas Company.

RATES

The basic service charge and commodity charge are set forth in the currently effective Statement of Rates of this Arizona Gas Tariff and are incorporated herein by reference.

Customers whose household income does not exceed 150 percent of the federal poverty level are eligible to receive a 20 percent Low Income Residential discount off the first 150 therms total commodity charge each month of the winter season. All special conditions of Schedule No. G-10 apply to this discount

MINIMUM CHARGE

The minimum charge per meter per month is the basic service charge.

SPECIAL CONDITIONS

The charges specified for this schedule are subject to adjustment for the applicable proportionate part of any taxes or governmental impositions which are assessed on the basis of the gross revenues of the Utility.

PURCHASED GAS ADJUSTMENT PROVISION

The rates specified for this schedule are subject to increases or decreases in the cost of gas purchased in accordance with those provisions set forth in the "Special Supplementary Tariff, Purchased Gas Cost Adjustment Provision," contained in this Arizona Gas Tariff.

RULES AND REGULATIONS

The standard Rules and Regulations of the Utility as authorized by the Commission shall apply where consistent with this schedule.

Schedule No. C-1

COMMERCIAL GAS SERVICE

APPLICABILITY

Applicable to commercial customers, as defined in Rule No. 1 of this Arizona Gas Tariff, located in the service area formerly served by Black Mountain Gas Company.

TERRITORY

Throughout the certificated area formerly served by Black Mountain Gas Company.

RATES

The basic service charge and commodity charge are set forth in the currently effective Statement of Rates of this Arizona Gas Tariff and are incorporated herein by reference.

The minimum charge per meter per month is the basic service charge.

SPECIAL CONDITIONS

The charges specified for this schedule are subject to adjustment for the applicable portion of any taxes or governmental impositions which are based on the gross revenues of the Utility.

PURCHASED GAS ADJUSTMENT PROVISION

The rates specified for this schedule are subject to increases or decreases in the cost of gas purchased in accordance with those provisions set forth in the "Special Supplementary Tariff, Purchased Gas Cost Adjustment Provision," contained in this Arizona Gas Tariff.

RULES AND REGULATIONS

The standard Rules and Regulations of the Utility as authorized by the Commission shall apply where consistent with this schedule.

Schedule No. CRS-1

RESORT GAS SERVICE

APPLICABILITY

Applicable to all resort hotel customers located in the service area formerly served by Black Mountain Gas Company.

TERRITORY

Throughout the certificated area formerly served by Black Mountain Gas Company.

RATES

The basic service charge and commodity charge are set forth in the currently effective Statement of Rates of this Arizona Gas Tariff and are incorporated herein by reference.

The minimum charge per meter per month is the basic service charge.

SPECIAL CONDITIONS

The charges specified for this schedule are subject to adjustment for the applicable portion of any taxes or governmental impositions which are based on the gross revenues of the Utility.

PURCHASED GAS ADJUSTMENT PROVISION

The rates specified for this schedule are subject to increases or decreases in the cost of gas purchased in accordance with those provisions set forth in the "Special Supplementary Tariff, Purchased Gas Cost Adjustment Provision," contained in this Arizona Gas Tariff.

RULES AND REGULATIONS

The standard Rules and Regulations of the Utility as authorized by the Commission shall apply where consistent with this schedule.

Schedule No. GAC-1

AIR-CONDITIONING GAS SERVICE

APPLICABILITY

Applicable to gas service to customers in conjunction with service under Schedule No. R-1, C-1 or CRS-1.

All of the provisions of the customer's otherwise applicable gas sales tariff schedule shall apply to this service unless specifically modified within this schedule.

The volume of gas used for air-conditioning purposes shall be supplied through a separately metered delivery point.

Service for any end use of gas other than for air-conditioning purposes, such as space heating, water heating, processing or boiler fuel use, is not permitted under this schedule and shall be billed under the otherwise applicable gas sales tariff schedule.

TERRITORY

Throughout the certificated area formerly served by Black Mountain Gas Company.

RATES

The basic service charge and commodity charge are set forth in the currently effective Statement of Rates of this Arizona Gas Tariff and are incorporated herein by reference.

MINIMUM CHARGE

The minimum charge per meter per month is the basic service charge as set forth in the customer's otherwise applicable gas sales tariff schedule.

SPECIAL CONDITIONS

The charges specified for this schedule are subject to adjustment for the applicable proportionate part of any taxes or governmental impositions which are assessed on the basis of the gross revenues of the Utility.

Schedule No. GAC-1

AIR-CONDITIONING GAS SERVICE
(Continued)

PURCHASED GAS ADJUSTMENT PROVISION

The rates specified for this schedule are subject to increases or decreases in the cost of gas purchased in accordance with those provisions set forth in the "Special Supplementary Tariff, Purchased Gas Cost Adjustment Provision," contained in this Arizona Gas Tariff.

RULES AND REGULATIONS

The standard Rules and Regulations of the Utility as authorized by the Commission shall apply where consistent with this schedule.

Schedule No. CGEN-1

COGENERATION GAS SERVICE

APPLICABILITY

Applicable to gas service to customers located in the service area formerly served by Black Mountain Gas Company where natural gas is used in a cogeneration facility that meets the efficiency standards outlined in Title 18, Code of Federal Regulation, Part 292, Subparts A and B, and where the customer's generators and load are located at the same premise. This schedule is available for only the cogeneration portion of the customer's gas purchases.

TERRITORY

Throughout the certificated area formerly served by Black Mountain Gas Company.

RATES

The basic service charge and commodity charge are set forth in the currently effective Statement of Rates of this Arizona Gas Tariff and are incorporated herein by reference.

MINIMUM CHARGE

The minimum charge per meter per month is the basic service charge.

SPECIAL CONDITIONS

The charges specified for this schedule are subject to adjustment for the applicable proportionate part of any taxes or governmental impositions which are assessed on the basis of the gross revenues of the Utility.

PURCHASED GAS ADJUSTMENT PROVISION

The charges specified for this schedule are subject to increases or decreases in the cost of gas purchased by the Utility. Such change shall be reflected in the commodity charge of the currently effective tariff rates as shown on A.C.C. Sheet No. 12 of this Arizona Gas Tariff.

RULES AND REGULATIONS

The standard Rules and Regulations of the Utility as authorized by the Commission shall apply where consistent with this schedule.

Schedule No. CNG-1

COMPRESSED NATURAL GAS SERVICE

APPLICABILITY

Applicable to gas service to natural gas vehicle (NGV) operators and retail distributors in conjunction with service under Schedule No. R-1, C-1 or CRS-1 for the sole purpose of compressing natural gas for use as a fuel in vehicular internal combustion engines.

Service under this schedule shall be through one point of delivery and through one meter. The customer shall install, at its expense, facilities required to receive service under this schedule.

TERRITORY

Throughout the certificated area formerly served by Black Mountain Gas Company.

RATES

The basic service charge and commodity charge are set forth in the currently effective Statement of Rates of this Arizona Gas Tariff and are incorporated herein by reference.

MINIMUM CHARGE

The minimum charge per meter per month is the basic service charge.

SPECIAL CONDITIONS

The charges specified for this schedule are subject to adjustment for the applicable proportionate part of any taxes or governmental impositions which are assessed on the basis of the gross revenues of the Utility.

PURCHASED GAS ADJUSTMENT PROVISION

The rates specified for this schedule are subject to increases or decreases in the cost of gas purchased in accordance with those provisions set forth in the “Special Supplementary Tariff, Purchased Gas Cost Adjustment Provision,” contained in this Arizona Gas Tariff.

RULES AND REGULATIONS

The standard Rules and Regulations of the Utility as authorized by the Commission shall apply where consistent with this schedule.

HELD FOR FUTURE USE

Schedule No. T-1

TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS

1. AVAILABILITY

This schedule is available to any customer for transportation of natural gas by the Utility from any existing interconnection between the Utility and EL Paso Natural Gas Company (herein called Receipt Point) to the Delivery Point(s) on the Utility's system under the following conditions:

1.1 The Utility has available capacity to render the requested service without construction of any additional facilities, except as provided by Section 8 hereof;

1.2 The customer has demonstrated to the Utility's satisfaction in accordance with Section 6.8(d) hereof, the assurance of natural gas supplies and third-party transportation agreements with quantities and for a term compatible with the service being requested from the Utility. Except for customers otherwise served under Schedule No. G-55, service under this schedule is limited to: (a) customers whose average monthly requirements at one of the customer's premises on an annual basis are no less than 15,000 therms, and (b) customers whose average monthly requirements at one of the customer's premises during the months of May through September are no less than 15,000 therms. Projected transportation quantities for customers otherwise served under Schedule No. G-55 shall not be less than 50,000 therms annually at one of the customer's premises.

1.3 The customer and the Utility have executed a service agreement in the form contained in this Arizona Gas Tariff for service under this schedule. A single service agreement may provide for service to any or all of the customer's separate premises, provided that all of the premises are under common ownership.

2. APPLICABILITY AND CHARACTER OF SERVICE

This schedule shall apply to gas transported by the Utility for customer pursuant to the executed service agreement.

2.1 The basic transportation service rendered under this schedule shall consist of:

(a) The receipt by the Utility for the account of the customer of the customer's gas at the Receipt Point;

Schedule No. T-1

TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS
(Continued)

3. RATES

3.1 The customer shall pay the Utility monthly the sum of the following charges:

(a) Basic Service Charge. The basic service charge shall be the charge per meter set as set forth in the customer's otherwise applicable gas sales tariff schedule and is set forth in the currently effective Statement of Rates of this Arizona Gas Tariff. Customers receiving service under contract rates that were negotiated prior to September 1, 1997 shall pay the basic service charge as set forth in the customer's service agreement. Where transportation service is rendered in combination with a gas sales tariff schedule, the customer shall not be billed for more than one basic service charge per meter set each month.

(b) Demand Charge. The monthly demand charge applicable to large general gas service transportation customers shall be the product of the demand charge set forth in the Statement of Rates of this Arizona Gas Tariff, multiplied by the customer's billing determinant. The billing determinant shall be equal to each customer's throughput during the month in which the Utility's peak demand is established. Each customer's billing determinant shall be revised annually following the conclusion of each Winter Season (March) and shall be used with billings beginning May 1 of each year. For new customers or customers without a monthly consumption history, the initial billing determinant shall be the customer's estimated average monthly throughput.

(c) Volume Charge. An amount equal to the customer's unit transportation rate applicable to each therm of the customer's transportation billing quantity adjusted for any volumes traded pursuant to Section 7 of this schedule. The unit rates shall be as set forth in the currently effective Statement of Rates, A.C.C. Sheet No. 14 of this Arizona Gas Tariff, and are incorporated herein by reference. The volume charge will consist of the following:

Schedule No. T-1

TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS
(Continued)

3. RATES *(Continued)*

(i) An amount equal to the applicable unit sales margin for each therm, plus

(ii) An amount to reflect shrinkage as defined in Rule No. 1 of this Arizona Gas Tariff. This amount shall be recorded in Account No. 191, Unrecovered Purchased Gas Costs.

(d) Gas Cost Balancing Account Adjustment: For customers converting from sales service, an additional amount equal to the currently effective Gas Cost Balancing Account Adjustment to amortize the Gas Cost Balancing Account for a period of 12 months.

(e) Any applicable imbalance charges as specified in Section 7 of this schedule.

The Utility may adjust from time to time the applicable unit transportation rate to any individual customer, provided, however, that such adjusted rate shall not exceed the applicable maximum rate. When the Utility deviates from the maximum applicable rate, the sales margin set forth in Item (c)(i) above will be reduced.

In addition to the basic service charge, demand charge (if applicable), volume charge and any applicable imbalance charges, the Utility shall include as a surcharge on the customer's bill any charges from upstream pipeline transporters or suppliers which have been incurred by the Utility because of the transportation service rendered for the customer under this schedule.

Schedule No. T-1

TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS
(Continued)

3. RATES *(Continued)*

3.3 The charges specified for this schedule are subject to adjustment for the applicable proportionate part of any taxes, assessments or governmental impositions which are assessed on the basis of the gross revenues of the Utility.

4. MINIMUM CHARGE

The minimum charge per month is the basic service charge per month per meter and the demand charge per month per meter, if applicable.

5. FORCE MAJEURE

5.1 Relief From Liability: Neither party shall be liable in damages to the other on account of "force majeure" occasioned by any act, omission or circumstances occasioned by or in consequence of any act of God, strikes, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrests and restraints of rulers and people, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, depletion of or temporary failure of gas supply, the binding order of any court or governmental authority which has been resisted in good faith by all reasonable legal means, and any other cause, whether of the kind herein enumerated or not, and not within the control of the party claiming suspension and which by the exercise of due diligence such party is unable to prevent or overcome. Failure to settle or prevent any strikes or other 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 party claiming suspension.

5.2 Liabilities Not Relieved: Neither the customer nor the Utility shall be relieved from liability in the event of its concurring negligence or failure on its part to use due diligence to remedy the force majeure and remove the cause with all reasonable dispatch, nor shall such causes or contingencies affecting performance of any agreement relieve either party from its obligations to make payments when due in respect of gas theretofore delivered.

Schedule No. T-1

TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS
(Continued)

7. TRANSPORTATION IMBALANCE SERVICE *(Continued)*

(g) If, as the result of a billing error, metering error, or adjustments of scheduled supply, a customer trades an incorrect imbalance quantity based on notification by the Utility, the Utility will not be liable for any financial losses or damages incurred by customer nor will the Utility be financially liable to any of the customer's imbalance trading partners. If, as a result of such error, the Utility overbills the customer, the Utility shall refund the difference without interest. If the Utility underbills the customer, the customer shall be liable for the undercharge, including any associated penalty. For purposes of determining imbalances and any applicable charges hereunder, the Utility will include billing adjustments to the volume in prior periods as part of the current month's activity. Trades occurring in prior periods will not be affected by such billing adjustments.

7.2 Payment for Excess Imbalances

Customers will be assessed imbalance charges if, an imbalance exists in excess of applicable daily or monthly operating windows set forth in Section 6.9 hereof. (Monthly imbalances will be adjusted to reflect imbalance trading activity before assessing any imbalance charge.) The customer's daily imbalance is defined as the difference between the customer's daily metered quantities and the sum of the customer's daily scheduled transportation quantity plus any Utility-approved daily imbalance adjustment quantity. The customer's monthly imbalance is defined as the difference between the customer's total monthly metered quantity, including the effect of any adjustment for cycle billing of the customer's meters and the customer's total monthly scheduled transportation quantity. The portion of any imbalance quantity established by a customer in excess of the applicable monthly operating window is defined as an excess imbalance quantity. In addition to the charges payable under this schedule and the customer's otherwise applicable sales schedule, any monthly excess imbalance quantity shall be billed as follows:

Schedule No. T-1

TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS
(Continued)

7. TRANSPORTATION IMBALANCE SERVICE *(Continued)*

(ii) The weighted average cost of gas for the highest incremental purchases during the same month. The average will be determined by first weighting the highest priced gas purchased by the Utility during the month by the number of therms purchased at that price. The total therms to be allocated in this manner are equivalent to the total number of negative excess imbalance therms to be cashed out for the month. The weighted average cost of gas will also include any applicable upstream interstate transportation charges, such as fuel and variable transportation charges. A charge equal to the Utility's monthly average interstate transportation reservation cost is also included in the weighted average cost of gas.

7.3 Subject to mitigation through imbalance trading, if a customer is assessed an imbalance charge based on Utility billing information that is later determined to be in error, the portion of the imbalance charge not assessable based on the corrected billing information shall be reversed on the customer's bill without interest. If a customer is not assessed an imbalance charge based on Utility billing information that is later determined to be in error, the customer shall be billed for any applicable imbalance charges determined to be assessable based on the revised billing information. The original negative imbalance charge rate that is calculated for the applicable month will be used in any subsequent billings.

7.4 Should a customer elect to discontinue taking service under this schedule and change to a sales service schedule, the Utility may allow, in its sole good faith judgment, any remaining imbalance within the applicable operating window to be cleared as follows:

(a) The Utility shall credit the customer for any positive imbalance quantity at a price equal to the lowest incremental cost of gas purchased by the Utility during the prior month for gas delivered to the Utility within the state of Arizona.

(b) For any remaining negative imbalance quantity, the customer shall pay the Utility for the imbalance quantity at the otherwise applicable gas sales tariff rate.

(c) The customer may trade any remaining imbalance pursuant to this section; however, if a customer does not enter into a trade for any remaining imbalance quantity, the Utility will clear the remaining imbalance by utilizing paragraph (a) or (b) above, as applicable.

FORM OF SERVICE AGREEMENT APPLICABLE TO TRANSPORTATION SERVICE UNDER SCHEDULE NO. T-1

This is an AGREEMENT made and entered into as of the ____ day of , _____ , __ by and between SOUTHWEST GAS CORPORATION, a California corporation, herein called the Utility, and, ________________________________ herein called the Customer.

WITNESSETH:

In consideration of the mutual covenants and agreements as herein set forth, the Utility and the Customer agree as follows:

ARTICLE I - GAS TO BE TRANSPORTED

Subject to the terms, conditions and limitations hereof, the Utility agrees to receive from the Customer, or for the Customer's account, at the interconnection between the Utility and El Paso Natural Gas Company (herein called Receipt Point), for transportation, a quantity of natural gas daily, which shall not exceed the Customer's Maximum Daily Quantity as shown on Exhibit A.

At the Customer's request, the Utility shall thereupon transport the equivalent quantity of gas through its pipeline system and deliver the equivalent quantity to the Customer or for the account of the Customer at the Delivery Point(s) specified herein. The Utility shall not be obligated to receive and/or transport quantities of gas in excess of the Maximum Daily Quantity.

ARTICLE II - DELIVERY POINTS, PRESSURES AND QUANTITIES

Delivery of natural gas by the Utility to the Customer shall be at or near the points whose locations, delivery pressures, assumed atmospheric pressures, and maximum quantity per day are described on Exhibit A.

APPLICABLE TO TRANSPORTATION SERVICE
UNDER SCHEDULE NO. T-1
(Continued)

ARTICLE III- APPLICABLE TRANSPORTATION RATES AND RATE SCHEDULE

The Customer agrees to pay the Utility for all natural gas transportation service rendered under the terms of this Agreement in accordance with the Utility's Schedule No. T-1, as filed with the Arizona Corporation Commission, and as amended or superseded from time to time. The transportation rate to be charged pursuant to Section 3 of Schedule No. T-1 is set forth in Exhibit A, which may be amended by mutual agreement of the parties. This Agreement shall be subject to the provisions of such rate schedule and the Rules and Regulations applicable thereto on file with the Arizona Corporation Commission and effective from time to time, which by this reference are incorporated herein and made a part hereof. Customer has executed a Service Agreement and purchases natural gas from the Utility under Schedule No. ___ set forth in the Utility's Arizona Gas Tariff on file with the Arizona Corporation Commission as revised and approved from time to time.

ARTICLE IV - TERM OF AGREEMENT

This Agreement shall become effective on __________ and shall continue in effect for a period extending for a primary term to and including ____________ , and from month to month thereafter, subject, however, to termination at expiration of the said primary term or upon the first day of any calendar month thereafter by either party hereto through written notice so stating and given to the other no less than __________ in advance.

ARTICLE V - NOTICES

Unless herein provided to the contrary, any notice called for in this Agreement shall be in writing and shall be considered as having been given if delivered personally, or by mail, facsimile or telegraph with all postage and charges prepaid, to either the Customer or the Utility at the place designated. Routine communications shall be considered as duly delivered when mailed by ordinary mail. Normal operating instructions can be made by telephone. Unless changed, the addresses of the parties are as follows:

Southwest Gas Corporation
P.O. Box 98510
Las Vegas, Nevada 89193-8510
Attn: Large Customer Sales
Phone No.: (702) 876-7149
Fax No.: (702) 873-3820

____
"Customer"

Attn: ________________________
Phone No.: ____________________
Fax No.: ______________________

Either party may change its address at any time upon written notice to the other.

FORM OF SERVICE AGREEMENT APPLICABLE TO TRANSPORTATION SERVICE UNDER SCHEDULE NO. T-1

(Continued)

ARTICLE VI - OTHER OPERATING PROVISIONS

A. TELEMETRY SIGNALS

The Utility will provide a data signal to the Customer representing gas volumes the use of which shall be restricted as follows:

The Customer agrees that the data signal provided by the Utility shall be used for informational purposes only and shall not under any circumstances be used for process control of any kind. The Utility makes no guarantees of warranties as to the quality, accuracy and/or reliability of the data signal, and the Customer shall indemnify and hold harmless the Utility, its directors, officers, employees and agents against any and all loss or damage incurred by the Customer arising out of or in any manner connected with data signal operation or failure to operate and its effect upon the customer's equipment which may be interfaced to receive the data signal. The Customer further acknowledges that the data signal may differ from the billing registration due to periodic maintenance interruptions or other causes.

B. CONFIDENTIALITY

Neither the Utility nor the Customer, nor their respective affiliates, directors, officers, employees, agents or permitted assignees shall disclose to any third party the terms and provisions of this Agreement without the other party's prior written consent provided, however, that the Utility may make such disclosure of the terms and provisions of this Agreement to the Arizona Corporation Commission as in the opinion of counsel to the Utility is required by applicable law, rule or regulation, and provided that with respect to any such disclosure to the Arizona Corporation Commission, the Utility shall take all steps reasonably available to maintain the confidentiality of this Agreement and prevent its disclosure to third parties; and provided further that the Customer make such disclosure as required by law, and on a confidential basis, of the terms and provisions of this Agreement to prospective lenders and their consultants and attorneys.

C. OTHER PROVISIONS

(To be utilized when necessary to specify other operating provisions.)

FORM OF SERVICE AGREEMENT APPLICABLE TO TRANSPORTATION SERVICE UNDER SCHEDULE NO. T-1

(Continued)

ARTICLE VII - ADJUSTMENTS TO RULES AND REGULATIONS

Notwithstanding the provisions of Article XI hereof, certain of the Rules applicable to the transportation rate schedule are to be adjusted for the purpose of this Agreement, as specified below:

ARTICLE VIII - PRIOR AGREEMENTS

The Customer recognizes that the Utility has existing agreements and working relationships with its supplier pipeline companies, and the Utility agrees to cooperate reasonably with them for the purpose of receiving, transporting and delivering the Customer's gas in a practical and efficient manner. Nothing in this Agreement shall be construed in any manner as limiting or modifying the rights or obligations of either party under the Utility's Rate Schedule No. G-____ on file with the Arizona Corporation Commission and any service agreement executed by the parties for service thereunder.

When this Agreement takes effect, it supersedes, cancels and terminates the following agreement(s):

ARTICLE IX - REGULATORY REQUIREMENTS

The Customer shall not take any action which would subject the Utility to the jurisdiction of the Federal Energy Regulatory Commission, the Department of Energy or any successor governmental agency. Any such action shall be cause for immediate termination of this Agreement. This Agreement, all terms and provisions contained or incorporated herein, and the respective obligations of the parties hereunder are subject to all valid laws, orders, rules and regulations of duly constituted authorities having jurisdiction over the subject matter of this Agreement. This Agreement shall at all times be subject to such changes or modifications by the Arizona Corporation Commission as it may from time to time direct in the exercise of its jurisdiction.

Should the Federal Energy Regulatory Commission, the Arizona Corporation Commission or any other regulatory or successor governmental agency having jurisdiction impose by rule, order or regulation any terms or conditions upon this Agreement which are not mutually satisfactory to the parties, then either party upon the issuance of such rule, order or regulation, and notification to the other party, may terminate this Agreement.

FORM OF SERVICE AGREEMENT
APPLICABLE TO TRANSPORTATION SERVICE
UNDER SCHEDULE NO. T-1
(Continued)

ARTICLE X - SUCCESSORS AND ASSIGNS

This Agreement shall be binding upon and inure to the benefit of the parties hereto and their respective successors and assigns. No assignment or transfer by either party hereunder shall be made without written approval of the other party. Such approval shall not be unreasonably withheld. As between the parties hereto, such assignment shall become effective on the first day of the month following written notice that such assignment has been effectuated.

ARTICLE XI - RULES

The standard Rules of the Utility as authorized by and on file with the Arizona Corporation Commission in the Utility's Arizona Gas Tariff shall apply to the transaction to be performed hereunder and are hereby incorporated by reference into this Agreement, except as otherwise provided in this Agreement.

SOUTHWEST GAS CORPORATION "The Utility"	______________________ "Customer"
By: ______________________	By: ______________________
Title: ______________________	Title: ______________________
Date: ______________________	Date: ______________________

EXHIBIT A

SOUTHWEST GAS CORPORATION
STATEMENT OF EFFECTIVE RATES
SCHEDULE NO. T-1
TRANSPORTATION OF CUSTOMER-SECURED NATURAL GAS

CURRENTLY EFFECTIVE RATES	Amount
Basic Service Charge/Month	$ ____________
Transportation Service Charge/Month	$ ____________
Demand Charge/Month	$ ____________
Volumetric Charge/Therm	$ ____________
Effective Date:	$ ____________

Delivery Point(s)	Delivery Pressure (psig)	Atmospheric Pressure (psia)	Maximum Delivery Point Quantity per Day (Therms)	Therms by Priority

Date Issued:
Customer:

SOUTHWEST GAS CORPORATION "Utility" ______________________ "Customer"

By: ______________________ By: ______________________

Title: ______________________ Title: ______________________

Date: ______________________ Date: ______________________

ALTERNATE SERVICE AGREEMENT
APPLICABLE TO TRANSPORTATION SERVICE
UNDER SCHEDULE NO. T-1

This is an AGREEMENT made and entered into as of the ____ day of , _____ , ___ by and between SOUTHWEST GAS CORPORATION, a California corporation, herein called the Utility, and ______________________________________, herein called the Customer.

WITNESSETH:

In consideration of the mutual covenants and agreements as herein set forth, the Utility and the Customer agree as follows:

ARTICLE I – GAS TO BE TRANSPORTED

Subject to the terms, conditions and limitations hereof, the Utility agrees to receive from the Customer, or for the Customer's account, at the interconnection between the Utility and El Paso Natural Gas Company (herein called Receipt Point), for transportation, a quantity of natural gas daily, which shall constitute the Customer's Maximum Daily Quantity as shown on Exhibit A.

ARTICLE II – DELIVERY POINTS AND PROVISIONS OF SERVICE

Delivery of natural gas by the Utility to the Customer shall be at or near the points whose locations, delivery pressures, assumed atmospheric pressures, and maximum quantity per day are described on Exhibit A.

ARTICLE III – APPLICABLE TRANSPORTATION RATES AND RATE SCHEDULE

The Customer agrees to pay the Utility for all natural gas transportation service rendered under the terms of this Agreement in accordance with the Utility's Schedule No. T-1, as filed with the Arizona Corporation Commission and as amended or superseded from time to time. The transportation rate to be charged pursuant to Section 3 of Schedule No. T-1 is set forth in Exhibit A.

ALTERNATE SERVICE AGREEMENT
APPLICABLE TO TRANSPORTATION SERVICE
UNDER SCHEDULE NO. T-1
(Continued)

ARTICLE IV – TERM OF AGREEMENT

This Agreement shall become effective on __________ and shall continue in effect for a period extending for a primary term to and including ____________, and from month to month thereafter, subject, however, to termination at expiration of the said primary term or upon the first day of any calendar month thereafter by either party hereto through written notice so stating and given to the other no less than thirty (30) days in advance.

ARTICLE V – NOTICES

Unless herein provided to the contrary, any notice called for in this Agreement shall be in writing and shall be considered as having been given if delivered personally, or by mail, or facsimile to either the Customer or the Utility at the place designated. Routine communications shall be considered as duly delivered when mailed by ordinary mail. Normal operating instructions can be made by telephone. Either party may change its address at any time upon written notice to the other; unless changed, the addresses of the parties are as follows:

Southwest Gas Corporation	______________________________
P.O. Box 98510	"Customer"
Las Vegas, Nevada 89193-8510	
Attn: Large Customer Sales	Attn: ________________________
Phone No.: (702) 876-7149	Phone No.: ____________________
Fax No.: (702) 873-3820	Fax No.: ______________________
E-mail Address:	E-mail Address: _______________

ARTICLE VI – PRIOR AGREEMENTS

When this Agreement takes effect, it supersedes, cancels and terminates the following agreement(s):

ALTERNATE SERVICE AGREEMENT APPLICABLE TO TRANSPORTATION SERVICE UNDER SCHEDULE NO. T-1

(Continued)

ARTICLE VII – REGULATORY REQUIREMENTS

The Customer shall not take any action which would subject the Utility to the jurisdiction of the Federal Energy Regulatory Commission, the Department of Energy or any successor governmental agency. Any such action shall be cause for immediate termination of this Agreement. This Agreement is subject to all valid laws, orders, rules and regulations of duly constituted authorities having jurisdiction over the subject matter of this Agreement. This Agreement shall at all times be subject to such changes or modifications by the Arizona Corporation Commission as it may direct in the exercise of its jurisdiction.

ARTICLE VIII – SUCCESSORS AND ASSIGNS

This Agreement shall be binding upon and inure to the benefit of the parties hereto and their respective successors and assigns. No assignment or transfer by either party hereunder shall be made without written approval of the other party. Such approval shall not be unreasonably withheld. As between the parties hereto, such assignment shall become effective on the first day of the month following written notice that such assignment has been effectuated.

SOUTHWEST GAS CORPORATION "The Utility"	______________________ "Customer"
By: ______________________	By: ______________________
Title: ______________________	Title: ______________________
Date: ______________________	Date: ______________________

SPECIAL SUPPLEMENTARY TARIFF
PURCHASED GAS COST ADJUSTMENT PROVISION

APPLICABILITY

This Purchased Gas Cost Adjustment Provision ("PGA") shall apply to all schedules except for Schedule Nos. G-30, G-60 and G-80 of this Arizona Gas Tariff.

CHANGE IN RATES

Sales rate schedules covered by this provision include a base cost of gas ("BCOG") of $.37034 per therm. In accordance with Decision Nos. 61225 and 61711, a monthly adjustment to the BCOG will be made through a change in the Purchased Gas Adjustment ("PGA") rate that is based upon the rolling twelve-month average of actual purchased gas costs and sales. In accordance with Decision No. 62994, the PGA rate calculated for the month cannot be more than $.10 per therm different than any PGA rate in effect during the preceding twelve months.

BANK BALANCE

The Utility shall establish and maintain a Gas Cost Balancing Account, if necessary, for the schedules subject to this provision. Entries shall be made to this account each month, if appropriate, as follows:

1. A debit or credit entry equal to the difference between (a) the actual purchased gas cost for the month and (b) an amount determined by multiplying the average purchased gas cost included in the sum of the Base Tariff Rate Gas Cost and the Monthly Gas Cost Adjustment as set forth on Sheet Nos. 11 and 12 of this Arizona Gas Tariff by the therms billed during the month under the applicable schedules of this Arizona Gas Tariff.
2. A debit or credit entry equal to the therms billed during the month under the applicable schedules of this Arizona Gas Tariff, multiplied by the Gas Cost Balancing Account Adjustment, if any, reflected in the rates charged during the month.
3. A debit or credit entry for refunds or payments authorized by the Commission.
4. A debit or credit entry for interest to be applied to over- and under-collected bank balances based on the non-financial three-month commercial paper rate for each month contained in the Federal Reserve Statistical Release, G-13, or its successor publication.

SPECIAL SUPPLEMENTARY TARIFF
INTERSTATE PIPELINE CAPACITY SERVICES PROVISION

I. TITLE ASSIGNMENT SERVICE

A. APPLICABILITY

This Title Assignment Service provision shall apply only to natural gas transportation customers with Title Assignment Operating Agreements executed with the Utility prior to April 1, 1993, in conjunction with an executed service agreement pursuant to Schedule No. T-1, Transportation of Customer-Secured Natural Gas. It specifies the procedures to be utilized by the Utility in providing upstream pipeline firm transportation service to eligible Title Assignment transportation customers and recovering associated costs from such customers. This Title Assignment Service provision is closed to new customers.

B. CHARACTER OF SERVICE

1. The Utility will provide eligible transportation customers access to the Utility's upstream pipeline firm transportation capacity and service subject to the provisions and limitations set forth in this provision, Schedule No. T-1 and Rule No. 7 of this Arizona Gas Tariff. Upstream pipeline firm transportation service under this provision is available on a recallable basis only.

2. Title Assignment Service shall be recalled by the Utility only to protect service to Priority 1 and 2 customers pursuant to the provisions of Schedule No. T-1 and Rule No. 7 of this Arizona Gas Tariff, and in force majeure conditions which may occur from time to time on the upstream pipeline system.

C. TERRITORY

Throughout the certificated area served by the Utility in the communities as set forth on A.C.C. Sheet No. 8 of this Arizona Gas Tariff.

D. TERM

1. The minimum term for transportation customers electing service under this provision is 24 months.

SPECIAL SUPPLEMENTARY TARIFF
INTERSTATE PIPELINE CAPACITY SERVICES PROVISION
(Continued)

I. TITLE ASSIGNMENT SERVICE (Continued)

D. TERM *(Continued)*

2. The minimum requirement for notice of termination of Title Assignment Service shall be by written notice from the customer at least 24 months prior to the start of any calendar month.

E. RATES FOR TITLE ASSIGNMENT SERVICE

1. Title Assignment customers shall elect a Daily Contract Demand Quantity (DCDQ), not to exceed the maximum daily quantity specified in their respective transportation service agreement.

2. Title Assignment customers shall pay the Utility monthly the sum of the following charges for service under this provision:

   a. Reservation Charge: A monthly demand charge equal to the customer's DCDQ multiplied by the currently effective interstate pipeline(s) reservation charges for firm transportation, including applicable surcharges.

   b. Volume Charge: A rate per therm for all quantities transported by the Utility on behalf of the customer on the upstream pipeline(s) during the month, which includes the currently effective usage charges for firm upstream pipeline transportation service plus any applicable surcharges.

3. The customer's maximum daily entitlement for Title Assignment Service pursuant to this provision shall be equal to the DCDQ elected by the customer.

4. In the event that Title Assignment Service is recalled by the Utility, the customer shall receive a Reservation Charge credit to their regular monthly bill based on the pro rata portion of the capacity recalled to such customer's total DCDQ.

SPECIAL SUPPLEMENTARY TARIFF
INTERSTATE PIPELINE CAPACITY SERVICES PROVISION
(Continued)

I. TITLE ASSIGNMENT SERVICE (Continued)

F. CHANGES IN RATES

The Utility will revise rates for Title Assignment Service as necessary to reflect Federal Energy Regulatory Commission (FERC) authorized changes in upstream pipeline transportation rates and billing determinants. Any refunds received from upstream pipelines will be allocated on the basis of the customer's Title Assignment volumes billed during the refund period.

G. ACCOUNTING FOR TITLE ASSIGNMENT REVENUES

All revenues received by the Utility in providing service under this provision shall be credited to Account No. 191, Unrecovered Purchased Gas Costs.

II. CAPACITY RELEASE SERVICE

A. APPLICABILITY

The purpose of this Capacity Release Service provision is to govern the release of interstate pipeline capacity in excess of the requirements of the Utility's Title Assignment and Priority 1 and 2 customers. The Utility shall identify and offer for release any available interstate pipeline capacity reserved to serve such customers for the purpose of minimizing the overall cost of upstream interstate pipeline capacity.

1. Capacity released pursuant to this provision shall be made available on a non-discriminatory basis. As a condition precedent to obtaining released capacity under this provision, on-system transportation customers of the Utility must execute a transportation service agreement pursuant to Schedule No. T-1, Transportation of Customer-Secured Gas, and must comply with all applicable terms and conditions contained in this Arizona Gas Tariff.

2. In order to acquire any of the Utility's firm interstate pipeline capacity released under this provision, acquiring shippers must demonstrate to the Utility that they have met the creditworthiness and other requirements of the applicable interstate pipeline(s) and such other credit standards that the Utility may deem appropriate.

SPECIAL SUPPLEMENTARY TARIFF
INTERSTATE PIPELINE CAPACITY SERVICES PROVISION
(Continued)

II. CAPACITY RELEASE SERVICE (Continued)

A. APPLICABILITY (Continued)

3. Capacity release pursuant to this provision is subject to all FERC rules and regulations and the specific terms and conditions governing capacity release on the interstate pipeline system(s).

B. RATES AND BIDDING PROCEDURES

1. The Utility shall identify excess interstate pipeline capacity available for release on a monthly basis and from time-to-time more frequently thereafter as necessary to pre-arrange the release of any remaining available capacity. The Utility reserves the right to not release capacity if market conditions so warrant, or if the Utility is seeking to reduce its billing determinant or contract demand on the upstream interstate pipeline(s).

2. The Utility shall determine the minimum acceptable bid price for released capacity. The minimum acceptable bid represents the floor price for the Utility's consideration of any particular bid. The minimum acceptable bid shall be the greater of a., b. or c. below:

   a. The Utility's best determination of the current market value for such released capacity, based on a comparison of the price of completed bids of a like nature and term posted to the applicable interstate pipeline's electronic bulletin board.

   b. When an interruptible transportation crediting mechanism exists on the upstream interstate pipeline and, therefore, interruptible transportation credits could be earned if such capacity was not released, a bid price equal to the current market rate for interruptible transportation service.

   c. If the Utility is able to determine the cost allocation methodology that will be utilized by the upstream pipeline to develop future interstate pipeline charges, the Utility reserves the right to adjust the minimum acceptable bid price to protect the interests of its Priority 1 and Priority 2 gas sales customers.

SPECIAL SUPPLEMENTARY TARIFF
INTERSTATE PIPELINE CAPACITY SERVICES PROVISION
(Continued)

II. CAPACITY RELEASE SERVICE *(Continued)*

B. RATES AND BIDDING PROCEDURES *(Continued)*

3. The release of interstate pipeline capacity for a term of more than one month shall be accomplished according to the following procedures.

   a. The Utility shall offer to prearrange the release of interstate pipeline capacity at rates greater than or equal to the minimum acceptable bid for the release period being considered. All bids below the minimum acceptable bid floor shall be rejected. Bids for prearranged capacity release shall be accepted based on the highest price offered. If more than one bid is received at the same price, bids shall be accepted based on the longest term offered. Bids of an identical price and term shall be accepted on a pro rata basis up to the amount of capacity available for release.

   b. Successful prearranged bids shall then be submitted to the applicable interstate pipeline for posting on its electronic bulletin board.

      (1) Unless the bid price is equal to the interstate pipeline's full "as-billed" rate, other eligible parties will be allowed by the pipeline to submit bids higher than that of the prearranged shipper. If prearranged bids are outbid by another party, the prearranged bidder shall have the right of first refusal to match the higher bid and thereby acquire the released capacity.

      (2) If the higher bid is not matched, the award shall be made to the higher bidder(s) pursuant to the established bid evaluation and (or) "tie breaker" procedures of the interstate pipeline.

   c. Any remaining capacity available for release shall then be posted for open bidding to the applicable interstate pipeline electronic bulletin board at the minimum acceptable bid price determined according to Section B.2 above.

SPECIAL SUPPLEMENTARY TARIFF
INTERSTATE PIPELINE CAPACITY SERVICES PROVISION
(Continued)

II. CAPACITY RELEASE SERVICE *(Continued)*

B. RATES AND BIDDING PROCEDURES *(Continued)*

4. The Utility reserves the right to prearrange from time-to-time the release of excess capacity for a term of one month or less. Capacity released for a term of one month or less shall be subject to all FERC and interstate pipeline rules and regulations governing such releases, and shall be at rates greater than or equal to the minimum acceptable bid.

C. BILLING

Billing for released capacity shall be made by the interstate pipeline directly to acquiring customers and shippers. Shippers acquiring released capacity shall be billed by the pipeline at the accepted bid price plus applicable usage charges and surcharges. The Utility will receive credit from the interstate pipeline for the payment of reservation charges and reservation surcharges due from the acquiring shipper.

D. RECALL OF RELEASED CAPACITY

Capacity released by the Utility shall be recallable over the term of the release under the following conditions:

1. Force majeure situations occurring on the upstream pipeline system; or

2. To protect service to Priority 1 and Priority 2 customers; or

3. When the Utility's core demand for upstream pipeline capacity is greater than the Utility's current billing determinant or contract demand on the applicable interstate pipeline(s); or

4. If the acquiring shipper fails to remit payment for services rendered to the interstate pipeline when such amounts are due.

SPECIAL SUPPLEMENTARY TARIFF
INTERSTATE PIPELINE CAPACITY SERVICES PROVISION
(Continued)

II. CAPACITY RELEASE SERVICE (Continued)

E. ACCOUNTING FOR CAPACITY RELEASE CREDITS

All capacity release credits received by the Utility shall be credited to Account No. 191, Unrecovered Purchased Gas Costs.

HELD FOR FUTURE USE

RULE NO. 1

DEFINITIONS

For the purpose of these Tariffs, the terms and expressions listed below shall have the meanings set forth opposite:

Advance in Aid of Construction:	Funds provided to the Utility by an applicant for service under the terms of a main extension agreement, the amount of which may be refundable.
Alternate Fuel Capability:	A situation where an alternate fuel can be utilized whether or not the facilities for such use have actually been installed.
Applicant:	A person requesting the Utility to supply natural gas service.
Application:	A request to the Utility for natural gas service, as distinguished from an inquiry as to the availability or charges for such service.
Arizona Corporation Commission:	The regulatory authority of the State of Arizona having jurisdiction over the public service corporations operating in Arizona.
Average Month:	30.4 days.
Base Gas Supply:	Natural gas purchased by the Utility from its primary supplier.
Basic Service Charge:	A fixed amount a customer must pay the Utility for the availability of gas service, independent of consumption, as specified in the Utility's tariffs.
Billing Month:	The period between any two regular readings of the Utility's meters at intervals of approximately 30 days.
Billing Period:	The time interval between two consecutive meter readings that are taken for billing purposes.

RULE NO. 1

DEFINITIONS
(Continued)

Electronic Billing Service Provider:	An agent of the Utility that provides electronic bill presentment and payment service for the Utility and serves as a common link between the Utility and the customer.
Electronic Transfer:	Paperless exchange of data and/or funds.
Essential Agricultural Use:	Any use of natural gas which is certified by the Secretary of Agriculture as an "essential agricultural use."
Essential Industrial Process "process and Feedstock Uses:	Any use of natural gas by an industrial customer as gas" or as feedstock, or gas used for human comfort to protect health and hygiene in an industrial installation.
Excess Flow Valve:	A device designed to restrict the flow of gas in a customer's natural gas service line by automatically closing in the event of a service line break, thus mitigating the consequences of service line failures.
Expedited Service:	Service that is generally performed on the same workday the request for service is made. There may be instances where Company scheduling will not permit same day service; however, in no case will expedited service take longer than 24 hours from the time requested.
Farm Tap:	A service connection from a company distribution or transmission line operating at higher than normal distribution pressure, thereby requiring regulation and/or pressure limiting devices before the customer can be served.
Feedstock Gas:	Natural gas used as a raw material for its chemical properties in creating an end product.

RULE NO. 1

DEFINITIONS
(Continued)

Inability to Pay: Circumstances where a residential customer:

1. Is not gainfully employed and unable to pay, or

2. Qualifies for government welfare assistance, but has not begun to receive assistance on the date that he receives his bill and can obtain verification from the government welfare assistance agency, or

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

4. Signs a declaration verifying that he meets one of the above criteria and is either elderly, handicapped, or suffers from an illness.

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

Industrial Customer: A customer who is engaged primarily in a process which creates or changes raw or unfinished materials into another form or product, including electric power generation.

Intra-day Nomination: A Nomination submitted after the nominating deadline for Daily and Standing Nominations specified in Section 6.1 of Schedule T-1 which has an effective time no earlier than the beginning of the next Gas Day, and which has an ending time no later than the end of that Gas Day.

RULE NO. 1

DEFINITIONS
(Continued)

Meter:	The instrument for measuring and recording the volume of natural gas that has passed through it.
Meter Tampering:	A situation where a meter or meter piping has been illegally altered. Common examples are meter bypassing and other unauthorized connections.
Minimum Charge:	The amount the customer must pay for the availability of gas service as specified in the Utility's tariffs.
Mobile Home:	A residential unit designed and built to be towed on its own chassis. It is without a permanent foundation and is designed for year-round living.
Monthly Operating Window:	A transportation operating constraint governing the allowable monthly difference between the customer's metered quantities and the sum of the customer's scheduled transportation quantities, plus any Utility-approved imbalance adjustment quantity. The Monthly Operating Window requires such difference to be within plus or minus 5 percent (±5%) of the month's total of daily scheduled transportation quantities, plus any Utility-approved imbalance adjustment quantity, or 1,500 therms, whichever is greater.
Mountain Clock Time (MCT):	Mountain Standard Time or Mountain Daylight Time, whichever is currently in effect in the majority of the Mountain Time Zone, regardless of which time the State of Arizona is operating under.
Off-Peak Irrigation Season:	The six-month period beginning October 1 and ending March 31.
Operating Day:	The 24-hour period beginning 7:00 a.m. Mountain Standard Time.
Ownership:	The legal right of possession or proprietorship of the premise(s) where service is established.
Peak Day:	Maximum daily consumption as determined by the best practical method available.

RULE NO. 1

DEFINITIONS
(Continued)

Peak Irrigation Season:	The six-month period beginning April 1 and ending September 30.
Permanent Customer:	A customer who is a tenant or owner of a service location who applies for and receives natural gas service in a status other than transient, temporary or agent.
Permanent Service:	Natural gas service which, in the opinion of the Utility, is of a permanent and established character. The use of gas may be continuous, intermittent or seasonal in nature.
Person:	Any individual, partnership, corporation, governmental agency, or other organization operating as a single entity.
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.
Point of Delivery:	The point where pipes owned, leased, or under license by a customer and which are subject to inspection by the appropriate city, county or state authority connect to the Utility's pipes or at the outlet side of the meter.

RULE NO. 1

DEFINITIONS
(Continued)

Police Protection Uses:	Natural gas used by law enforcement agencies in the performance of their appointed duties.
Preemption of Gas Supply:	An emergency condition where the Utility may, under specified conditions, utilize the customer-owned gas supplies of low priority transportation customers to serve the requirements of higher priority transportation and sales customers.
Premises:	All of the real property and apparatus employed in a single enterprise on an integral parcel of land undivided by public streets, alleys or railways.
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 purpose of this definition, propane and other gaseous fuels shall not be considered alternate fuels.
Regular Working Hours:	Except for Utility observed holidays, the period from 8 a.m. to 5 p.m., Monday through Friday.
Residential Subdivision:	Any tract of land which has been divided into four or more contiguous lots for use for the construction of residential buildings or permanent mobile homes for either single or multiple occupancy.
Residential Use:	Service to customers using natural 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.

RULE NO. 1

DEFINITIONS
(Continued)

Service Line:	A natural gas pipe that transports gas from a common source of supply (normally a distribution main) to the customer's point of delivery.
Service Line Extension:	Consists of a service line provided for a new customer at a premise not heretofore served, in accordance with the service line extension rule.
Service Establishment Charge:	A charge as specified in the Utility's tariffs for establishing a new account.
Service Reconnect Charge:	A charge as specified in the Utility's tariffs which must be paid by the customer prior to reconnection of natural gas service each time the service is disconnected for nonpayment or whenever service is discontinued for failure to comply with the Utility's tariffs.
Service Reestablishment Charge:	A charge as specified in the Utility's tariffs for service at the same location where the same customer had ordered a service disconnection within the preceding 12-month period.
Shrinkage:	The cost of the gas volumes lost, unaccounted for, or used as company fuel in the transportation process and represented by the differential between the cost of gas on a sales basis and the cost of gas on a purchased basis.
Single Family Dwelling:	A house, an apartment, a mobile home permanently affixed to a lot, or any other permanent residential unit.
Southwest Vista:	An Electronic Bulletin Board service for subscribing users with computers and modems to dial up over telephone lines and access the many features available. The bulletin board is a communication tool that can support many users simultaneously.

RULE NO. 1

DEFINITIONS
(Continued)

Standard Delivery Pressure:	0.25 pounds per square inch gauge at the meter or point of delivery.
Standard Mantle:	A mantle which consumes a maximum of 2.6 cubic feet of gas per hour.
Standing Nomination:	A Daily Nomination which is effective for multiple Gas Days. Standing Nominations cannot exceed the term of the customer's Transportation Service Agreement. A Standing Nomination can be replaced by a new Daily Nomination or Intra-day Nomination; however, upon the expiration of such replacement Nomination, the Standing Nomination becomes effective again.
Storage Injection Gas:	Natural gas injected by a distributor into storage for later use.
Subdivision:	An area for single family dwellings which may be identified by filed subdivision plans.
Summer Season:	The six-month period beginning May 1 and ending October 31.
Supplemental Gas Supply:	Natural gas purchased by the Utility from all sources other than the base gas supply.
Supply Curtailment:	A condition occurring when the demand for natural gas exceeds the available supply of gas. This condition can occur due to supply failure or upstream pipeline capacity curtailment.
Tariffs:	The documents filed with and approved by the Commission which list the rules, regulations, services and products offered by the Utility and which set forth the terms and conditions and a schedule of the rates and charges for those services and products.
Tariff Sheets:	The individual sheets included in the tariff.

RULE NO. 1

DEFINITIONS
(Continued)

Utility's Operating Convenience:	This term refers to the utilization, under certain circumstances, of facilities or practices not ordinarily employed which contribute to the overall efficiency of the Utility's operations. It does not refer to customer convenience nor to the use of facilities or adoption of practices required to comply with applicable laws, ordinances, rules or regulations, or similar requirements of public authorities.
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, indicates that the temperature will not exceed 32 degrees Fahrenheit for the next day's forecast. The Commission may determine that other weather conditions are especially dangerous to health as the need arises.
Winter Season:	The six-month period beginning November 1 and ending April 30.
Workday:	The time period between 8 a.m. and 5 p.m., Monday through Friday, excluding holidays.

RULE NO. 3

ESTABLISHMENT OF SERVICE

A. INFORMATION FROM APPLICANTS

1. The Utility may request the following minimum information from each new applicant for service:

   a. Name or names of applicant(s), including information regarding spouse and/or roommate(s).

   b. Driver's license or other acceptable identification.

   c. Service address or location and telephone number.

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

   e. Address where service was provided previously.

   f. Date applicant will be ready for service.

   g. Indication of whether premises have previously been supplied with the Utility's service.

   h. Purpose for which service is to be used.

   i. Indication of whether applicant is owner or tenant of or agent for the premises.

   j. Information concerning the natural gas usage and demand requirements of the customers so as to determine which tariff schedule is applicable.

   k. Type and kind of life-support equipment, if any, used by the customer.

   l. Third party notification. If an applicant or customer who is elderly and/or handicapped lists a third party whom they wish notified in the event that their service is scheduled for discontinuance in accordance with Rule No. 10, such third party's name, address and telephone number shall be noted on the application for service.

RULE NO. 3

ESTABLISHMENT OF SERVICE
(Continued)

B. ESTABLISHMENT AND REESTABLISHMENT OF CREDIT/DEPOSITS *(Continued)*

a. Residential *(Continued)*

(2) When credit cannot be established to the satisfaction of the Utility, the applicant will be required to:

(a) Pay the deposit amount billed by the date specified on the bill or make acceptable payment arrangements, or

(b) Place a deposit utilizing cash or an acceptable credit card to secure payment of bills for service as prescribed herein, or

(c) Provide a surety bond acceptable to the Utility in an amount equal to the required deposit.

b. Nonresidential

(1) The Utility shall not require a deposit from a new applicant for nonresidential service if the applicant has had service of a comparable nature within the preceding 24 months at another service location with Southwest Gas and a satisfactory payment history was established.

(2) When a deposit is required from a new applicant for nonresidential service, the applicant will be required to:

(a) Pay the deposit amount billed by the date specified on the bill or make acceptable payment arrangements, or

(b) Place a deposit utilizing cash or an acceptable credit card to secure payment of bills for service as prescribed herein, or

(c) Provide security acceptable to the Utility for payment to the Utility in an amount equal to the required deposit.

2. Reestablishment of Credit

a. Former Customers with an Outstanding Balance

RULE NO. 3

ESTABLISHMENT OF SERVICE
(Continued)

B. ESTABLISHMENT AND REESTABLISHMENT OF CREDIT/DEPOSITS *(Continued)*

3. Deposits *(Continued)*

(1) Residential customer deposits shall not exceed two times the customer's estimated average monthly bill.

(2) Nonresidential customer deposits shall not exceed two and one-half times the customer's estimated maximum monthly bill.

b. The Utility may bill the customer for any required deposit amount provided that credit and payment arrangements have been made according to the Utility's policy and procedures.

c. Applicability to Unpaid Accounts

Deposits and interest prescribed herein will be applied to unpaid bills owing to the Utility when service is discontinued.

d. Refunds of Deposits

(1) Upon discontinuance of service, the Utility will refund any balance of the deposit, plus applicable interest, in excess of unpaid bills. The Utility will return any credit balance by check to the last known customer address.

(2) After a residential customer has, for 12 consecutive months, paid all bills without being delinquent more than twice, the Utility shall refund the deposit with earned interest within 30 days.

(3) After a nonresidential customer has, for 24 consecutive months, paid all bills prior to the next regular billing, the Utility shall refund the deposit with earned interest within 30 days.

(4) In the case of refunding a deposit which has been made by an agency from the Utility Assistance Fund (Fund) established by A.R.S. 46-731 to provide assistance for eligible customers, such deposit shall be refunded to the Fund. The standard Rules and Regulations of the Utility as authorized by the Arizona Corporation Commission shall apply to these refunds.

RULE NO. 3

ESTABLISHMENT OF SERVICE
(Continued)

B. ESTABLISHMENT AND REESTABLISHMENT OF CREDIT/DEPOSITS *(Continued)*

3. Deposits *(Continued)*

e. Interest on Deposits

The Utility will pay 6 percent interest on deposits from the date of deposit until the date of settlement or withdrawal of deposit. Where such deposit remains for a period of one year or more and the person making the deposit continues to be a customer, the interest on the deposit at the end of the year shall be applied to the customer's account.

f. The Utility may review the customer's usage after service has been connected and adjust the deposit amount based upon the customer's actual usage.

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

h. The Utility shall issue a non-negotiable receipt to the applicant for the deposit. The inability of the customer to produce such a receipt shall in no way impair his right to receive a refund of the deposit which is reflected on the Utility's records.

C. GROUNDS FOR REFUSAL OF SERVICE

1. The Utility may refuse to establish service if any of the following conditions exists:

a. The applicant has an outstanding amount due for the same class of service with the Utility and the applicant is unwilling to make satisfactory arrangements with the Utility for payment.

b. A condition exists which in the Utility's judgment is unsafe or hazardous to the applicant, the general population, or the Utility's personnel or facilities.

c. Refusal by the applicant to provide the Utility with a deposit when the customer has failed to meet the credit criteria for waiver of deposit requirements.

RULE NO. 3

ESTABLISHMENT OF SERVICE
(Continued)

C. GROUNDS FOR REFUSAL OF SERVICE (Continued)

d. Customer is known to be in violation of the Utility's tariffs filed with and approved by the Commission.

e. Failure of the customer to furnish such funds, service, equipment, and/or rights-of-way necessary to serve the customer and which have been specified by the Utility as a condition for providing service.

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

g. Where service has been discontinued for fraudulent use, in which case Rule No. 11 will apply.

h. If the intended use of the service is for any restricted apparatus or prohibited use.

2. Notification to Applicants or Customers

When an applicant or customer is refused service or service has been discontinued under the provisions of this rule, the Utility will notify the applicant or customer of the reasons for the refusal to serve and of the right of applicant or customer to appeal the Utility's decision to the Commission.

D. SERVICE ESTABLISHMENT, REESTABLISHMENT OR RECONNECTION

1. In order to partially cover the operating and clerical costs, the Utility shall collect a service charge whenever service is established, reestablished or reconnected as set forth and referred to as "Service Establishment Charge" in the currently effective Statement of Rates, A.C.C. Sheet No. 15 of this Arizona Gas Tariff. This charge will be applicable for (1) establishing a new account; (2) reestablishing service at the same location where the same customer had ordered a service disconnection; or (3) reconnecting service after having been discontinued for nonpayment of bills or for failure to otherwise comply with filed rules or tariff schedules.

RULE NO. 9

BILLING AND COLLECTION
(Continued)

K. EQUAL PAYMENT PLAN

1. The Equal Payment Plan (EPP) is available to all residential customers receiving (or applicants qualifying and applying to receive) natural gas service provided that the customer (applicant) has established credit to the satisfaction of the Utility.

2. Participation in the EPP is subject to approval by the Utility.

3. Customers may sign up for the EPP at any time of year. The EPP amount will be based on the annual estimated bill divided into 12 equal monthly payments.

4. The Utility will render its regular monthly billing statement showing both the amount for actual usage for the period and the designated EPP amount. The customer will pay his designated EPP amount, plus any additional amount shown on the bill for materials, parts, labor or other charges.

5. The settlement month will be the customer's anniversary date, 12 months from the time the customer entered the EPP. The settlement amount is the difference between the EPP payments made and the amount actually owing based on actual usage during the period the customer was billed under the EPP. All debit amounts are due and payable in the settlement month. However, debit amounts of $50 or less may be carried forward and added to the total annual estimated bill for the next EPP year. Credit amounts of $10 or less will be carried forward and applied against the first billing or billings due in the next EPP year. Credit amounts over $10 will be refunded by check.

6. The EPP amount may be adjusted quarterly to reduce the likelihood of an excessive debit or credit balance in the settlement month for changes in rates due to Commission-approved rate increases or decreases greater than 5 percent, or when estimates indicate that an overpayment or undercollection of $50 or more may occur by the end of the plan year.

7. The Utility may remove from the EPP and place on regular billing any customer who fails to make timely payments according to his EPP obligation. Such a customer will then be subject to termination of service in accordance with Rule No. 10 for nonpayment of a bill.

A

SOUTHWEST GAS CORPORATION
ARIZONA
INCREASE IN GROSS REVENUE REQUIREMENT
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description	Reference	Original Cost	Reconstruction Cost New Depreciated	50% Original Cost 50% RCND Fair Value	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	Adjusted Rate Base	B-1	$ 925,212,447	$ 1,417,642,156	$ 1,171,427,301	1
2	Adjusted Operating Income	C-1	$ 44,233,345	$ 44,233,345	$ 44,233,345	2
3	Current Rate of Return		4.78%	3.12%	3.78%	3
4	Required Operating Income		$ 86,957,942	$ 86,957,942	$ 86,957,942	4
5	Required Rate of Return	D-1	9.40%	6.13%	7.42%	5
6	Operating Income Deficiency (Ln 4 - Ln 2)				$ 42,724,598	6
7	Gross Revenue Conversion Factor	C-3			1.6573	7
8	Increase in Gross Revenue Requirements				$ 70,809,128	8

SOUTHWEST GAS CORPORATION
ARIZONA
SUMMARY OF THE OVERALL RESULTS OF OPERATIONS
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Recorded at 08/31/04 (b)	Adjustments (c)	Adjusted Amounts (d)	Deficiency (e)	Adjusted for Deficiency (f)	Line No.
1	Operating Revenue	$ 647,277,066	$ (324,411,088)	$ 322,865,978	$ 70,809,128	$ 393,675,106	1
2	Gas Cost	327,132,801	(327,132,801)	0	0	0	2
3	Operating Margin	$ 320,144,265	$ 2,721,713	$ 322,865,978	$ 70,809,128	$ 393,675,106	3
	Operating Expenses						
4	Other Gas Supply	$ 720,807	$ 19,584	$ 740,391	$ 0	$ 740,391	4
5	Distribution	75,753,130	2,827,336	78,580,466	0	78,580,466	5
6	Customer Accounts	33,133,096	870,183	34,003,279	155,858	34,159,137	6
7	Customer Service & Information	596,225	(47,730)	548,496	0	548,496	7
8	Sales	512,205	(512,205)	0	0	0	8
	Administrative and General						
9	Direct	6,967,455	25,845	6,993,300	0	6,993,300	9
10	System Allocable	41,676,104	3,811,798	45,487,902	0	45,487,902	10
	Depreciation and Amortization						
11	Direct	64,380,219	2,958,642	67,338,861	0	67,338,861	11
12	System Allocable	8,194,311	(1,131,728)	7,062,583	0	7,062,583	12
13	Regulatory Amortizations	887,124	661,080	1,548,204	0	1,548,204	13
14	Taxes Other Than Income	29,122,261	4,332,862	33,455,124	0	33,455,124	14
15	Interest on Customer Deposits	1,404,209	(686,844)	717,364	0	717,364	15
16	Income Taxes	6,290,071	(4,133,407)	2,156,664	27,928,672	30,085,336	16
17	Total Operating Expenses	$ 269,637,217	$ 8,995,416	$ 278,632,633	$ 28,084,530	$ 306,717,164	17
18	Net Operating Income	$ 50,507,047	$ (6,273,703)	$ 44,233,345	$ 42,724,598	$ 86,957,942	18
	Rate Base						
	Gas Plant in Service						
19	Direct	$ 1,597,681,797	$ (323,685)	$ 1,597,358,112		$ 1,597,358,112	19
20	System Allocable	87,176,689	969,345	88,146,033		88,146,033	20
21	Total Gross Plant	$ 1,684,858,486	$ 645,659	$ 1,685,504,145		$ 1,685,504,145	21
	Accumulated Provision for Depreciation and Amortization						
22	Direct	$ 546,303,859	$ (318,494)	$ 545,985,365		$ 545,985,365	22
23	System Allocable	47,556,640	0	47,556,640		47,556,640	23
24	Total Accumulated Provision for Depreciation and Amortization	$ 593,860,500	$ (318,494)	$ 593,542,006		$ 593,542,006	24
25	Net Plant in Service	$ 1,090,997,986	$ 964,153	$ 1,091,962,139		$ 1,091,962,139	25
	Other Rate Base Items						
26	Working Capital	$ 881,148	$ 0	$ 881,148		$ 881,148	26
27	Customer Advances	(7,027,372)	0	(7,027,372)		(7,027,372)	27
28	Customer Deposits	(23,912,141)	0	(23,912,141)		(23,912,141)	28
29	Deferred Taxes	(136,856,969)	165,641	(136,691,328)		(136,691,328)	29
30	Total Other Rate Base Items	$ (166,915,334)	$ 165,641	$ (166,749,693)		$ (166,749,693)	30
31	Total Rate Base	$ 924,082,652	$ 1,129,794	$ 925,212,447		$ 925,212,447	31
32	Rate of Return	5.47%		4.78%		9.40%	32

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SPREAD OF REVENUE INCREASE BY CUSTOMER CLASS
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Proposed Schedule Number (b)	Increase/(Decrease) [1] Dollars (c)	Increase/(Decrease) [1] Percent (d)	Line No.
	Sales Service				
1	Residential Gas Service	G-5	$ 50,863,570	15.46%	1
2	Low Income Residential Gas Service [3]	G-5	438,114	4.32%	2
3	Multi-Family Residential Gas Service	G-6	3,060,045	15.04%	3
4	Low Income Multi-Family Residential [3]	G-6	45,587	3.30%	4
	Master Metered Mobile Home Park				
5	Gas Service	G-20	134,393	6.12%	5
	General Gas Service	G-25			
6	Small		2,152,189	28.93%	6
7	Medium		3,745,616	8.64%	7
8	Large		5,248,248	4.30%	8
9	Transporation Eligible		1,577,631	2.56%	9
10	Optional Gas Service	G-30	66,740	0.11%	10
11	Air Conditioning Gas Service	G-40	29,983	2.61%	11
12	Street Lighting Gas Service	G-45	6,988	6.92%	12
	Gas Service for Compression on				
	Customer's Premises	G-55			
13	Small		1,983	1.56%	13
14	Large		65,232	4.93%	14
15	Residential		5,570	8.74%	15
16	Electric Generation Gas Service	G-60	215,137	2.70%	16
17	Small Essential Agriculture User Gas Service	G-75	112,672	5.17%	17
18	Natural Gas Engine Gas Service	G-80	(85)	(0.00%)	18
19	Total Sales and Full Margin Transportation		$ 67,769,613	21.87%	19
20	Special Contract Service	B-1	0	0.00%	20
21	Other Operating Revenue		1,250,597	12.28%	21
22	Plus Low Income Benefit		1,788,022	12.28%	22
23	Total Arizona Revenue		$ 70,808,232	10.40%	23

[1] Schedule H-1, Sheet 1.

SOUTHWEST GAS CORPORATION
ARIZONA
SUMMARY OF RESULTS OF OPERATIONS

Line No.	Description	Prior Years		Test Year		Projected Year		Line No.
		Year Ending 2002 [1]	Year Ending 2003 [1]	Actual 8/31/04 [2]	Adjusted 8/31/04 [2]	Present Rates 8/31/05 [3]	Proposed Rates 8/31/05 [3]	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
1	Operating Revenues	$ 652,504,295	$ 593,690,708	$ 320,144,265	$ 322,865,978	$ 323,345,708	$ 397,611,857	1
2	Operating Expenses and Taxes	251,716,903	256,669,683	269,637,217	278,632,633	283,152,150	312,603,213	2
3	Net Operating Income	$ 400,787,392	$ 337,021,025	$ 50,507,047	$ 44,233,345	$ 40,193,557	$ 85,008,644	3
4	Other Income and Deductions	0	0	0	0	0	0	4
5	Interest Expense	38,803,204	41,108,025	40,472,048	40,521,530	40,521,530	40,521,530	5
6	Net Income	$ 361,984,188	$ 295,913,000	$ 10,035,000	$ 3,711,815	$ (327,972)	$ 44,487,114	6

[1] Supporting Schedule E-2.
[2] Supporting Schedule C-1.
[3] Supporting Schedule F-1.
NOTE: Operating revenue and expenses reflected on a margin basis in columns (d), (e), (f), and (g).

SOUTHWEST GAS CORPORATION
TOTAL SYSTEM
SUMMARY RESULTS OF OPERATIONS [1]

Line No.	Description	Prior Years Year Ended 2002	Prior Years Year Ended 2003	Test Year 12 Months Ended 8/31/04	Line No.
	(a)	(b)	(c)	(d)	
1	Gross Revenues	$ 1,099,250,200	$ 1,021,747,900	$ 1,140,678,129	1
2	Revenue Deductions & Operating Expenses	982,736,543	911,849,697	1,022,058,924	2
3	Operating Income	$ 116,513,657	$ 109,898,203	$ 118,619,205	3
4	Other Income and (Deductions)	11,433,318	11,776,605	12,691,677	4
5	Income Before Interest Deductions	$ 127,946,975	$ 121,674,808	$ 131,310,882	5
6	Interest Expense	$ 85,871,787	$ 84,637,059	$ 84,320,115	6
7	Allowance for Debt Funds Used During Construction	1,889,720	1,463,996	1,055,527	7
8	Net Interest Expense	$ 83,982,067	$ 83,173,063	$ 83,264,588	8
9	Net Income	$ 43,964,908	$ 38,501,745	$ 48,046,294	9
10	Preferred and Preference Dividend Requirements	-	-	-	10
11	Net Income Applicable to Common Stock	$ 43,964,908	$ 38,501,745	$ 48,046,294	11
12	Weighted Average Shares of Common Stock Outstanding	32,593,192	33,759,895	34,517,648	12
13	Earnings per Common Share	$ 1.35	$ 1.14	$ 1.39	13
14	Dividends paid per Common Share	$ 0.82	$ 0.82	$ 0.82	14
15	Dividend Pay-out Ratio	61%	72%	59%	15
16	Return on Average Invested Capital	6.88%	5.98%	7.43%	16
17	Return on Year End Invested Capital	6.70%	6.11%	7.25%	17
18	Return on Average Common Equity	7.60%	6.28%	7.43%	18
19	Return on year End Common Equity	7.37%	6.11%	7.25%	19
20	Times Bond Interest Earned- Before Income Taxes	1.79	1.70	1.92	20
21	Times Total Interest and Preferred Dividend Earned - After Income Taxes	1.52	1.46	1.58	21

[1] In this proceeding, the Company is requesting rate relief for the Arizona rate jurisdiction of its system only. Projections for the total Company's financial position are not compiled or available.

SOUTHWEST GAS CORPORATION
TOTAL SYSTEM
SUMMARY OF CAPITAL STRUCTURE [1]

Line No.	Description	Prior Years At 12/31/02	Prior Years At 12/31/03	At 8/31/04	Projected At 8/31/05 [2]	Line No.
	(a)	(b)	(c)	(d)	(e)	
	Capital Amounts					
1	Short-Term Debt	$ 53,000,000	$ 52,000,000	$ 27,000,000	$ 47,700,000	1
2	Long-Term Debt	1,080,296,691	1,117,056,568	1,181,436,630	1,232,254,958	2
3	Total Debt	1,133,296,691	1,169,056,568	1,208,436,630	1,279,954,958	3
4	Preferred Equity	60,000,000	100,000,000	100,000,000	100,000,000	4
5	Common Equity	596,166,851	630,467,408	662,978,685	732,096,000	5
6	Total Capital	$ 1,789,463,542	$ 1,899,523,976	$ 1,971,415,315	$ 2,112,050,958	6
	Capitalization Ratios					
7	Short-Term Debt	2.96%	2.74%	1.37%	2.26%	7
8	Long-Term Debt	60.37%	58.81%	59.93%	58.34%	8
9	Total Debt					9
10	Preferred Equity	3.35%	5.26%	5.07%	4.73%	10
11	Common Equity	33.32%	33.19%	33.63%	34.66%	11
12	Total	100.00%	100.00%	100.00%	100.00%	12
	Weighted Cost of Capital					
13	Short-Term Debt	0.12%	0.09%	0.14%	0.10%	13
14	Long-Term Debt	4.38%	3.92%	4.00%	3.91%	14
15	Preferred Equity	0.32%	0.43%	0.42%	0.39%	15
16	Common Equity	3.98%	3.97%	4.02%	4.14%	16
17	Total Weighted Cost of Capital	8.79%	8.41%	8.57%	8.54%	17

[1] Based on the equity method of accounting
[2] Estimated

SOUTHWEST GAS CORPORATION
ARIZONA
CONSTRUCTION EXPENDITURES, PLANT PLACED IN SERVICE, AND GROSS PLANT
FOR THE YEARS ENDED DECEMBER 31, 2002 AND 2003,
THE TEST YEAR ENDED AUGUST 31, 2004
AND PROJECTED YEARS ENDING AUGUST 31, 2005, 2006 AND 2007

		Actual			Projected			
Line No.	Description	Year Ended 2002	Year Ended 2003	Test Year Ended 8/31/04	Year Ending 8/31/05	Year Ending 8/31/06	Year Ending 8/31/07	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
	Construction Expenditures							
1	Arizona Direct	$ 119,162,793	$ 105,512,194	$ 184,282,181	$ 124,380,422	$ 93,605,255	$ 73,905,730	1
2	System Allocable [1]	11,355,537	5,147,182	7,366,285	7,844,123	10,452,127	7,757,381	2
3	Total Construction Expenditures	$ 130,518,330	$ 110,659,376	$ 191,648,466	$ 132,224,545	$ 104,057,382	$ 81,663,111	3
	Net Plant Placed in Service							
4	Arizona Direct [1]	$ 104,143,667	$ 119,971,510	$ 139,021,712	$ 114,000,000	$ 82,000,000	$ 64,000,000	4
5	System Allocable [2]	3,935,236	18,660,126	2,699,058	6,679,250	9,788,556	6,909,569	5
6	Total Net Plant Placed in Service	$ 108,078,903	$ 138,631,636	$ 141,720,770	$ 120,679,250	$ 91,788,556	$ 70,909,569	6
	Gross Utility Plant in Service							
7	Arizona Direct	$ 1,396,818,551	$ 1,516,790,061	$ 1,597,681,797	$ 1,711,681,797	$ 1,793,681,797	$ 1,857,681,797	7
8	System Allocable [2]	66,221,396	84,881,522	87,176,689	93,855,939	103,644,495	110,554,064	8
9	Total Gross Utility Plant in Service	$ 1,463,039,947	$ 1,601,671,583	$ 1,684,858,486	$ 1,805,537,736	$ 1,897,326,292	$ 1,968,235,861	9

[1] The 2003 and Test Year 2004 Net Plant Placed in Service includes $23,974,224 for the Black Mountain Gas acquisition.
[2] Allocation based on the 4-Factor (57.58%)

SOUTHWEST GAS CORPORATION
TOTAL SYSTEM
SUMMARY STATEMENT OF CASH FLOWS [1]

Line No.	Description	Prior Years Year Ended 2002	Prior Years Year Ended 2003	Test Year 12 Months Ended 8/31/04	Line No.
	(a)	(b)	(c)	(d)	
1	Cash Flows from Operating Activities	$ 279,500,529	$ 151,759,633	$ 96,253,132	1
2	Cash Flows from Financing Activities	(239,904,161)	(211,928,184)	(235,138,929)	2
3	Cash Flows from Investing Activities	(50,886,754)	58,914,876	73,676,671	3
4	Increase (Decrease) in Cash and Cash Equivalents	$ (11,290,386)	$ (1,253,675)	$ (65,209,126)	4

[1] Supporting Schedule E-3.

B

SOUTHWEST GAS CORPORATION
ARIZONA
ADJUSTED ORIGINAL COST AND RCND RATE BASE
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Schedule Reference (b)	Adjusted Original Cost Rate Base (c)	RCND (d)	Fair Value [1] (e)	Line No.
1	Gas Plant in Service	B-2 & B-3	$ 1,685,504,145	$ 2,441,205,028	$ 2,063,354,587	1
2	Accumulated Depreciation and Amortization	B-2 & B-3	593,542,006	856,813,179	725,177,592	2
3	Net Gas Plant in Service		$ 1,091,962,139	$ 1,584,391,849	$ 1,338,176,994	3
	Additions					
4	Working Capital	B-5	$ 881,148	$ 881,148	$ 881,148	4
5	Total Additions		$ 881,148	$ 881,148	$ 881,148	5
	Deductions					
6	Customer Advances for Construction	B-6	$ (7,027,372)	$ (7,027,372)	$ (7,027,372)	6
7	Customer Deposits	B-6	(23,912,141)	(23,912,141)	(23,912,141)	7
8	Deferred Income Taxes	B-6	(136,691,328)	(136,691,328)	(136,691,328)	8
9	Total Deductions		$ (167,630,841)	$ (167,630,841)	$ (167,630,841)	9
10	Total Rate Base		$ 925,212,447	$ 1,417,642,156	$ 1,171,427,301	10

[1] 50/50 weighting to Original Cost and Reconstructed Cost.

SOUTHWEST GAS CORPORATION
ARIZONA
RECORDED RATE BASE, AS ADJUSTED
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Recorded at 08/31/04 (b)	Adjustments (c)	Adjusted at 08/31/04 (d)	Line No.
	Rate Base				
	Gas Plant in Service				
1	Direct	$ 1,597,681,797	$ (323,685)	$ 1,597,358,112	1
2	System Allocable	87,176,689	969,345	88,146,033	2
3	Total Gross Plant	$ 1,684,858,486	$ 645,659	$ 1,685,504,145	3
	Accumulated Provision for Depreciation and Amortization				
4	Direct	$ 546,303,859	$ (318,494)	$ 545,985,365	4
5	System Allocable	47,556,640	0	47,556,640	5
6	Total Accumulated Provision for Depreciation and Amortization	$ 593,860,500	$ (318,494)	$ 593,542,006	6
7	Net Plant in Service [1]	$ 1,090,997,986	$ 964,153	$ 1,091,962,139	7
	Other Rate Base Items				
8	Working Capital [2]	$ 881,148	$ 0	$ 881,148	8
9	Customer Advances [3]	(7,027,372)	0	(7,027,372)	9
10	Customer Deposits [3]	(23,912,141)	0	(23,912,141)	10
11	Deferred Taxes [3]	(136,856,969)	165,641	(136,691,328)	11
12	Total Other Rate Base Items	$ (166,915,334)	$ 165,641	$ (166,749,693)	12
13	Total Rate Base	$ 924,082,652	$ 1,129,794	$ 925,212,447	13

[1] Supporting Workpaper B-2
[2] Supporitng Schedule B-5
[3] Supporitng Schedule B-6

SOUTHWEST GAS CORPORATION
ARIZONA
SUMMARY COST OF GAS PLANT
AT AUGUST 31, 2004

Line No.	Description (a)	Account Number (b)	Balance at 08/31/04 (c) WP B-2	Adjustments (d) WP B-2	Adjusted Balance (e) WP B-2	Allocation Of System Allocable Amounts [1] (f)	Test Year Balance As Allocated at 08/31/04 (g)	Line No.
	Direct Gas Plant in Service							
1	Intangible Plant		$ 3,271,603	$ 431,082	$ 3,702,685	$ 61,170,431	$ 64,873,117	1
2	Distribution Plant		1,503,887,463	(998,279)	1,502,889,184	0	1,502,889,184	2
3	General Plant		90,522,731	243,512	90,766,242	26,975,602	117,741,844	3
4	Total Gas Plant in Service	101	$ 1,597,681,797	$ (323,685)	$ 1,597,358,112	$ 88,146,033	$ 1,685,504,145	4
	Accumulated Provision for Depreciation and Amortization							
5	Intangible Plant		$ 2,196,699	$ 0	$ 2,196,699	$ 34,769,569	$ 36,966,268	5
6	Distribution Plant		527,966,923	(318,494)	527,648,429	0	527,648,429	6
7	General Plant		16,140,237	0	16,140,237	12,787,072	28,927,309	7
8	Total Accumulated Depreciation and Amortization	108 & 111	$ 546,303,859	$ (318,494)	$ 545,985,365	$ 47,556,640	$ 593,542,006	8
9	Total Net Gas Plant In Service		$ 1,051,377,938	$ (5,191)	$ 1,051,372,747	$ 40,589,393	$ 1,091,962,139	9
	System Allocable Gas Plant in Service							
10	Intangible Plant		$ 104,762,572	$ 1,473,459	$ 106,236,031			10
11	General Plant		46,639,097	210,023	46,849,120			11
12	Total System Allocable Gas Plant	101	$ 151,401,669	$ 1,683,482	$ 153,085,151			12
	Accumulated Provision For Depreciation and Amortization							
13	Intangible Plant		$ 60,385,073	$ 0	$ 60,385,073			13
14	General Plant		22,207,588	0	22,207,588			14
15	Total System Allocable Accumulated Depreciation and Amortization	108 & 111	$ 82,592,661	$ 0	$ 82,592,661			15
16	System Allocable Net Gas Plant In Service		$ 68,809,008	$ 1,683,482	$ 70,492,490			16

[1] Allocated based on the 4-Factor. Supporting Schedule C-1, Sh 18

SOUTHWEST GAS CORPORATION
ARIZONA
COMPLETED CONSTRUCTION NOT CLASSIFIED
ADJUSTMENT NO. 20

Line No.	Description (a)	Account (b)		Completed Cost of Plant [1] (c)	Line No.
	Intangible Plant				
1	Franchise & Consents	302.0	$	431,082	1
2	Total Intangible Plant		$	431,082	2
	Distribution Plant				
3	Mains	376.0	$	1,145,356	3
4	Total Distribution Plant		$	1,145,356	4
	General Plant				
5	Structures	390.1	$	6,938	5
6	Computer Equipment	391.1		188,528	6
7	Tools, Shop, & Garage Equipment	394.0		22,979	7
8	Communication Equipment	397.0		5,251	8
9	Telemetering Equipment	397.2		5,834	9
10	Miscellaneous Equipment	398.0		13,982	10
11	Total General Plant		$	243,512	11
12	Total Arizona		$	1,819,949	12

Explanation - *To record direct Arizona non-revenue producing plant completed but not yet classified to plant-in-service accounts.*

[1] Supporting Workpapers B-2, Adj. 20

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
COMPLETED CONSTRUCTION NOT CLASSIFIED
ADJUSTMENT NO. 20

Line No.	Description (a)	Account (b)		Completed Cost of Plant (c)	Line No.
	Intangible Plant				
1	Miscellaneous Intangible [1]	303.0	$	1,473,459	1
2	Total Intangible Plant		$	1,473,459	2
	General Plant [2]				
3	Office Furniture & Equipment	391.0	$	12,307	3
4	Computer Equipment	391.1		128,028	4
5	Transportation Equipment	392.1		50,507	5
6	Tools, Shop, & Garage Equipment	394.0		16,720	6
7	Miscellaneous Equipment	398.0		2,462	7
8	Total General Plant		$	210,023	8
9	Total System Allocable		$	1,683,482	9
10	Arizona 4-Factor [3]			57.58%	10
11	Amount Allocated to Arizona		$	969,345	11

Explanation - To record System Allocable plant completed but not yet classified to plant-in-service accounts.

[1] Adjustment to Miscellaneous Intangible Plant detailed on WP C-2, Adj. 17
[2] Supporting Workpapers B-2, Adj. 20
[3] Supporting Schedule C-1, Sh 18

SOUTHWEST GAS CORPORATION
ARIZONA
LIGHT RAIL PROJECT
ADJUSTMENT NO. 21

Line No.	Work Order Number	Account	Gross Plant	Accum. Depreciation	Line No.
	(a)	(b)	(c)	(d)	
1	0042-C3646797	376	$ 180,780	$ 5,179	1
2	0042-C3625522	376	109,345	4,177	2
3	0042-C2603463	376	481,489	13,795	3
4	Total		$ 771,614	$ 23,151	4

Explanation
To remove plant related to the Light Rail Project from the cost of service.

Source: Company Records

SOUTHWEST GAS CORPORATION
ARIZONA
RCND GAS PLANT IN SERVICE
AT AUGUST 31, 2004

Line No.	Description	Reference	Balance at 08/31/04	Allocation Of System Allocable Amounts [1]	Test Year Balance As Allocated at 08/31/04	Line No.
	(a)	(b)	(c)	(d)	(e)	
	Gas Plant in Service					
1	Intangible Plant	B-2, Sh 1	$ 3,271,604	$ 60,322,017	$ 63,593,621	1
2	Distribution Plant	B-4	2,236,345,320	0	2,236,345,320	2
3	General Plant	B-4	109,432,123	31,833,964	141,266,087	3
4	Total Gas Plant in Service		$ 2,349,049,047	$ 92,155,981	$ 2,441,205,028	4
	Accumulated Provision for Depreciation and Amortization					
5	Intangible Plant	B-2, Sh 1	$ 2,196,699	$ 34,769,569	$ 36,966,268	5
6	Distribution Plant	[2]	785,179,009	0	785,179,009	6
7	General Plant	[2]	19,509,899	15,158,003	34,667,902	7
8	Total Accumulated Depreciation and Amortization		$ 806,885,607	$ 49,927,572	$ 856,813,179	8
9	Total Net Gas Plant In Service		$ 1,542,163,440	$ 42,228,409	$ 1,584,391,849	9
	System Allocable Gas Plant in Service					
10	Intangible Plant	B-2, Sh 1	$ 106,236,031			10
11	General Plant	B-4	55,286,744			11
12	Total System Allocable Gas Plant		$ 161,522,775			12
	Accumulated Provision For Depreciation and Amortization					
13	Intangible Plant	B-2, Sh 1	$ 60,385,073			13
14	General Plant	[2]	26,325,236			14
15	Total System Allocable Accumulated Depreciation and Amortization		$ 86,710,309			15
16	System Allocable Net Gas Plant In Service		$ 74,812,466			16

[1] Amounts are allocated to Arizona using the 4-Factor of 57.58% as calculated in Sch C-1, Sh 18.
[2] RCND accumulated provision for depreciation and amortization reflected as a percent of RCND gas plant in the same ratio as adjusted accumulated provision for depreciation and amortization as a percent of adjusted gas plant.

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF AUGUST 31, 2004

Account 374.1 & 374.2 - Land and Land Rights

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	1	1.00	$ 0	1
2	1931	0	1	1.00	0	2
3	1932	0	1	1.00	0	3
4	1933	0	1	1.00	0	4
5	1934	0	1	1.00	0	5
6	1935	0	1	1.00	0	6
7	1936	0	1	1.00	0	7
8	1937	0	1	1.00	0	8
9	1938	0	1	1.00	0	9
10	1939	0	1	1.00	0	10
11	1940	112	1	1.00	112	11
12	1941	14	1	1.00	14	12
13	1942	0	1	1.00	0	13
14	1943	160	1	1.00	160	14
15	1944	0	1	1.00	0	15
16	1945	2	1	1.00	2	16
17	1946	0	1	1.00	0	17
18	1947	0	1	1.00	0	18
19	1948	952	1	1.00	952	19
20	1949	139	1	1.00	139	20
21	1950	101	1	1.00	101	21
22	1951	667	1	1.00	667	22
23	1952	183	1	1.00	183	23
24	1953	124	1	1.00	124	24
25	1954	104	1	1.00	104	25
26	1955	121	1	1.00	121	26
27	1956	116	1	1.00	116	27
28	1957	138	1	1.00	138	28
29	1958	9,892	1	1.00	9,892	29
30	1959	75	1	1.00	75	30
31	1960	164	1	1.00	164	31
32	1961	178	1	1.00	178	32
33	1962	896	1	1.00	896	33
34	1963	2,944	1	1.00	2,944	34
35	1964	2,322	1	1.00	2,322	35
36	1965	849	1	1.00	849	36
37	1966	1,145	1	1.00	1,145	37
38	1967	664	1	1.00	664	38
39	1968	896	1	1.00	896	39
40	1969	4,059	1	1.00	4,059	40
41	1970	20,184	1	1.00	20,184	41
42	1971	18,376	1	1.00	18,376	42
43	1972	11,259	1	1.00	11,259	43
44	1973	16,606	1	1.00	16,606	44
45	1974	29,634	1	1.00	29,634	45
46	1975	8,619	1	1.00	8,619	46
47	1976	15,469	1	1.00	15,469	47
48	1977	13,306	1	1.00	13,306	48
49	1978	12,233	1	1.00	12,233	49
50	1979	5,998	1	1.00	5,998	50
51	1980	3,835	1	1.00	3,835	51
52	1981	69,501	1	1.00	69,501	52
53	1982	21,828	1	1.00	21,828	53
54	1983	13,467	1	1.00	13,467	54
55	1984	5,304	1	1.00	5,304	55
56	1985	387,575	1	1.00	387,575	56
57	1986	20,552	1	1.00	20,552	57
58	1987	8,770	1	1.00	8,770	58
59	1988	3,206	1	1.00	3,206	59
60	1989	3,127	1	1.00	3,127	60
61	1990	0	1	1.00	0	61
62	1991	0	1	1.00	0	62
63	1992	0	1	1.00	0	63
64	1993	4,750	1	1.00	4,750	64
65	1994	6,025	1	1.00	6,025	65
66	1995	0	1	1.00	0	66
67	1996	0	1	1.00	0	67
68	1997	130,099	1	1.00	130,099	68
69	1998	1,767	1	1.00	1,767	69
70	1999	0	1	1.00	0	70
71	2000	39,620	1	1.00	39,620	71
72	2001	15,864	1	1.00	15,864	72
73	2002	36,423	1	1.00	36,423	73
74	2003	18,148	1	1.00	18,148	74
75	2004	104,102	1	1.00	104,102	75
76	Total	$ 1,072,664			$ 1,072,664	76

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF AUGUST 31, 2004

Account 375 - Structures and Improvements

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	19	17.74	$ 0	1
2	1931	0	17	19.82	0	2
3	1932	0	16	21.06	0	3
4	1933	0	17	19.82	0	4
5	1934	0	19	17.74	0	5
6	1935	0	18	18.72	0	6
7	1936	0	19	17.74	0	7
8	1937	196	20	16.85	3,303	8
9	1938	94	20	16.85	1,584	9
10	1939	1,659	20	16.85	27,954	10
11	1940	373	20	16.85	6,285	11
12	1941	2,797	22	15.32	42,850	12
13	1942	0	23	14.65	0	13
14	1943	0	23	14.65	0	14
15	1944	0	24	14.04	0	15
16	1945	5,437	24	14.04	76,335	16
17	1946	2,032	27	12.48	25,359	17
18	1947	895	32	10.53	9,424	18
19	1948	4,989	36	9.36	46,697	19
20	1949	6,441	37	9.11	58,678	20
21	1950	8,724	39	8.64	75,375	21
22	1951	21,212	42	8.02	170,120	22
23	1952	1,568	44	7.66	12,011	23
24	1953	4,318	44	7.66	33,076	24
25	1954	2,625	46	7.33	19,241	25
26	1955	959	48	7.02	6,732	26
27	1956	4,816	52	6.48	31,208	27
28	1957	0	55	6.13	0	28
29	1958	0	57	5.91	0	29
30	1959	0	58	5.81	0	30
31	1960	0	59	5.71	0	31
32	1961	0	58	5.81	0	32
33	1962	0	59	5.71	0	33
34	1963	0	60	5.62	0	34
35	1964	0	61	5.52	0	35
36	1965	394	64	5.27	2,076	36
37	1966	0	65	5.18	0	37
38	1967	0	67	5.03	0	38
39	1968	0	71	4.75	0	39
40	1969	0	75	4.49	0	40
41	1970	0	79	4.27	0	41
42	1971	0	87	3.87	0	42
43	1972	0	93	3.62	0	43
44	1973	23,733	100	3.37	79,980	44
45	1974	8,122	118	2.86	23,229	45
46	1975	0	133	2.53	0	46
47	1976	0	138	2.44	0	47
48	1977	437	148	2.28	996	48
49	1978	674	161	2.09	1,409	49
50	1979	0	177	1.90	0	50
51	1980	0	194	1.74	0	51
52	1981	0	204	1.65	0	52
53	1982	0	207	1.63	0	53
54	1983	0	215	1.57	0	54
55	1984	0	224	1.50	0	55
56	1985	0	226	1.49	0	56
57	1986	0	231	1.46	0	57
58	1987	0	232	1.45	0	58
59	1988	0	232	1.45	0	59
60	1989	0	232	1.45	0	60
61	1990	2,068	236	1.43	2,958	61
62	1991	2,033	233	1.45	2,948	62
63	1992	0	238	1.42	0	63
64	1993	0	251	1.34	0	64
65	1994	0	261	1.29	0	65
66	1995	3,960	265	1.27	5,029	66
67	1996	0	278	1.21	0	67
68	1997	0	282	1.20	0	68
69	1998	0	285	1.18	0	69
70	1999	0	287	1.17	0	70
71	2000	0	295	1.14	0	71
72	2001	0	303	1.11	0	72
73	2002	0	310	1.09	0	73
74	2003	0	320	1.05	0	74
75	2004	0	337	1.00	0	75
76	Total	$ 110,556			$ 764,857	76

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF AUGUST 31, 2004

Account 376 - Mains - Steel

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 117,275	19	22.47	$ 2,635,169	1
2	1931	2,569	18	23.72	60,937	2
3	1932	0	18	23.72	0	3
4	1933	0	17	25.12	0	4
5	1934	2,743	18	23.72	65,064	5
6	1935	8,484	19	22.47	190,635	6
7	1936	25	18	23.72	593	7
8	1937	18,672	20	21.35	398,647	8
9	1938	21,117	20	21.35	450,848	9
10	1939	255	20	21.35	5,444	10
11	1940	418	20	21.35	8,924	11
12	1941	65,273	20	21.35	1,393,579	12
13	1942	42,600	21	20.33	866,058	13
14	1943	37,505	21	20.33	762,477	14
15	1944	20,119	21	20.33	409,019	15
16	1945	77,207	22	19.41	1,498,588	16
17	1946	2,783	24	17.79	49,510	17
18	1947	349,659	27	15.81	5,528,109	18
19	1948	965,557	31	13.77	13,295,720	19
20	1949	615,778	33	12.94	7,968,167	20
21	1950	983,011	35	12.20	11,992,734	21
22	1951	819,317	37	11.54	9,454,918	22
23	1952	868,550	39	10.95	9,510,623	23
24	1953	622,311	41	10.41	6,478,258	24
25	1954	733,095	44	9.70	7,111,022	25
26	1955	2,987,039	46	9.28	27,719,722	26
27	1956	1,358,492	48	8.90	12,090,579	27
28	1957	1,355,291	52	8.21	11,126,939	28
29	1958	2,253,918	54	7.91	17,828,491	29
30	1959	2,428,840	57	7.49	18,192,012	30
31	1960	2,091,235	58	7.36	15,391,490	31
32	1961	2,217,240	61	7.00	15,520,680	32
33	1962	2,029,158	63	6.78	13,757,691	33
34	1963	1,669,397	64	6.67	11,134,878	34
35	1964	2,160,965	66	6.47	13,981,444	35
36	1965	2,070,053	68	6.28	12,999,933	36
37	1966	1,746,834	69	6.19	10,812,902	37
38	1967	1,174,609	73	5.85	6,871,463	38
39	1968	810,518	75	5.69	4,611,847	39
40	1969	1,655,573	80	5.34	8,840,760	40
41	1970	1,039,026	84	5.08	5,278,252	41
42	1971	2,152,650	90	4.74	10,203,561	42
43	1972	3,460,424	96	4.45	15,398,887	43
44	1973	2,700,135	100	4.27	11,529,576	44
45	1974	3,016,532	117	3.65	11,010,342	45
46	1975	1,365,502	133	3.21	4,383,261	46
47	1976	707,618	142	3.01	2,129,930	47
48	1977	1,264,722	155	2.75	3,477,986	48
49	1978	1,467,530	171	2.50	3,668,825	49
50	1979	1,054,551	187	2.28	2,404,376	50
51	1980	1,612,117	200	2.14	3,449,930	51
52	1981	3,147,108	219	1.95	6,136,861	52
53	1982	1,680,558	239	1.79	3,008,199	53
54	1983	2,568,650	246	1.74	4,469,451	54
55	1984	3,698,764	251	1.70	6,287,899	55
56	1985	2,236,015	245	1.74	3,890,666	56
57	1986	2,964,734	233	1.83	5,425,463	57
58	1987	3,410,542	241	1.77	6,036,659	58
59	1988	2,496,848	257	1.66	4,144,768	59
60	1989	3,792,176	269	1.59	6,029,560	60
61	1990	3,325,826	276	1.55	5,155,030	61
62	1991	4,718,810	282	1.51	7,125,403	62
63	1992	5,798,269	286	1.49	8,639,421	63
64	1993	5,239,513	297	1.44	7,544,899	64
65	1994	6,798,125	316	1.35	9,177,469	65
66	1995	8,733,487	316	1.35	11,790,207	66
67	1996	7,150,333	318	1.34	9,581,446	67
68	1997	7,154,527	327	1.31	9,372,430	68
69	1998	7,087,418	330	1.29	9,142,769	69
70	1999	7,186,705	341	1.25	8,983,381	70
71	2000	9,828,095	356	1.20	11,793,714	71
72	2001	13,013,848	362	1.18	15,356,341	72
73	2002	14,418,547	367	1.16	16,725,515	73
74	2003	13,293,401	385	1.11	14,755,675	74
75	2004	8,792,154	427	1.00	8,792,154	75
76	Total	$ 202,758,745			$ 553,316,180	76

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF AUGUST 31, 2004

Account 376 - Mains - Plastic

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	0	0.00	$ 0	1
2	1931	0	0	0.00	0	2
3	1932	0	0	0.00	0	3
4	1933	0	0	0.00	0	4
5	1934	0	0	0.00	0	5
6	1935	0	0	0.00	0	6
7	1936	0	0	0.00	0	7
8	1937	0	0	0.00	0	8
9	1938	0	0	0.00	0	9
10	1939	0	0	0.00	0	10
11	1940	0	0	0.00	0	11
12	1941	0	0	0.00	0	12
13	1942	0	0	0.00	0	13
14	1943	0	0	0.00	0	14
15	1944	0	0	0.00	0	15
16	1945	0	0	0.00	0	16
17	1946	0	0	0.00	0	17
18	1947	0	0	0.00	0	18
19	1948	0	0	0.00	0	19
20	1949	0	0	0.00	0	20
21	1950	0	0	0.00	0	21
22	1951	0	0	0.00	0	22
23	1952	0	0	0.00	0	23
24	1953	0	0	0.00	0	24
25	1954	0	0	0.00	0	25
26	1955	1,049	0	0.00	0	26
27	1956	18,161	0	0.00	0	27
28	1957	30,964	0	0.00	0	28
29	1958	62,319	0	0.00	0	29
30	1959	44,373	0	0.00	0	30
31	1960	68,299	0	0.00	0	31
32	1961	141,576	0	0.00	0	32
33	1962	377,958	71	5.10	1,927,586	33
34	1963	428,972	72	5.03	2,157,729	34
35	1964	476,461	73	4.96	2,363,247	35
36	1965	309,410	74	4.89	1,513,015	36
37	1966	932,243	76	4.76	4,437,477	37
38	1967	1,075,038	79	4.58	4,923,674	38
39	1968	630,800	81	4.47	2,819,676	39
40	1969	1,237,196	84	4.31	5,332,315	40
41	1970	675,549	87	4.16	2,810,284	41
42	1971	1,463,260	92	3.93	5,750,612	42
43	1972	2,115,632	96	3.77	7,975,933	43
44	1973	1,993,868	100	3.62	7,217,802	44
45	1974	2,080,342	112	3.23	6,719,505	45
46	1975	1,624,281	130	2.78	4,515,501	46
47	1976	537,223	137	2.64	1,418,269	47
48	1977	1,097,706	147	2.46	2,700,357	48
49	1978	605,402	158	2.29	1,386,371	49
50	1979	2,470,744	174	2.08	5,139,148	50
51	1980	3,367,009	193	1.88	6,329,977	51
52	1981	4,176,519	209	1.73	7,225,378	52
53	1982	2,715,390	224	1.62	4,398,932	53
54	1983	4,510,350	232	1.56	7,036,146	54
55	1984	6,558,126	236	1.53	10,033,933	55
56	1985	5,459,273	235	1.54	8,407,280	56
57	1986	17,455,876	238	1.52	26,532,932	57
58	1987	18,095,930	245	1.48	26,781,976	58
59	1988	21,130,170	257	1.41	29,793,540	59
60	1989	16,451,667	272	1.33	21,880,717	60
61	1990	21,790,283	281	1.29	28,109,465	61
62	1991	6,737,210	287	1.26	8,488,885	62
63	1992	9,808,411	290	1.25	12,260,514	63
64	1993	22,176,738	297	1.22	27,055,620	64
65	1994	27,142,347	302	1.20	32,570,816	65
66	1995	33,750,929	305	1.19	40,163,606	66
67	1996	32,125,532	312	1.16	37,265,617	67
68	1997	28,232,716	319	1.13	31,902,969	68
69	1998	32,057,600	324	1.12	35,904,512	69
70	1999	42,115,089	329	1.10	46,326,598	70
71	2000	42,256,050	336	1.08	45,636,534	71
72	2001	45,185,173	344	1.05	47,444,432	72
73	2002	47,315,893	350	1.03	48,735,370	73
74	2003	38,318,664	357	1.01	38,701,851	74
75	2004	37,253,875	362	1.00	37,253,875	75
76	Total	$ 586,685,646			$ 737,349,976	76

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF AUGUST 31, 2004

Account 378 - Measuring and Regulating Equipment - Gen.

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	24	16.38	$ 0	1
2	1931	0	24	16.38	0	2
3	1932	0	23	17.09	0	3
4	1933	0	22	17.86	0	4
5	1934	0	22	17.86	0	5
6	1935	0	22	17.86	0	6
7	1936	9	22	17.86	163	7
8	1937	0	24	16.38	0	8
9	1938	0	24	16.38	0	9
10	1939	0	24	16.38	0	10
11	1940	0	26	15.12	0	11
12	1941	0	26	15.12	0	12
13	1942	0	26	15.12	0	13
14	1943	0	26	15.12	0	14
15	1944	0	26	15.12	0	15
16	1945	0	26	15.12	0	16
17	1946	257	29	13.55	3,487	17
18	1947	0	34	11.56	0	18
19	1948	0	37	10.62	0	19
20	1949	0	39	10.08	0	20
21	1950	0	40	9.83	0	21
22	1951	0	44	8.93	0	22
23	1952	0	45	8.73	0	23
24	1953	0	46	8.54	0	24
25	1954	206	47	8.36	1,722	25
26	1955	350	49	8.02	2,807	26
27	1956	2,201	54	7.28	16,023	27
28	1957	862	57	6.89	5,939	28
29	1958	4,597	60	6.55	30,110	29
30	1959	9,479	62	6.34	60,097	30
31	1960	990	64	6.14	6,079	31
32	1961	2,924	64	6.14	17,953	32
33	1962	2,126	66	5.95	12,650	33
34	1963	2,126	67	5.87	12,480	34
35	1964	3,760	68	5.78	21,733	35
36	1965	11,106	68	5.78	64,193	36
37	1966	18,449	70	5.61	103,499	37
38	1967	1,213	72	5.46	6,623	38
39	1968	6,213	73	5.38	33,426	39
40	1969	11,938	76	5.17	61,719	40
41	1970	7,092	83	4.73	33,545	41
42	1971	29,221	90	4.37	127,696	42
43	1972	123,201	97	4.05	498,964	43
44	1973	7,125	100	3.93	28,001	44
45	1974	26,280	116	3.39	89,089	45
46	1975	10,207	135	2.91	29,702	46
47	1976	21,645	148	2.66	57,576	47
48	1977	51,354	158	2.49	127,871	48
49	1978	48,042	173	2.27	109,055	49
50	1979	19,178	187	2.10	40,274	50
51	1980	39,406	203	1.94	76,448	51
52	1981	14,510	224	1.75	25,393	52
53	1982	123,813	249	1.58	195,625	53
54	1983	195,817	249	1.58	309,391	54
55	1984	226,472	247	1.59	360,090	55
56	1985	36,610	242	1.62	59,308	56
57	1986	248,816	242	1.62	403,082	57
58	1987	85,410	250	1.57	134,094	58
59	1988	159,597	266	1.48	236,204	59
60	1989	89,064	277	1.42	126,471	60
61	1990	178,679	277	1.42	253,724	61
62	1991	166,568	278	1.41	234,861	62
63	1992	684,597	288	1.36	931,052	63
64	1993	920,473	299	1.31	1,205,820	64
65	1994	1,241,248	311	1.26	1,563,972	65
66	1995	1,686,936	314	1.25	2,108,670	66
67	1996	1,419,417	327	1.20	1,703,300	67
68	1997	855,913	331	1.19	1,018,536	68
69	1998	2,163,602	335	1.17	2,531,414	69
70	1999	4,537,208	342	1.15	5,217,789	70
71	2000	1,033,395	352	1.12	1,157,402	71
72	2001	2,040,048	358	1.10	2,244,053	72
73	2002	3,173,344	363	1.08	3,427,212	73
74	2003	1,849,010	365	1.08	1,996,931	74
75	2004	862,886	393	1.00	862,886	75
76	Total	$ 24,454,990			$ 29,986,204	76

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF AUGUST 31, 2004

Account 380 - Services - Steel

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 8,202	16	22.81	$ 187,088	1
2	1931	0	15	24.33	0	2
3	1932	89	15	24.33	2,165	3
4	1933	0	14	26.07	0	4
5	1934	18	15	24.33	438	5
6	1935	0	15	24.33	0	6
7	1936	27	16	22.81	616	7
8	1937	0	17	21.47	0	8
9	1938	57	17	21.47	1,224	9
10	1939	2,685	17	21.47	57,647	10
11	1940	91	18	20.28	1,845	11
12	1941	6,353	18	20.28	128,839	12
13	1942	14,258	19	19.21	273,896	13
14	1943	1,116	19	19.21	21,438	14
15	1944	18,959	19	19.21	364,202	15
16	1945	44,298	19	19.21	850,965	16
17	1946	102,820	22	16.59	1,705,784	17
18	1947	171,752	25	14.60	2,507,579	18
19	1948	282,168	28	13.04	3,679,471	19
20	1949	194,453	30	12.17	2,366,493	20
21	1950	373,967	32	11.41	4,266,963	21
22	1951	469,036	33	11.06	5,187,538	22
23	1952	544,923	35	10.43	5,683,547	23
24	1953	444,529	37	9.86	4,383,056	24
25	1954	431,300	39	9.36	4,036,968	25
26	1955	1,071,441	41	8.90	9,535,825	26
27	1956	660,181	45	8.11	5,354,068	27
28	1957	714,097	48	7.60	5,427,137	28
29	1958	726,449	50	7.30	5,303,078	29
30	1959	364,421	53	6.89	2,510,861	30
31	1960	47,065	54	6.76	318,159	31
32	1961	58,694	58	6.29	369,185	32
33	1962	40,866	60	6.08	248,465	33
34	1963	37,668	60	6.08	229,021	34
35	1964	12,971	63	5.79	75,102	35
36	1965	54,015	64	5.70	307,886	36
37	1966	31,700	66	5.53	175,301	37
38	1967	23,002	69	5.29	121,681	38
39	1968	7,560	72	5.07	38,329	39
40	1969	1,610	77	4.74	7,631	40
41	1970	8,414	84	4.35	36,601	41
42	1971	21,229	90	4.06	86,190	42
43	1972	57,097	95	3.84	219,252	43
44	1973	49,367	100	3.65	180,190	44
45	1974	88,620	113	3.23	286,243	45
46	1975	18,595	129	2.83	52,624	46
47	1976	29,598	138	2.64	78,139	47
48	1977	24,701	149	2.45	60,517	48
49	1978	2,967	161	2.27	6,735	49
50	1979	158,247	176	2.07	327,571	50
51	1980	288,903	192	1.90	548,916	51
52	1981	280,946	208	1.75	491,656	52
53	1982	59,119	226	1.62	95,773	53
54	1983	516,248	232	1.57	810,509	54
55	1984	256,584	237	1.54	395,139	55
56	1985	42,553	234	1.56	66,383	56
57	1986	32,002	233	1.57	50,243	57
58	1987	15,631	241	1.51	23,603	58
59	1988	38,681	246	1.48	57,248	59
60	1989	18,337	251	1.45	26,589	60
61	1990	262,837	262	1.39	365,343	61
62	1991	123,872	271	1.35	167,227	62
63	1992	304,939	277	1.32	402,519	63
64	1993	1,200,106	287	1.27	1,524,135	64
65	1994	616,047	295	1.24	763,898	65
66	1995	884,333	292	1.25	1,105,416	66
67	1996	496,781	295	1.24	616,008	67
68	1997	642,315	301	1.21	777,201	68
69	1998	772,840	306	1.19	919,680	69
70	1999	478,953	313	1.17	560,375	70
71	2000	436,127	323	1.13	492,824	71
72	2001	536,174	331	1.10	589,791	72
73	2002	482,449	338	1.08	521,045	73
74	2003	425,327	347	1.05	446,593	74
75	2004	300,767	365	1.00	300,767	75
76	Total	$ 16,934,547			$ 79,182,434	76

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF AUGUST 31, 2004

Account 380 - Services - Plastic

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	0	0.00	$ 0	1
2	1931	0	0	0.00	0	2
3	1932	0	0	0.00	0	3
4	1933	0	0	0.00	0	4
5	1934	0	0	0.00	0	5
6	1935	0	0	0.00	0	6
7	1936	0	0	0.00	0	7
8	1937	0	0	0.00	0	8
9	1938	0	0	0.00	0	9
10	1939	0	0	0.00	0	10
11	1940	0	0	0.00	0	11
12	1941	0	0	0.00	0	12
13	1942	0	0	0.00	0	13
14	1943	0	0	0.00	0	14
15	1944	0	0	0.00	0	15
16	1945	0	0	0.00	0	16
17	1946	0	0	0.00	0	17
18	1947	0	0	0.00	0	18
19	1948	0	0	0.00	0	19
20	1949	0	0	0.00	0	20
21	1950	0	0	0.00	0	21
22	1951	17	0	0.00	0	22
23	1952	0	0	0.00	0	23
24	1953	12,736	45	7.62	97,048	24
25	1954	22,162	46	7.46	165,329	25
26	1955	104,432	47	7.30	762,354	26
27	1956	70,662	49	7.00	494,634	27
28	1957	146,694	52	6.60	968,180	28
29	1958	182,293	54	6.35	1,157,561	29
30	1959	430,909	56	6.13	2,641,472	30
31	1960	176,341	57	6.02	1,061,573	31
32	1961	215,040	59	5.81	1,249,382	32
33	1962	381,555	61	5.62	2,144,339	33
34	1963	406,297	62	5.53	2,246,822	34
35	1964	349,358	64	5.36	1,872,559	35
36	1965	373,095	65	5.28	1,969,942	36
37	1966	289,281	68	5.04	1,457,976	37
38	1967	326,103	71	4.83	1,575,077	38
39	1968	219,629	74	4.64	1,019,079	39
40	1969	3,995	78	4.40	17,578	40
41	1970	64,858	84	4.08	264,621	41
42	1971	118,325	89	3.85	455,551	42
43	1972	331,002	95	3.61	1,194,917	43
44	1973	204,814	100	3.43	702,512	44
45	1974	815,587	111	3.09	2,520,164	45
46	1975	210,028	127	2.70	567,076	46
47	1976	205,787	134	2.56	526,815	47
48	1977	292,368	144	2.38	695,836	48
49	1978	141,793	155	2.21	313,363	49
50	1979	1,289,042	170	2.02	2,603,865	50
51	1980	2,508,598	184	1.86	4,665,992	51
52	1981	3,270,535	197	1.74	5,690,731	52
53	1982	3,122,208	218	1.57	4,901,867	53
54	1983	18,669,140	227	1.51	28,190,401	54
55	1984	21,017,152	230	1.49	31,315,556	55
56	1985	13,265,905	226	1.52	20,164,176	56
57	1986	21,064,913	230	1.49	31,386,720	57
58	1987	18,726,451	236	1.45	27,153,354	58
59	1988	18,389,615	240	1.43	26,297,149	59
60	1989	13,169,977	247	1.39	18,306,268	60
61	1990	16,724,035	256	1.34	22,410,207	61
62	1991	7,797,346	264	1.30	10,136,550	62
63	1992	13,000,337	269	1.28	16,640,431	63
64	1993	15,966,691	278	1.23	19,639,030	64
65	1994	22,742,257	282	1.22	27,745,554	65
66	1995	25,868,461	279	1.23	31,818,207	66
67	1996	30,549,996	286	1.20	36,659,995	67
68	1997	27,037,634	292	1.17	31,634,032	68
69	1998	27,587,162	297	1.15	31,725,236	69
70	1999	34,197,600	304	1.13	38,643,288	70
71	2000	30,342,600	312	1.10	33,376,860	71
72	2001	31,961,935	323	1.06	33,879,651	72
73	2002	32,096,346	333	1.03	33,059,236	73
74	2003	31,322,829	339	1.01	31,636,057	74
75	2004	20,285,194	343	1.00	20,285,194	75
76	Total	$ 508,069,120			$ 648,107,367	76

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF AUGUST 31, 2004

Account 381 - Meters, Regulators, and Installations

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 71,979	27	6.70	$ 482,259	1
2	1931	4,694	26	6.96	32,670	2
3	1932	2,225	25	7.24	16,109	3
4	1933	1,940	25	7.24	14,046	4
5	1934	11,552	25	7.24	83,636	5
6	1935	14,275	25	7.24	103,351	6
7	1936	17,343	25	7.24	125,563	7
8	1937	35,440	26	6.96	246,662	8
9	1938	20,062	26	6.96	139,632	9
10	1939	14,218	26	6.96	98,957	10
11	1940	20,598	26	6.96	143,362	11
12	1941	33,191	26	6.96	231,009	12
13	1942	26,318	26	6.96	183,173	13
14	1943	17,598	26	6.96	122,482	14
15	1944	18,091	26	6.96	125,913	15
16	1945	22,927	26	6.96	159,572	16
17	1946	74,822	33	5.48	410,025	17
18	1947	239,493	41	4.41	1,056,164	18
19	1948	231,451	42	4.31	997,554	19
20	1949	190,351	45	4.02	765,211	20
21	1950	233,870	48	3.77	881,690	21
22	1951	422,217	55	3.29	1,389,094	22
23	1952	332,741	55	3.29	1,094,718	23
24	1953	321,537	55	3.29	1,057,857	24
25	1954	215,074	55	3.29	707,593	25
26	1955	627,433	56	3.23	2,026,609	26
27	1956	348,616	63	2.87	1,000,528	27
28	1957	291,989	66	2.74	800,050	28
29	1958	610,346	71	2.55	1,556,382	29
30	1959	436,474	71	2.55	1,113,009	30
31	1960	839,816	71	2.55	2,141,531	31
32	1961	484,927	73	2.48	1,202,619	32
33	1962	630,058	79	2.29	1,442,833	33
34	1963	601,749	79	2.29	1,378,005	34
35	1964	258,732	79	2.29	592,496	35
36	1965	377,497	79	2.29	864,468	36
37	1966	199,420	86	2.10	418,782	37
38	1967	230,449	88	2.06	474,725	38
39	1968	287,229	88	2.06	591,692	39
40	1969	236,036	89	2.03	479,153	40
41	1970	791,075	94	1.93	1,526,775	41
42	1971	1,220,328	100	1.81	2,208,794	42
43	1972	1,099,080	100	1.81	1,989,335	43
44	1973	1,127,882	100	1.81	2,041,466	44
45	1974	1,345,149	111	1.63	2,192,593	45
46	1975	558,057	128	1.41	786,860	46
47	1976	503,396	131	1.38	694,686	47
48	1977	557,561	136	1.33	741,556	48
49	1978	396,415	139	1.30	515,340	49
50	1979	993,151	143	1.27	1,261,302	50
51	1980	1,694,386	149	1.21	2,050,207	51
52	1981	1,528,426	158	1.15	1,757,690	52
53	1982	1,760,379	158	1.15	2,024,436	53
54	1983	4,179,928	146	1.24	5,183,111	54
55	1984	3,254,235	147	1.23	4,002,709	55
56	1985	3,766,258	158	1.15	4,331,197	56
57	1986	1,846,816	166	1.09	2,013,029	57
58	1987	2,017,467	165	1.10	2,219,214	58
59	1988	4,094,765	170	1.06	4,340,451	59
60	1989	4,352,368	177	1.02	4,439,415	60
61	1990	3,740,063	185	0.98	3,665,262	61
62	1991	4,402,183	190	0.95	4,182,074	62
63	1992	2,711,780	191	0.95	2,576,191	63
64	1993	342,923	190	0.95	325,777	64
65	1994	8,449,604	189	0.96	8,111,620	65
66	1995	6,289,456	190	0.95	5,974,983	66
67	1996	6,036,318	191	0.95	5,734,502	67
68	1997	5,923,635	195	0.93	5,508,981	68
69	1998	6,547,639	196	0.92	6,023,828	69
70	1999	10,079,298	193	0.94	9,474,540	70
71	2000	8,879,100	202	0.90	7,991,190	71
72	2001	10,150,772	209	0.87	8,831,172	72
73	2002	11,774,899	203	0.89	10,479,660	73
74	2003	13,282,767	191	0.95	12,618,629	74
75	2004	12,057,627	181	1.00	12,057,627	75
76	Total	$ 156,809,964			$ 176,627,386	76

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF AUGUST 31, 2004

Account 385 - Measuring and Regulating Equipment - Ind.

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	24	16.38	$ 0	1
2	1931	0	24	16.38	0	2
3	1932	0	23	17.09	0	3
4	1933	0	22	17.86	0	4
5	1934	0	22	17.86	0	5
6	1935	0	22	17.86	0	6
7	1936	0	22	17.86	0	7
8	1937	0	24	16.38	0	8
9	1938	0	24	16.38	0	9
10	1939	0	24	16.38	0	10
11	1940	0	26	15.12	0	11
12	1941	0	26	15.12	0	12
13	1942	0	26	15.12	0	13
14	1943	0	26	15.12	0	14
15	1944	0	26	15.12	0	15
16	1945	0	26	15.12	0	16
17	1946	0	29	13.55	0	17
18	1947	0	34	11.56	0	18
19	1948	0	37	10.62	0	19
20	1949	0	39	10.08	0	20
21	1950	0	40	9.83	0	21
22	1951	0	44	8.93	0	22
23	1952	0	45	8.73	0	23
24	1953	0	46	8.54	0	24
25	1954	0	47	8.36	0	25
26	1955	0	49	8.02	0	26
27	1956	0	54	7.28	0	27
28	1957	0	57	6.89	0	28
29	1958	0	60	6.55	0	29
30	1959	0	62	6.34	0	30
31	1960	0	64	6.14	0	31
32	1961	0	64	6.14	0	32
33	1962	0	66	5.95	0	33
34	1963	0	67	5.87	0	34
35	1964	0	68	5.78	0	35
36	1965	0	68	5.78	0	36
37	1966	0	70	5.61	0	37
38	1967	0	72	5.46	0	38
39	1968	61,233	73	5.38	329,434	39
40	1969	0	76	5.17	0	40
41	1970	0	83	4.73	0	41
42	1971	0	90	4.37	0	42
43	1972	22,967	97	4.05	93,016	43
44	1973	32,288	100	3.93	126,892	44
45	1974	103,218	116	3.39	349,909	45
46	1975	76,790	135	2.91	223,459	46
47	1976	45,302	148	2.66	120,503	47
48	1977	16,356	158	2.49	40,726	48
49	1978	17,162	173	2.27	38,958	49
50	1979	31,941	187	2.10	67,076	50
51	1980	126,417	203	1.94	245,249	51
52	1981	102,045	224	1.75	178,579	52
53	1982	140,659	249	1.58	222,241	53
54	1983	173,442	249	1.58	274,038	54
55	1984	365,456	247	1.59	581,075	55
56	1985	62,688	242	1.62	101,555	56
57	1986	156,319	242	1.62	253,237	57
58	1987	14,460	250	1.57	22,702	58
59	1988	164,131	266	1.48	242,914	59
60	1989	90,436	277	1.42	128,419	60
61	1990	52,403	277	1.42	74,412	61
62	1991	61,230	278	1.41	86,334	62
63	1992	35,239	288	1.36	47,925	63
64	1993	162,818	299	1.31	213,292	64
65	1994	253,335	311	1.26	319,202	65
66	1995	329,429	314	1.25	411,786	66
67	1996	486,187	327	1.20	583,424	67
68	1997	646,146	331	1.19	768,914	68
69	1998	686,294	335	1.17	802,964	69
70	1999	521,190	342	1.15	599,369	70
71	2000	202,831	352	1.12	227,171	71
72	2001	314,786	358	1.10	346,265	72
73	2002	373,683	363	1.08	403,578	73
74	2003	423,575	365	1.08	457,461	74
75	2004	176,043	393	1.00	176,043	75
76	Total	$ 6,528,499			$ 9,158,122	76

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF AUGUST 31, 2004

Account 387 - Other Distribution Equipment

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	24	16.38	$ 0	1
2	1931	0	24	16.38	0	2
3	1932	0	23	17.09	0	3
4	1933	0	22	17.86	0	4
5	1934	0	22	17.86	0	5
6	1935	0	22	17.86	0	6
7	1936	0	22	17.86	0	7
8	1937	0	24	16.38	0	8
9	1938	0	24	16.38	0	9
10	1939	0	24	16.38	0	10
11	1940	0	26	15.12	0	11
12	1941	0	26	15.12	0	12
13	1942	0	26	15.12	0	13
14	1943	0	26	15.12	0	14
15	1944	0	26	15.12	0	15
16	1945	0	26	15.12	0	16
17	1946	0	29	13.55	0	17
18	1947	0	34	11.56	0	18
19	1948	0	37	10.62	0	19
20	1949	0	39	10.08	0	20
21	1950	0	40	9.83	0	21
22	1951	0	44	8.93	0	22
23	1952	0	45	8.73	0	23
24	1953	0	46	8.54	0	24
25	1954	0	47	8.36	0	25
26	1955	0	49	8.02	0	26
27	1956	0	54	7.28	0	27
28	1957	0	57	6.89	0	28
29	1958	0	60	6.55	0	29
30	1959	0	62	6.34	0	30
31	1960	0	64	6.14	0	31
32	1961	0	64	6.14	0	32
33	1962	0	66	5.95	0	33
34	1963	0	67	5.87	0	34
35	1964	0	68	5.78	0	35
36	1965	0	68	5.78	0	36
37	1966	0	70	5.61	0	37
38	1967	0	72	5.46	0	38
39	1968	0	73	5.38	0	39
40	1969	0	76	5.17	0	40
41	1970	0	83	4.73	0	41
42	1971	0	90	4.37	0	42
43	1972	0	97	4.05	0	43
44	1973	0	100	3.93	0	44
45	1974	0	116	3.39	0	45
46	1975	2,618	135	2.91	7,618	46
47	1976	0	148	2.66	0	47
48	1977	0	158	2.49	0	48
49	1978	0	173	2.27	0	49
50	1979	35,268	187	2.10	74,063	50
51	1980	34,199	203	1.94	66,346	51
52	1981	88,691	224	1.75	155,209	52
53	1982	254,179	249	1.58	401,603	53
54	1983	0	249	1.58	0	54
55	1984	12,674	247	1.59	20,152	55
56	1985	45	242	1.62	73	56
57	1986	29,911	242	1.62	48,456	57
58	1987	1,134	250	1.57	1,780	58
59	1988	0	266	1.48	0	59
60	1989	0	277	1.42	0	60
61	1990	0	277	1.42	0	61
62	1991	193	278	1.41	272	62
63	1992	541	288	1.36	736	63
64	1993	0	299	1.31	0	64
65	1994	0	311	1.26	0	65
66	1995	245	314	1.25	306	66
67	1996	0	327	1.20	0	67
68	1997	2,006	331	1.19	2,387	68
69	1998	0	335	1.17	0	69
70	1999	0	342	1.15	0	70
71	2000		352	1.12	0	71
72	2001	1,026	358	1.10	1,129	72
73	2002	0	363	1.08	0	73
74	2003	0	365	1.08	0	74
75	2004	0	393	1.00	0	75
76	Total	$ 462,730			$ 780,130	76

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF AUGUST 31, 2004

Account 389 - Land and Land Rights

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	1	1.00	$ 0	1
2	1931	0	1	1.00	0	2
3	1932	0	1	1.00	0	3
4	1933	0	1	1.00	0	4
5	1934	0	1	1.00	0	5
6	1935	0	1	1.00	0	6
7	1936	0	1	1.00	0	7
8	1937	0	1	1.00	0	8
9	1938	0	1	1.00	0	9
10	1939	0	1	1.00	0	10
11	1940	0	1	1.00	0	11
12	1941	0	1	1.00	0	12
13	1942	0	1	1.00	0	13
14	1943	0	1	1.00	0	14
15	1944	0	1	1.00	0	15
16	1945	0	1	1.00	0	16
17	1946	0	1	1.00	0	17
18	1947	0	1	1.00	0	18
19	1948	0	1	1.00	0	19
20	1949	0	1	1.00	0	20
21	1950	0	1	1.00	0	21
22	1951	0	1	1.00	0	22
23	1952	0	1	1.00	0	23
24	1953	0	1	1.00	0	24
25	1954	0	1	1.00	0	25
26	1955	0	1	1.00	0	26
27	1956	0	1	1.00	0	27
28	1957	0	1	1.00	0	28
29	1958	0	1	1.00	0	29
30	1959	0	1	1.00	0	30
31	1960	0	1	1.00	0	31
32	1961	0	1	1.00	0	32
33	1962	0	1	1.00	0	33
34	1963	0	1	1.00	0	34
35	1964	0	1	1.00	0	35
36	1965	0	1	1.00	0	36
37	1966	0	1	1.00	0	37
38	1967	0	1	1.00	0	38
39	1968	0	1	1.00	0	39
40	1969	0	1	1.00	0	40
41	1970	27,505	1	1.00	27,505	41
42	1971	0	1	1.00	0	42
43	1972	0	1	1.00	0	43
44	1973	0	1	1.00	0	44
45	1974	0	1	1.00	0	45
46	1975	0	1	1.00	0	46
47	1976	0	1	1.00	0	47
48	1977	0	1	1.00	0	48
49	1978	0	1	1.00	0	49
50	1979	0	1	1.00	0	50
51	1980	573,337	1	1.00	573,337	51
52	1981	0	1	1.00	0	52
53	1982	0	1	1.00	0	53
54	1983	0	1	1.00	0	54
55	1984	792,870	1	1.00	792,870	55
56	1985	895,545	1	1.00	895,545	56
57	1986	355,216	1	1.00	355,216	57
58	1987	0	1	1.00	0	58
59	1988	7,000	1	1.00	7,000	59
60	1989	3,091,144	1	1.00	3,091,144	60
61	1990	0	1	1.00	0	61
62	1991	0	1	1.00	0	62
63	1992	0	1	1.00	0	63
64	1993	0	1	1.00	0	64
65	1994	0	1	1.00	0	65
66	1995	0	1	1.00	0	66
67	1996	0	1	1.00	0	67
68	1997	209,928	1	1.00	209,928	68
69	1998	0	1	1.00	0	69
70	1999	502,044	1	1.00	502,044	70
71	2000	0	1	1.00	0	71
72	2001	0	1	1.00	0	72
73	2002	0	1	1.00	0	73
74	2003	0	1	1.00	0	74
75	2004	0	1	1.00	0	75
76	Total	$ 6,454,589			$ 6,454,589	76

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF AUGUST 31, 2004

Account 390.1 - Structures and Improvements

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	19	17.74	$ 0	1
2	1931	0	17	19.82	0	2
3	1932	0	16	21.06	0	3
4	1933	0	17	19.82	0	4
5	1934	0	19	17.74	0	5
6	1935	0	18	18.72	0	6
7	1936	0	19	17.74	0	7
8	1937	0	20	16.85	0	8
9	1938	0	20	16.85	0	9
10	1939	0	20	16.85	0	10
11	1940	0	20	16.85	0	11
12	1941	0	22	15.32	0	12
13	1942	0	23	14.65	0	13
14	1943	0	23	14.65	0	14
15	1944	0	24	14.04	0	15
16	1945	0	24	14.04	0	16
17	1946	0	27	12.48	0	17
18	1947	0	32	10.53	0	18
19	1948	0	36	9.36	0	19
20	1949	0	37	9.11	0	20
21	1950	0	39	8.64	0	21
22	1951	0	42	8.02	0	22
23	1952	0	44	7.66	0	23
24	1953	0	44	7.66	0	24
25	1954	0	46	7.33	0	25
26	1955	0	48	7.02	0	26
27	1956	0	52	6.48	0	27
28	1957	0	55	6.13	0	28
29	1958	0	57	5.91	0	29
30	1959	0	58	5.81	0	30
31	1960	0	59	5.71	0	31
32	1961	0	58	5.81	0	32
33	1962	0	59	5.71	0	33
34	1963	0	60	5.62	0	34
35	1964	0	61	5.52	0	35
36	1965	0	64	5.27	0	36
37	1966	0	65	5.18	0	37
38	1967	0	67	5.03	0	38
39	1968	0	71	4.75	0	39
40	1969	0	75	4.49	0	40
41	1970	0	79	4.27	0	41
42	1971	0	87	3.87	0	42
43	1972	39,375	93	3.62	142,538	43
44	1973	2,858	100	3.37	9,631	44
45	1974	14,234	118	2.86	40,709	45
46	1975	29,685	133	2.53	75,103	46
47	1976	0	138	2.44	0	47
48	1977	333,672	148	2.28	760,772	48
49	1978	2,837	161	2.09	5,929	49
50	1979	1,442	177	1.90	2,740	50
51	1980	5,619,654	194	1.74	9,778,198	51
52	1981	83,899	204	1.65	138,433	52
53	1982	0	207	1.63	0	53
54	1983	0	215	1.57	0	54
55	1984	2,512,131	224	1.50	3,768,197	55
56	1985	1,807,487	226	1.49	2,693,156	56
57	1986	1,051,025	231	1.46	1,534,497	57
58	1987	72,051	232	1.45	104,474	58
59	1988	5,270,095	232	1.45	7,641,638	59
60	1989	3,226,627	232	1.45	4,678,609	60
61	1990	173,889	236	1.43	248,661	61
62	1991	841,792	233	1.45	1,220,598	62
63	1992	194,321	238	1.42	275,936	63
64	1993	98,925	251	1.34	132,560	64
65	1994	260,571	261	1.29	336,137	65
66	1995	503,096	265	1.27	638,932	66
67	1996	193,758	278	1.21	234,447	67
68	1997	359,207	282	1.20	431,048	68
69	1998	492,267	285	1.18	580,875	69
70	1999	1,090,681	287	1.17	1,276,097	70
71	2000	779,977	295	1.14	889,174	71
72	2001	177,400	303	1.11	196,914	72
73	2002	336,702	310	1.09	367,005	73
74	2003	263,058	320	1.05	276,211	74
75	2004	445,469	337	1.00	445,469	75
76	Total	$ 26,278,185			$ 38,924,688	76

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF AUGUST 31, 2004

Account 390.2 - Leasehold Structures and Improvements

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	19	17.74	$ 0	1
2	1931	0	17	19.82	0	2
3	1932	0	16	21.06	0	3
4	1933	0	17	19.82	0	4
5	1934	0	19	17.74	0	5
6	1935	0	18	18.72	0	6
7	1936	0	19	17.74	0	7
8	1937	0	20	16.85	0	8
9	1938	0	20	16.85	0	9
10	1939	0	20	16.85	0	10
11	1940	0	20	16.85	0	11
12	1941	0	22	15.32	0	12
13	1942	0	23	14.65	0	13
14	1943	0	23	14.65	0	14
15	1944	0	24	14.04	0	15
16	1945	0	24	14.04	0	16
17	1946	0	27	12.48	0	17
18	1947	0	32	10.53	0	18
19	1948	0	36	9.36	0	19
20	1949	0	37	9.11	0	20
21	1950	0	39	8.64	0	21
22	1951	0	42	8.02	0	22
23	1952	0	44	7.66	0	23
24	1953	0	44	7.66	0	24
25	1954	0	46	7.33	0	25
26	1955	0	48	7.02	0	26
27	1956	0	52	6.48	0	27
28	1957	0	55	6.13	0	28
29	1958	0	57	5.91	0	29
30	1959	0	58	5.81	0	30
31	1960	0	59	5.71	0	31
32	1961	0	58	5.81	0	32
33	1962	0	59	5.71	0	33
34	1963	0	60	5.62	0	34
35	1964	0	61	5.52	0	35
36	1965	0	64	5.27	0	36
37	1966	0	65	5.18	0	37
38	1967	0	67	5.03	0	38
39	1968	0	71	4.75	0	39
40	1969	0	75	4.49	0	40
41	1970	0	79	4.27	0	41
42	1971	0	87	3.87	0	42
43	1972	0	93	3.62	0	43
44	1973	0	100	3.37	0	44
45	1974	0	118	2.86	0	45
46	1975	0	133	2.53	0	46
47	1976	0	138	2.44	0	47
48	1977	0	148	2.28	0	48
49	1978	0	161	2.09	0	49
50	1979	19,087	177	1.90	36,265	50
51	1980	7,025	194	1.74	12,224	51
52	1981	0	204	1.65	0	52
53	1982	0	207	1.63	0	53
54	1983	0	215	1.57	0	54
55	1984	68,562	224	1.50	102,843	55
56	1985	27,722	226	1.49	41,306	56
57	1986	30,477	231	1.46	44,496	57
58	1987	0	232	1.45	0	58
59	1988	87,786	232	1.45	127,290	59
60	1989	119,619	232	1.45	173,448	60
61	1990	0	236	1.43	0	61
62	1991	0	233	1.45	0	62
63	1992	0	238	1.42	0	63
64	1993	89,014	251	1.34	119,279	64
65	1994	10,978	261	1.29	14,162	65
66	1995	0	265	1.27	0	66
67	1996	31,836	278	1.21	38,522	67
68	1997	9,418	282	1.20	11,302	68
69	1998	121,696	285	1.18	143,601	69
70	1999	55,047	287	1.17	64,405	70
71	2000	14,670	295	1.14	16,724	71
72	2001	235,573	303	1.11	261,486	72
73	2002	60,614	310	1.09	66,069	73
74	2003	5,638	320	1.05	5,920	74
75	2004	10,805	337	1.00	10,805	75
76	Total	$ 1,005,567			$ 1,290,147	76

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF AUGUST 31, 2004

Account 391 - Office Furniture and Equipment

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	11	26.91	$ 0	1
2	1931	0	11	26.91	0	2
3	1932	0	11	26.91	0	3
4	1933	0	11	26.91	0	4
5	1934	0	11	26.91	0	5
6	1935	0	11	26.91	0	6
7	1936	0	12	24.67	0	7
8	1937	0	13	22.77	0	8
9	1938	0	13	22.77	0	9
10	1939	0	13	22.77	0	10
11	1940	0	13	22.77	0	11
12	1941	0	13	22.77	0	12
13	1942	0	15	19.73	0	13
14	1943	0	15	19.73	0	14
15	1944	0	15	19.73	0	15
16	1945	0	16	18.50	0	16
17	1946	0	20	14.80	0	17
18	1947	0	23	12.87	0	18
19	1948	0	26	11.38	0	19
20	1949	0	26	11.38	0	20
21	1950	0	27	10.96	0	21
22	1951	0	29	10.21	0	22
23	1952	0	31	9.55	0	23
24	1953	0	33	8.97	0	24
25	1954	0	34	8.71	0	25
26	1955	0	36	8.22	0	26
27	1956	0	39	7.59	0	27
28	1957	0	41	7.22	0	28
29	1958	0	42	7.05	0	29
30	1959	0	45	6.58	0	30
31	1960	0	46	6.43	0	31
32	1961	0	51	5.80	0	32
33	1962	0	53	5.58	0	33
34	1963	0	55	5.38	0	34
35	1964	0	57	5.19	0	35
36	1965	2,051	60	4.93	10,111	36
37	1966	3,149	62	4.77	15,021	37
38	1967	0	66	4.48	0	38
39	1968	283	70	4.23	1,197	39
40	1969	1,554	74	4.00	6,216	40
41	1970	615	81	3.65	2,245	41
42	1971	0	87	3.40	0	42
43	1972	0	94	3.15	0	43
44	1973	0	100	2.96	0	44
45	1974	0	109	2.72	0	45
46	1975	249	122	2.43	605	46
47	1976	208	130	2.28	474	47
48	1977	3,374	140	2.11	7,119	48
49	1978	0	150	1.97	0	49
50	1979	0	163	1.82	0	50
51	1980	247,294	177	1.67	412,981	51
52	1981	1,097	187	1.58	1,733	52
53	1982	502	202	1.47	738	53
54	1983	9,167	209	1.42	13,017	54
55	1984	54,735	211	1.40	76,629	55
56	1985	1,039,950	211	1.40	1,455,930	56
57	1986	385,190	218	1.36	523,858	57
58	1987	53,836	225	1.32	71,064	58
59	1988	540,938	218	1.36	735,676	59
60	1989	120,311	213	1.39	167,232	60
61	1990	6,975	228	1.30	9,068	61
62	1991	14,321	242	1.22	17,472	62
63	1992	29,616	249	1.19	35,243	63
64	1993	29,863	249	1.19	35,537	64
65	1994	69,698	257	1.15	80,153	65
66	1995	93,459	246	1.20	112,151	66
67	1996	48,437	250	1.18	57,156	67
68	1997	92,529	251	1.18	109,184	68
69	1998	87,423	254	1.17	102,285	69
70	1999	461,041	261	1.13	520,976	70
71	2000	660,913	268	1.10	727,004	71
72	2001	42,515	281	1.05	44,641	72
73	2002	546,892	289	1.02	557,830	73
74	2003	25,848	293	1.01	26,106	74
75	2004	175,794	296	1.00	175,794	75
76	Total	$ 4,849,827			$ 6,112,446	76

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF AUGUST 31, 2004

Account 391.1 - Computer Equipment

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	11	26.91	$ 0	1
2	1931	0	11	26.91	0	2
3	1932	0	11	26.91	0	3
4	1933	0	11	26.91	0	4
5	1934	0	11	26.91	0	5
6	1935	0	11	26.91	0	6
7	1936	0	12	24.67	0	7
8	1937	0	13	22.77	0	8
9	1938	0	13	22.77	0	9
10	1939	0	13	22.77	0	10
11	1940	0	13	22.77	0	11
12	1941	0	13	22.77	0	12
13	1942	0	15	19.73	0	13
14	1943	0	15	19.73	0	14
15	1944	0	15	19.73	0	15
16	1945	0	16	18.50	0	16
17	1946	0	20	14.80	0	17
18	1947	0	23	12.87	0	18
19	1948	0	26	11.38	0	19
20	1949	0	26	11.38	0	20
21	1950	0	27	10.96	0	21
22	1951	0	29	10.21	0	22
23	1952	0	31	9.55	0	23
24	1953	0	33	8.97	0	24
25	1954	0	34	8.71	0	25
26	1955	0	36	8.22	0	26
27	1956	0	39	7.59	0	27
28	1957	0	41	7.22	0	28
29	1958	0	42	7.05	0	29
30	1959	0	45	6.58	0	30
31	1960	0	46	6.43	0	31
32	1961	0	51	5.80	0	32
33	1962	0	53	5.58	0	33
34	1963	0	55	5.38	0	34
35	1964	0	57	5.19	0	35
36	1965	0	60	4.93	0	36
37	1966	0	62	4.77	0	37
38	1967	0	66	4.48	0	38
39	1968	0	70	4.23	0	39
40	1969	0	74	4.00	0	40
41	1970	0	81	3.65	0	41
42	1971	0	87	3.40	0	42
43	1972	0	94	3.15	0	43
44	1973	0	100	2.96	0	44
45	1974	0	109	2.72	0	45
46	1975	0	122	2.43	0	46
47	1976	0	130	2.28	0	47
48	1977	0	140	2.11	0	48
49	1978	0	150	1.97	0	49
50	1979	0	163	1.82	0	50
51	1980	0	177	1.67	0	51
52	1981	0	187	1.58	0	52
53	1982	0	202	1.47	0	53
54	1983	0	209	1.42	0	54
55	1984	0	211	1.40	0	55
56	1985	0	211	1.40	0	56
57	1986	0	218	1.36	0	57
58	1987	0	225	1.32	0	58
59	1988	1,080	218	1.36	1,469	59
60	1989	0	213	1.39	0	60
61	1990	0	228	1.30	0	61
62	1991	0	242	1.22	0	62
63	1992	0	249	1.19	0	63
64	1993	18,529	249	1.19	22,050	64
65	1994	27,180	257	1.15	31,257	65
66	1995	37,950	246	1.20	45,540	66
67	1996	72,237	250	1.18	85,240	67
68	1997	44,508	251	1.18	52,519	68
69	1998	47,451	254	1.17	55,518	69
70	1999	42,608	261	1.13	48,147	70
71	2000	885,596	268	1.10	974,156	71
72	2001	1,879,557	281	1.05	1,973,535	72
73	2002	2,365,077	289	1.02	2,412,379	73
74	2003	1,550,766	293	1.01	1,566,274	74
75	2004	1,327,971	296	1.00	1,327,971	75
76	Total	$ 8,300,510			$ 8,596,055	76

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF AUGUST 31, 2004

Account 392.1 - Transportation Equipment

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	22	18.59	$ 0	1
2	1931	0	20	20.45	0	2
3	1932	0	19	21.53	0	3
4	1933	0	19	21.53	0	4
5	1934	0	20	20.45	0	5
6	1935	0	21	19.48	0	6
7	1936	0	21	19.48	0	7
8	1937	0	23	17.78	0	8
9	1938	0	23	17.78	0	9
10	1939	0	23	17.78	0	10
11	1940	0	24	17.04	0	11
12	1941	0	25	16.36	0	12
13	1942	0	28	14.61	0	13
14	1943	0	29	14.10	0	14
15	1944	0	29	14.10	0	15
16	1945	0	29	14.10	0	16
17	1946	0	34	12.03	0	17
18	1947	0	37	11.05	0	18
19	1948	0	39	10.49	0	19
20	1949	0	40	10.23	0	20
21	1950	0	42	9.74	0	21
22	1951	0	45	9.09	0	22
23	1952	0	46	8.89	0	23
24	1953	0	49	8.35	0	24
25	1954	0	49	8.35	0	25
26	1955	0	51	8.02	0	26
27	1956	0	55	7.44	0	27
28	1957	0	59	6.93	0	28
29	1958	0	62	6.60	0	29
30	1959	0	64	6.39	0	30
31	1960	0	65	6.29	0	31
32	1961	0	67	6.10	0	32
33	1962	0	67	6.10	0	33
34	1963	0	68	6.01	0	34
35	1964	0	70	5.84	0	35
36	1965	0	71	5.76	0	36
37	1966	0	73	5.60	0	37
38	1967	0	76	5.38	0	38
39	1968	0	80	5.11	0	39
40	1969	0	84	4.87	0	40
41	1970	0	88	4.65	0	41
42	1971	0	93	4.40	0	42
43	1972	0	95	4.31	0	43
44	1973	0	100	4.09	0	44
45	1974	0	117	3.50	0	45
46	1975	0	141	2.90	0	46
47	1976	0	153	2.67	0	47
48	1977	0	164	2.49	0	48
49	1978	0	178	2.30	0	49
50	1979	3,530	197	2.08	7,342	50
51	1980	24,702	222	1.84	45,452	51
52	1981	0	246	1.66	0	52
53	1982	0	263	1.56	0	53
54	1983	1,020	269	1.52	1,550	54
55	1984	23,004	273	1.50	34,506	55
56	1985	19,935	276	1.48	29,504	56
57	1986	15,181	280	1.46	22,164	57
58	1987	52,607	286	1.43	75,228	58
59	1988	18,237	295	1.39	25,349	59
60	1989	24,749	308	1.33	32,916	60
61	1990	21,628	319	1.28	27,684	61
62	1991	129,861	325	1.26	163,625	62
63	1992	134,387	332	1.23	165,296	63
64	1993	179,593	347	1.18	211,920	64
65	1994	378,512	351	1.17	442,859	65
66	1995	1,458,919	358	1.14	1,663,168	66
67	1996	255,174	365	1.12	285,795	67
68	1997	1,766,639	373	1.10	1,943,303	68
69	1998	3,622,818	380	1.08	3,912,643	69
70	1999	3,119,918	385	1.06	3,307,113	70
71	2000	4,522,333	389	1.05	4,748,450	71
72	2001	6,601,997	390	1.05	6,932,097	72
73	2002	4,256,476	395	1.04	4,426,735	73
74	2003	1,295,927	401	1.02	1,321,846	74
75	2004	2,520,000	409	1.00	2,520,000	75
76	Total	$ 30,447,147			$ 32,346,545	76

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF AUGUST 31, 2004

Account 393 - Stores Equipment

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	22	18.59	$ 0	1
2	1931	0	20	20.45	0	2
3	1932	0	19	21.53	0	3
4	1933	0	19	21.53	0	4
5	1934	0	20	20.45	0	5
6	1935	0	21	19.48	0	6
7	1936	0	21	19.48	0	7
8	1937	0	23	17.78	0	8
9	1938	0	23	17.78	0	9
10	1939	0	23	17.78	0	10
11	1940	0	24	17.04	0	11
12	1941	0	25	16.36	0	12
13	1942	0	28	14.61	0	13
14	1943	0	29	14.10	0	14
15	1944	0	29	14.10	0	15
16	1945	0	29	14.10	0	16
17	1946	0	34	12.03	0	17
18	1947	0	37	11.05	0	18
19	1948	0	39	10.49	0	19
20	1949	0	40	10.23	0	20
21	1950	0	42	9.74	0	21
22	1951	0	45	9.09	0	22
23	1952	0	46	8.89	0	23
24	1953	0	49	8.35	0	24
25	1954	0	49	8.35	0	25
26	1955	0	51	8.02	0	26
27	1956	0	55	7.44	0	27
28	1957	0	59	6.93	0	28
29	1958	0	62	6.60	0	29
30	1959	0	64	6.39	0	30
31	1960	0	65	6.29	0	31
32	1961	0	67	6.10	0	32
33	1962	0	67	6.10	0	33
34	1963	0	68	6.01	0	34
35	1964	0	70	5.84	0	35
36	1965	0	71	5.76	0	36
37	1966	0	73	5.60	0	37
38	1967	0	76	5.38	0	38
39	1968	0	80	5.11	0	39
40	1969	0	84	4.87	0	40
41	1970	0	88	4.65	0	41
42	1971	0	93	4.40	0	42
43	1972	0	95	4.31	0	43
44	1973	0	100	4.09	0	44
45	1974	0	117	3.50	0	45
46	1975	0	141	2.90	0	46
47	1976	0	153	2.67	0	47
48	1977	0	164	2.49	0	48
49	1978	0	178	2.30	0	49
50	1979	2,936	197	2.08	6,107	50
51	1980	31,662	222	1.84	58,258	51
52	1981	0	246	1.66	0	52
53	1982	0	263	1.56	0	53
54	1983	2,855	269	1.52	4,340	54
55	1984	0	273	1.50	0	55
56	1985	69,961	276	1.48	103,542	56
57	1986	30,615	280	1.46	44,698	57
58	1987	17,738	286	1.43	25,365	58
59	1988	36,482	295	1.39	50,710	59
60	1989	1,293	308	1.33	1,720	60
61	1990	0	319	1.28	0	61
62	1991	0	325	1.26	0	62
63	1992	0	332	1.23	0	63
64	1993	9,251	347	1.18	10,916	64
65	1994	54,326	351	1.17	63,561	65
66	1995	0	358	1.14	0	66
67	1996	0	365	1.12	0	67
68	1997	43,406	373	1.10	47,747	68
69	1998	5,158	380	1.08	5,571	69
70	1999	50,326	385	1.06	53,346	70
71	2000	19,100	389	1.05	20,055	71
72	2001	7,243	390	1.05	7,605	72
73	2002	73,301	395	1.04	76,233	73
74	2003	0	401	1.02	0	74
75	2004	26,256	409	1.00	26,256	75
76	Total	$ 481,909			$ 606,030	76

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF AUGUST 31, 2004

Account 394 - Tools, Shop and Garage Equipment

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	22	18.59	$ 0	1
2	1931	0	20	20.45	0	2
3	1932	0	19	21.53	0	3
4	1933	0	19	21.53	0	4
5	1934	0	20	20.45	0	5
6	1935	0	21	19.48	0	6
7	1936	0	21	19.48	0	7
8	1937	0	23	17.78	0	8
9	1938	0	23	17.78	0	9
10	1939	0	23	17.78	0	10
11	1940	0	24	17.04	0	11
12	1941	0	25	16.36	0	12
13	1942	0	28	14.61	0	13
14	1943	0	29	14.10	0	14
15	1944	0	29	14.10	0	15
16	1945	0	29	14.10	0	16
17	1946	0	34	12.03	0	17
18	1947	0	37	11.05	0	18
19	1948	0	39	10.49	0	19
20	1949	0	40	10.23	0	20
21	1950	0	42	9.74	0	21
22	1951	0	45	9.09	0	22
23	1952	0	46	8.89	0	23
24	1953	0	49	8.35	0	24
25	1954	0	49	8.35	0	25
26	1955	0	51	8.02	0	26
27	1956	0	55	7.44	0	27
28	1957	0	59	6.93	0	28
29	1958	0	62	6.60	0	29
30	1959	0	64	6.39	0	30
31	1960	0	65	6.29	0	31
32	1961	0	67	6.10	0	32
33	1962	0	67	6.10	0	33
34	1963	0	68	6.01	0	34
35	1964	0	70	5.84	0	35
36	1965	0	71	5.76	0	36
37	1966	0	73	5.60	0	37
38	1967	0	76	5.38	0	38
39	1968	0	80	5.11	0	39
40	1969	0	84	4.87	0	40
41	1970	0	88	4.65	0	41
42	1971	0	93	4.40	0	42
43	1972	0	95	4.31	0	43
44	1973	0	100	4.09	0	44
45	1974	0	117	3.50	0	45
46	1975	573	141	2.90	1,662	46
47	1976	0	153	2.67	0	47
48	1977	0	164	2.49	0	48
49	1978	245	178	2.30	564	49
50	1979	125	197	2.08	260	50
51	1980	58,802	222	1.84	108,196	51
52	1981	29,627	246	1.66	49,181	52
53	1982	35,285	263	1.56	55,045	53
54	1983	13,062	269	1.52	19,854	54
55	1984	22,904	273	1.50	34,356	55
56	1985	21,379	276	1.48	31,641	56
57	1986	304,545	280	1.46	444,636	57
58	1987	38,057	286	1.43	54,422	58
59	1988	93,946	295	1.39	130,585	59
60	1989	259,615	308	1.33	345,288	60
61	1990	21,537	319	1.28	27,567	61
62	1991	33,691	325	1.26	42,451	62
63	1992	94,018	332	1.23	115,642	63
64	1993	112,884	347	1.18	133,203	64
65	1994	374,395	351	1.17	438,042	65
66	1995	433,928	358	1.14	494,678	66
67	1996	222,326	365	1.12	249,005	67
68	1997	92,300	373	1.10	101,530	68
69	1998	558,583	380	1.08	603,270	69
70	1999	333,247	385	1.06	353,242	70
71	2000	401,286	389	1.05	421,350	71
72	2001	260,144	390	1.05	273,151	72
73	2002	407,285	395	1.04	423,576	73
74	2003	139,030	401	1.02	141,811	74
75	2004	506,200	409	1.00	506,200	75
76	Total	$ 4,869,019			$ 5,600,408	76

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF AUGUST 31, 2004

Account 395 - Laboratory Equipment

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	11	26.91	$ 0	1
2	1931	0	11	26.91	0	2
3	1932	0	11	26.91	0	3
4	1933	0	11	26.91	0	4
5	1934	0	11	26.91	0	5
6	1935	0	11	26.91	0	6
7	1936	0	12	24.67	0	7
8	1937	0	13	22.77	0	8
9	1938	0	13	22.77	0	9
10	1939	0	13	22.77	0	10
11	1940	0	13	22.77	0	11
12	1941	0	13	22.77	0	12
13	1942	0	15	19.73	0	13
14	1943	0	15	19.73	0	14
15	1944	0	15	19.73	0	15
16	1945	0	16	18.50	0	16
17	1946	0	20	14.80	0	17
18	1947	0	23	12.87	0	18
19	1948	0	26	11.38	0	19
20	1949	0	26	11.38	0	20
21	1950	0	27	10.96	0	21
22	1951	0	29	10.21	0	22
23	1952	0	31	9.55	0	23
24	1953	0	33	8.97	0	24
25	1954	0	34	8.71	0	25
26	1955	0	36	8.22	0	26
27	1956	0	39	7.59	0	27
28	1957	0	41	7.22	0	28
29	1958	0	42	7.05	0	29
30	1959	0	45	6.58	0	30
31	1960	0	46	6.43	0	31
32	1961	0	51	5.80	0	32
33	1962	0	53	5.58	0	33
34	1963	0	55	5.38	0	34
35	1964	0	57	5.19	0	35
36	1965	0	60	4.93	0	36
37	1966	0	62	4.77	0	37
38	1967	0	66	4.48	0	38
39	1968	0	70	4.23	0	39
40	1969	0	74	4.00	0	40
41	1970	0	81	3.65	0	41
42	1971	0	87	3.40	0	42
43	1972	0	94	3.15	0	43
44	1973	0	100	2.96	0	44
45	1974	0	109	2.72	0	45
46	1975	0	122	2.43	0	46
47	1976	0	130	2.28	0	47
48	1977	0	140	2.11	0	48
49	1978	0	150	1.97	0	49
50	1979	0	163	1.82	0	50
51	1980	0	177	1.67	0	51
52	1981	0	187	1.58	0	52
53	1982	0	202	1.47	0	53
54	1983	0	209	1.42	0	54
55	1984	0	211	1.40	0	55
56	1985	0	211	1.40	0	56
57	1986	0	218	1.36	0	57
58	1987	0	225	1.32	0	58
59	1988	0	218	1.36	0	59
60	1989	0	213	1.39	0	60
61	1990	2,960	228	1.30	3,848	61
62	1991	0	242	1.22	0	62
63	1992	0	249	1.19	0	63
64	1993	1,176	249	1.19	1,399	64
65	1994	35,045	257	1.15	40,302	65
66	1995	11,623	246	1.20	13,948	66
67	1996	10,818	250	1.18	12,765	67
68	1997	0	251	1.18	0	68
69	1998	60,911	254	1.17	71,266	69
70	1999	189,739	261	1.13	214,405	70
71	2000	0	268	1.10	0	71
72	2001	51,600	281	1.05	54,180	72
73	2002	59,897	289	1.02	61,095	73
74	2003	1,553	293	1.01	1,569	74
75	2004	0	296	1.00	0	75
76	Total	$ 425,322			$ 474,777	76

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF AUGUST 31, 2004

Account 396 - Power Operated Equipment

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	22	18.59	$ 0	1
2	1931	0	20	20.45	0	2
3	1932	0	19	21.53	0	3
4	1933	0	19	21.53	0	4
5	1934	0	20	20.45	0	5
6	1935	0	21	19.48	0	6
7	1936	0	21	19.48	0	7
8	1937	0	23	17.78	0	8
9	1938	0	23	17.78	0	9
10	1939	0	23	17.78	0	10
11	1940	0	24	17.04	0	11
12	1941	0	25	16.36	0	12
13	1942	0	28	14.61	0	13
14	1943	0	29	14.10	0	14
15	1944	0	29	14.10	0	15
16	1945	0	29	14.10	0	16
17	1946	0	34	12.03	0	17
18	1947	0	37	11.05	0	18
19	1948	0	39	10.49	0	19
20	1949	0	40	10.23	0	20
21	1950	0	42	9.74	0	21
22	1951	0	45	9.09	0	22
23	1952	0	46	8.89	0	23
24	1953	0	49	8.35	0	24
25	1954	0	49	8.35	0	25
26	1955	0	51	8.02	0	26
27	1956	0	55	7.44	0	27
28	1957	0	59	6.93	0	28
29	1958	0	62	6.60	0	29
30	1959	0	64	6.39	0	30
31	1960	0	65	6.29	0	31
32	1961	0	67	6.10	0	32
33	1962	0	67	6.10	0	33
34	1963	0	68	6.01	0	34
35	1964	0	70	5.84	0	35
36	1965	0	71	5.76	0	36
37	1966	0	73	5.60	0	37
38	1967	0	76	5.38	0	38
39	1968	0	80	5.11	0	39
40	1969	0	84	4.87	0	40
41	1970	0	88	4.65	0	41
42	1971	0	93	4.40	0	42
43	1972	0	95	4.31	0	43
44	1973	1,420	100	4.09	5,808	44
45	1974	0	117	3.50	0	45
46	1975	0	141	2.90	0	46
47	1976	0	153	2.67	0	47
48	1977	0	164	2.49	0	48
49	1978	0	178	2.30	0	49
50	1979	17,412	197	2.08	36,217	50
51	1980	2,846	222	1.84	5,237	51
52	1981	0	246	1.66	0	52
53	1982	0	263	1.56	0	53
54	1983	842	269	1.52	1,280	54
55	1984	72,932	273	1.50	109,398	55
56	1985	9,790	276	1.48	14,489	56
57	1986	33,552	280	1.46	48,986	57
58	1987	10,232	286	1.43	14,632	58
59	1988	136,908	295	1.39	190,302	59
60	1989	31,416	308	1.33	41,783	60
61	1990	49,705	319	1.28	63,622	61
62	1991	100,895	325	1.26	127,128	62
63	1992	37,484	332	1.23	46,105	63
64	1993	71,336	347	1.18	84,176	64
65	1994	1,071,405	351	1.17	1,253,544	65
66	1995	281,122	358	1.14	320,479	66
67	1996	112,568	365	1.12	126,076	67
68	1997	25,800	373	1.10	28,380	68
69	1998	330,032	380	1.08	356,435	69
70	1999	301,944	385	1.06	320,061	70
71	2000	360,624	389	1.05	378,655	71
72	2001	323,545	390	1.05	339,722	72
73	2002	145,971	395	1.04	151,810	73
74	2003	91,305	401	1.02	93,131	74
75	2004	186,461	409	1.00	186,461	75
76	Total	$ 3,807,547			$ 4,343,917	76

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF AUGUST 31, 2004

Account 397.1 - Communication Equipment

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	15	21.53	$ 0	1
2	1931	0	15	21.53	0	2
3	1932	0	15	21.53	0	3
4	1933	0	15	21.53	0	4
5	1934	0	15	21.53	0	5
6	1935	0	15	21.53	0	6
7	1936	0	15	21.53	0	7
8	1937	0	17	19.00	0	8
9	1938	0	17	19.00	0	9
10	1939	0	17	19.00	0	10
11	1940	0	17	19.00	0	11
12	1941	0	18	17.94	0	12
13	1942	0	19	17.00	0	13
14	1943	0	19	17.00	0	14
15	1944	0	19	17.00	0	15
16	1945	0	19	17.00	0	16
17	1946	0	21	15.38	0	17
18	1947	0	24	13.46	0	18
19	1948	0	26	12.42	0	19
20	1949	0	28	11.54	0	20
21	1950	0	30	10.77	0	21
22	1951	0	31	10.42	0	22
23	1952	0	33	9.79	0	23
24	1953	0	34	9.50	0	24
25	1954	0	36	8.97	0	25
26	1955	0	37	8.73	0	26
27	1956	0	39	8.28	0	27
28	1957	0	41	7.88	0	28
29	1958	0	42	7.69	0	29
30	1959	0	45	7.18	0	30
31	1960	0	46	7.02	0	31
32	1961	0	49	6.59	0	32
33	1962	0	51	6.33	0	33
34	1963	0	52	6.21	0	34
35	1964	0	54	5.98	0	35
36	1965	0	57	5.67	0	36
37	1966	0	58	5.57	0	37
38	1967	0	62	5.21	0	38
39	1968	0	64	5.05	0	39
40	1969	0	69	4.68	0	40
41	1970	1,328	78	4.14	5,498	41
42	1971	0	88	3.67	0	42
43	1972	0	95	3.40	0	43
44	1973	3,598	100	3.23	11,622	44
45	1974	0	109	2.96	0	45
46	1975	0	121	2.67	0	46
47	1976	0	131	2.47	0	47
48	1977	0	142	2.27	0	48
49	1978	0	151	2.14	0	49
50	1979	0	160	2.02	0	50
51	1980	0	170	1.90	0	51
52	1981	0	186	1.74	0	52
53	1982	0	206	1.57	0	53
54	1983	7,261	218	1.48	10,746	54
55	1984	267	219	1.47	392	55
56	1985	339,161	213	1.52	515,525	56
57	1986	50,148	215	1.50	75,222	57
58	1987	62,691	216	1.50	94,037	58
59	1988	35,672	214	1.51	53,865	59
60	1989	45,804	214	1.51	69,164	60
61	1990	6,723	220	1.47	9,883	61
62	1991	2,143	225	1.44	3,086	62
63	1992	72,622	232	1.39	100,945	63
64	1993	36,691	236	1.37	50,267	64
65	1994	251,741	239	1.35	339,850	65
66	1995	114,702	247	1.31	150,260	66
67	1996	40,048	254	1.27	50,861	67
68	1997	250,043	257	1.26	315,054	68
69	1998	214,085	265	1.22	261,184	69
70	1999	490,884	275	1.17	574,334	70
71	2000	115,484	285	1.13	130,497	71
72	2001	10,168	299	1.08	10,981	72
73	2002	0	309	1.05	0	73
74	2003	37,364	318	1.02	38,111	74
75	2004	29,805	323	1.00	29,805	75
76	Total	$ 2,218,433			$ 2,901,189	76

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF AUGUST 31, 2004

Account 397.2 - Telemetering Equipment

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	15	21.53	$ 0	1
2	1931	0	15	21.53	0	2
3	1932	0	15	21.53	0	3
4	1933	0	15	21.53	0	4
5	1934	0	15	21.53	0	5
6	1935	0	15	21.53	0	6
7	1936	0	15	21.53	0	7
8	1937	0	17	19.00	0	8
9	1938	0	17	19.00	0	9
10	1939	0	17	19.00	0	10
11	1940	0	17	19.00	0	11
12	1941	0	18	17.94	0	12
13	1942	0	19	17.00	0	13
14	1943	0	19	17.00	0	14
15	1944	0	19	17.00	0	15
16	1945	0	19	17.00	0	16
17	1946	0	21	15.38	0	17
18	1947	0	24	13.46	0	18
19	1948	0	26	12.42	0	19
20	1949	0	28	11.54	0	20
21	1950	0	30	10.77	0	21
22	1951	0	31	10.42	0	22
23	1952	0	33	9.79	0	23
24	1953	0	34	9.50	0	24
25	1954	0	36	8.97	0	25
26	1955	0	37	8.73	0	26
27	1956	0	39	8.28	0	27
28	1957	0	41	7.88	0	28
29	1958	0	42	7.69	0	29
30	1959	0	45	7.18	0	30
31	1960	0	46	7.02	0	31
32	1961	0	49	6.59	0	32
33	1962	0	51	6.33	0	33
34	1963	0	52	6.21	0	34
35	1964	0	54	5.98	0	35
36	1965	0	57	5.67	0	36
37	1966	0	58	5.57	0	37
38	1967	0	62	5.21	0	38
39	1968	0	64	5.05	0	39
40	1969	0	69	4.68	0	40
41	1970	0	78	4.14	0	41
42	1971	0	88	3.67	0	42
43	1972	0	95	3.40	0	43
44	1973	0	100	3.23	0	44
45	1974	0	109	2.96	0	45
46	1975	0	121	2.67	0	46
47	1976	0	131	2.47	0	47
48	1977	0	142	2.27	0	48
49	1978	0	151	2.14	0	49
50	1979	0	160	2.02	0	50
51	1980	0	170	1.90	0	51
52	1981	0	186	1.74	0	52
53	1982	0	206	1.57	0	53
54	1983	0	218	1.48	0	54
55	1984	0	219	1.47	0	55
56	1985	0	213	1.52	0	56
57	1986	0	215	1.50	0	57
58	1987	0	216	1.50	0	58
59	1988	19,285	214	1.51	29,120	59
60	1989	0	214	1.51	0	60
61	1990	2,507	220	1.47	3,685	61
62	1991	242,953	225	1.44	349,852	62
63	1992	24,637	232	1.39	34,245	63
64	1993	3,280	236	1.37	4,494	64
65	1994	42,163	239	1.35	56,920	65
66	1995	130,115	247	1.31	170,451	66
67	1996	16,779	254	1.27	21,309	67
68	1997	0	257	1.26	0	68
69	1998	0	265	1.22	0	69
70	1999	9,868	275	1.17	11,546	70
71	2000	62,886	285	1.13	71,061	71
72	2001	0	299	1.08	0	72
73	2002	0	309	1.05	0	73
74	2003	0	318	1.02	0	74
75	2004	0	323	1.00	0	75
76	Total	$ 554,473			$ 752,683	76

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF AUGUST 31, 2004

Account 398 - Miscellaneous Equipment

Line No.	Year Installed (a)	Original Cost Total Arizona (b)	H - W Index (c)	Ratio To Current Index (d)	RCN Total Arizona (e)	Line No.
1	1930	$ 0	15	21.53	$ 0	1
2	1931	0	15	21.53	0	2
3	1932	0	15	21.53	0	3
4	1933	0	15	21.53	0	4
5	1934	0	15	21.53	0	5
6	1935	0	15	21.53	0	6
7	1936	0	15	21.53	0	7
8	1937	0	17	19.00	0	8
9	1938	0	17	19.00	0	9
10	1939	0	17	19.00	0	10
11	1940	0	17	19.00	0	11
12	1941	0	18	17.94	0	12
13	1942	0	19	17.00	0	13
14	1943	0	19	17.00	0	14
15	1944	0	19	17.00	0	15
16	1945	0	19	17.00	0	16
17	1946	0	21	15.38	0	17
18	1947	0	24	13.46	0	18
19	1948	0	26	12.42	0	19
20	1949	0	28	11.54	0	20
21	1950	0	30	10.77	0	21
22	1951	0	31	10.42	0	22
23	1952	0	33	9.79	0	23
24	1953	0	34	9.50	0	24
25	1954	0	36	8.97	0	25
26	1955	0	37	8.73	0	26
27	1956	0	39	8.28	0	27
28	1957	0	41	7.88	0	28
29	1958	0	42	7.69	0	29
30	1959	0	45	7.18	0	30
31	1960	0	46	7.02	0	31
32	1961	0	49	6.59	0	32
33	1962	0	51	6.33	0	33
34	1963	0	52	6.21	0	34
35	1964	0	54	5.98	0	35
36	1965	0	57	5.67	0	36
37	1966	0	58	5.57	0	37
38	1967	561	62	5.21	2,923	38
39	1968	0	64	5.05	0	39
40	1969	0	69	4.68	0	40
41	1970	0	78	4.14	0	41
42	1971	0	88	3.67	0	42
43	1972	909	95	3.40	3,091	43
44	1973	0	100	3.23	0	44
45	1974	1,816	109	2.96	5,375	45
46	1975	0	121	2.67	0	46
47	1976	0	131	2.47	0	47
48	1977	4,754	142	2.27	10,792	48
49	1978	0	151	2.14	0	49
50	1979	3,438	160	2.02	6,945	50
51	1980	32,264	170	1.90	61,302	51
52	1981	5,188	186	1.74	9,027	52
53	1982	0	206	1.57	0	53
54	1983	0	218	1.48	0	54
55	1984	1,062	219	1.47	1,561	55
56	1985	21,976	213	1.52	33,404	56
57	1986	37,656	215	1.50	56,484	57
58	1987	8,566	216	1.50	12,849	58
59	1988	3,370	214	1.51	5,089	59
60	1989	3,341	214	1.51	5,045	60
61	1990	13,839	220	1.47	20,343	61
62	1991	5,291	225	1.44	7,619	62
63	1992	553	232	1.39	769	63
64	1993	17,590	236	1.37	24,098	64
65	1994	27,683	239	1.35	37,372	65
66	1995	41,250	247	1.31	54,038	66
67	1996	22,089	254	1.27	28,053	67
68	1997	8,397	257	1.26	10,580	68
69	1998	15,676	265	1.22	19,125	69
70	1999	32,305	275	1.17	37,797	70
71	2000	357,301	285	1.13	403,750	71
72	2001	55,058	299	1.08	59,463	72
73	2002	63,963	309	1.05	67,161	73
74	2003	14,307	318	1.02	14,593	74
75	2004	30,001	323	1.00	30,001	75
76	Total	$ 830,204			$ 1,028,649	76

SOUTHWEST GAS CORPORATION
ARIZONA
SUMMARY OF WORKING CAPITAL ALLOWANCE
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Reference (b)		Balance (c)	Line No.
1	Cash Working Capital	B-5, Sh 2	$	(11,082,156)	1
2	Materials and Supplies	B-5, Sh 3		9,222,489	2
3	Prepayments	B-5, Sh 4		2,740,815	3
4	Total Working Capital		$	881,148	4

SOUTHWEST GAS CORPORATION
ARIZONA
LEAD-LAG STUDY
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description [1]	Cost	Lag Days	Dollar Days	Line No.
	(a)	(b)	(c)	(d)	
1	Cost of Gas [2]	$ 298,559,015	43.78	13,070,913,677	1
2	Labor Cost	107,117,974	14.01	1,500,332,454	2
3	Provision for Uncollected Accounts	1,498,151	120.00	179,778,121	3
4	Other O & M Expenses	45,068,143	6.32	284,830,661	4
5	Total O & M Expenses	$ 452,243,282	33.25	15,035,854,913	5
6	Interest	40,521,530	87.34	3,539,150,388	6
7	Taxes Other Than Income Taxes	33,455,124	206.50	6,908,483,010	7
8	Income Taxes-Current	18,192,843	37.00	673,135,208	8
9	Total Operating Expenses	$ 544,412,779	48.05	26,156,623,519	9
10	Number of Days in Test Period	365			10
11	Average Daily Operating Expense	$ 1,491,542			11
12	Lag in Receipt of Revenue		40.62		12
13	Net Difference Revenue-Expense Lag	(7.43)			13
14	Cash Working Capital	$ (11,082,156)			14

[1] Supporting Workpapers B-5
[2] Gas costs adjusted for present volumes and rates to synchronize with gas cost adjustment.

SOUTHWEST GAS CORPORATION
ARIZONA
MATERIALS AND SUPPLIES
FOR THE THIRTEEN MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Account Number [1] 154 (b)	Account Number [1] 155 (c)	Account Number [1] 163 (d)	System Allocable (e)	Total Materials and Supplies (f)	Line No.
1	August 2003	$ 7,093,206	$ 31,835	$ 790,866	$ (9,755)	$ 7,906,153	1
2	September	7,780,136	31,565	807,234	(10,026)	8,608,908	2
3	October	7,971,179	34,790	927,229	(10,639)	8,922,559	3
4	November	8,461,601	35,065	742,627	(10,809)	9,228,483	4
5	December	8,526,191	31,523	475,427	(242)	9,032,899	5
6	January 2004	8,744,041	33,209	462,161	(10,662)	9,228,749	6
7	February	8,645,011	32,735	307,899	(11,144)	8,974,501	7
8	March	8,473,634	34,246	559,761	(11,252)	9,056,389	8
9	April	8,316,421	41,188	636,464	(11,493)	8,982,580	9
10	May	8,092,091	38,989	544,264	(11,593)	8,663,751	10
11	June	8,622,789	35,804	443,632	(11,588)	9,090,636	11
12	July	9,131,707	36,166	457,488	(11,304)	9,614,056	12
13	August	12,020,084	39,682	534,759	(11,829)	12,582,696	13
14	Thirteen Month Total	$ 111,878,090	$ 456,795	$ 7,689,811	$ (132,335)	$ 119,892,361	14
15	Thirteen Month Average	$ 8,606,007	$ 35,138	$ 591,524	$ (10,180)	$ 9,222,489	15

Note:
System Allocable includes common inventory accounts for 154, 155 and 163 after 4-Factor allocation on Supporting Schedule C-1, Sh 18 of 57.58%

[1] Supporting Workpapers B-5

SOUTHWEST GAS CORPORATION
ARIZONA
PREPAYMENTS
FOR THE THIRTEEN MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Balance [1] (b)	4-Factor [2] (c)	Allocation (d)	Line No.
1	August 2003	$ 5,130,082			1
2	September 2003	4,798,680			2
3	October 2003	3,784,576			3
4	November 2003	3,956,561			4
5	December 2003	5,938,689			5
6	January 2004	5,258,062			6
7	February 2004	4,984,761			7
8	March 2004	4,810,591			8
9	April 2004	4,204,986			9
10	May 2004	4,296,987			10
11	June 2004	3,639,813			11
12	July 2004	3,377,801			12
13	August 2004	7,698,845			13
14	Thirteen Month Total	$ 61,880,434			14
15	13 Month Average	$ 4,760,033			15
16	Deferred Taxes	0			16
17	Net of Deferred Tax	$ 4,760,033	57.58%	$ 2,740,815	17

[1] Eligible Prepayments - Account 165. Supporting Workpapers B-5
[2] Supporting Schedule C-1, Sh 18

SOUTHWEST GAS CORPORATION
ARIZONA
CUSTOMER ADVANCES FOR CONSTRUCTION
FOR THE THIRTEEN MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)		Balance [1] (b)	Line No.
1	August 2003	$	5,256,145	1
2	September 2003		5,605,563	2
3	October 2003		5,668,202	3
4	November 2003		5,870,615	4
5	December 2003		7,111,517	5
6	January 2004		7,275,363	6
7	February 2004		7,388,986	7
8	March 2004		7,593,596	8
9	April 2004		7,573,984	9
10	May 2004		7,808,975	10
11	June 2004		7,992,414	11
12	July 2004		8,034,485	12
13	August 2004		8,175,998	13
14	Thirteen Month Total	$	91,355,841	14
15	Thirteen Month Average	$	7,027,372	15

[1] Source: Company Records, Account 252

SOUTHWEST GAS CORPORATION
ARIZONA
CUSTOMER DEPOSITS
FOR THE THIRTEEN MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Balance [1] (b)	Line No.
1	August 2003	$ 21,697,818	1
2	September 2003	22,116,629	2
3	October 2003	22,421,280	3
4	November 2003	22,915,023	4
5	December 2003	23,429,731	5
6	January 2004	23,858,508	6
7	February 2004	24,244,633	7
8	March 2004	24,547,955	8
9	April 2004	24,807,840	9
10	May 2004	24,958,957	10
11	June 2004	25,170,362	11
12	July 2004	25,267,247	12
13	August 2004	25,421,849	13
14	Thirteen Month Total	$ 310,857,833	14
15	Thirteen Month Average	$ 23,912,141	15

[1] Source: Company Records, Account 235
(excludes 235.0 1330)

SOUTHWEST GAS CORPORATION
DEFERRED TAXES
AT AUGUST 31, 2004
AS ADJUSTED

Line No.	Description [1] (a)	Arizona (b)	System Allocable Allocation (c)	Recorded Deferred Tax (d)	Adjustments (e)	Adjusted Deferred Tax (f)	Line No.
1	Account 282\Deferred Tax Liability	$ 147,524,713	$ 10,452,814	$ 157,977,527	$ (165,641)	$ 157,811,886	1
2	Account 190\Deferred Tax Asset	0	(21,120,559)	(21,120,559)	0	(21,120,559)	2
3	Total	$ 147,524,713	$ (10,667,744)	$ 136,856,969	$ (165,641)	$ 136,691,328	3

Deferred Tax Detail
Arizona

Line No.	Description	Federal	State	Total Recorded	Adjustment [2]	Adjusted	Line No.
4	Account 282\Deferred Tax Liability	$ 127,619,768	$ 19,904,945	$ 147,524,713	$ (165,641)	$ 147,359,072	4
5	Account 190\Deferred Tax Asset	0	0	0	0	0	5
6	Total	$ 127,619,768	$ 19,904,945	$ 147,524,713	$ (165,641)	$ 147,359,072	6

System Allocable

Line No.	Description [1]	Recorded	Adjustment	Adjusted	Line No.
7	Account 282\Deferred Tax Liability	$ 18,153,632	$ 0	$ 18,153,632	7
8	4-Factor [3]	57.58%	57.58%	57.58%	8
9	Arizona Allocation	$ 10,452,814	$ 0	$ 10,452,814	9
10	Account 190\Deferred Tax Asset	$ (36,680,538)	$ 0	$ (36,680,538)	10
11	4-Factor [3]	57.58%	57.58%	57.58%	11
12	Arizona Allocation	$ (21,120,559)	$ 0	$ (21,120,559)	12
				Ln 2, Col (c)	

[1] Source: Company Records
[2] Supporting Schedule C-2, Adj. 11, Pipe Replacement, Leak Survey and Repair
[3] Supporting Schedule C-1, Sh 18

C

SOUTHWEST GAS CORPORATION
ARIZONA
ADJUSTED TEST YEAR INCOME STATEMENT
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Reference Sch C-1, Sheet (b)	Recorded at 08/31/04 (c)	Adjustments (d)	Adjusted at 08/31/04 (e)	Line No.
1	Revenues	2	$ 647,277,066	$ (324,411,088)	$ 322,865,978	1
2	Gas Cost	3	327,132,801	(327,132,801)	0	2
3	Total Margin		$ 320,144,265	$ 2,721,713	$ 322,865,978	3
	Expenses					
4	Other Gas Supply	3	$ 720,807	$ 19,584	$ 740,391	4
5	Distribution	3	75,753,130	2,827,336	78,580,466	5
6	Customer Accounts	3	33,133,096	870,183	34,003,279	6
7	Customer Information	4	596,225	(47,730)	548,496	7
8	Sales	4	512,205	(512,205)	0	8
	Administrative & General					
9	Direct	4	6,967,455	25,845	6,993,300	9
10	System Allocable	4	41,676,104	3,811,791	45,487,895	10
	Depreciation & Amortization					
11	Direct	15	64,380,219	2,958,642	67,338,861	11
12	System Allocable	15	8,194,311	(1,131,728)	7,062,583	12
13	Regulatory Amortizations	15	887,124	661,080	1,548,204	13
14	Other Taxes	16	29,122,261	4,332,862	33,455,124	14
15	Interest On Customer Deposits	C-2, Adj 19	1,404,209	(686,844)	717,364	15
16	Income Taxes	17	6,290,071	(4,133,407)	2,156,664	16
17	Total Expenses		$ 269,637,217	$ 8,995,409	$ 278,632,626	17
18	Net Income		$ 50,507,047	$ (6,273,696)	$ 44,233,351	18

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
ADJUSTED SALES AND REVENUES
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description	Recorded At 08/31/2004	Adjustment No. 1	Test Period Balance As Adjusted	Line No.
	(a)	(b)	(c)	(d)	
1	Sales Quantity (therms)	663,721,397	(21,043,264)	642,678,133	1
2	Revenue	$ 647,277,066	$(324,411,088)	$ 322,865,978	2
3	Total Revenue Adjustment		$(324,411,088)		3

SOUTHWEST GAS CORPORATION
ARIZONA
OPERATION AND MAINTENANCE EXPENSES
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004
AS ADJUSTED FOR THE TEST YEAR

Line No.	Description	Account Number	Recorded at 08/31/04	Adjustments	Adjusted at 08/31/04	Line No.
	(a)	(b)	(c)	(d)	(e)	
	Gas Supply Expenses					
1	Natural Gas Transmission Line Purchases	803	$ 321,120,351	$ (321,120,351)	$ 0	1
2	Purchased Gas Cost Adjustments	805.1	(22,561,336)	22,561,336	0	2
3	Gas Used for Compressor Station Fuel	810	0	0	0	3
4	Other Gas Supply Expenses	813	720,807	19,584	740,391	4
5	Total Other Gas Supply Expenses		$ 299,279,823	$ (298,539,432)	$ 740,391	5
	Transmission Expenses					
6	Trans. and Compression of Gas by Others	858	$ 28,573,786	$ (28,573,786)	$ 0	6
	Distribution Expenses					
7	Operation Supervision and Engineering	870	$ 8,366,912	$ 91,927	$ 8,458,839	7
8	Distribution Load Dispatching	871	645,376	14,983	660,359	8
9	Mains and Services Expenses	874	9,537,188	1,604,688	11,141,876	9
10	Measuring and Regulating Expenses - General	875	2,710,867	31,010	2,741,877	10
11	Meter and House Regulator Expenses	878	6,579,366	92,291	6,671,656	11
12	Customer Installation Expenses	879	7,784,691	109,025	7,893,716	12
13	Other Expenses	880	10,509,449	46,237	10,555,686	13
14	Rents	881	1,860,559	119,824	1,980,383	14
15	Maintenance Supervision and Engineering	885	2,589,475	39,630	2,629,104	15
16	Maintenance of Structures and Improvements	886	64,171	219	64,389	16
17	Maintenance of Mains	887	12,871,755	609,048	13,480,803	17
18	Maintenance of Meas. and Reg. Sta. Equip.	889	1,930,217	17,811	1,948,028	18
19	Maintenance of Services	892	8,196,754	30,286	8,227,040	19
20	Maintenance of Meters and House Regulators	893	1,914,127	17,961	1,932,088	20
21	Maintenance of Other Equipment	894	192,224	2,398	194,621	21
22	Total Distribution Expenses		$ 75,753,130	$ 2,827,336	$ 78,580,466	22
	Customer Accounts Expenses					
23	Supervision	901	$ 3,735,913	$ 56,878	$ 3,792,791	23
24	Meter Reading	902	6,334,632	81,718	6,416,351	24
25	Customer Records and Collection Expenses	903	21,562,100	339,818	21,901,919	25
26	Uncollectible Accounts	904	1,112,324	385,827	1,498,151	26
27	Miscellaneous Customer Accounts Expenses	905	388,127	5,941	394,068	27
28	Total Customer Accounts Expenses		$ 33,133,096	$ 870,183	$ 34,003,279	28

Supporting Schedules C-1, Sh 5-7

SOUTHWEST GAS CORPORATION
ARIZONA
OPERATION AND MAINTENANCE EXPENSES
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004
AS ADJUSTED FOR THE TEST YEAR

Line No.	Description	Account Number	Recorded at 08/31/04	Adjustments	Adjusted at 08/31/04	Line No.
	(a)	(b)	(c)	(d)	(e)	
	Customer Service and Informational Expenses					
1	Customer Assistance Expenses	908	$ 562,187	$ (38,296)	$ 523,891	1
2	Inform. and Instruc. Advertising Expenses	909	(2,154)	2,154	0	2
3	Misc. Customer Service and Inform. Expenses	910	36,192	(11,587)	24,605	3
4	Total Customer Service and Informational Expenses		$ 596,225	$ (47,730)	$ 548,496	4
	Sales Expenses					
5	Supervision	911	$ 0	$ 0	$ 0	5
6	Demonstrating and Selling Expenses	912	9,511	(9,511)	0	6
7	Advertising Expenses	913	502,695	(502,695)	0	7
8	Total Sales Expenses		$ 512,205	$ (512,205)	$ 0	8
9	Total Operation and Maintenance Expenses		$ 437,848,266	$ (323,975,634)	$ 113,872,632	9
	Administrative and General Expenses					
10	Administrative and General Salaries	920	$ 27,657,594	$ 547,952	$ 28,205,547	10
11	Office Supplies and Expenses	921	4,912,427	30,704	4,943,131	11
12	Admin. and Gen. Exp. Transferred - Credit	922	(4,307,602)	(48,888)	(4,356,490)	12
13	Outside Services Employed	923	5,374,416	161,749	5,536,165	13
14	Property Insurance	924	163,931	15,506	179,438	14
15	Injuries and Damages	925	6,157,437	3,069,110	9,226,547	15
16	Employee Pension and Benefits	926	56,991	0	56,991	16
17	Regulatory Commission Expenses	928	63,324	15,009	78,333	17
18	Miscellaneous General Expenses	930	2,982,585	1,305	2,983,890	18
19	Rents	931	2,473,979	24,459	2,498,438	19
20	Maintenance of General Plant	935	3,108,476	20,729	3,129,206	20
21	Total Administrative and General Expenses		$ 48,643,559	$ 3,837,636	$ 52,481,195	21
22	Total Operation, Maintenance and Administrative General Expenses		$ 486,491,825	$ (320,137,998)	$ 166,353,827	22

Supporting Schedules C-1, Sh 8-14

SOUTHWEST GAS CORPORATION
ARIZONA
OPERATION AND MAINTENANCE EXPENSES
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Account Number (b)	Recorded at 08/31/04 (c)	Purchased Gas Cost Adj. No. 2 (d)	Labor Annualization Adj. No. 3 (e)	Customer Billing Annualization Adj. No. 4 (f)	Uncollectibles Annualization Adj. No. 5 (g)	Promotional Expenses Adj. No. 6 (h)	Pipe Replace/Leak Survey and Repair Adj. No. 11 (i)	TRIMP Adj. No. 12 (j)	Miscellaneous Adjustments Adj. No. 14 (k)	Vehicle Compensation Adj. No. 15 (l)	Out of Period Expenses Adj. No. 16 (m)	Total (n)	Line No.
	Gas Supply Expenses														
1	Natural Gas Transmission Line Purchases	803	321,120,351	(321,120,351)	0	0	0	0	0	0	0	0	0	0	1
2	Purchased Gas Cost Adjustments	805.1	(22,561,336)	22,561,336	0	0	0	0	0	0	0	0	0	0	2
3	Gas Used for Compressor Station Fuel	810	0	0	0	0	0	0	0	0	0	0	0	0	3
4	Total Gas Supply Expenses		298,559,015	(298,559,015)	0	0	0	0	0	0	0	0	0	0	4
	Other Gas Costs														
	Other Gas Supply Expenses	813													
5	Labor		445,504	0	20,761	0	0	0	0	0	0	0	0	466,265	5
6	Labor Loadings		218,101	0	(1,177)	0	0	0	0	0	0	0	0	216,924	6
7	Materials and Expenses		57,202	0	0	0	0	0	0	0	0	0	0	57,202	7
8	Total		720,807	0	19,584	0	0	0	0	0	0	0	0	740,391	8
	Transmission Expenses														
	Transmission and Compression of Gas	858													
9	Labor		0	0	0	0	0	0	0	0	0	0	0	0	9
10	Labor Loadings		0	0	0	0	0	0	0	0	0	0	0	0	10
11	Materials and Expenses		28,573,786	(28,573,786)	0	0	0	0	0	0	0	0	0	0	11
12	Total		28,573,786	(28,573,786)	0	0	0	0	0	0	0	0	0	0	12
	Distribution Expenses														
	Operation														
	Operation Supervision and Engineering	870													
13	Labor		4,690,934	0	129,914	0	0	0	0	0	0	0	0	4,820,848	13
14	Labor Loadings		2,501,390	0	(8,005)	0	0	0	0	0	0	0	0	2,493,386	14
15	Materials and Expenses		1,174,587	0	0	0	0	0	0	0	(6,859)	(23,124)	0	1,144,604	15
16	Total		8,366,912	0	121,910	0	0	0	0	0	(6,859)	(23,124)	0	8,458,839	16
	Distribution Load Dispatching	871													
17	Labor		346,137	0	15,887	0	0	0	0	0	0	0	0	362,024	17
18	Labor Loadings		170,310	0	(904)	0	0	0	0	0	0	0	0	169,405	18
19	Materials and Expenses		128,930	0	0	0	0	0	0	0	0	0	0	128,930	19
20	Total		645,376	0	14,983	0	0	0	0	0	0	0	0	660,359	20
	Mains and Services Expenses	874													
21	Labor		3,355,907	0	88,712	0	0	0	0	0	0	0	0	3,444,619	21
22	Labor Loadings		1,788,514	0	(5,453)	0	0	0	0	0	0	0	0	1,783,061	22
23	Materials and Expenses		4,392,767	0	0	0	0	0	0	1,521,429	0	0	0	5,914,196	23
24	Total		9,537,188	0	83,259	0	0	0	0	1,521,429	0	0	0	11,141,876	24
	Measuring and Regulating Station Expenses	875													
25	Labor		1,261,411	0	33,345	0	0	0	0	0	0	0	0	1,294,755	25
26	Labor Loadings		671,414	0	(2,047)	0	0	0	0	0	0	0	0	669,367	26
27	Materials and Expenses		778,043	0	0	0	0	0	0	0	(288)	0	0	777,755	27
28	Total		2,710,867	0	31,298	0	0	0	0	0	(288)	0	0	2,741,877	28
	Meter and House Regulator Expenses	878													
29	Labor		3,720,142	0	98,340	0	0	0	0	0	0	0	0	3,818,482	29
30	Labor Loadings		1,984,120	0	(6,049)	0	0	0	0	0	0	0	0	1,978,070	30
31	Materials and Expenses		875,104	0	0	0	0	0	0	0	0	0	0	875,104	31
32	Total		6,579,366	0	92,291	0	0	0	0	0	0	0	0	6,671,656	32
	Customer Installation Expenses	879													
33	Labor		4,394,991	0	116,179	0	0	0	0	0	0	0	0	4,511,169	33
34	Labor Loadings		2,346,526	0	(7,154)	0	0	0	0	0	0	0	0	2,339,372	34
35	Materials and Expenses		1,043,174	0	0	0	0	0	0	0	0	0	0	1,043,174	35
36	Total		7,784,691	0	109,025	0	0	0	0	0	0	0	0	7,893,716	36

SOUTHWEST GAS CORPORATION
ARIZONA
OPERATION AND MAINTENANCE EXPENSES
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Account Number (b)	Recorded at 08/31/04 (c)	Purchased Gas Cost Adj. No. 2 (d)	Labor Annualization Adj. No. 3 (e)	Customer Billing Annualization Adj. No. 4 (f)	Uncollectibles Annualization Adj. No. 5 (g)	Promotional Expenses Adj. No. 6 (h)	Pipe Replace/Leak Survey and Repair Adj. No. 11 (i)	TRIMP Adj. No. 12 (j)	Miscellaneous Adjustments Adj. No. 14 (k)	Vehicle Compensation Adj. No. 15 (l)	Out of Period Expenses Adj. No. 16 (m)	Total (n)	Line No.
	Other Expenses	880													
1	Labor		4,042,664	0	107,414	0	0	0	0	0	0	0	0	4,150,078	1
2	Labor Loadings		2,149,602	0	(6,584)	0	0	0	0	0	0	0	0	2,143,019	2
3	Materials and Expenses		4,317,182	0	0	0	0	0	0	0	(54,593)	0	0	4,262,589	3
4	Total		10,509,449	0	100,830	0	0	0	0	0	(54,593)	0	0	10,555,686	4
	Rents	881													
5	Labor		0	0	0	0	0	0	0	0	0	0	0	0	5
6	Labor Loadings		0	0	0	0	0	0	0	0	0	0	0	0	6
7	Materials and Expenses		1,860,559	0	0	0	0	0	0	0	0	0	119,824	1,980,383	7
8	Total		1,860,559	0	0	0	0	0	0	0	0	0	119,824	1,980,383	8
	Maintenance														
	Maintenance Supervision and Engineering	885													
9	Labor		1,522,131	0	42,234	0	0	0	0	0	0	0	0	1,564,365	9
10	Labor Loadings		812,501	0	(2,604)	0	0	0	0	0	0	0	0	809,897	10
11	Materials and Expenses		254,842	0	0	0	0	0	0	0	0	0	0	254,842	11
12	Total		2,589,475	0	39,630	0	0	0	0	0	0	0	0	2,629,104	12
	Maintenance of Structures and Improvements	886													
13	Labor		8,807	0	233	0	0	0	0	0	0	0	0	9,039	13
14	Labor Loadings		4,657	0	(14)	0	0	0	0	0	0	0	0	4,643	14
15	Materials and Expenses		50,707	0	0	0	0	0	0	0	0	0	0	50,707	15
16	Total		64,171	0	219	0	0	0	0	0	0	0	0	64,389	16
	Maintenance of Mains	887													
17	Labor		4,817,762	0	127,354	0	0	0	0	0	0	0	0	4,945,116	17
18	Labor Loadings		2,566,414	0	(7,825)	0	0	0	0	0	0	0	0	2,558,589	18
19	Materials and Expenses		5,487,579	0	0	0	0	0	(81,017)	570,536	0	0	0	5,977,097	19
20	Total		12,871,755	0	119,530	0	0	0	(81,017)	570,536	0	0	0	13,480,803	20
	Maint. of Meas. & Reg. Station Equipment	889													
21	Labor		717,892	0	18,977	0	0	0	0	0	0	0	0	736,868	21
22	Labor Loadings		382,448	0	(1,166)	0	0	0	0	0	0	0	0	381,282	22
23	Materials and Expenses		829,877	0	0	0	0	0	0	0	0	0	0	829,877	23
24	Total		1,930,217	0	17,811	0	0	0	0	0	0	0	0	1,948,028	24
	Maintenance of Services	892													
25	Labor		3,412,920	0	90,218	0	0	0	0	0	0	0	0	3,503,139	25
26	Labor Loadings		1,819,964	0	(5,549)	0	0	0	0	0	0	0	0	1,814,415	26
27	Materials and Expenses		2,963,870	0	0	0	0	0	(54,384)	0	0	0	0	2,909,486	27
28	Total		8,196,754	0	84,670	0	0	0	(54,384)	0	0	0	0	8,227,040	28
	Maintenance of Meters and House Regulators	893													
29	Labor		723,859	0	19,134	0	0	0	0	0	0	0	0	742,993	29
30	Labor Loadings		384,895	0	(1,173)	0	0	0	0	0	0	0	0	383,721	30
31	Materials and Expenses		805,373	0	0	0	0	0	0	0	0	0	0	805,373	31
32	Total		1,914,127	0	17,961	0	0	0	0	0	0	0	0	1,932,088	32
	Maintenance of Other Equipment	894													
33	Labor		96,617	0	2,554	0	0	0	0	0	0	0	0	99,171	33
34	Labor Loadings		51,305	0	(156)	0	0	0	0	0	0	0	0	51,148	34
35	Materials and Expenses		44,303	0	0	0	0	0	0	0	0	0	0	44,303	35
36	Total		192,224	0	2,398	0	0	0	0	0	0	0	0	194,621	36
	Total Distribution Expenses														
37	Labor		33,112,173	0	890,496	0	0	0	0	0	0	0	0	34,002,669	37
38	Labor Loadings		17,634,059	0	(54,684)	0	0	0	0	0	0	0	0	17,579,375	38
39	Materials and Expenses		25,006,899	0	0	0	0	0	(135,401)	2,091,964	(61,740)	(23,124)	119,824	26,998,422	39
40	Total		75,753,130	0	835,813	0	0	0	(135,401)	2,091,964	(61,740)	(23,124)	119,824	78,580,466	40

SOUTHWEST GAS CORPORATION
ARIZONA
OPERATION AND MAINTENANCE EXPENSES
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Account Number (b)	Recorded at 08/31/04 (c)	Purchased Gas Cost Adj. No. 2 (d)	Labor Annualization Adj. No. 3 (e)	Customer Billing Annualization Adj. No. 4 (f)	Uncollectibles Annualization Adj. No. 5 (g)	Promotional Expenses Adj. No. 6 (h)	Pipe Replace/Leak Survey and Repair Adj. No. 11 (i)	TRIMP Adj. No. 12 (j)	Miscellaneous Adjustments Adj. No. 14 (k)	Vehicle Compensation Adj. No. 15 (l)	Out of Period Expenses Adj. No. 16 (m)	Total (n)	Line No.
	Customer Accounts Expenses														
	Operation														
	Supervision	901													
1	Labor		2,292,925	0	60,612	0	0	0	0	0	0	0	0	2,353,537	1
2	Labor Loadings		1,224,660	0	(3,734)	0	0	0	0	0	0	0	0	1,220,926	2
3	Materials and Expenses		218,328	0	0	0	0	0	0	0	0	0	0	218,328	3
4	Total		3,735,913	0	56,878	0	0	0	0	0	0	0	0	3,792,791	4
	Meter Reading Expenses	902													
5	Labor		3,293,771	0	87,069	0	0	0	0	0	0	0	0	3,380,840	5
6	Labor Loadings		1,755,049	0	(5,351)	0	0	0	0	0	0	0	0	1,749,699	6
7	Materials and Expenses		1,285,812	0	0	0	0	0	0	0	0	0	0	1,285,812	7
8	Total		6,334,632	0	81,718	0	0	0	0	0	0	0	0	6,416,351	8
	Customer Records and Collections - Division	903													
9	Labor		9,801,933	0	304,824	0	0	0	0	0	0	0	0	10,106,757	9
10	Labor Loadings		5,161,342	0	(16,499)	0	0	0	0	0	0	0	0	5,144,843	10
11	Materials and Expenses		6,591,649	0	0	77,249	0	(23,062)	0	0	(2,250)	0	0	6,643,585	11
12	Total		21,554,924	0	288,326	77,249	0	(23,062)	0	0	(2,250)	0	0	21,895,186	12
	Customer Records and Collections - Allocation	903													
13	Labor		0	0	0	0	0	0	0	0	0	0	0	0	13
14	Labor Loadings		0	0	0	0	0	0	0	0	0	0	0	0	14
15	Materials and Expenses		7,177	0	0	0	0	0	0	0	(444)	0	0	6,733	15
16	Total		7,177	0	0	0	0	0	0	0	(444)	0	0	6,733	16
	Uncollectible Accounts Expenses	904													
17	Labor		0	0	0	0	0	0	0	0	0	0	0	0	17
18	Labor Loadings		0	0	0	0	0	0	0	0	0	0	0	0	18
19	Materials and Expenses		1,112,324	0	0	0	385,827	0	0	0	0	0	0	1,498,151	19
20	Total		1,112,324	0	0	0	385,827	0	0	0	0	0	0	1,498,151	20
	Miscellaneous Customer Accounts Expenses	905													
21	Labor		239,446	0	6,330	0	0	0	0	0	0	0	0	245,776	21
22	Labor Loadings		127,481	0	(389)	0	0	0	0	0	0	0	0	127,093	22
23	Materials and Expenses		21,199	0	0	0	0	0	0	0	0	0	0	21,199	23
24	Total		388,127	0	5,941	0	0	0	0	0	0	0	0	394,068	24
	Total Customer Accounts Expenses														
25	Labor		15,628,075	0	458,835	0	0	0	0	0	0	0	0	16,086,910	25
26	Labor Loadings		8,268,532	0	(25,972)	0	0	0	0	0	0	0	0	8,242,561	26
27	Materials and Expenses		9,236,488	0	0	77,249	385,827	(23,062)	0	0	(2,694)	0	0	9,673,808	27
28	Total		33,133,096	0	432,863	77,249	385,827	(23,062)	0	0	(2,694)	0	0	34,003,279	28

SOUTHWEST GAS CORPORATION
ARIZONA
OPERATION AND MAINTENANCE EXPENSES
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Account Number (b)	Recorded at 08/31/04 (c)	Purchased Gas Cost Adj. No. 2 (d)	Labor Annualization Adj. No. 3 (e)	Customer Billing Annualization Adj. No. 4 (f)	Uncollectibles Annualization Adj. No. 5 (g)	Promotional Expenses Adj. No. 6 (h)	Pipe Replace/Leak Survey and Repair Adj. No. 11 (i)	TRIMP Adj. No. 12 (j)	Miscellaneous Adjustments Adj. No. 14 (k)	Vehicle Compensation Adj. No. 15 (l)	Out of Period Expenses Adj. No. 16 (m)	Total (n)	Line No.
	Customer Service and Informational Expenses														
	Operation														
	Customer Assistance Expenses	908													
1	Labor		$ 176,816	$ 0	$ 4,674	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 181,490	1
2	Labor Loadings		94,231	0	(287)	0	0	0	0	0	0	0	0	93,943	2
3	Materials and Expenses		291,140	0	0	0	0	(18,978)	0	0	(23,705)	0	0	248,457	3
4	Total		$ 562,187	$ 0	$ 4,387	$ 0	$ 0	$ (18,978)	$ 0	$ 0	$ (23,705)	$ 0	$ 0	$ 523,891	4
	Informational and Instructional Expenses	909													
5	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	5
6	Labor Loadings		0	0	0	0	0	0	0	0	0	0	0	0	6
7	Materials and Expenses		(2,154)	0	0	0	0	2,154	0	0	0	0	0	0	7
8	Total		$ (2,154)	$ 0	$ 0	$ 0	$ 0	$ 2,154	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	8
	Misc. Customer Service & Inform. Expense	910													
9	Labor		$ 504	$ 0	$ 13	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 517	9
10	Labor Loadings		257	0	(1)	0	0	0	0	0	0	0	0	256	10
11	Materials and Expenses		35,432	0	0	0	0	0	0	0	(11,600)	0	0	23,832	11
12	Total		$ 36,192	$ 0	$ 13	$ 0	$ 0	$ 0	$ 0	$ 0	$ (11,600)	$ 0	$ 0	$ 24,605	12
	Total Customer Service & Info. Expense														
13	Labor		$ 177,320	$ 0	$ 4,687	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 182,008	13
14	Labor Loadings		94,487	0	(288)	0	0	0	0	0	0	0	0	94,199	14
15	Materials and Expenses		324,418	0	0	0	0	(16,824)	0	0	(35,305)	0	0	272,289	15
16	Total		$ 596,225	$ 0	$ 4,399	$ 0	$ 0	$ (16,824)	$ 0	$ 0	$ (35,305)	$ 0	$ 0	$ 548,496	16
	Sales Expenses														
	Supervision	911													
17	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	17
18	Labor Loadings		0	0	0	0	0	0	0	0	0	0	0	0	18
19	Materials and Expenses		0	0	0	0	0	0	0	0	0	0	0	0	19
20	Total		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	20
	Demonstration and Selling Expenses	912													
21	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	21
22	Labor Loadings		0	0	0	0	0	0	0	0	0	0	0	0	22
23	Materials and Expenses		9,511	0	0	0	0	(9,511)	0	0	0	0	0	0	23
24	Total		$ 9,511	$ 0	$ 0	$ 0	$ 0	$ (9,511)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	24
	Advertising Expenses	913													
25	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	25
26	Labor Loadings		0	0	0	0	0	0	0	0	0	0	0	0	26
27	Materials and Expenses		502,695	0	0	0	0	(502,695)	0	0	0	0	0	0	27
28	Total		$ 502,695	$ 0	$ 0	$ 0	$ 0	$ (502,695)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	28
	Total Sales Expenses														
29	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	29
30	Labor Loadings		0	0	0	0	0	0	0	0	0	0	0	0	30
31	Materials and Expenses		512,205	0	0	0	0	(512,205)	0	0	0	0	0	0	31
32	Total		$ 512,205	$ 0	$ 0	$ 0	$ 0	$ (512,205)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	32
	Total Rate Jurisdiction														
33	Labor		$ 49,363,072	$ 0	$ 1,374,779	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 50,737,851	33
34	Labor Loadings		26,215,180	0	(82,121)	0	0	0	0	0	0	0	0	26,133,059	34
35	Materials and Expenses		362,270,014	(327,132,801)	0	77,249	385,827	(552,091)	(135,401)	2,091,964	(99,738)	(23,124)	119,824	37,001,722	35
36	Total		$ 437,848,266	$ (327,132,801)	$ 1,292,659	$ 77,249	$ 385,827	$ (552,091)	$ (135,401)	$ 2,091,964	$ (99,738)	$ (23,124)	$ 119,824	$ 113,872,632	36

SOUTHWEST GAS CORPORATION
ARIZONA
ALLOCATION OF RECORDED ADMINISTRATIVE AND GENERAL EXPENSES
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Account Number (b)	Total Company (c)	Direct Charges: Total Arizona (d)	Direct Charges: Other Jurisdictions (e)	To Be Allocated (f) (c-d-e)	Allocation Factor: 4-Factor (g)	Allocation Factor: Factor II (h)	Allocation Factor: Factor III (i)	Allocation Factor: A&G Allocation (j)	Allocation Factor: Total Allocation (k)	Total (l) (d) + (k)	Line No.
	Administrative and General Salaries	920											
1	Labor		$ 36,052,755	$ 0	$ 0	$ 36,052,755	$ 20,759,083	$ 0	$ 0	$ 0	$ 20,759,083	$ 20,759,083	1
2	Labor Loadings		14,318,114	0	0	14,318,114	8,244,333	0	0	0	8,244,333	8,244,333	2
3	Materials and Expense		(2,337,318)	0	0	(2,337,318)	(1,345,822)	0	0	0	(1,345,822)	(1,345,822)	3
4	Total Administrative and General Salaries		$ 48,033,551	$ 0	$ 0	$ 48,033,551	$ 27,657,594	$ 0	$ 0	$ 0	$ 27,657,594	$ 27,657,594	4
5	Office Supplies	921	$ 8,531,520	$ 0	$ 0	$ 8,531,520	$ 4,912,427	$ 0	$ 0	$ 0	$ 4,912,427	$ 4,912,427	5
6	Administrative Expenses Transferred - Credit	922	$ (8,048,526)	$ 0	$ 0	$ (8,048,526)	$ 0	$ 0	$ 0	$ (4,307,602)	$ (4,307,602)	$ (4,307,602)	6
7	Outside Services Employed	923	$ 9,026,980	$ 531,565	$ 84,729	$ 8,410,686	$ 4,842,851	$ 0	$ 0	$ 0	$ 4,842,851	$ 5,374,416	7
8	Property Insurance	924	$ 297,460	$ 0	$ 0	$ 297,460	$ 0	$ 163,931	$ 0	$ 0	$ 163,931	$ 163,931	8
9	Injuries and Damages	925	$ 9,051,382	$ 3,487,793	$ 927,160	$ 4,636,429	$ 2,669,644	$ 0	$ 0	$ 0	$ 2,669,644	$ 6,157,437	9
10	Employee Pensions and Benefits	926	$ 0	$ 179,704	$ 26,005	$ (205,710)	$ 0	$ 0	$ (122,714)	$ 0	$ (122,714)	$ 56,991	10
11	Regulatory Commission Expenses	928	$ 321,426	$ 63,324	$ 258,102	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 63,324	11
	Miscellaneous General Expenses	930											
12	Labor		$ 29,125	$ 0	$ 0	$ 29,125	$ 16,770	$ 0	$ 0	$ 0	$ 16,770	$ 16,770	12
13	Labor Loadings		14,237	0	0	14,237	8,198	0	0	0	8,198	8,198	13
14	Materials and Expense		5,128,364	389,433	278,710	4,460,222	2,568,184	0	0	0	2,568,184	2,957,617	14
15	Total Miscellaneous General Expenses		$ 5,171,726	$ 389,433	$ 278,710	$ 4,503,583	$ 2,593,151	$ 0	$ 0	$ 0	$ 2,593,151	$ 2,982,585	15
16	Rents	931	$ 4,296,614	$ 0	$ 0	$ 4,296,614	$ 2,473,979	$ 0	$ 0	$ 0	$ 2,473,979	$ 2,473,979	16
	Maintenance of General Plant	935											
17	Labor		$ 655,470	$ 436,709	$ 38,505	$ 180,256	$ 103,791	$ 0	$ 0	$ 0	$ 103,791	$ 540,500	17
18	Labor Loadings		340,936	232,471	19,787	88,678	51,061	0	0	0	51,061	283,532	18
19	Materials and Expense		3,141,456	1,646,455	386,991	1,108,010	637,989	0	0	0	637,989	2,284,445	19
20	Total Maintenance of General Plant		$ 4,137,863	$ 2,315,635	$ 445,283	$ 1,376,944	$ 792,841	$ 0	$ 0	$ 0	$ 792,841	$ 3,108,476	20
	Total Administrative and General Expenses												
21	Labor		$ 36,737,350	$ 436,709	$ 38,505	$ 36,262,136	$ 20,879,644	$ 0	$ 0	$ 0	$ 20,879,644	$ 21,316,353	21
22	Labor Loadings		14,673,287	232,471	19,787	14,421,029	8,303,591	0	0	0	8,303,591	8,536,062	22
23	Materials and Expense		29,409,359	6,298,275	1,961,696	21,149,388	16,759,253	163,931	(122,714)	(4,307,602)	12,492,869	18,791,144	23
24	Total Administrative and General Expenses		$ 80,819,996	$ 6,967,455	$ 2,019,989	$ 71,832,553	$ 45,942,488	$ 163,931	$ (122,714)	$ (4,307,602)	$ 41,676,104	$ 48,643,559	24

SOUTHWEST GAS CORPORATION
ARIZONA
DIRECT ADJUSTMENTS TO ADMINISTRATIVE AND GENERAL EXPENSE
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Account Number (b)	Labor Annualization Adj. No. 3 (c)	Rate Case Expense Adj. No. 13 (d)	Total Adjustments (e)	Line No.
	Administrative and General Salaries	920				
1	Labor		$ 0	$ 0	$ 0	1
2	Labor Loadings		0	0	0	2
3	Materials and Expenses		0	0	0	3
4	Total Administrative and General Salaries		$ 0	$ 0	$ 0	4
5	Office Supplies and Expense	921	$ 0	$ 0	$ 0	5
6	Administrative Expenses Transferred - Credit	922	$ 0	$ 0	$ 0	6
7	Outside Services Employed	923	$ 0	$ 0	$ 0	7
8	Property Insurance	924	$ 0	$ 0	$ 0	8
9	Injuries and Damages	925	$ 0	$ 0	$ 0	9
10	Employee Pensions and Benefits	926	$ 0	$ 0	$ 0	10
11	Regulatory Commission Expense	928	$ 0	$ 15,009	$ 15,009	11
	Miscellaneous General Expense	930				
12	Labor		$ 0	$ 0	$ 0	12
13	Labor Loadings		0	0	0	13
14	Materials and Expenses		0	0	0	14
15	Total Miscellaneous General Expense		$ 0	$ 0	$ 0	15
16	Rents	931	$ 0	$ 0	$ 0	16
	Maintenance of General Plant	935				
17	Labor		$ 11,544	$ 0	$ 11,544	17
18	Labor Loadings		(709)	0	(709)	18
19	Materials and Expenses		0	0	0	19
20	Total Maintenance of General Plant		$ 10,835	$ 0	$ 10,835	20
	Total Administrative and General					
21	Labor		$ 11,544	$ 0	$ 11,544	21
22	Labor Loadings		(709)	0	(709)	22
23	Materials and Expenses		0	15,009	15,009	23
24	Total Administrative and General Expense		$ 10,835	$ 15,009	$ 25,845	24

SOUTHWEST GAS CORPORATION
ARIZONA
SYSTEM ALLOCABLE ADJUSTMENTS TO ADMINISTRATIVE AND GENERAL EXPENSE
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Account Number (b)	Labor Annualization Adj. No. 3 (c)	AGA Dues Adj. No. 7 (d)	Sarbanes-Oxley Adj. No. 8 (e)	Paiute/SGTC Annualization Adj. No. 9 (f)	Injuries and Damages Adj. No. 10 (g)	Line No.
	Administrative and General Salaries	920						
1	Labor		$ 637,751	$ 0	$ 0	$ 0	$ 0	1
2	Labor Loadings		24,087	0	0	0	0	2
3	Materials and Expenses		0	0	0	434,709	0	3
4	Total Administrative and General Salaries		$ 661,838	$ 0	$ 0	$ 434,709	$ 0	4
5	Office Supplies and Expense	921	$ 0	$ 0	$ (13,175)	$ 81,191	$ 0	5
6	Administrative Expenses Transferred - Credit	922	$ (91,345)	$ 0	$ 0	$ 0	$ 0	6
7	Outside Services Employed	923	$ 0	$ 0	$ 364,450	$ 80,041	$ 0	7
8	Property Insurance	924	$ 0	$ 0	$ 0	$ 28,137	$ 0	8
9	Injuries and Damages	925	$ 0	$ 0	$ 0	$ 44,123	$ 5,286,068	9
10	Employee Pensions and Benefits	926	$ 0	$ 0	$ 0	$ 0	$ 0	10
11	Regulatory Commission Expense	928	$ 0	$ 0	$ 0	$ 0	$ 0	11
	Miscellaneous General Expense	930						
12	Labor		$ 635	$ 0	$ 0	$ 0	$ 0	12
13	Labor Loadings		24	0	0	0	0	13
14	Materials and Expenses		0	(12,956)	0	42,246	0	14
15	Total Miscellaneous General Expense		$ 659	$ (12,956)	$ 0	$ 42,246	$ 0	15
16	Rents	931	$ 0	$ 0	$ 0	$ 42,479	$ 0	16
	Maintenance of General Plant	935						
17	Labor		$ 3,930	$ 0	$ 0	$ 0	$ 0	17
18	Labor Loadings		149	0	0	0	0	18
19	Materials and Expenses		0	0	0	13,104	0	19
20	Total Maintenance of General Plant		$ 4,079	$ 0	$ 0	$ 13,104	$ 0	20
	Total Administrative and General							
21	Labor		$ 642,316	$ 0	$ 0	$ 0	$ 0	21
22	Labor Loadings		24,261	0	0	0	0	22
23	Materials and Expenses		(91,345)	(12,956)	351,275	766,029	5,286,068	23
24	Total Administrative and General Expense		$ 575,231	$ (12,956)	$ 351,275	$ 766,029	$ 5,286,068	24

SOUTHWEST GAS CORPORATION
ARIZONA
SYSTEM ALLOCABLE ADJUSTMENTS TO ADMINISTRATIVE AND GENERAL EXPENSE
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Account Number (b)	Miscellaneous Adjustments Adj. No. 14 (c)	Vehicle Compensation Adj. No. 15 (d)	Out of Period Expenses Adj. No. 16 (e)	Total Adjustments (f)	Line No.
	Administrative and General Salaries	920					
1	Labor		$ 0	$ 0	$ 0	$ 637,751	1
2	Labor Loadings		0	0	0	24,087	2
3	Materials and Expenses		0	(144,906)	0	289,802	3
4	Total Administrative and General Salaries		$ 0	$ (144,906)	$ 0	$ 951,641	4
5	Office Supplies and Expense	921	$ (14,692)	$ 0	$ 0	$ 53,324	5
6	Administrative Expenses Transferred - Credit	922	$ 0	$ 0	$ 0	$ (91,345)	6
7	Outside Services Employed	923	$ (71,785)	$ 0	$ (91,794)	$ 280,912	7
8	Property Insurance	924	$ 0	$ 0	$ 0	$ 28,137	8
9	Injuries and Damages	925	$ 0	$ 0	$ 0	$ 5,330,190	9
10	Employee Pensions and Benefits	926	$ 0	$ 0	$ 0	$ 0	10
11	Regulatory Commission Expense	928	$ 0	$ 0	$ 0	$ 0	11
	Miscellaneous General Expense	930					
12	Labor		$ 0	$ 0	$ 0	$ 635	12
13	Labor Loadings		0	0	0	24	13
14	Materials and Expenses		(27,682)	0	0	1,608	14
15	Total Miscellaneous General Expense		$ (27,682)	$ 0	$ 0	$ 2,267	15
16	Rents	931	$ 0	$ 0	$ 0	$ 42,479	16
	Maintenance of General Plant	935					
17	Labor		$ 0	$ 0	$ 0	$ 3,930	17
18	Labor Loadings		0	0	0	149	18
19	Materials and Expenses		0	0	0	13,104	19
20	Total Maintenance of General Plant		$ 0	$ 0	$ 0	$ 17,183	20
	Total Administrative and General						
21	Labor		$ 0	$ 0	$ 0	$ 642,316	21
22	Labor Loadings		0	0	0	24,261	22
23	Materials and Expenses		(114,158)	(144,906)	(91,794)	5,948,212	23
24	Total Administrative and General Expense		$ (114,158)	$ (144,906)	$ (91,794)	$ 6,614,788	24

SOUTHWEST GAS CORPORATION
ARIZONA
ALLOCATION OF ADMINISTRATIVE AND GENERAL EXPENSE ADJUSTMENTS
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Account Number (b)	Total Company [1] (c)	Direct Charges: Arizona [2] (d)	Direct Charges: Other Jurisdictions (e)	To Be Allocated (f) (c-d-e)	Allocation Factor: 4-Factor (g)	Allocation Factor: Factor II (h)	Allocation Factor: Factor III (i)	Allocation Factor: A&G Allocation (j)	Allocation Factor: Total Allocation (k)	Adjustment Total (l) (d) + (k)	Line No.
	Administrative and General Salaries	920											
1	Labor		637,751	0	0	637,751	367,215	0	0	0	367,215	367,215	1
2	Labor Loadings		24,087	0	0	24,087	13,869	0	0	0	13,869	13,869	2
3	Materials and Expense		289,802	0	0	289,802	166,868	0	0	0	166,868	166,868	3
4	Total Administrative and General Salaries		951,641	0	0	951,641	547,952	0	0	0	547,952	547,952	4
5	Office Supplies	921	53,324	0	0	53,324	30,704	0	0	0	30,704	30,704	5
6	Administrative Expenses Transferred - Credit	922	(91,345)	0	0	(91,345)	0	0	0	(48,888)	(48,888)	(48,888)	6
7	Outside Services Employed	923	280,912	0	0	280,912	161,748	0	0	0	161,748	161,748	7
8	Property Insurance	924	28,137	0	0	28,137	0	15,506	0	0	15,506	15,506	8
9	Injuries and Damages	925	5,330,190	0	0	5,330,190	3,069,110	0	0	0	3,069,110	3,069,110	9
10	Employee Pensions and Benefits	926	0	0	0	0	0	0	0	0	0	0	10
11	Regulatory Commission Expenses	928	15,009	15,009	0	0	0	0	0	0	0	15,009	11
	Miscellaneous General Expenses	930											
12	Labor		635	0	0	635	366	0	0	0	366	366	12
13	Labor Loadings		24	0	0	24	14	0	0	0	14	14	13
14	Materials and Expense		1,608	0	0	1,608	926	0	0	0	926	926	14
15	Total Miscellaneous General Expenses		2,267	0	0	2,267	1,305	0	0	0	1,305	1,305	15
16	Rents	931	42,479	0	0	42,479	24,459	0	0	0	24,459	24,459	16
	Maintenance of General Plant	935											
17	Labor		15,474	11,544	0	3,930	2,263	0	0	0	2,263	13,807	17
18	Labor Loadings		(560)	(709)	0	149	86	0	0	0	86	(623)	18
19	Materials and Expenses		13,104	0	0	13,104	7,545	0	0	0	7,545	7,545	19
20	Total Maintenance of General Plant		28,018	10,835	0	17,183	9,894	0	0	0	9,894	20,729	20
	Total Administrative and General Expenses												
21	Labor		653,860	11,544	0	642,316	369,844	0	0	0	369,844	381,388	21
22	Labor Loadings		23,552	(709)	0	24,261	13,969	0	0	0	13,969	13,260	22
23	Materials and Expenses		5,963,221	15,009	0	5,948,212	3,461,360	15,506	0	(48,888)	3,427,978	3,442,987	23
24	Total Administrative and General Expenses		6,640,633	25,845	0	6,614,788	3,845,173	15,506	0	(48,888)	3,811,791	3,837,636	24

[1] Schedule C-1, Sheet 10, Column f + Schedule C-1, Sheet 12, Column h
[2] Schedule C-1, Sheet 10, Column f

SOUTHWEST GAS CORPORATION
ARIZONA
ALLOCATION OF ADJUSTED ADMINISTRATIVE AND GENERAL EXPENSES
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Account Number (b)	Total Company [1] (c)	Direct Charges: Arizona [2] (d)	Direct Charges: Other Jurisdictions [3] (e)	To Be Allocated (f) (c-d-e)	Allocation Factor: 4-Factor (g)	Allocation Factor: Factor II (h)	Allocation Factor: Factor III (i)	Allocation Factor: A&G Allocation (j)	Total Allocation (k)	Total (l) (d) + (k)	Line No.
	Administrative and General Salaries	920											
1	Labor		$ 36,690,506	$ 0	$ 0	$ 36,690,506	$ 21,126,298	$ 0	$ 0	$ 0	$ 21,126,298	$ 21,126,298	1
2	Labor Loadings		14,342,201	0	0	14,342,201	8,258,202	0	0	0	8,258,202	8,258,202	2
3	Materials and Expense		(2,047,515)	0	0	(2,047,515)	(1,178,954)	0	0	0	(1,178,954)	(1,178,954)	3
4	Total Administrative and General Salaries		$ 48,985,192	$ 0	$ 0	$ 48,985,192	$ 28,205,547	$ 0	$ 0	$ 0	$ 28,205,547	$ 28,205,547	4
5	Office Supplies	921	$ 8,584,844	$ 0	$ 0	$ 8,584,844	$ 4,943,131	$ 0	$ 0	$ 0	$ 4,943,131	$ 4,943,131	5
6	Administrative Expenses Transferred - Credit	922	$ (8,139,871)	$ 0	$ 0	$ (8,139,871)	$ 0	$ 0	$ 0	$ (4,356,490)	$ (4,356,490)	$ (4,356,490)	6
7	Outside Services Employed	923	$ 9,307,892	$ 531,565	$ 84,729	$ 8,691,598	$ 5,004,600	$ 0	$ 0	$ 0	$ 5,004,600	$ 5,536,165	7
8	Property Insurance	924	$ 325,597	$ 0	$ 0	$ 325,597	$ 0	$ 179,438	$ 0	$ 0	$ 179,438	$ 179,438	8
9	Injuries and Damages	925	$ 14,381,572	$ 3,487,793	$ 927,160	$ 9,966,620	$ 5,738,754	$ 0	$ 0	$ 0	$ 5,738,754	$ 9,226,547	9
10	Employee Pensions and Benefits	926	$ 0	$ 179,704	$ 26,005	$ (205,710)	$ 0	$ 0	$ (122,714)	$ 0	$ (122,714)	$ 56,991	10
11	Regulatory Commission Expenses	928	$ 336,435	$ 78,333	$ 258,102	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 78,333	11
	Miscellaneous General Expenses	930											
12	Labor		$ 29,760	$ 0	$ 0	$ 29,760	$ 17,135	$ 0	$ 0	$ 0	$ 17,135	$ 17,135	12
13	Labor Loadings		14,261	0	0	14,261	8,211	0	0	0	8,211	8,211	13
14	Materials and Expense		5,129,973	389,433	278,710	4,461,830	2,569,110	0	0	0	2,569,110	2,958,543	14
15	Total Miscellaneous General Expenses		$ 5,173,993	$ 389,433	$ 278,710	$ 4,505,850	$ 2,594,457	$ 0	$ 0	$ 0	$ 2,594,457	$ 2,983,890	15
16	Rents	931	$ 4,339,093	$ 0	$ 0	$ 4,339,093	$ 2,498,438	$ 0	$ 0	$ 0	$ 2,498,438	$ 2,498,438	16
	Maintenance of General Plant	935											
17	Labor		$ 670,944	$ 448,253	$ 38,505	$ 184,186	$ 106,054	$ 0	$ 0	$ 0	$ 106,054	$ 554,307	17
18	Labor Loadings		340,376	231,762	19,787	88,827	51,146	0	0	0	51,146	282,909	18
19	Materials and Expense		3,154,560	1,646,455	386,991	1,121,114	645,535	0	0	0	645,535	2,291,990	19
20	Total Maintenance of General Plant		$ 4,165,881	$ 2,326,471	$ 445,283	$ 1,394,127	$ 802,735	$ 0	$ 0	$ 0	$ 802,735	$ 3,129,206	20
	Total Administrative and General Expenses												
21	Labor		$ 37,391,210	$ 448,253	$ 38,505	$ 36,904,452	$ 21,249,488	$ 0	$ 0	$ 0	$ 21,249,488	$ 21,697,741	21
22	Labor Loadings		14,696,839	231,762	19,787	14,445,289	8,317,560	0	0	0	8,317,560	8,549,322	22
23	Materials and Expense		35,372,580	6,313,284	1,961,696	27,097,599	20,220,614	179,438	(122,714)	(4,356,490)	15,920,847	22,234,132	23
24	Total Administrative and General Expenses		$ 87,460,629	$ 6,993,300	$ 2,019,989	$ 78,447,340	$ 49,787,662	$ 179,438	$ (122,714)	$ (4,356,490)	$ 45,487,895	$ 52,481,195	24

[1] Schedule C-1, Sheet 9, Column (c) + Schedule C-1, Sheet 13, Column (c)
[2] Schedule C-1, Sheet 9, Column (d) + Schedule C-1, Sheet 13, Column (d)
[3] Schedule C-1, Sheet 9, Column (e) + Schedule C-1, Sheet 13, Column (e)

SOUTHWEST GAS CORPORATION
ARIZONA
DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description [1]	Account Number	Recorded at 08/31/04	Adjustments	Adjusted at 08/31/04	Line No.
	(a)	(b)	(c)	(d)	(e)	
	Arizona					
1	Depreciation	403	$ 64,205,210	$ 2,914,314	$ 67,119,524	1
2	Amortization	404.3	228,005	44,328	272,333	2
3	Amortization of Gas Plant Acquisition	406	(52,996)	0	(52,996)	3
4	Amortization of PBOP Costs	407.3	337,524	0	337,524	4
5	Amortization of Service Investigation	407.3	549,600	(549,600)	0	5
6	Amortization of TRIMP Costs	407.3	0	1,183,333	1,183,333	6
7	Amortization of SOX Implementation Costs	407.3	0	27,346	27,346	7
8	Total Depreciation and Amortization Expense		$ 65,267,343	$ 3,619,722	$ 68,887,065	8
	System Allocable					
9	Depreciation	403	$ 5,477,865	$ (1,384,636)	$ 4,093,229	9
10	Amortization	404.3	8,753,375	(580,861)	8,172,514	10
11	Total System Allocable Depreciation and Amortization		$ 14,231,239	$ (1,965,496)	$ 12,265,743	11
12	Arizona 4-Factor [2]		57.58%	57.58%	57.58%	12
13	Arizona Allocation		$ 8,194,311	$ (1,131,728)	$ 7,062,583	13
14	Total Depreciation and Amortization (Ln 9 + Ln 14)		$ 73,461,654	$ 2,487,994	$ 75,949,648	14

[1] Supporting Workpapers C-2, Adj. 17
[2] Supporting Schedule C-1, Sheet 18

SOUTHWEST GAS CORPORATION
ARIZONA
SUMMARY OF OTHER TAXES
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004
AS ADJUSTED FOR THE TEST YEAR

Line No.	Description (a)	Account Number (b)	Recorded at 08/31/04 (c) [1]	Adjustment (d) [2]	Adjusted at 08/31/04 (e)	Line No.
1	Property Tax	408.1	$ 29,114,451	$ 4,332,862	$ 33,447,313	1
2	Miscellaneous	408.1	7,811	0	7,811	2
3	Total Other Taxes		$ 29,122,261	$ 4,332,862	$ 33,455,124	3

[1] Source: Company Records
[2] Supporting Schedule C-2, Adj. 18

SOUTHWEST GAS CORPORATION
ARIZONA
INCOME TAXES ON OPERATIONS
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004
AS ADJUSTED

Line No.	Description (a)	Recorded at 08/31/04 (b)	Adjusted at 08/31/04 (c)	After Rate Relief (d)	Line No.
	State Income Tax				
1	Margin	$ 320,144,265	$ 322,865,978	$ 393,675,106	1
2	Expenses	263,347,147	276,475,970	276,631,828	2
3	Taxable Income Before Interest	$ 56,797,118	$ 46,390,008	$ 117,043,278	3
4	Interest Expense [1]	40,472,048	40,521,530	40,521,530	4
5	State Taxable Income	$ 16,325,070	$ 5,868,479	$ 76,521,749	5
6	Effective State Income Tax Rate	6.9680%	6.9680%	6.9680%	6
7	State Income Tax	$ 1,137,531	$ 408,916	$ 5,332,035	7
8	South Georgia Amortization	77,020	77,020	77,020	8
9	Investment Tax Credit	0	0	0	9
10	State Income Tax	$ 1,214,551	$ 485,936	$ 5,409,055	10
	Federal Income Tax				
11	Margin	$ 320,144,265	$ 322,865,978	$ 393,675,106	11
12	Expenses	263,347,147	276,475,970	276,631,828	12
13	Taxable Income Before Interest	$ 56,797,118	$ 46,390,008	$ 117,043,278	13
14	Interest Expense [1]	40,472,048	40,521,530	40,521,530	14
15	Federal Taxable Income	$ 16,325,070	$ 5,868,479	$ 76,521,749	15
16	Federal Income Tax Rate	32.5612%	32.5612%	32.5612%	16
17	Federal Income Tax	$ 5,315,639	$ 1,910,847	$ 24,916,400	17
18	South Georgia Amortization	288,233	288,233	288,233	18
19	Investment Tax Credit	(528,352)	(528,352)	(528,352)	19
20	Federal Income Tax	$ 5,075,520	$ 1,670,728	$ 24,676,281	20
21	Total Federal and State Income Tax	$ 6,290,071	$ 2,156,664	$ 30,085,336	21
	[1] Interest Calculation				
22	Rate Base	$ 924,082,652	$ 925,212,447	$ 925,212,447	22
23	Weighted cost of Debt [2]	4.38%	4.38%	4.38%	23
24	Interest Expense	$ 40,472,048	$ 40,521,530	$ 40,521,530	24

[2] Includes tax deductible preferred equity requirements

SOUTHWEST GAS CORPORATION
COMPUTATION OF FOUR FACTOR ALLOCATION RATE
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Arizona (b)	Northern California (c)	Southern California (d)	Northern Nevada (e)	Southern Nevada (f)	Total (g)	Line No.
	Factor I							
1	Direct Operating Expenses	$ 116,563,418	$ 2,092,571	$ 15,566,112	$ 12,946,441	$ 46,598,026	$ 193,766,568	1
2	Percent of Total	60.16%	1.08%	8.03%	6.68%	24.05%	100.00%	2
	Factor II							
3	Average Direct Gross Plant in Service	$ 1,534,218,463	$ 68,266,432	$ 196,058,666	$ 161,043,670	$ 824,311,024	$ 2,783,898,255	3
4	Percent of Total	55.11%	2.45%	7.04%	5.78%	29.61%	100.00%	4
	Factor III							
5	Direct Labor	$ 49,799,780	$ 794,602	$ 7,400,173	$ 5,727,238	$ 19,759,452	$ 83,481,245	5
6	Percent of Total	59.65%	0.95%	8.86%	6.86%	23.67%	100.00%	6
	Factor IV							
7	Average Number of Customers	$ 843,134	$ 21,923	$ 115,535	$ 81,430	$ 459,934	$ 1,521,956	7
8	Percent of Total	55.40%	1.44%	7.59%	5.35%	30.22%	100.00%	8
9	Total 4-Factor	230.32%	5.92%	31.53%	24.68%	107.55%	400.00%	9
10	4-Factor	57.58%	1.48%	7.88%	6.17%	26.89%	100.00%	10
	A&G Transfer Rate							
11	A&G Overheads	$ 4,285,410	$ 119,483	$ 674,828	$ 245,698	$ 2,681,642	$ 8,007,061	11
12	Percent of Total	53.52%	1.49%	8.43%	3.07%	33.49%	100.00%	12

SOUTHWEST GAS CORPORATION
CALCULATION OF THE MODIFIED
MASSACHUSETTS FORMULA
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Arizona (b)	Northern California (c)	Southern California (d)	Northern Nevada (e)	Southern Nevada (f)	Paiute (g)	SGTC (h)	Total (i)	Line No.
1	Total Direct Labor	$ 49,799,780	$ 794,602	$ 7,400,173	$ 5,727,238	$ 19,759,452	$ 2,776,087	$ 8,866	$ 86,266,199	1
2	Percent to Total	57.73%	0.92%	8.58%	6.64%	22.91%	3.22%	0.01%	100.00%	2
3	Margin	$ 320,144,268	$ 14,179,467	$ 48,509,503	$ 31,531,324	$ 148,734,830	$ 26,167,961	$ 299,144	$ 589,566,497	3
4	Percent to Total	54.30%	2.41%	8.23%	5.35%	25.23%	4.44%	0.05%	100.00%	4
5	Gross Plant	$ 1,597,681,797	$ 69,651,376	$ 203,461,714	$ 164,252,435	$ 855,797,698	$ 154,987,205	$ 1,794,544	$ 3,047,626,770	5
6	Percent to Total	52.42%	2.29%	6.68%	5.39%	28.08%	5.09%	0.06%	100.00%	6
7	Total (Ln 2 + Ln 4 + Ln 6)	164.45%	5.61%	23.48%	17.38%	76.21%	12.74%	0.12%	300.00%	7
8	Total Modified Mass Formula (Ln 7 / 3)	54.82%	1.87%	7.83%	5.79%	25.40%	4.25%	0.04%	100.00%	8

SOUTHWEST GAS CORPORATION
ARIZONA
SUMMARY OF ADJUSTMENTS
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Revenue Adj. No. 1 (b)	Purchased Gas Cost Adj. No. 2 (c)	Labor Annualization Adj. No. 3 (d)	Customer Billing Annualization Adj. No. 4 (e)	Uncollectibles Annualization Adj. No. 5 (f)	Promotional Expenses Adj. No. 6 (g)	AGA Dues Adj. No. 7 (h)	Sarbanes-Oxley 404 Adj. No. 8 (i)	Line No.
1	Operating Revenue	$ (324,411,088)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	1
2	Gas Cost	0	(327,132,801)	0	0	0	0	0	0	2
3	Operating Margin	$ (324,411,088)	$ 327,132,801	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	3
	Operating Expenses									
4	Other Gas Supply	$ 0	$ 0	$ 19,584	$ 0	$ 0	$ 0	$ 0	$ 0	4
5	Distribution	0	0	835,813	0	0	0	0	0	5
6	Customer Accounts	0	0	432,863	77,249	385,827	(23,062)	0	0	6
7	Customer Service & Information	0	0	4,399	0	0	(16,824)	0	0	7
8	Sales	0	0	0	0	0	(512,205)	0	0	8
	Administrative and General									
9	Direct	0	0	10,835	0	0	0	0	0	9
10	System Allocable	0	0	334,925	0	0	0	(7,460)	202,263	10
	Depreciation and Amortization									
11	Direct	0	0	0	0	0	0	0	0	11
12	System Allocable	0	0	0	0	0	0	0	0	12
13	Regulatory Amortizations	0	0	0	0	0	0	0	0	13
14	Taxes Other Than Income	0	0	0	0	0	0	0	0	14
15	Interest on Customer Deposits	0	0	0	0	0	0	0	0	15
16	Total Operating Expenses	$ 0	$ 0	$ 1,638,419	$ 77,249	$ 385,827	$ (552,091)	$ (7,460)	$ 202,263	16
17	Net Operating Income	$ (324,411,088)	$ 327,132,801	$ (1,638,419)	$ (77,249)	$ (385,827)	$ 552,091	$ 7,460	$ (202,263)	17
	Rate Base									
	Gas Plant in Service									
18	Direct	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	18
19	System Allocable	0	0	0	0	0	0	0	0	19
20	Total Gross Plant	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	20
	Accumulated Provision for Depreciation and Amortization									
21	Direct	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	21
22	System Allocable	0	0	0	0	0	0	0	0	22
23	Total Accumulated Provision for Depreciation and Amortization	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	23
24	Net Plant in Service	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	24
	Other Rate Base Items									
25	Working Capital	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	25
26	Customer Advances	0	0	0	0	0	0	0	0	26
27	Customer Deposits	0	0	0	0	0	0	0	0	27
28	Deferred Taxes	0	0	0	0	0	0	0	0	28
29	Total Other Rate Base Items	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	29
30	Total Rate Base	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	30

SOUTHWEST GAS CORPORATION
ARIZONA
SUMMARY OF ADJUSTMENTS
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Paiute Alloc. Annualization Adj. No. 9 (b)	Injuries and Damages Adj. No. 10 (c)	Pipe Replace/Leak Survey and Repair Adj. No. 11 (d)	TRIMP Adj. No. 12 (e)	Rate Case Expense Adj. No. 13 (f)	Miscellaneous Adj. No. 14 (g)	Vehicle Compensation Adj. No. 15 (h)	Out of Period Expenses Adj. No. 16 (i)	Line No.
1	Operating Revenue	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	1
2	Gas Cost	0	0	0	0	0	0	0	0	2
3	Operating Margin	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	3
	Operating Expenses									
4	Other Gas Supply	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	4
5	Distribution	0	0	(135,401)	2,091,964	0	(61,740)	(23,124)	119,824	5
6	Customer Accounts	0	0	0	0	0	(2,694)	0	0	6
7	Customer Service & Information	0	0	0	0	0	(35,305)	0	0	7
8	Sales	0	0	0	0	0	0	0	0	8
	Administrative and General									
9	Direct	0	0	0	0	15,009	0	0	0	9
10	System Allocable	440,383	3,043,711	0	0	0	(65,732)	(83,437)	(52,855)	10
	Depreciation and Amortization									
11	Direct	0	0	0	0	0	0	0	0	11
12	System Allocable	0	0	0	0	0	0	0	0	12
13	Regulatory Amortizations	0	0	0		0	0	0	0	13
14	Taxes Other Than Income	0	0	0	0	0	0	0	0	14
15	Interest on Customer Deposits	0	0	0		0	0	0	0	15
16	Total Operating Expenses	$ 440,383	$ 3,043,711	$ (135,401)	$ 2,091,964	$ 15,009	$ (165,470)	$ (106,561)	$ 66,969	16
17	Net Operating Income	$ (440,383)	$ (3,043,711)	$ 135,401	$ (2,091,964)	$ (15,009)	$ 165,470	$ 106,561	$ (66,969)	17
	Rate Base									
	Gas Plant in Service									
18	Direct	$ 0	$ 0	$ (1,372,020)	$ 0	$ 0	$ 0	$ 0	$ 0	18
19	System Allocable	0	0	0	0	0	0	0	0	19
20	Total Gross Plant	$ 0	$ 0	$ (1,372,020)	$ 0	$ 0	$ 0	$ 0	$ 0	20
	Accumulated Provision for Depreciation and Amortization									
21	Direct	$ 0	$ 0	$ (295,343)	$ 0	$ 0	$ 0	$ 0	$ 0	21
22	System Allocable	0	0	0	0	0	0	0	0	22
23	Total Accumulated Provision for Depreciation and Amortization	$ 0	$ 0	$ (295,343)	$ 0	$ 0	$ 0	$ 0	$ 0	23
24	Net Plant in Service	$ 0	$ 0	$ (1,076,677)	$ 0	$ 0	$ 0	$ 0	$ 0	24
	Other Rate Base Items									
25	Working Capital	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	25
26	Customer Advances	0	0	0	0	0	0	0	0	26
27	Customer Deposits	0	0	0		0	0	0	0	27
28	Deferred Taxes	0	0	165,641	0	0	0	0	0	28
29	Total Other Rate Base Items	$ 0	$ 0	$ 165,641	$ 0	$ 0	$ 0	$ 0	$ 0	29
30	Total Rate Base	$ 0	$ 0	$ (911,037)	$ 0	$ 0	$ 0	$ 0	$ 0	30

SOUTHWEST GAS CORPORATION
ARIZONA
SUMMARY OF ADJUSTMENTS
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Annualized Dep. & Amort. Adj. No. 17 (b)	Property Tax Adj. No. 18 (c)	Interest on Customer Dep. Adj. No. 19 (d)	CCNC Adj. No. 20 (e)	Light Rail Adj. No. 21 (f)	Total of Adjustments (g)	Line No.
1	Operating Revenue	$ 0	$ 0	$ 0	$ 0	$ 0	$ (324,411,088)	1
2	Gas Cost	0	0	0	0	0	(327,132,801)	2
3	Operating Margin	$ 0	$ 0	$ 0	$ 0	$ 0	$ 2,721,713	3
	Operating Expenses							
4	Other Gas Supply	$ 0	$ 0	$ 0	$ 0	$ 0	$ 19,584	4
5	Distribution	0	0	0	0	0	2,827,336	5
6	Customer Accounts	0	0		0	0	870,183	6
7	Customer Service & Information	0	0	0	0	0	(47,730)	7
8	Sales	0	0	0	0	0	(512,205)	8
	Administrative and General							
9	Direct	0	0	0	0	0	25,845	9
10	System Allocable	0	0	0	0	0	3,811,798	10
	Depreciation and Amortization							
11	Direct	2,958,642	0	0	0	0	2,958,642	11
12	System Allocable	(1,131,728)	0	0	0	0	(1,131,728)	12
13	Regulatory Amortizations	661,080	0	0	0	0	661,080	13
14	Taxes Other Than Income	0	4,332,862	0	0	0	4,332,862	14
15	Interest on Customer Deposits	0	0	(686,844)	0	0	(686,844)	15
16	Total Operating Expenses	$ 2,487,994	$ 4,332,862	$ (686,844)	$ 0	$ 0	$ 13,128,823	16
17	Net Operating Income	$ (2,487,994)	$ (4,332,862)	$ 686,844	$ 0	$ 0	$ (10,407,110)	17
	Rate Base							
	Gas Plant in Service							
18	Direct	$ 0	$ 0	$ 0	$ 1,819,949	$ (771,614)	$ (323,685)	18
19	System Allocable	0	0	0	969,345	0	969,345	19
20	Total Gross Plant	$ 0	$ 0	$ 0	$ 2,789,294	$ (771,614)	$ 645,659	20
	Accumulated Provision for Depreciation and Amortization							
21	Direct	$ 0	$ 0	$ 0	$ 0	$ (23,151)	$ (318,494)	21
22	System Allocable	0	0	0	0	0	0	22
23	Total Accumulated Provision for Depreciation and Amortization	$ 0	$ 0	$ 0	$ 0	$ (23,151)	$ (318,494)	23
24	Net Plant in Service	$ 0	$ 0	$ 0	$ 2,789,294	$ (748,463)	$ 964,153	24
	Other Rate Base Items							
25	Working Capital	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	25
26	Customer Advances	0	0	0	0	0	0	26
27	Customer Deposits	0	0	0	0	0	0	27
28	Deferred Taxes	0	0	0	0	0	165,641	28
29	Total Other Rate Base Items	$ 0	$ 0	$ 0	$ 0	$ 0	$ 165,641	29
30	Total Rate Base	$ 0	$ 0	$ 0	$ 2,789,294	$ (748,463)	$ 1,129,794	30

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SALES & TRANSPORTATION QUANTITY AND REVENUES
ADJUSTMENT NO.1
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Recorded At 08/31/2004 (b)	Adjustment No. 1 (c)	Test Period Balance As Adjusted (d)	Line No.
1	Sales Quantity (therms)	663,721,397	(21,043,264)	642,678,133	1
2	Transportation Quantity (therms)	65,680,156	(934,587)	64,745,569	2
3	Total Quantity	729,401,553	(21,977,851)	707,423,702	3
4	Revenue	$ 647,277,066	$(324,411,088)	$ **322,865,978**	4
5	Total Revenue Adjustment		$(324,411,088)		5

Explanation:
To adjust for changes in number of bills and sales volumes, to annualize revenues at currently effective rates, to reverse unbilled revenues and to remove gas cost ($357,771,219) from the cost of service.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PURCHASED GAS COST
ADJUSTMENT NO. 2
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	FERC Account Number (b)	Amount (c)	Line No.
1	Operating Expenses	401	$(327,132,801)	1
	Explanation: To adjust for changes in sales volumes and to adjust the average cost of purchased gas to match the average cost of purchased gas included in currently effective base tariff sales rates.			
	Details			
	Gas Supply Expenses			
2	Natural Gas Wellhead Purchases	800	$ 0	2
3	Present Volume Adjustment	803	4,532,785	3
4	Present Rate Adjustment	803	32,118,083	4
5	Proposed Rate Making Adjustment	803	(357,771,219)	5
6	Purchased Gas Cost Adjustments	805.1	22,561,336	6
7	Gas Used for Compressor Station Fuel	808.1	0	7
8	Gas Withdrawn from Storage	808.2	0	8
9	Total Gas Supply Expenses		$(298,559,015)	9
	Transmission Expenses			
	Transmission & Compression			
10	of Gas by Others	858	$(28,573,786)	10
11	Total Transmission Expenses		$(28,573,786)	11
12	Adjustment No. 2		$(327,132,801)	12

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
COST OF PURCHASED GAS - ACCOUNT NO. 803
ADJUSTED AT PRESENT RATES
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description	Recorded Total	Volume Adjustment Sales	Volume Adjustment Seasonal	Volume Adjustment Optional	Volume Adjustment Resale	Rate Adjustment Sales	Rate Adjustment Seasonal	Rate Adjustment Optional	Rate Adjustment Resale	Adjusted Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
1	Sales Volumes - Therms	663,721,397	10,620,367	1,082,645	(2,348,733)	14,502	535,163,962	36,279,112	101,647,104	0	673,090,178	1
2	Recorded Average Cost of Purchased Gas - Account No. 803	$ 0.48382	$ 0.48382	$ 0.48382	$ 0.48382	$ 0.48382	$ 0.48382	$ 0.48382	$ 0.48382	$ 0.48382		2
3	Cost of Purchased Gas @ August 31, 2004 [1]						$ 0.53436	$ 0.43742	$ 0.55025	$ 0.00000		3
4	Change In Average Cost of Purchased Gas						$ 0.05054	(0.04640)	$ 0.06644	$(0.48382)		4
5	Cost of Purchased Gas - Account No. 803	$ 321,120,351	$ 5,138,325	$ 523,803	$(1,136,359)	$ 7,016	$ 27,048,263	$(1,683,278)	$ 6,753,098	$ 0	$ 357,771,219	5

[1] Excluding Account No. 191 surcharge.

SOUTHWEST GAS CORPORATION
ARIZONA
LABOR AND LABOR LOADING ADJUSTMENT
ADJUSTMENT NO. 3

Line No.	Description (a)	Labor [1] (b)	Loading [1] (c)	Total (d) (b) + (c)	Line No.
	Operations				
1	Account 813	$ 20,761	$ (1,177)	$ 19,584	1
2	Account 870	129,914	(8,005)	121,910	2
3	Account 871	15,887	(904)	14,983	3
4	Account 874	88,712	(5,453)	83,259	4
5	Account 875	33,345	(2,047)	31,298	5
6	Account 878	98,340	(6,049)	92,291	6
7	Account 879	116,179	(7,154)	109,025	7
8	Account 880	107,414	(6,584)	100,830	8
9	Account 901	60,612	(3,734)	56,878	9
10	Account 902	87,069	(5,351)	81,718	10
11	Account 903	304,824	(16,499)	288,326	11
12	Account 905	6,330	(389)	5,941	12
13	Account 908	4,674	(287)	4,387	13
14	Account 909	0	0	0	14
15	Account 910	13	(1)	13	15
16	Account 920	367,215	13,869	381,085	16
17	Account 922	(47,109)	(1,779)	(48,888)	17
18	Account 930	366	14	379	18
19	Total Operating Expense	$ 1,394,546	$ (51,529)	$ 1,343,017	19
	Maintenance				
20	Account 885	$ 42,234	$ (2,604)	$ 39,630	20
21	Account 886	233	(14)	219	21
22	Account 887	127,354	(7,825)	119,530	22
23	Account 889	18,977	(1,166)	17,811	23
24	Account 892	90,218	(5,549)	84,670	24
25	Account 893	19,134	(1,173)	17,961	25
26	Account 894	2,554	(156)	2,398	26
27	Account 935	13,807	(623)	13,184	27
28	Total Maintenance Expense	$ 314,512	$ (19,111)	$ 295,401	28
29	Total Operations and Maintenance	$ 1,709,058	$ (70,640)	$ 1,638,419	29
	Functionalization				
30	Other Gas Supply	$ 20,761	$ (1,177)	$ 19,584	30
31	Distribution	890,496	(54,684)	835,813	31
32	Customer Accounts	458,835	(25,972)	432,863	32
33	Customer Service & Information	4,687	(288)	4,399	33
34	Sales	0	0	0	34
35	Administrative and General	334,279	11,481	345,760	35
36	Total	$ 1,709,058	$ (70,640)	$ 1,638,419	36

Explanation

To annualize labor and related loadings as of August 31, 2004, and to reflect within grade increases through August 2005 and a 2% labor increase effective June 2005.

[1] Supporting Workpapers C-2, Adj. 3

SOUTHWEST GAS CORPORATION
ARIZONA AND CORPORATE STAFF
INCREMENTAL BILLING COSTS FOR ANNUALIZED CUSTOMERS
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004
ADJUSTMENT NO. 4

Line No.	Description (a)	Reference (b)	Amount [1] (c)	Line No.
	Bill Print Function			
	Hardware/Software Maintenance Lease & Supplies:	Company Records		
1	Variable Form Usage Fee from IBM		$ 37,490	1
2	Equipment Supplies (toner, developer & fuser)		25,800	2
3	Bill Stock (regular, disconnect & final)		202,340	3
4	Subtotal - Bill Print Function		$ 265,630	4
	Bill Insert Function			
	Hardware/Software Maintenance Lease & Supplies:	Company Records		
5	Supplies (B&H, strapping & tags)		$ 4,808	5
6	Envelopes (mailing & remittance)		347,239	6
7	Subtotal - Bill Insert Function		$ 352,047	7
	Postage			
8	Postage for Bills Only	Company Records	$ 5,048,674	8
9	Subtotal - Postage		$ 5,048,674	9
10	Total Annual Variable Costs Related to Customer Billing		$ 5,666,351	10
11	Annual Number of Bills	Company Records	17,903,098	11
12	Incremental Cost per Customer Bill		$ 0.32	12
13	Annual Number of Bills in Test Year	Company Records	10,117,613	13
14	Annual Number of Bills in Test Year As Adjusted	Company Records	10,361,684	14
15	Increase in Annual Number of Bills		244,071	15
16	Adjustment to Recognize Incremental Billing Costs for Annualized Customers (Ln 12 x Ln 15)	Account 903	$ 77,249	16

Explanation: To recognize the incremental costs of billing for additional customer bills added to the Test Year based on annualized customer levels.

[1] Supporting Workpapers C-2, Adj. 4

SOUTHWEST GAS CORPORATION
ARIZONA
UNCOLLECTIBLE EXPENSE ANNUALIZATION
ADJUSTMENT NO. 5

Line No.	Description (a)	Amount (b)	Line No.
1	Revenue at Present Rates [1]	$ 680,637,200	1
2	Write-Off Percent of Revenue	0.2201%	2
3	Annualized Uncollectible Expense	$ 1,498,151	3
4	Less: Recorded Uncollectible Expense [2]	1,112,324	4
5	Adjustment to Uncollectible Expense	$ 385,827	5
	Detail:		
6	Net Closing Bill Write-Offs 12 Months Ended 08/31/04	$ 1,424,722	6
7	Recorded Revenue	$ 647,277,066	7
8	Net Closing Bill Write-Off as a Percent of Revenue	0.2201% Ln 2	8

Explanation:
This adjustment annualizes uncollectible accounts expense to reflect the test year net closing bill write-offs as a percentage of gross revenues and multiplying that percent by the adjusted revenues at present rates.

[1] Supporting Schedule C-1, Sh 2
[2] Supporting Schedule C-1, Sh 3

SOUTHWEST GAS CORPORATION
ARIZONA
PROMOTIONAL EXPENSES
ADJUSTMENT NO. 6

Line No.	Description (a)	Account Number (b)	Recorded at 08/31/04 (c) [1]	Adjustment (d) [2]	Adjusted at 08/31/04 (e)	Line No.
	Direct					
1	Customer Records and Collections	903	$ 21,554,924	$ (23,062)	$ 21,531,862	1
2	Customer Assistance Expenses	908	562,187	(18,978)	543,209	2
3	Informational and Instructional Expenses	909	(2,154)	2,154	0	3
4	Misc. Cust Svc and Information Expenses	910	36,192	0	36,192	4
5	Demonstrating and Selling Expenses	912	9,511	(9,511)	0	5
6	Advertising Expenses	913	502,695	(502,695)	0	6
7	Total Direct Promotional Expenses		$ 22,663,354	$ (552,091)	$ 22,111,263	7

Explanation:
Removes expenses related to promotional marketing and advertising programs that have been disallowed in previous rate applications.

[1] Supporting Schedule C-1, Sh 5
[2] Source: Company Records

SOUTHWEST GAS CORPORATION
ARIZONA
AMERICAN GAS ASSOCIATION (AGA) DUES
ADJUSTMENT NO. 7

Line No.	Description (a)	Reference (b)	Account Number (c)	Amounts (d)	Line No.
1	2004 AGA Dues	Company Records	930.2	$ 384,566	1
2	Marketing & Lobbying Percentage	WP C-2, Adj. 7		3.52%	2
3	Marketing & Lobbying Amount of Dues	Ln 1 * Ln 2		$ (13,537)	3
4	Less: Paiute & SGTC Allocation at 4.29%	C-1, 19		580	4
5	Adjustment to AGA Dues Before 4-Factor	Ln 3 + Ln 4		$ (12,956)	5
6	Arizona 4-Factor Allocation	C-1, Sh 18		57.58%	6
7	Adjustment to Arizona for Removal of Marketing & Lobbying from AGA Dues	Ln 5 * Ln 6		$ (7,460)	7

Explanation:
To remove from test year expenses that portion of the AGA dues paid by SWG that have been disallowed in prior rate cases.

Note: AGA eliminated promotional expenditures in 2000.

SOUTHWEST GAS CORPORATION
ARIZONA
INCREMENTAL SARBANES-OXLEY 404 (SOX 404) COMPLIANCE COSTS
ADJUSTMENT NO. 8

Line No.	Description	Reference	Account Number		Amounts	Line No.
	(a)	(b)	(c)		(d)	
	Test Period SOX 404 Incremental Costs					
1	Incremental Costs Recorded During Test Period	WP C-2, Adj. 8	921	$	13,765	1
2	Incremental Costs Recorded During Test Period	WP C-2, Adj. 8	923		69,225	2
3	Total Incremental Costs Recorded During Test Period	Ln 1 + Ln 2		$	82,990	3
4	Test Year Costs to Reclassify	Ln 3 * -1			(82,990)	4
5	Less: Paiute & SGTC Allocation at 4.29%	Ln 4 * 4.29% [1]			3,558	5
6	Amount to Reclassify Before 4-Factor	Ln 4 + Ln 5		$	(79,432)	6
7	Arizona 4-Factor	C-1, Sh 18			57.58%	7
8	Reclassification Allocated to Arizona	Ln 6 * Ln 7		$	(45,737)	8
	Regulatory Amortization - SOX 404					
9	Additional Incremental Costs Invoiced	WP C-2, Adj. 8		$	20,870	9
10	Estimated Additional Incremental Costs	WP C-2, Adj. 8			45,000	10
11	Total Implementation Costs	Ln 3 + Ln 9 + Ln 10		$	148,861	11
12	Proposed Amortization Period				3	12
13	Total Annual Amortization Before Allocation	Ln 11 / Ln 12			49,620	13
14	Less: Paiute & SGTC Allocation at 4.29%	Ln 13 * 4.29% [1]			(2,127)	14
15	Total Annual Amortization Before 4-Factor	Ln 13 + Ln 14		$	47,493	15
16	Arizona 4-Factor	C-1, Sh 18			57.58%	16
17	Amortization Allocated to Arizona [2]	407.3		$	27,346	17
	Estimated Incremental Annual Audit Fees					
18	for SOX 404 Opinion		923	$	450,000	18
19	Less: Paiute & SGTC Allocation at 4.29%	Ln 18 * 4.29% [1]			(19,293)	19
20	Allocation Before 4-Factor	Ln 18 + Ln 19		$	430,707	20
21	Arizona 4-Factor	C-1, Sh 18			57.58%	21
22	Amount Allocated to Arizona	Ln 20 * Ln 21		$	248,000	22
23	Net Adjustment to A&G Expense	Ln 8 + Ln 22		$	202,263	23

[1] Supporting Schedule C-1, Sh 19
[2] The regulatory amortization is included in the Depreciation and Amortization adjustment.

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
ADMINISTRATIVE AND GENERAL EXPENSES
ANNUALIZED PAIUTE ALLOCATION
ADJUSTMENT NO. 9

Line No.	Description (a)	FERC Account Number (b)	12 Months Ended 08/31/04 Net Recorded [1] (c)	Charged to Paiute [2] (d)	Gross Recorded (e) (c) + (d)	MMF Allocation Paiute [3] (f)	Paiute Annualized (g)	Reduction to Paiute's A&G Expenses (h) (d) - (g)	Amount Allocated to Arizona [4] (i)	Line No.
1	Administrative and General Salaries	920	$ 48,033,551	$ 2,584,642	$ 50,618,194	4.25%	$ 2,149,934	$ 434,709	$ 250,304	1
2	Office Supplies	921	8,531,520	463,230	8,994,750	4.25%	382,039	81,191	46,749	2
3	Outside Services Employed	923	8,410,686	456,669	8,867,355	4.25%	376,628	80,041	46,087	3
4	Property Insurance	924	297,460	115,106	412,566	21.08%	86,969	28,137	15,506	4
5	Injuries and Damages	925	4,636,429	251,741	4,888,170	4.25%	207,618	44,123	25,406	5
6	Miscellaneous General Expenses	930.2	4,420,498	240,203	4,660,701	4.25%	197,956	42,246	24,325	6
7	Rents	931	4,296,614	234,951	4,531,565	4.25%	192,472	42,479	24,459	7
8	Maintenance of General Plant	935	1,376,944	74,763	1,451,707	4.25%	61,659	13,104	7,545	8
9	Total		$ 80,003,703	$ 4,421,304	$ 84,425,007		$ 3,655,275	$ 766,029	$ 440,383	9

Explanation:
Consistent with the methodology accepted by the Commission in previous rate cases, this adjustment annualizes the recorded amounts allocated to Paiute Pipeline to reflect Paiute's MMF allocation percentage based on the test year ended August 31, 2004

Note:
Account 493, Rent from Gas Property, was increased by $14,740 due to annualizing the Paiute rental charge at August 31, 2004. Supporting Workpaper C-2, Adj. 9

[1] Supporting Schedule C-1, Sh 9
[2] Source: Company Records
[3] Modified Massachusetts Formula as calculated in Sch C-1, Sh 19, Col (g); 21.08% based on insurable property. Supporting Workpaper C-2, Adj. 9.
[4] All accounts except 924 are allocated to Arizona using the 4-Factor. Account 924 uses the Factor II percentage. Supporting Schedule C-1, Sh 19.

SOUTHWEST GAS CORPORATION
ARIZONA
INJURIES AND DAMAGES
SELF-INSURED RETENTION NORMALIZATION
ADJUSTMENT NO. 10

Line No.	Description [1] (a)	Reference (b)	Allocation Percent (c)	System Allocable (d)	14-Year Total (e)	Total Arizona Accrual (f)	Line No.
	Claims Paid	WP C-2, Adj. 10					
1	< $1,000,000				$ 8,557,891		1
2	At $1,000,000				10,000,000		2
3	> $1,000,000 < $10,000,000				36,347,300		3
4	Total Claims Paid				$ 54,905,191		4
5	14 Year Average					$ 3,921,799	5
6	Less FERC Allocation @4.29%	C-1, Sh 18	4.29%			(168,245)	6
7	Net System Allocable					$ 3,753,554	7
8	Arizona 4-Factor	C-1, Sh 19	57.58%			$ 2,161,296	8
9	Recorded Amounts [2]			$ 275,000			9
10	Less FERC Allocation @4.29%	C-1, Sh 18	4.29%	(11,798)			10
11	Net System Allocable			$ 263,203			11
12	Arizona 4-Factor	C-1, Sh 19	57.58%			$ 151,552	12
13	Arizona Direct [2]		100.00%			411,000	13
14	Total Recorded Arizona					$ 562,552	14
15	Total Adjustment (Ln 8 - Ln 14)					$ 1,598,744	15

[1] Supporting Workpapers C-2, Adj. 10
[2] Source: Company Records

SOUTHWEST GAS CORPORATION
ARIZONA
INJURIES AND DAMAGES
LIABILITY INSURANCE AMORTIZATION ANNUALIZATION
ADJUSTMENT NO. 10

Line No.	Description (a)	Reference (b)	Account Number (c)		Amounts (d)	Line No.
1	Amortization Recorded During Test Period	WP C-2, Adj. 10	925	$	5,450,501	1
2	Current Annual Insurance Premiums [1]	WP C-2, Adj. 10			8,072,417	2
3	Adjustment Before Allocation	Ln 2 - Ln 1		$	2,621,915	3
4	Less: Paiute & SGTC Allocation at 4.29%	C-1, Sh 19			(112,410)	4
5	Adjustment Before 4-Factor Allocation	Ln 3 + Ln 4		$	2,509,505	5
6	Arizona 4-Factor Allocation	C-1, Sh 18			57.58%	6
7	Adjustment to Arizona to Annualize Liability Insurance Premiums	Ln 5 * Ln 6		$	1,444,967	7

[1] Based on annual bills from policy renewals occurring during the test period.

SOUTHWEST GAS CORPORATION
ARIZONA
PIPE REPLACEMENT
ADJUSTMENT PER DECISION NO. 58693
ADJUSTMENT NO. 11

Line No.	Description (a)	2000 (b)	2001 (c)	2002 (d)	2003 (e)	2004 (f)	Total Gross Plant (g)	Accumulated Depreciation (h)	Deferred Taxes (i)	Total Adjustment to Rate Base (j) -(g)+(h)+(i)	Line No.
	Aldyl HD Mains										
1	Footage Replaced	$ 2,459	$ 10,064	$ 10,532	$ 3,638	$ 2,530	$ 29,223				1
2	Cost Per Foot	6.42	14.94	8.68	22.59	15.46					2
3	Replacement Cost	$ 15,796	$ 150,399	$ 91,463	$ 82,185	$ 39,107	$ 378,951				3
4	Disallowance percent	50.0%	47.5%	45.0%	42.5%	40.0%					4
5	Disallowance	$ 7,898	$ 71,440	$ 41,158	$ 34,929	$ 15,643	$ 171,068	$ 32,436	$ 18,044	$ (120,588)	5
	Aldyl HD Services										
6	Footage Replaced	$ 9,776	$ 35,016	$ 30,257	$ 46,614	$ 40,813	$ 162,476				6
7	Cost Per Foot	20.85	16.11	19.19	15.62	15.94					7
8	Replacement Cost	$ 203,854	$ 564,117	$ 580,723	$ 728,319	$ 650,523	$ 2,727,536				8
9	Disallowance percent	50.00%	47.50%	45.00%	42.50%	40.00%					9
10	Disallowance	$ 101,927	$ 267,956	$ 261,325	$ 309,536	$ 260,209	$ 1,200,953	$ 262,907	$ 147,597	$ (790,449)	10
11	Total Disallowance	$ 109,825	$ 339,395	$ 302,484	$ 344,465	$ 275,852	$ 1,372,020	$ 295,343	$ 165,641	$ (911,037)	11

SOUTHWEST GAS CORPORATION
ARIZONA
LEAK MAINTENANCE AND ACCELERATED LEAK SURVEY
ADJUSTMENT PER DECISION NO. 58693
ADJUSTMENT NO. 11

Line No.	Description (a)	Account Number (b)	Leak Repair [1] (c)	Accelerated Leak Survey [1] (d)	Total Adjustment (e)	Line No.
1	Maintenance of Mains	887	$ (55,598)	$ (25,419)	$ (81,017)	1
2	Maintenance of Services	892	(31,735)	(22,649)	(54,384)	2
3	Total Adjustment		$ (87,333)	$ (48,068)	$ (135,401)	3

[1] Supporting Workpapers C-2, Adj. 11

SOUTHWEST GAS CORPORATION
ARIZONA
TRANSMISSION INTEGRITY MANAGEMENT PROGRAM (TRIMP)
THREE YEAR AMORTIZATION OF AMOUNTS DEFERRED THROUGH DECEMBER 2005 AND THE PRO FORMA ADJUSTMENT FOR ONGOING EXPENSE
ADJUSTMENT NO. 12

Line No.	Description [1] (a)	Account Number (b)	2004 (c)	2005 (d)	Total (e)	2006 (f)	Line No.
1	Direct Assessment 10 Yr. Cycle		$ 355,000	$ 532,500	$ 887,500		1
2	Direct Examination		1,065,000	1,597,500	2,662,500		2
3	Total Deferred		$ 1,420,000	$ 2,130,000	$ 3,550,000		3
4	Amortization Period				3		4
5	Regulatory Amortization [2]	407.3				$ 1,183,333	5
	ProForma Expense Adjustment						
6	Direct Assessment 10 Yr. Cycle	874				$ 380,357	6
7	Direct Examination	874				1,141,071	7
8	Maintenance - Repairs	887				570,536	8
9	Total Operation & Maintenance					$ 2,091,964	9
10	Total Revenue Requirement Impact					$ 3,275,298	10

Explanation
The Company proposes to defer non-capital TRIMP related incremental cost incured during 2004 through December 2005, or the date new rates become effective in this rate proceeding. Included in the cost of service is a three year amortization of these deferred cost.
The Company proposes to include, in the cost of service, an ongoing level of non-capital related TRIMP expense, based on the estimated average annual incremental expense during the years 2006-2012.
All of the above cost do *not* include Company labor and labor loading.

[1] Source: Company Records
[2] The regulatory amortization adjustment is part of Depreciation/Amortization Adjustment No. 17.

SOUTHWEST GAS CORPORATION
ARIZONA
SCHEDULE OF ESTIMATED RATE CASE EXPENSE
ADJUSTMENT NO. 13

Line No.	Description (a)	Account (b)	Estimated Amounts (c)	Line No.
	2004 Arizona Rate Case			
1	Printing/Copying/Postage/Freight		$ 38,000	1
2	Professional Services		140,000	2
3	Notice/Publication		5,000	3
4	Court Reporting		10,000	4
5	Travel/Transportation		42,000	5
6	Total Arizona Rate Case Expense		$ 235,000	6
7	Amortization Period (In Years)		3	7
8	Annual Arizona Rate Case Expense	928	$ 78,333	8
9	Rate Case Expense Recorded in Test Year	928	63,324	9
10	Adjustment to Test Year Expense		$ 15,009	10

Source: Company Records

SOUTHWEST GAS CORPORATION
ARIZONA
MISCELLANEOUS ADJUSTMENTS
ADJUSTMENT NO. 14

Line No.	Account Number (a)	Reference (b)	Amount (c)	Paiute & SGTC Allocation [1] 4.29% (d)	Net of Paiute (e)	Allocation Factor [2] (f)	Total (g)	Line No.
	Arizona							
1	870	WP C-2, Adj. 14	$ 6,859				$ 6,859	1
2	875	WP C-2, Adj. 14	288				288	2
3	880	WP C-2, Adj. 14	54,593				54,593	3
4	Subtotal Distribution	Ln 1 to Ln 3	$ 61,740				$ 61,740	4
5	903	WP C-2, Adj. 14	$ 2,250				$ 2,250	5
6	Subtotal Customer Accounts	Ln 5	$ 2,250				$ 2,250	6
7	908	WP C-2, Adj. 14	$ 23,705				$ 23,705	7
8	910	WP C-2, Adj. 14	11,600				11,600	8
9	Subtotal Customer Service & Info.	Ln 7 to Ln 8	$ 35,305				$ 35,305	9
10	Subtotal Arizona	Ln 4 + Ln 6 + Ln 9	$ 99,295				$ 99,295	10
	System Allocable							
11	903	WP C-2, Adj. 14	$ 801	N/A	$ 801	55.40%	$ 444	11
12	Subtotal Customer Accounts	Ln 11	$ 801		$ 801		$ 444	12
13	921	WP C-2, Adj. 14	$ 15,350	$ 658	$ 14,692	57.58%	$ 8,460	13
14	932	WP C-2, Adj. 14	75,000	3,215	71,785	57.58%	41,333	14
15	930.2	WP C-2, Adj. 14	28,922	1,240	27,682	57.58%	15,939	15
16	Subtotal Administrative and General	Ln 13 to Ln 15	$ 119,272	$ 5,114	$ 114,158		$ 65,732	16
17	Subtotal System Allocable	Ln 12 + Ln 16	$ 120,073	$ 5,114	$ 114,959		$ 66,176	17
18	Total Adjustment	Ln 10 + Ln 17					$ 165,470	18

Explanation
To remove various expenditures from the cost of service.

[1] Supporting Schedule C-1, Sh 19
[2] Accounts 813, 921, 930.2, and 935 are allocated using the 4-Factor as calculated in C-1, Sh 18.
Account 903 is allocated based on Factor IV.

SOUTHWEST GAS CORPORATION
ARIZONA
EMPLOYEE VEHICLE COMPENSATION
ADJUSTMENT NO. 15

Line No.	Description (a)	Reference (b)	Account (c)	Amount (d)	Line No.
1	Arizona	Company Records	870	$ 23,124	1
2	System Allocable	Company Records		$ 151,397	2
3	Less: Paiute & SGTC Allocation at 4.29%	C-1, Sh 19		6,491	3
4	Adjustment Before 4-Factor Allocation	Ln 2 - Ln 3		$ 144,906	4
5	Arizona 4-Factor Allocation	C-1, Sh 18		57.58%	5
6	Adjustment Allocated to Arizona	Ln 4 * Ln 5	920	$ 83,437	6
7	Total Adjustment	Ln 1 + Ln 6		$ 106,561	7

Explanation
To remove imputed earnings associated with employees' personal use of a company vehicle. Includes employees who fall under "Category D" of the Southwest Gas Standard Practice 100.1.

SOUTHWEST GAS CORPORATION
ARIZONA
OUT OF PERIOD EXPENSES
ADJUSTMENT NO. 16

Line No.	Description (a)	Reference (b)	Account Number (c)		Total (d)	Line No.
	Arizona					
1	AmeriVest Black Canyon Inc. [1]	Company Records	881	$	119,824	1
	System Allocable					
2	SAS Institute, Inc. [2]	Company Records	923	$	(95,906)	2
3	Subtotal	Ln 2		$	(95,906)	3
4	Less: Paiute & SGTC Allocation at 4.29%	C-1, Sh 19			4.29%	4
5	Amount to be Allocated	Ln 3 * Ln 4		$	(91,794)	5
6	Arizona 4-Factor	C-1, Sh 18			57.58%	6
7	Net System Allocable to Arizona	Ln 5 * Ln 6		$	(52,855)	7
8	Total Adjustment	Ln 1 + Ln 7		$	66,969	8

[1] Paid in August 2003, one month prior to the test period, for September 2004 rent.
This adjustment is necessary to have 12 months of rent payments during the test period.
[2] Two payments for this item were recorded during the test year.
The payment with a service period of September 1, 2004 - August 31, 2005 was removed.

SOUTHWEST GAS CORPORATION
ARIZONA
DEPRECIATION AND AMORTIZATION EXPENSE ANNUALIZATION
ADJUSTMENT NO. 17

Line No.	Description (a)	Recorded at 08/31/04 (b)	Annualization Adjustment (c)	Adjusted at 08/31/04 (d)	Line No.
	Arizona [1]				
1	Depreciation Expense	$ 64,205,210	$ 2,914,314	$ 67,119,524	1
2	Amortization Expense	1,062,133	705,408	1,767,541	2
3	Total	$ 65,267,343	$ 3,619,722	$ 68,887,065	3
	System Allocable [1]				
4	Depreciation Expense	$ 5,477,865	$ (1,384,636)	$ 4,093,229	4
5	Amortization Expense	8,753,375	(580,861)	8,172,514	5
6	Total	$ 14,231,239	$ (1,965,496)	$ 12,265,743	6
7	Arizona 4-Factor [2]	57.58%	57.58%	57.58%	7
8	Amount Allocated to Arizona	$ 8,194,311	$ (1,131,728)	$ 7,062,583	8
9	Total (Ln 3 + Ln 8)	$ 73,461,654	$ 2,487,994	$ 75,949,648	9

Explanation:
This adjustment annualizes depreciation and amortization expense as of 08/31/04.
Information on the various components of the annualization adjustment is contained in Adjustment No. 17 Workpapers.

[1] Supporting Workpapers C-2, Adj. 17

SOUTHWEST GAS CORPORATION
ARIZONA
PROPERTY TAX
ADJUSTMENT NO. 18

Line No.	Description (a)	Reference (b)		Arizona (c)	Line No.
1	Net Plant in Service	B-2, Sh 1	$	1,051,372,747	1
	Add:				
2	Customer Contributions in Aid of Construction	[1]		12,779,095	2
3	Materials and Supplies	B-5, Sh 3		9,222,489	3
	Less:				
4	Transportation Equipment	[2]		(25,153,605)	4
5	Land Rights	[3]		(797,670)	5
6	Estimated Full Cash Value	Ln 1 to Ln 5	$	1,047,423,056	6
7	Assessment Rate	[4]		25.00%	7
8	Assessed Value	Ln 6 * Ln 7	$	261,855,764	8
9	Property Tax Rate With Bond Issues	[4]		12.77%	9
10	Annualized Property Tax Expense	Ln 8 * Ln 9	$	33,447,313	10
11	Recorded Property Tax Expense	C-1, Sh 16		29,114,451	11
12	Total Adjustment		$	4,332,862	12

Explanation:
To annualize Property Tax Expense to reflect adjusted investment at 08/31/04 based on the most recent property tax rates.

[1] Source: Company Records
[2] Adjusted balance net of accumulated depreciation. Supporting Workpapers B-2
[3] Balance as recorded at 08/31/04. Supporting Workpapers B-2
[4] Rates per latest Arizona tax bills.

SOUTHWEST GAS CORPORATION
ARIZONA
INTEREST ON CUSTOMER DEPOSITS
ADJUSTMENT NO. 19

Line No.	Description (a)	Account Number (b)	Recorded at 08/31/04 [1] (c)	Adjustment (d)	Adjusted at 08/31/04 (e)	Line No.
1	Interest Expense	431	$ 1,404,209	$ (686,844)	$ 717,364	1
	Customer Deposits	235				
2	August 2003				$ 21,697,818	2
3	September				22,116,629	3
4	October				22,421,280	4
5	November				22,915,023	5
6	December				23,429,731	6
7	January 2004				23,858,508	7
8	February				24,244,633	8
9	March				24,547,955	9
10	April				24,807,840	10
11	May				24,958,957	11
12	June				25,170,362	12
13	July				25,267,247	13
14	August				25,421,849	14
15	Thirteen Month Total				$ 310,857,833	15
16	Thirteen Month Average				$ 23,912,141	16
17	Interest Rate				3.00%	17
18	Adjusted Interest Expense				$ 717,364	18
					Ln 1	

Explanation:
To synchronize interest on Customer Deposits with the adjusted average of the thirteen monthly balances of customer deposits used as a Rate Base reduction.

[1] Supporting Workpapers C-2, Adj. 19

SOUTHWEST GAS CORPORATION
ARIZONA
COMPUTATION OF GROSS REVENUE CONVERSION FACTOR

Line No.	Description (a)		Base Amount (b)	Rate (c)		Amount (d)	Line No.
1	Gross Operating Revenues				$	1,000.00	1
2	Less: Uncollectibles [1]	$	1,000.00	0.2201%		2.20	2
3	Subtotal				$	997.80	3
4	Less: State Income Tax [2]	$	997.80	6.9680%		69.53	4
5	Subtotal				$	928.27	5
6	Less: Federal Income Tax [2]	$	997.80	32.5612%		324.90	6
7	Total				$	603.38	7
8	Gross Revenue Conversion Factor (Line 1 / Line 7)					1.6573	8

[1] Supporting Schedule C-2, Adj. 5
[2] Supporting Schedule C-3, Sh 2

SOUTHWEST GAS CORPORATION
ARIZONA
COMPUTATION OF STATE AND FEDERAL TAX RATES
AS OF AUGUST 31, 2004

Line No.	Description (a)	Rate (b)	Rate (c)	Line No.
1	Current State Income Tax Rate (SIT)		6.9680%	1
2	Current Federal Income Tax Rate (FIT)	35.0000%		2
	Effective Rate = FIT x (1-ESIT)			
3	.35 x (1-.06968)		32.5612%	3
4	Total Effective Rate		39.5292%	4

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SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
COST OF CAPITAL AT AUGUST 31, 2004

Line No.	Description (a)	Capital Ratio (b)	Capital Cost (c)	Weighted Cost of Capital (d)	Line No.
1	Long-Term Debt	53.00%	7.49% [1]	3.97%	1
2	Preferred Equity	5.00%	8.20% [2]	0.41%	2
3	Common Equity	42.00%	11.95% [3]	5.02%	3
4	Total	100.00%		9.40%	4

[1] Reference Schedule D-2, Sheet 1 of 4
[2] Reference Schedule D-3, Sheet 1 of 2
[3] Reference Schedule D-4, Sheet 1 of 1

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
NET CAPITAL AT AUGUST 31, 2004

Line No.	Description	Net System Balance at 08/31/2004	Adjustments[1]	Pro Forma Net Capital Amounts	Capital Ratio	Line No.
	(a)	(b)	(c)	(d)	(e)	
	Debt					
	Long-Term Debt:					
1	Debentures	$ 537,516,778	$ -	$ 537,516,778	34.70%	1
2	Medium-Term Notes	149,148,342	-	149,148,342	9.63%	2
3	Term Facilities	99,285,114	-	99,285,114	6.41%	3
4	Clark County IDRB's	324,008,020	(324,008,020)	-	0.00%	4
5	Big Bear IDRB's	49,239,747	(49,239,747)	-	0.00%	5
6	Total Long-Term Debt	$ 1,159,198,001	$ (373,247,767)	$ 785,950,234	50.74%	6
	Equity					
7	Preferred Equity	$ 100,000,000	-	$ 100,000,000	6.46%	7
8	Common Equity	662,978,685	-	662,978,685	42.80%	8
9	Total Equity	$ 762,978,685	$ -	$ 762,978,685	49.26%	9
10	Total Capital	$ 1,922,176,686	$ (373,247,767)	$ 1,548,928,919	100.00%	10

[1] Adjustments:

Clark County and Big Bear IDRB's are eliminated because those issues are used solely to fund qualified construction expenditures in Clark County, Nevada and San Bernardino County, California.

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
COST OF DEBT AT AUGUST 31, 2004

Line No.	Description	Net Principal Amount Outstanding	Interest Rate	Cost of Debt	Line No.
	(a)	(b)	(c)	(d)	
1	Fixed Rate Debt [1]	$ 686,665,120	8.20%	$ 56,282,787	1
2	Variable Rate Debt [2]	99,285,114	2.59%	2,576,267	2
3	Total Long-Term Debt	$ 785,950,234	7.49%	$ 58,859,054	3

[1] Reference Schedule D-2, Sheet 2 of 4
[2] Reference Schedule D-2, Sheet 3 of 4

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
COST OF LONG-TERM FIXED RATE DEBT
AT AUGUST 31, 2004

Line No.	Description (a)	Principal Amount Outstanding (b)	Unamortized Debt Expense and Discount (c)	Net Proceeds (d)	Effective Interest Rate (e)	Cost of Debt (f)	Line No.
	Debentures						
1	7.5% Debenture, Due 2006	$ 75,000,000	$ 1,889,326	$ 73,110,674	8.96%	$ 6,550,716	1
2	8.0% Debenture, Due 2026	75,000,000	6,380,396	68,619,604	8.89%	6,100,283	2
3	8.375% Note, Due 2011	200,000,000	2,286,851	197,713,149	8.61%	17,023,102	3
4	7.625% Note, Due 2012	200,000,000	1,926,649	198,073,351	7.79%	15,429,914	4
5	Total Debentures	$ 550,000,000	$ 12,483,222	$ 537,516,778	8.39%	$ 45,104,015	5
	Medium Term Notes						
6	7.59% MTN, Due 2017	$ 25,000,000	$ 172,074	$ 24,827,926	7.68%	$ 1,906,785	6
7	7.78% MTN, Due 2022	25,000,000	191,074	24,808,926	7.86%	1,949,982	7
8	7.92% MTN, Due 2027	25,000,000	214,516	24,785,484	8.00%	1,982,839	8
9	6.89% MTN, Due 2007	17,500,000	54,408	17,445,592	7.00%	1,221,191	9
10	6.76% MTN, Due 2027	7,500,000	24,384	7,475,616	6.88%	514,322	10
11	6.27% MTN, Due 2008	25,000,000	114,113	24,885,887	6.40%	1,592,697	11
12	7.75% MTN, Due 2005	25,000,000	81,089	24,918,911	8.07%	2,010,956	12
13	Total Medium Term Notes	$ 150,000,000	$ 851,658	$ 149,148,342	7.50%	$ 11,178,772	13
14	Total Debentures and MTNs	$ 700,000,000	$ 13,334,880	$ 686,665,120	8.20% Sch D-2, Sheet 1	$ 56,282,787	14
	Tax Exempt Clark County						
15	1993 Series A, Due 2033	$ 75,000,000	$ 1,273,285	$ 73,726,715	6.67%	$ 4,917,572	15
16	1999 Series A, Due 2038	12,410,000	637,917	11,772,083	6.51%	766,363	16
17	1999 Series C, Due 2038	14,320,000	870,650	13,449,350	6.42%	863,448	17
18	1999 Series D, Due 2038	8,270,000	502,425	7,767,575	5.99%	465,278	18
19	2003 Series C, Due 2038	30,000,000	1,574,900	28,425,100	5.92%	1,682,766	19
20	2003 Series D, Due 2038	20,000,000	1,758,495	18,241,505	6.04%	1,101,787	20
21	2003 Series E, Due 2038	15,000,000	207,240	14,792,760	5.92%	875,731	21
22	2004 Series A, Due 2034	65,000,000	3,644,949	61,355,051	6.02%	3,693,574	22
23	Total Tax Exempt	$ 240,000,000	$ 6,493,134	$ 229,530,139	6.26%	$ 14,366,519	23
24	Total Fixed-Rate Debt	$ 940,000,000	$ 19,828,014	$ 916,195,259	7.71%	$ 70,649,306	24

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
VARIABLE RATE DEBT COST OF DEBT
AT AUGUST 31, 2004

Line No.	Description (a)	Net Proceeds (b)	Interest Rate (c)	Cost of Debt (d)	Line No.
1	Term Facility[1]	$ 99,285,114	2.59%	$ 2,576,267	1
			Sch D-2, Sheet 1		
2	Big Bear 1993 Series A IDRB [2]	$ 49,239,747	2.71%	$ 1,334,209	2
3	Clark Co.2003 Series A & B IDRB [3]	94,477,881	1.77%	$ 1,674,899	3

[1] Based on $100 million designated long-term of the $250 million Bank Facility less $715 thousand of unamortized expense.

[2] The net amount represents $50 million face value less $ $760 thousand of unamortized balances.

[3] The net amount represents $100 million face value less $5.52 million of unamortized balances thousand of unamortized balances.

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
COST OF LONG-TERM DEBT
ORIGINAL NET PROCEEDS OF ISSUES OUTSTANDING [2]

Line No.	Description (a)	Origination Date (b)	Maturity Date (c)	Coupon Rate (d)	Offered (e)	Gross Proceeds (f)	Underwriter's Commission and Discounts: Amount (g)	Underwriter's Commission and Discounts: Percent of Gross Proceeds (h)	Debt and Issuance Expense: Amount (i)	Debt and Issuance Expense: Percent of Gross Proceeds (j)	Net Proceeds: Amount (k)	Net Proceeds: Per $100 Unit (l)	Cost of Money [1] (m)	Line No.
	Debentures													
1	7.5% Debenture, Due 2006	08/01/96	08/01/06	7.50%	$ 75,000,000	$ 75,000,000	$ 1,105,500	1.47%	$ 6,031,631	8.04%	$ 67,862,869	90.48	8.96%	1
2	8.0% Debenture, Due 2026	08/01/96	08/01/26	8.00%	75,000,000	75,000,000	894,750	1.19%	6,048,405	8.06%	68,056,845	90.74	8.89%	2
3	8.375% Note, Due 2011	02/13/01	02/15/11	8.38%	200,000,000	200,000,000	2,818,000	1.41%	288,784	0.14%	196,893,216	98.45	8.61%	3
4	7.625 Note, Due 2012	05/06/02	05/15/12	7.63%	200,000,000	200,000,000	2,052,000	1.03%	270,042	0.14%	197,677,958	98.84	7.79%	4
5	Total Debentures				$ 550,000,000	$ 550,000,000	$ 6,870,250	1.25%	$ 12,638,862	2.30%	$ 530,490,888	96.45		5
	Medium Term Notes													
6	7.59% MTN, Due 2017	01/17/97	01/17/17	7.59%	$ 25,000,000	$ 25,000,000	$ 187,500	0.75%	$ 33,400	0.13%	$ 24,779,100	99.12	7.68%	6
7	7.78% MTN, Due 2022	02/03/97	02/03/22	7.78%	25,000,000	25,000,000	187,500	0.75%	33,400	0.13%	24,779,100	99.12	7.86%	7
8	7.92% MTN, Due 2027	06/04/97	06/04/27	7.92%	25,000,000	25,000,000	187,500	0.75%	45,761	0.18%	24,766,739	99.07	8.00%	8
9	6.89% MTN, Due 2007	09/23/97	09/24/07	6.89%	17,500,000	17,500,000	102,325	0.58%	40,200	0.23%	17,357,475	99.19	7.00%	9
10	6.76% MTN, Due 2027	09/23/97	09/24/27	6.76%	7,500,000	7,500,000	46,875	0.63%	17,228	0.23%	7,435,897	99.15	6.88%	10
11	6.27% MTN, Due 2008	09/24/98	09/22/08	6.27%	25,000,000	25,000,000	156,250	0.63%	79,928	0.32%	24,763,822	99.06	6.40%	11
12	6.27% MTN, Due 2005	10/02/00	09/30/05	7.75%	25,000,000	25,000,000	125,000	0.50%	197,928	0.79%	24,677,072	98.71	8.07%	12
13	Total Medium Term Notes				$ 150,000,000	$ 150,000,000	$ 992,950	0.66%	$ 447,845	0.30%	$ 148,559,205	99.04		13
	Tax Exempt Clark County													
14	1993 Series A, Due 2033	12/15/93	12/01/33	6.50%	$ 75,000,000	$ 75,000,000	$ 1,406,250	1.88%	$ 330,048	0.44%	$ 73,263,702	97.68	6.67%	14
15	1999 Series A, Due 2038	10/05/99	12/01/38	6.10%	12,410,000	12,410,000	53,920	0.43%	658,490	5.31%	11,697,590	94.26	6.51%	15
16	1999 Series C, Due 2038	07/19/00	12/01/38	5.95%	14,320,000	14,320,000	38,342	0.27%	936,800	6.54%	13,344,858	93.19	6.42%	16
17	1999 Series D, Due 2038	09/26/01	12/01/38	5.55%	8,270,000	8,270,000	21,451	0.26%	523,760	6.33%	7,724,789	93.41	5.99%	17
18	2003 Series A, Due 2038	03/25/03	03/01/38	Var	50,000,000	50,000,000	128,076	0.26%	2,820,818	5.64%	47,051,106	94.10	Var	18
19	2003 Series B, Due 2038	03/25/03	03/01/38	Var	50,000,000	50,000,000	128,076	0.26%	2,820,818	5.64%	47,051,106	94.10	Var	19
20	2003 Series C, Due 2038	03/25/03	03/01/38	5.45%	30,000,000	30,000,000	200,538	0.67%	1,440,962	4.80%	28,358,500	94.53	5.92%	20
22	2003 Series D, Due 2038	03/25/03	03/01/38	5.25%	20,000,000	20,000,000	133,692	0.67%	1,533,688	7.67%	18,332,620	91.66	6.04%	22
21	2003 Series E, Due 2038	03/25/03	03/01/38	5.80%	15,000,000	15,000,000	100,269	0.67%	115,735	0.77%	14,783,996	98.56	5.92%	21
22	2004 Series A, Due 2027	07/16/04	12/01/38	5.25%	65,000,000	65,000,000	1,081,500	1.66%	2,610,686	4.02%	61,307,814	94.32	6.02%	22
23	Total Tax Exempt Clark County				$ 340,000,000	$ 340,000,000	$ 3,292,114	0.97%	$ 13,791,805	4.06%	$ 322,916,081	94.98		23
	Tax Exempt Big Bear													
24	1993 Series A, Due 2028	12/01/93	12/01/28	Var	$ 50,000,000	$ 50,000,000	$ 175,000	0.35%	$ 656,763	1.31%	$ 49,168,237	98.34	Var	24
25	Term Facility [4]	05/04/04	05/03/07	Var	$ 100,000,000	$ 100,000,000	$ -	0.00%	$ 545,897	0.55%	$ 99,454,103	99.45	Var	25
26	Total Debt Capital				$ 1,190,000,000	$ 1,190,000,000	$ 11,330,314	0.95%	$ 28,081,172	2.36%	$ 1,150,588,514	96.69		26

[1] Based on the Net Proceeds method.
[2] Based on Company records.
[3] Effective Rate at August 31, 2004
[4] A Commercial Paper program was initiated in October 2002 and is backed by $50 million of the term facility.

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
COST OF PREFERRED SECURITIES
AT AUGUST 31, 2004

Line No.	Description	Net Proceeds Per Security	Number of Securities	Net Proceeds	Effective Cost [1]	Annual Cost	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
1	Trust Originated Preferred Securities Liquidation Amount $25[2]	$ 23.52	4,000,000	$ 94,111,144	8.20% Sch D-1, sh 1	$ 7,717,114	1

[1] See T. Wood's Testimony, Exhibit No.__(TKW-7).
[2] The 7.70% Trust Originated Preferred Securities were issued in a public offering on August 25, 2003 by Southwest Gas Capital II. Southwest Gas Capital II is a business trust which exists for the sole purpose of issuing Preferred Securities and Common Securities and investing the proceeds thereof in an equivalent amount of 7.70% Subordinated Deferrable Interest Notes due September 15, 2043 of Southwest Gas Corporation. Southwest Gas Corporation owns all of the common securities representing undivided beneficial interests in the assets of the Trust.

SOUTHWEST GAS CORPORATION
COST OF PREFERRED SECURITIES
ORIGINAL NET PROCEEDS OF ISSUES OUTSTANDING AT AUGUST 31, 2004

			Total Issued		Underwriter's Commission		Reacquired Debt Expense		Issuance Expense		Net Proceeds	
Line No.	Description	Annual Dividend Rate/Share	At Par	Gross Proceeds	Amount	Percent of Gross Proceeds	Amount	Percent of Gross Proceeds	Amount	Percent of Gross Proceeds	Amount	Amount Per Share
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Trust Originated Preferred Securities Liquidation Amount $25[1]	7.70%	$ 100,000,000	$ 100,000,000	$ 3,150,000	3.150%	$ 2,221,449	2.221%	$ 537,824	0.538%	$ 94,090,727	$ 23.52

[1] The 7.70% Preferred Trust Securities were issued in a public offering on August 25, 2003 by Southwest Gas Capital II. Southwest Gas Capital II is a business trust which exists for the sole purpose of issuing Preferred Securities and Common Securities and investing the proceeds thereof in an equivalent amount of 7.70% junior subordinated debentures due September 15, 2043 of Southwest Gas Corporation. Southwest Gas Corporation owns all of the common securities representing undivided beneficial interests in the assets of the Trust.
Southwest Gas Capital II may redeem some or all of the preferred trust securities on or after August 25, 2008, or all of the preferred trust securities at any time upon the occurrence of a special event at a redemption price equal to $25 per preferred trust security plus accumulated and unpaid distributions, if any.

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
COST OF COMMON EQUITY

Line No.	Description	Line No.
	(a)	
1	See F.J. Hanley's Testimony for details regarding the cost of common equity.	1

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SOUTHWEST GAS CORPORATION
TOTAL SYSTEM
COMPARATIVE BALANCE SHEETS

Line No.	Description	Balance At 8/31/04	Balance At 12/31/03	Balance At 12/31/02	Line No.
	(a)	(b)	(c)	(d)	
	Assets and Other Debits				
	Utility Plant				
1	Utility Plant (101, 105, 114, 118)	$ 3,044,869,150	$ 2,893,469,458	$ 2,649,950,414	1
2	Construction Work in Progress (107)	21,366,323	33,489,492	66,408,838	2
3	Total Utility Plant	$ 3,066,235,473	$ 2,926,958,950	$ 2,716,359,252	3
	Less: Accumulated Provision for Depreciation				
4	and Amortization (108, 111, 119)	983,084,637	913,442,794	823,579,022	4
5	Net Utility Plant	$ 2,083,150,836	$ 2,013,516,156	$ 1,892,780,230	5
	Other Property and Investments				
6	Northern California Surcharge (120)	$ 7,390,694	$ 9,375,439	$ 9,701,340	6
7	Non-Utility Property (121)	410,036	410,036	410,036	7
8	Non-Utility Accumulated Depreciation (122)	-	-	-	8
	Investment in Subsidiary and Associated				
9	Companies (123, 123.1)	103,878,478	98,284,509	90,512,393	9
10	Other Investments (124)	250,000	-	-	10
11	Special Funds (125, 128)	44,428,297	43,251,175	40,087,873	11
12	Total Other Property and Investments	$ 156,357,505	$ 151,321,159	$ 140,711,642	12
	Current and Accrued Assets				
13	Cash (131)	$ (11,786,944)	$ (3,922,702)	$ (11,097,128)	13
14	Working Funds (135)	552,044	405,928	472,726	14
15	Temporary Cash Investments (136)	10,083,675	7,023,359	9,713,178	15
	Notes and Accounts Receivables Less Accumulated				
16	Provision for Uncollectible Accounts (141 - 144)	59,120,281	102,220,241	103,050,267	16
17	Receivables from Associated Companies (145-146)	23,715,869	25,007,230	18,764,538	17
18	Materials and Supplies (151, 154, 155, 163)	20,625,677	16,578,496	13,960,517	18
19	Liquefied Natural Gas Stored (164.1, 164.2)	7,563,546	8,900,293	12,187,589	19
20	Prepayments (165)	7,905,770	6,294,043	4,172,682	20
21	Interest and Dividends Receivable (171)	-	923	176	21
22	Accrued Utility Revenue (173)	28,200,000	66,700,000	65,073,000	22
23	Miscellaneous Current and Accrued Assets (174)	10,669,629	356,920	721,592	23
24	Total Current and Accrued Assets	$ 156,649,547	$ 229,564,731	$ 217,019,137	24
	Deferred Debits				
25	Unamortized Debt Discount and Expenses (181)	$ 12,019,300	$ 9,148,218	$ 4,784,557	25
26	Other Regulatory Assets (182)	34,148,721	45,169,522	37,794,093	26
27	Preliminary Survey and Investigation Charges (183)	185,385	118,400	-	27
28	Clearing Accounts (184)	600,475	41,541	(25,190)	28
29	Miscellaneous Deferred Debits (186)	6,472,447	6,128,672	414,826	29
30	Research & Development (188)	37,400	-	-	30
31	Loss on Reacquired Debt (189)	17,684,272	18,559,924	12,613,852	31
32	Accumulated Deferred Income Taxes (190)	36,680,538	36,680,538	26,040,574	32
33	Unrecovered Purchased Gas Costs (191)	53,579,892	9,151,173	(26,717,706)	33
34	Total Deferred Debits	$ 161,408,430	$ 124,997,988	$ 54,905,006	34
35	Total Assets and Other Debits	$ 2,557,566,318	$ 2,519,400,034	$ 2,305,416,015	35

SOUTHWEST GAS CORPORATION
TOTAL SYSTEM
COMPARATIVE BALANCE SHEETS

Line No.	Description (a)	Balance At 8/31/04 (b)	Balance At 12/31/03 (c)	Balance At 12/31/02 (d)	Line No.
	Liabilities and Other Credits				
	Proprietary Capital				
1	Common Stock Issued (201)	$ 37,161,054	$ 35,861,974	$ 34,918,891	1
2	Preferred Stock Issued (204)	-	-	60,000,000	2
3	Premium on Capital Stock (207)	545,600,121	519,672,931	499,313,268	3
4	Other Paid in Capital (208-211)	-	-	-	4
5	Reacquired Capital Stock (217)	-	-	-	5
6	Capital Stock Expense (214)	(9,290,914)	(9,151,645)	(11,525,575)	6
7	Retained Earnings (216)	89,508,423	84,084,148	73,460,267	7
8	Total Proprietary Capital	$ 662,978,684	$ 630,467,408	$ 656,166,851	8
	Long-Term Debt				
9	Bonds (221, 222)	$ 1,090,000,000	$ 1,025,000,000	$ 990,000,000	9
10	Other Long-Term Debt (224, 226)	91,436,630	92,056,568	90,296,692	10
11	Other - Preferred Securities (224.1)	100,000,000	100,000,000	-	11
12	Total Long-Term Debt	$ 1,281,436,630	$ 1,217,056,568	$ 1,080,296,692	12
	Current and Accured Liabilities				
13	Notes Payable (231)	$ 27,000,000	$ 52,000,000	$ 53,000,000	13
14	Accounts Payable (232)	48,416,825	96,006,361	66,512,269	14
15	Payables to Associated Companies (233,234)	7,054,800	7,205,109	6,782,649	15
16	Customer Deposits (235)	47,635,986	44,290,398	34,313,441	16
17	Taxes Accrued (236)	27,363,958	(2,423,076)	20,391,462	17
18	Interest Accrued (237)	17,435,265	19,664,671	21,136,863	18
19	Dividends Declared (238)	7,243,564	7,017,580	6,824,257	19
20	Tax Collections Payable (241)	12,308,485	17,021,177	16,017,409	20
21	Miscellaneous Current and Accrued Liabilities (242)	62,442,379	61,376,708	62,971,415	21
22	Total Current and Accrued Liabilities	$ 256,901,262	$ 302,158,928	$ 287,949,765	22
	Deferred Credits				
23	Customer Advances for Construction (252)	$ 18,548,829	$ 16,411,995	$ 11,072,339	23
24	Other Deferred Credits (253)	33,186,736	31,557,551	28,281,880	24
25	Other Regulatory Liabilities (254)	8,116,127	8,462,353	8,995,660	25
26	Accumulated Deferred Investment Tax Credit (255)	12,354,653	12,933,037	13,800,613	26
27	Accumulated Deferred Income Taxes (282, 283)	280,815,888	296,402,685	216,402,215	27
28	Total Deferred Credits	$ 353,022,233	$ 365,767,621	$ 278,552,707	28
	Other Long-Term Liabilities				
29	Injuries and Damages Reserve (228)	$ 3,227,509	$ 3,949,509	$ 2,450,000	29
30	Provision for Rate Refunds (229)	-	-	-	30
31	Total Other Long-Term Liabilities	$ 3,227,509	$ 3,949,509	$ 2,450,000	31
32	Total Liabilities and Other Credits	$ 2,557,566,318	$ 2,519,400,034	$ 2,305,416,015	32

SOUTHWEST GAS CORPORATION
ARIZONA
COMPARATIVE INCOME STATEMENTS

Line No.	Description (a)	For the Test Year Ended 8/31/04 (b)	For the Year Ended 12/31/03 (c)	For the Year Ended 12/31/02 (d)	Line No.
1	Operating Revenue	$ 647,277,069	$ 593,690,708	$ 652,504,295	1
2	Operating Expenses and Taxes	596,770,019	256,669,683	251,716,903	2
3	Operating Income	$ 50,507,050	$ 337,021,025	$ 400,787,392	3
4	Other Income and Deductions	0	0	0	4
5	Income Before Interest Deductions	$ 50,507,050	$ 337,021,025	$ 400,787,392	5
6	Net Interest Deductions	40,472,048	41,108,025	38,803,204	6
7	Net Income	$ 10,035,002	$ 295,913,000	$ 361,984,188	7

SOUTHWEST GAS CORPORATION
STATEMENTS OF INCOME

Line No.	Description	Year Ended 8/31/04	Year Ended 12/31/03	Year Ended 12/31/02	Line No.
	(a)	(b)	(c)	(d)	
	Utility Operating Income				
1	Operating Revenues (400)	$ 1,140,678,129	$ 1,021,747,900	$ 1,099,250,200	1
	Operating Expenses:				
2	Operation Expense (401)	$ 796,656,193	$ 703,802,456	$ 778,950,993	2
3	Maintenance Expense (402)	48,563,434	44,994,299	44,416,957	3
4	Depreciation Expense (403)	111,874,446	106,762,298	99,722,513	4
5	Amortization of Other Limited Term Gas Plant (404.3)	9,191,279	7,312,002	8,996,405	5
6	Amortization of Utility Plant Acquisition Adjustment (406)	154,011	154,011	154,011	6
7	Amortization of Property Losses (407.1)	-	-	-	7
8	Amortization of Regulatory assets (407.3)	2,512,962	2,342,277	2,293,450	8
9	Taxes Other than Income Taxes (408.1)	36,376,016	35,052,524	33,538,884	9
10	Income Taxes - Federal (409.1)	(50,804,132)	(62,817,956)	4,247,159	10
11	Income Taxes - Other (409.1)	(6,683,857)	(4,967,445)	3,672,693	11
12	Provision for Deferred Income Taxes (410.1)	115,861,785	101,507,823	65,408,791	12
13	Provision for Deferred Income Taxes - Credit (411.1)	(40,775,637)	(21,425,016)	(57,797,737)	13
14	Investment Tax Credit Adjustment - Net (411.4)	(867,576)	(867,576)	(867,576)	14
15	Total Utility Operating Expenses	$ 1,022,058,924	$ 911,849,697	$ 982,736,543	15
16	Net Utility Operating Income	$ 118,619,205	$ 109,898,203	$ 116,513,657	16
	Other Income and Deductions				
	Other Income:				
17	Non-Utility Operating Income (415-418)	$ -	$ -	$ -	17
18	Equity in Earnings of Subsidiary Companies (418.1)	8,713,450	7,970,203	8,735,979	18
19	Interest and Dividend Income (419)	4,170,680	2,199,666	4,066,888	19
20	Allowance for Equity Funds Used During Construction (419.1)	890,489	1,068,626	1,231,487	20
21	Amortization of Investment Tax Credits (420)	-	-	-	21
22	Miscellaneous Non-Operating Income (421)	372,229	454,120	6,157,935	22
23	Total Other Income	$ 14,146,848	$ 11,692,615	$ 20,192,289	23
	Other (Income) Deductions:				
24	Miscellaneous Amortization (425)	$ 26,358	$ 26,358	$ 26,358	24
25	Miscellaneous (Income) Deductions (426)	792,387	(391,505)	6,895,634	25
26	Total (Income) Deductions	$ 818,745	$ (365,147)	$ 6,921,992	26
	Taxes Applicable to Other Income and Deductions				
27	Taxes Other than Income Taxes (408.2)	$ 10,604	$ 10,812	$ 7,895	27
28	Income Taxes - (409.2)	(251,841)	(756,905)	(1,062,678)	28
29	Provision for Deferred Income Taxes (410.2,411.2)	877,663	1,027,250	2,891,762	29
30	Investment Tax Credit Adjustment - Net (411.5)	-	-	-	30
31	Total Taxes Applicable to Other Income and Deductions	$ 636,426	$ 281,157	$ 1,836,979	31
32	Net Other Income and (Deductions)	$ 12,691,677	$ 11,776,605	$ 11,433,318	32
	Interest Charges				
33	Interest on Long-Term Debt (427)	$ 70,650,316	$ 71,552,024	$ 74,120,965	33
34	Amortization of Debt Discount and Expense (428)	2,961,435	2,752,402	2,277,873	34
35	Other Interest Expense (430-431)	10,708,364	10,332,633	9,472,949	35
36	Total Interest Charges	$ 84,320,115	$ 84,637,059	$ 85,871,787	36
37	Allowance for Borrowed Funds Used During Construction (432)	1,055,527	1,463,996	1,889,720	37
38	Net Interest Charges	$ 83,264,588	$ 83,173,063	$ 83,982,067	38
39	Net Income	$ 48,046,294	$ 38,501,745	$ 43,964,908	39

SOUTHWEST GAS CORPORATION
TOTAL SYSTEM
COMPARATIVE STATEMENT OF CASH FLOWS

Line No.	Description	Test Year Ended 8/31/04	Year Ended 12/31/03	Year Ended 12/31/02	Line No.
	(a)	(b)	(c)	(d)	
	CASH FLOWS FROM OPERATING ACTIVITIES:				
1	Net Income	$ 48,046,294	$ 38,501,745	$ 43,964,908	1
	Adjustments to reconcile net income to net cash provided by operating activities:				
2	Depreciation and amortization	123,732,698	116,570,588	111,166,379	2
3	Deferred income taxes	38,216,360	66,326,028	(19,096,072)	3
	Changes in current assets and liabilities:				
4	Accounts receivable	(1,019,191)	928,745	27,354,198	4
5	Accrued utility revenue	-	(1,627,000)	(1,300,000)	5
6	Unrecovered purchased gas costs	(81,682,508)	(35,868,879)	110,219,045	6
7	Accounts payable	8,135,968	31,828,301	(15,633,380)	7
8	Accrued taxes	7,945,147	(19,643,870)	32,520,012	8
9	Other current assets and liabilities	-	-	-	9
10	Other	(47,121,636)	(45,256,025)	(9,694,561)	10
11	Net cash provided by operating activities	$ 96,253,132	$ 151,759,633	$ 279,500,529	11
	CASH FLOWS FROM INVESTING ACTIVITIES:				
12	Construction expenditures	$ (262,645,182)	$ (240,711,179)	$ (261,990,867)	12
13	Other	27,506,253	28,782,995	22,086,706	13
14	Net cash used in investing activities	$ (235,138,929)	$ (211,928,184)	$ (239,904,161)	14
	CASH FLOWS FROM FINANCING ACTIVITIES:				
15	Issuance of common stock	$ 36,913,347	$ 21,290,246	$ 18,173,810	15
16	Issuance of preferred securities, net	(537,824)	96,312,176	-	16
17	Retirement of preferred securities	(60,000,000)	(60,000,000)	-	17
18	Dividends paid	(28,101,735)	(27,684,541)	(27,008,564)	18
19	Issuance of long-term debt, net	98,402,883	159,996,995	197,948,000	19
20	Retirement of long-term debt	-	(130,000,000)	(200,000,000)	20
21	Issuance (repayment) of short-term debt	27,000,000	(1,000,000)	(40,000,000)	21
22	Net cash provided by (used in) financing activitie	$ 73,676,671	$ 58,914,876	$ (50,886,754)	22
23	Change in cash and temporary cash investments	$ (65,209,126)	$ (1,253,675)	$ (11,290,386)	23
24	Cash at beginning of period	77,374,957	15,428,665	26,719,051	24
25	Cash at end of period	$ 12,165,831	$ 14,174,990	$ 15,428,665	25

SOUTHWEST GAS CORPORATION
TOTAL SYSTEM
STATEMENT OF CHANGES IN STOCKHOLDERS' EQUITY AND PREFERRED SECURITIES

Line No.	Description	Preferred Securities (1) Shares/Units	Preferred Securities (1) Amount	Common Shares	Common Amount	Additional Paid-In Capital	Retained Earnings	Capital Stock Expense	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	
1	Balance December 31, 2001	2,400,000	$ 60,000,000	32,492,832	$ 34,122,708	$ 481,923,578	$ 56,667,140	$ (11,513,512)	1
2	Net Earnings	-	-	-	-	-	43,964,908	-	2
	Cash Dividends Declared-								
3	Common	-	-	-	-	-	(27,171,781)	-	3
4	Common Stock Issue	-	-	796,183	796,183	17,389,690	-	(12,063)	4
5	Balance December 31, 2002	2,400,000	$ 60,000,000	33,289,015	$ 34,918,891	$ 499,313,268	$ 73,460,267	$ (11,525,575)	5
6	Redemption	(2,400,000)	(60,000,000)					2,386,430	6
7	Net Earnings	-	-	-	-	-	38,501,745	-	7
	Cash Dividends Declared-								
8	Common	-	-	-	-	-	(27,877,864)	-	8
9	Common Stock Issue	-	-	943,083	943,083	20,359,663	-	(12,500)	9
10	Balance December 31, 2003	-	$ -	34,232,098	$ 35,861,974	$ 519,672,931	$ 84,084,148	$ (9,151,645)	10
11	Net Earnings	-	-	-	-	-	19,826,350	-	11
	Cash Dividends Declared-								
12	Common	-	-	-	-	-	(14,402,075)	-	12
13	Common Stock Issue	-	-	1,299,080	1,299,080	25,927,190	-	(139,269)	13
14	Balance August 31, 2004	-	$ -	35,531,178	$ 37,161,054	$ 545,600,121	$ 89,508,423	$ (9,290,914)	14

(1) Represents Company-obligated mandatorily redeemable preferred securities of the Company's subsidiary, Southwest Gas Capital I, holding solely $61.8 million principal amount of 9.125% subordinated notes of the Company due 2025. Preferred securities were redeemed in September 2003.

SOUTHWEST GAS CORPORATION
ARIZONA
DETAIL OF UTILITY PLANT - NET ADDITIONS
FOR THE YEAR ENDED AUGUST 31, 2004

Line No.	Description (a)	Account Number (b)	Balance at 31-Aug-04 (c)	Net Plant Additions (Deletions) (d)	Balance at 31-Dec-03 (e)	Line No.
	Intangible					
1	Organizational Costs	301	$ 42,653	$ 0	$ 42,653	1
2	Franchise and Consents	302	1,283,320	0	1,283,320	2
3	Miscellaneous Intangible	303	1,945,631	25,145	1,920,486	3
4	Total Intangible		$ 3,271,603	$ 25,145	$ 3,246,458	4
	Distribution					
5	Land and Land Rights	374.1	$ 351,685	$ 0	$ 351,685	5
6	Rights of Way	374.2	720,979	104,102	616,877	6
7	Structures	375	110,557	0	110,557	7
8	Mains	376	789,444,391	45,934,092	743,510,299	8
9	Measuring and Regulating Station	378	24,454,990	1,085,500	23,369,491	9
10	Services	380	525,003,667	17,860,451	507,143,216	10
11	Meters	381	156,809,964	10,671,025	146,138,939	11
12	Industrial Measuring and Reg. Station	385	6,528,499	246,841	6,281,658	12
13	Other Equipment	387	462,730	0	462,730	13
14	Total Distribution		$ 1,503,887,463	$ 75,902,010	$ 1,427,985,453	14
	General					
15	Land and Land Rights	389	$ 6,454,589	$ 0	$ 6,454,589	15
16	Structures & Improvements - General	390.1	26,278,185	445,468	25,832,716	16
17	Structures and Improve. - Leasehold	390.2	1,005,567	10,805	994,762	17
18	Office Furniture and Equipment	391	4,849,827	175,794	4,674,033	18
19	Computer Equipment	391.1	8,300,510	1,327,971	6,972,539	19
20	Transportation Equipment	392.1	30,447,147	2,333,754	28,113,393	20
21	Stores Equipment	393	481,909	26,256	455,653	21
22	Tools, Shop, Garage Equipment	394	4,869,019	398,016	4,471,003	22
23	Laboratory Equipment	395	425,322	0	425,322	23
24	Power Operated Equipment	396	3,807,547	186,711	3,620,836	24
25	Communication Equipment - General	397	2,218,433	29,804	2,188,629	25
26	Telemetering Equipment	397.2	554,473	0	554,473	26
27	Miscellaneous Equipment	398	830,204	30,000	800,204	27
28	Total General		$ 90,522,731	$ 4,964,580	$ 85,558,150	28
29	Total Plant in Service		$ 1,597,681,797	$ 80,891,736	$ 1,516,790,061	29
30	Construction Work in Progress		6,249,731	(8,490,118)	14,739,849	30
31	Less: Accumulated Depreciation/Amort.		546,349,029	35,669,478	510,679,551	31
32	Total Net Plant		$ 1,057,582,499	$ 36,732,140	$ 1,020,850,359	32

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE PLANT
DETAIL OF UTILITY PLANT - NET ADDITIONS
FOR THE YEAR ENDED AUGUST 31, 2004

Line No.	Description (a)	Account Number (b)	Balance at 31-Aug-04 (c)	Net Plant Additions (Deletions) (d)	Balance at 31-Dec-03 (e)	Line No.
	Intangible					
1	Organizational Costs	301	$ 61,816	$ 0	$ 61,816	1
2	Miscellaneous Intangible	303	104,700,756	2,289,160	102,411,596	2
3	Total Intangible		$ 104,762,572	$ 2,289,160	$ 102,473,412	3
	General					
4	Land and Land Rights	389	$ 391,307	$ 0	$ 391,307	4
5	Structures and Improvements - Gen	390.1	11,831,108	0	11,831,108	5
6	Structure and Improve. - Leasehold	390.2	3,144,329	82,570	3,061,758	6
7	Office Furniture and Equipment	391	7,743,488	207,718	7,535,769	7
8	Computer Equipment	391.1	13,445,898	721,663	12,724,236	8
9	Transportation Equipment - Light	392.11	3,338,897	438,918	2,899,979	9
10	Transportation Equipment - Heavy	392.12	111,293	0	111,293	10
11	Stores Equipment	393	24,106	0	24,106	11
12	Tools, Shop, Garage Equipment	394	397,973	164,945	233,028	12
13	Laboratory Equipment	395	268,894	15,738	253,155	13
14	Communication Equipment	397.1	4,605,689	35,517	4,570,172	14
15	Telemetering Equipment	397.2	401,430	3,729	397,701	15
16	Miscellaneous Equipment	398	934,686	26,108	908,578	16
17	Total General		$ 46,639,097	$ 1,696,907	$ 44,942,190	17
18	Total Systems - Plant in Service		$ 151,401,669	$ 3,986,066	$ 147,415,603	18
19	Construction Work in Progress		929,241	(478,832)	1,408,072	19
20	Less: Accumulated Depreciation/Amort.		82,592,661	9,190,643	73,402,018	20
21	Total Net Plant		$ 69,738,248	$ (5,683,409)	$ 75,421,657	21

SOUTHWEST GAS CORPORATION
ARIZONA
COMPARATIVE DEPARTMENTAL OPERATING INCOME STATEMENTS

Line No.	Description	For the TestYear Ended 8/31/04	For the Year Ended 12/31/03	For the Year Ended 12/31/02	Line No.
	(a)	(b)	(c)	(d)	
	Revenues				
1	Residential	$ 343,721,617	$ 309,874,359	$ 342,041,183	1
2	Small Commercial	153,667,156	139,953,245	158,792,305	2
3	Large Commercial	26,177,756	23,775,125	30,957,627	3
4	Small Industrial	24,609,297	22,297,004	27,253,289	4
5	Commercial-Compressed Nat. Gas	1,408,137	1,228,584	1,336,664	5
6	Irrigation/Water Pumping	12,718,204	11,664,286	10,508,866	6
7	Industrial-Essential Agriculture	6,213,502	6,116,022	9,612,842	7
8	Procurement Sales	59,580,963	58,894,947	54,340,966	8
9	Other Gas Sales	196,127	763,118	609,942	9
10	Transportation of Gas for Others	9,099,185	8,984,026	6,978,565	10
11	Rent from Gas Property	752,458	701,258	582,461	11
12	Other Gas Revenues	(8,293)	0	0	12
13	Miscellaneous Service Revenue	9,416,690	8,631,478	8,388,792	13
14	LIRA Program Recovery	(200,569)	(89,821)	390,029	14
15	Accrued Unbilled Revenues	(75,161)	897,077	710,764	15
16	Total Revenues	$ 647,277,069	$ 593,690,708	$ 652,504,295	16
	Operating Expenses				
17	Other Gas Supply	$ 327,853,609	$ 570,698	$ 613,355	17
18	Transmission	0	5,904	(4,212)	18
19	Distribution	75,753,130	70,154,844	65,851,849	19
20	Customer Accounts	33,133,096	33,063,560	34,184,827	20
21	Customer Service & Information	596,225	451,289	834,637	21
22	Sales	512,205	514,931	919,423	22
23	Administrative and General	48,643,559	44,713,886	40,385,834	23
24	Depreciation and Amortization	73,461,654	70,355,962	68,050,534	24
25	Interest on Customer Deposits	1,404,209	1,231,254	0	25
26	Taxes Other Than Income	29,122,261	28,003,506	27,204,986	26
27	Income Taxes - Federal	5,075,520	6,157,711	11,244,598	27
28	Income Taxes - State	1,214,551	1,446,138	2,431,072	28
29	Total Expenses	$ 596,770,019	$ 256,669,683	$ 251,716,903	29
30	Operating Income	$ 50,507,050	$ 337,021,025	$ 400,787,392	30

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
OPERATING STATISTICS
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

			Recorded Test Year Data			
Line No.	Description (a)	Schedule No. (b)	Average Customers (c)	Sales (Therms) (d)	Average per Customer (e)	Line No.
1	Residential Gas Service	G-5	771,088	267,837,474	347	1
2	Low Income Residential Gas Service	G-10	30,973	10,695,648	345	2
3	Special Residential Gas Service for A/C	G-15	157	228,821	1,458	3
4	Special Residential Gas Service for Electric Generation	G-16	0	0	-	4
	Master Metered Mobile Home Park					
5	Gas Service	G-20	191	2,519,499	13,185	5
	General Gas Service	G-25				
6	Small		32,597	47,557,432	1,459	6
7	Medium		6,785	136,866,745	20,171	7
8	Large		105	44,280,034	423,732	8
9	Optional Gas Service	G-30	33	103,995,837	3,159,367	9
10	Gas Service to Armed Forces	G-35	8	3,308,091	400,981	10
11	Air Conditioning Gas Service	G-40	39	1,067,788	27,556	11
12	Street Lighting Gas Service	G-45	28	100,215	3,558	12
	Gas Service for Compression on Customer's Premises	G-55				
13	Small		26	196,184	7,619	13
14	Large		27	1,873,025	69,586	14
15	Residential		112	80,334	715	15
16	Cogeneration Gas Service	G-60	22	14,998,373	669,072	16
	Small Essential Agriculture User					
17	Gas Service	G-75	97	7,932,305	81,427	17
18	Natural Gas Engine Gas Service	G-80	614	20,198,094	32,878	18
19	Resale Gas Service	G-95	1	(14,502)	(14,502)	19
20	Total Gas Sales		842,904	663,721,397	787	20
	Transportation Service Including					
21	Special Contract	T-1/B-1	231	65,680,156	284,535	21
22	Total Arizona		843,135	729,401,553	865	22

SOUTHWEST GAS CORPORTATION
ARIZONA DIVISION
OPERATING STATISTICS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2003

Line No.	Description	Schedule No.	Recorded Test Year Data Average Customers	Sales (Therms)	Average per Customer	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	Residential Gas Service	G-5	744,407	246,908,831	332	1
2	Low Income Residential Gas Service	G-10	29,765	9,961,331	335	2
3	Special Residential Gas Service for A/C	G-15	163	238,377	1,460	3
4	Special Residential Gas Service for Electric Generation	G-16	0	0	-	4
	Master Metered Mobile Home Park					
5	Gas Service	G-20	191	2,517,554	13,164	5
	General Gas Service	G-25				
6	Small		32,401	45,446,868	1,403	6
7	Medium		6,731	132,727,148	19,718	7
8	Large		104	42,716,175	412,385	8
9	Optional Gas Service	G-30	49	110,809,491	2,246,138	9
10	Gas Service to Armed Forces	G-35	8	3,259,469	407,434	10
11	Air Conditioning Gas Service	G-40	35	1,064,025	30,546	11
12	Street Lighting Gas Service	G-45	30	101,103	3,418	12
	Gas Service for Compression on Customer's Premises	G-55				
13	Small		35	182,885	5,164	13
14	Large		26	1,791,093	68,016	14
15	Residential		112	86,505	771	15
16	Cogeneration Gas Service	G-60	22	15,194,921	706,741	16
	Small Essential Agriculture User					
17	Gas Service	G-75	93	7,715,447	82,813	17
18	Natural Gas Engine Gas Service	G-80	614	21,950,600	35,755	18
19	Resale Gas Service	G-95	1	972,796	972,796	19
20	Total Gas Sales		814,787	643,644,619	790	20
	Transportation Service Including					
21	Special Contract	T-1/B-1	234	67,093,045	286,825	21
22	Total Arizona		815,021	710,737,664	872	22

SOUTHWEST GAS CORPORTATION
ARIZONA DIVISION
OPERATING STATISTICS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2002

Line No.	Description	Schedule No.	Recorded Test Year Data: Average Customers	Recorded Test Year Data: Sales (Therms)	Recorded Test Year Data: Average per Customer	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	Residential Gas Service	G-5	720,061	254,771,067	354	1
2	Low Income Residential Gas Service	G-10	24,862	8,574,479	345	2
3	Special Residential Gas Service for A/C	G-15	185	271,105	1,469	3
4	Special Residential Gas Service for Electric Generation	G-16	0	0	-	4
5	Master Metered Mobile Home Park Gas Service	G-20	199	2,784,158	14,008	5
	General Gas Service	G-25				
6	Small		32,425	47,337,222	1,460	6
7	Medium		6,622	133,223,203	20,118	7
8	Large		118	51,611,995	438,940	8
9	Optional Gas Service	G-30	52	164,464,846	3,193,492	9
10	Gas Service to Armed Forces	G-35	10	5,497,107	536,303	10
11	Air Conditioning Gas Service	G-40	37	1,531,343	41,110	11
12	Street Lighting Gas Service	G-45	29	99,723	3,449	12
	Gas Service for Compression on Customer's Premises	G-55				
13	Small		47	104,285	2,211	13
14	Large		26	1,730,493	66,771	14
15	Residential		112	104,463	933	15
16	Cogeneration Gas Service	G-60	19	7,247,659	381,456	16
17	Small Essential Agriculture User Gas Service	G-75	100	11,251,287	112,889	17
18	Natural Gas Engine Gas Service	G-80	615	21,042,016	34,205	18
19	Resale Gas Service	G-95	1	757,284	757,284	19
20	Total Gas Sales		785,518	712,403,735	907	20
21	Transportation Service Including Special Contract	T-1/B-1	199	51,076,191	256,449	21
22	Total Arizona		785,717	763,479,926	972	22

SOUTHWEST GAS CORPORATION
ARIZONA
TAXES CHARGED TO OPERATIONS
AS RECORDED AT AUGUST 31, 2004

Line No.	Description (a)	For the Test Year Ended 8/31/04 (b)	For the Year Ended 12/31/03 (c)	For the Year Ended 12/31/02 (d)	Line No.
	Federal Taxes				
1	Federal Income Tax	$ 5,075,520	$ 6,157,711	$ 11,244,598	1
	State Taxes				
2	State Income Tax	$ 1,214,551	$ 1,446,138	$ 2,431,072	2
	Local Taxes				
3	Property and Miscellaneous	$ 29,122,261	$ 28,003,506	$ 27,204,986	3

SOUTHWEST GAS CORPORATION
NOTES TO FINANCIAL STATEMENTS

1. The Company uses the accrual method of accounting as prescribed by the Uniform System of Accounts.

2. The Company uses the straight line method for calculating depreciation expense. Depreciation rates by major classification can be found in the Workpapers, Schedule C-2.

3. The Allowance for Funds Used During Construction (AFUDC) rate for 2003 was 8.87% and is estimated to be 4.86% for 2004.

4. Additional information concerning these statements is contained in Southwest's 2003 Annual Report which is included in the instant application.

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SOUTHWEST GAS CORPORATION
ARIZONA
PROJECTED INCOME STATEMENTS - PRESENT AND PROPOSED RATES

Line No.	Description	Test Year Ended 8/31/04	Projected Year Present Rates 8/31/05	Projected Year Proposed Rates 8/31/05	Line No.
	(a)	(b)	(c)	(d)	
1	Operating Margin	$ 320,144,265	$ 323,345,708	$ 397,611,857	1
	Operating Expenses				
2	Other Gas Supply Expenses	$ 720,807	$ 740,391	$ 740,391	2
3	Distribution Expenses	75,753,130	78,643,225	78,643,225	3
4	Customer Accounts Expenses	33,133,096	34,003,279	34,159,137	4
5	Customer Service and Info. Expenses	596,225	548,496	548,496	5
6	Sales Expenses	512,205	0	0	6
7	Administrative and General Expenses	48,643,559	52,737,675	52,737,675	7
8	Depreciation and Amortization Expenses	73,461,654	81,787,051	81,787,051	8
9	Taxes Other than Income	29,122,261	34,458,777	34,458,777	9
10	Interest on Customer Deposits	1,404,209	717,364	717,364	10
11	Federal Income Taxes	5,075,520	(504,542)	23,626,658	11
12	State Income Taxes	1,214,551	20,434	5,184,439	12
13	Total Operating Expenses	$ 269,637,217	$ 283,152,150	$ 312,603,213	13
14	Operating Income	$ 50,507,047	$ 40,193,557	$ 85,008,644	14
15	Less: Interest Expense	40,472,048	40,521,530	40,521,530	15
16	Net Income	$ 10,035,000	$ (327,972)	$ 44,487,114	16
17	Earnings per Share of Average Common Stock Outstanding	N/A	N/A	N/A	17
18	Percent Return on Common Equity	N/A	N/A	N/A	18

SOUTHWEST GAS CORPORATION
PROJECTED CHANGES IN FINANCIAL POSITION
PRESENT AND PROPOSED RATES

In this proceeding Southwest Gas Corporation is requesting rate relief for the Arizona rate jurisdiction portion of its system only. Projections for the total Company's financial position/cash flow are not compiled or available.

SOUTHWEST GAS CORPORATION
ARIZONA
CONSTRUCTION EXPENDITURES BY PROPERTY CLASSIFICATION
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004
AND PROJECTED TWELVE MONTHS ENDING AUGUST 31, 2005, 2006, AND 2007

Line No.	Description	Test Year Ended 8/31/04	Projected Year Ending 8/31/05	Projected Year Ending 8/31/06	Projected Year Ending 8/31/07	Line No.
	(a)	(b)	(c)	(d)	(e)	
	Intangible Plant					
1	Arizona Direct	$ 803,287	$ 1,175,000	$ 10,000	$ 20,000	1
2	System Allocable [1]	4,832,336	1,810,659	5,278,934	2,510,488	2
3	Total Intangible Plant	$ 5,635,623	$ 2,985,659	$ 5,288,934	$ 2,530,488	3
	Distribution Plant					
4	Arizona Direct	$ 175,510,703	$ 118,448,833	$ 89,292,563	$ 69,807,055	4
5	System Allocable [1]	0	0	0	0	5
6	Total Distribution Plant	$ 175,510,703	$ 118,448,833	$ 89,292,563	$ 69,807,055	6
	General Plant					
7	Arizona Direct	$ 7,968,191	$ 4,756,589	$ 4,302,692	$ 4,078,675	7
8	System Allocable [1]	2,533,982	6,033,500	5,173,240	5,246,928	8
9	Total General Plant	$ 10,502,173	$ 10,790,089	$ 9,475,932	$ 9,325,603	9
10	Total Arizona Plant Construction	$ 191,648,499	$ 132,224,581	$ 104,057,429	$ 81,663,146	10

[1] Allocation based on the 4-Factor (57.58%). Supporting Schedule C-1, Sh 18

SOUTHWEST GAS CORPORATION
ARIZONA
ASSUMPTIONS USED IN DEVELOPING PROJECTIONS

1. Customer Growth
2. *Growth in Consumption and Customer Demand*

   Margin related to customer growth and consumption is anticipated to increase by 1% in the year following the test year.

3. Changes in Expense

   Operation and Maintenance Expenses - The actual amounts for the recorded test year ended August 31, 2004, were adjusted to give the annual effect for known and measurable changes occurring during the test year ending August 31, 2004. The operation and maintenance expenses for the projected year ending August 31, 2005, were calculated by taking the adjusted test year and generally increasing the non-labor expenses by 3%.

   Depreciation and Amortization Expenses - The actual amounts for the recorded test year ended August 31, 2004 were adjusted to annualize depreciation expense at the end of the test period plant balances, and to reflect depreciation expense on projected construction expenditures.

4. Construction Requirements, Including Production Reserves and Changes in Plant Capacity

   Additions to gas plant were based upon anticipated construction expenditures.

5. Capital Structures Changes
6. Financing Costs, Interest Rates

Items 5 and 6 are not applicable. In this proceeding Southwest Gas Corporation is requesting rate relief for only a portion of its three-state system.

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SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY SUMMARY AT PRESENT RATES
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Description (a)	Allocation Factor No. (b)	Total Amount (c)	Residential (d)	MMMHP (e)	Small Gen. Service (f)	Medium Gen. Service (g)	Large Gen. Service (h)
	Rate Base							
1	Direct Net Plant		$ 1,051,372,747	$ 818,802,798	$ 2,006,233	$ 93,471,429	$ 74,994,825	$ 39,340,610
2	Systems Allocable Net Plant		40,589,393	31,610,776	77,453	3,608,567	2,895,257	1,518,787
3	Cash Working Capital	11.2	(11,082,156)	(8,659,111)	(23,537)	(1,010,689)	(798,999)	(311,043)
4	Materials & Supplies	1.1	9,222,489	7,182,419	17,598	819,918	657,844	345,090
5	Prepayments	Direct Net Plant	2,740,815	2,134,530	5,230	243,670	195,503	102,557
6	Gas Plant Acquisition Adjustment	Direct Net Plant	-	-	-	-	-	-
7	Customer Deposits	8	(23,912,141)	(22,804,948)	(5,242)	(909,540)	(192,412)	-
8	Customer Advances	8	(7,027,372)	(6,701,987)	(1,541)	(267,298)	(56,547)	-
9	Deferred Taxes	1.1	(136,691,328)	(106,454,387)	(260,835)	(12,152,430)	(9,750,245)	(5,114,761)
10	Deferred Gain Hdqtrs Bldg	4	-	-	-	-	-	-
11	Total Rate Base		$ 925,212,447	$ 715,110,091	$ 1,815,360	$ 83,803,626	$ 67,945,226	$ 35,881,240
	Margin							
12	Net Operating Margin	Direct	$ 305,070,666	$ 209,915,969	$ 883,856	$ 26,068,861	$ 45,665,407	$ 13,547,232
13	Special Contract Margin	Net Op. Marg.	$ 7,611,429	$ 5,237,348	$ 22,052	$ 650,411	$ 1,139,339	$ 338,000
14	Other Revenue	Net Op. Marg.	10,183,882	7,007,424	29,505	870,232	1,524,405	452,234
15	Total Revenue		$ 322,865,978	$ 222,160,739	$ 935,413	$ 27,589,504	$ 48,329,151	$ 14,337,466
	Operating Deductions							
16	O & M		$(113,872,632)	$(88,975,085)	$(241,849)	$(10,385,151)	$(8,209,970)	$(3,196,065)
17	A & G	O & M	(52,481,195)	(41,006,506)	(111,462)	(4,786,270)	(3,783,781)	(1,472,991)
18	Depreciation Expense		(75,949,648)	(59,149,131)	(144,927)	(6,752,241)	(5,417,518)	(2,841,909)
19	Interest on Customer Deposits	8	(717,364)	(684,148)	(157)	(27,286)	(5,772)	-
20	Taxes other than Income	1.1	(33,455,124)	(26,054,650)	(63,839)	(2,974,300)	(2,386,367)	(1,251,835)
21	Total Operating Deductions		$(276,475,963)	$(215,869,520)	$(562,235)	$(24,925,248)	$(19,803,408)	$(8,762,800)
	State Income Tax							
22	Taxable Income before Interest Exp.		$ 46,390,015	$ 6,291,219	$ 373,178	$ 2,664,255	$ 28,525,743	$ 5,574,666
23	Interest Expense	1.1	(40,521,530)	(31,557,924)	(77,323)	(3,602,533)	(2,890,416)	(1,516,248)
24	State Taxable Income		$ 5,868,486	$(25,266,705)	$ 295,854	$(938,278)	$ 25,635,327	$ 4,058,418
25	State Income Tax		408,916	(1,760,584)	20,615	(65,379)	1,786,270	282,791
26	South Georgia	1.1	77,020	59,983	147	6,847	5,494	2,882
27	Total State Income Tax		$ 485,936	$(1,700,601)	$ 20,762	$(58,532)	$ 1,791,763	$ 285,673
	Federal Income Tax							
28	Taxable Income before Interest Exp.		$ 46,390,015	$ 6,291,219	$ 373,178	$ 2,664,255	$ 28,525,743	$ 5,574,666
29	Interest Expense		(40,521,530)	(31,557,924)	(77,323)	(3,602,533)	(2,890,416)	(1,516,248)
30	Federal Taxable Income		$ 5,868,486	$(25,266,705)	$ 295,854	$(938,278)	$ 25,635,327	$ 4,058,418
31	Federal Income Tax		$ 1,910,849	$(8,227,142)	$ 96,334	$(305,515)	$ 8,347,170	$ 1,321,470
32	I T C	1.1	(528,352)	(411,477)	(1,008)	(46,973)	(37,688)	(19,770)
33	South Georgia	1.1	288,233	224,474	550	25,625	20,560	10,785
34	Total Federal Income Tax		$ 1,670,730	$(8,414,146)	$ 95,876	$(326,862)	$ 8,330,042	$ 1,312,485
35	Regulatory Amortization	Depr. Exp.	-	-	-	-	-	-
36	Net Income		$ 44,233,349	$ 16,405,966	$ 256,540	$ 3,049,649	$ 18,403,937	$ 3,976,509
37	Rate of Return on Rate Base		4.78%	2.29%	14.13%	3.64%	27.09%	11.08%

Line No.	Description (a)	Armed Forces (i)	Air Conditioning (j)	CNG - Small (k)	CNG - Large (l)	CNG - Residential (m)	Cogeneration (n)	Small Ess. Agr. (o)	Natural Gas Engines (p)	Street Lighting (q)	Special Residential A/C (r)	Line No.
	Rate Base											
1	Direct Net Plant	$ 4,597,022	$ 433,679	$ 57,644	$ 849,410	$ 105,543	$ 3,403,847	$ 4,819,112	$ 8,290,863	$ 45,703	$ 154,029	1
2	Systems Allocable Net Plant	177,473	16,743	2,225	32,792	4,075	131,409	186,047	320,078	1,764	5,946	2
3	Cash Working Capital	(27,036)	(5,186)	(767)	(10,889)	(1,171)	(35,130)	(53,710)	(140,277)	(2,118)	(2,492)	3
4	Materials & Supplies	40,324	3,804	506	7,451	926	29,858	42,273	72,726	401	1,351	4
5	Prepayments	11,984	1,131	150	2,214	275	8,873	12,563	21,613	119	402	5
6	Gas Plant Acquisition Adjustment	-	-	-	-	-	-	-	-	-	-	6
7	Customer Deposits	-	-	-	-	-	-	-	-	-	-	7
8	Customer Advances	-	-	-	-	-	-	-	-	-	-	8
9	Deferred Taxes	(597,669)	(56,384)	(7,494)	(110,434)	(13,722)	(442,542)	(626,544)	(1,077,914)	(5,942)	(20,026)	9
10	Deferred Gain Hdqtrs Bldg	-	-	-	-	-	-	-	-	-	-	10
11	Total Rate Base	$ 4,202,098	$ 393,787	$ 52,264	$ 770,545	$ 95,925	$ 3,096,316	$ 4,379,741	$ 7,487,090	$ 39,928	$ 139,210	11
	Margin											
12	Net Operating Margin	$ 638,779	$ 167,216	$ 29,537	$ 307,716	$ 21,167	$ 1,405,352	$ 2,549,950	$ 3,733,422	$ 47,592	$ 88,611	12
13	Special Contract Margin	$ 15,937	$ 4,172	$ 737	$ 7,677	$ 528	$ 35,063	$ 63,621	$ 93,146	$ 1,187	$ 2,211	13
14	Other Revenue	21,324	5,582	986	10,272	707	46,914	85,123	124,629	1,589	2,958	14
15	Total Revenue	$ 676,040	$ 176,970	$ 31,260	$ 325,666	$ 22,402	$ 1,487,329	$ 2,698,693	$ 3,951,199	$ 50,368	$ 93,780	15
	Operating Deductions											
16	O & M	$(277,803)	$(53,290)	$(7,877)	$(111,890)	$(12,035)	$(360,977)	$(551,883)	$(1,441,389)	$(21,763)	$(25,606)	16
17	A & G	(128,033)	(24,560)	(3,630)	(51,567)	(5,546)	(166,366)	(254,350)	(664,302)	(10,030)	(11,801)	17
18	Depreciation Expense	(332,082)	(31,328)	(4,164)	(61,360)	(7,624)	(245,889)	(348,126)	(598,920)	(3,302)	(11,127)	18
19	Interest on Customer Deposits	-	-	-	-	-	-	-	-	-	-	19
20	Taxes other than Income	(146,279)	(13,800)	(1,834)	(27,029)	(3,358)	(108,312)	(153,346)	(263,819)	(1,454)	(4,901)	20
21	Total Operating Deductions	$(884,198)	$(122,978)	$(17,506)	$(251,846)	$(28,564)	$(881,543)	##########	$(2,968,429)	$(36,548)	$(53,436)	21
	State Income Tax											
22	Taxable Income before Interest Exp.	$(208,157)	$ 53,992	$ 13,754	$ 73,820	$(6,162)	$ 605,785	$ 1,390,989	$ 982,770	$ 13,820	$ 40,344	22
23	Interest Expense	(177,176)	(16,715)	(2,222)	(32,738)	(4,068)	(131,190)	(185,736)	(319,543)	(1,761)	(5,937)	23
24	State Taxable Income	$(385,334)	$ 37,277	$ 11,532	$ 41,082	$(10,230)	$ 474,596	$ 1,205,253	$ 663,227	$ 12,058	$ 34,407	24
25	State Income Tax	(26,850)	2,597	804	2,863	(713)	33,070	83,982	46,214	840	2,398	25
26	South Georgia	337	32	4	62	8	249	353	607	3	11	26
27	Total State Income Tax	$(26,513)	$ 2,629	$ 808	$ 2,925	$(705)	$ 33,319	$ 84,335	$ 46,821	$ 844	$ 2,409	27
	Federal Income Tax											
28	Taxable Income before Interest Exp.	$(208,157)	$ 53,992	$ 13,754	$ 73,820	$(6,162)	$ 605,785	$ 1,390,989	$ 982,770	$ 13,820	$ 40,344	28
29	Interest Expense	(177,176)	(16,715)	(2,222)	(32,738)	(4,068)	(131,190)	(185,736)	(319,543)	(1,761)	(5,937)	29
30	Federal Taxable Income	$(385,334)	$ 37,277	$ 11,532	$ 41,082	$(10,230)	$ 474,596	$ 1,205,253	$ 663,227	$ 12,058	$ 34,407	30
31	Federal Income Tax	$(125,469)	$ 12,138	$ 3,755	$ 13,377	$(3,331)	$ 154,534	$ 392,445	$ 215,955	$ 3,926	$ 11,203	31
32	I T C	(2,310)	(218)	(29)	(427)	(53)	(1,711)	(2,422)	(4,166)	(23)	(77)	32
33	South Georgia	1,260	119	16	233	29	933	1,321	2,273	13	42	33
34	Total Federal Income Tax	$(126,519)	$ 12,039	$ 3,742	$ 13,183	$(3,355)	$ 153,757	$ 391,344	$ 214,061	$ 3,916	$ 11,168	34
35	Regulatory Amortization	-	-	-	-	-	-	-	-	-	-	35
36	Net Income	$(55,125)	$ 39,324	$ 9,204	$ 57,712	$(2,102)	$ 418,709	$ 915,310	$ 721,888	$ 9,060	$ 26,767	36
37	Rate of Return on Rate Base	(1.31%)	9.99%	17.61%	7.49%	(2.19%)	13.52%	20.90%	9.64%	22.69%	19.23%	37

SCHEDULE G-2 IS NOT APPLICABLE IN THE CLASS COST OF SERVICE STUDY AT PRESENT RATES

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
AUGUST 31, 2004

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Residential Gas Service Demand	Residential Gas Service Customer	Residential Gas Service Commodity	MMMHP Gas Service Demand	MMMHP Gas Service Customer	MMMHP Gas Service Commodity	Small General Gas Service Demand	Small General Gas Service Customer	Small General Gas Service Commodity	Medium General Gas Service Demand	Medium General Gas Service Customer	Medium General Gas Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
		Net Plant in Service - Direct														
		Intangible														
1	301	Organization	1.1	$ 42,653	$ 5,030	$ 27,629	$ 558	$ 43	$ 33	$ 5	$ 656	$ 3,042	$ 94	$ 1,633	$ 1,135	$ 275
2	302	Franchise & Consent	1.1	1,185,155	139,771	767,706	15,516	1,208	920	133	18,233	84,529	2,604	45,381	31,524	7,633
3	303	Misc. Intangible	1.1	278,178	32,807	180,195	3,642	284	216	31	4,280	19,840	611	10,652	7,399	1,792
4		Total Intangible		$ 1,505,987	$ 177,608	$ 975,530	$ 19,716	$ 1,535	$ 1,169	$ 170	$ 23,168	$ 107,411	$ 3,309	$ 57,666	$ 40,058	$ 9,699
5		Allocation Percentage	Intang. Plant	100.00%	11.79%	64.78%	1.31%	0.10%	0.08%	0.01%	1.54%	7.13%	0.22%	3.83%	2.66%	0.64%
		Production														
6	326	Other Land & Land Rights	3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	332	Field Lines	3	-	-	-	-	-	-	-	-	-	-	-	-	-
8	334	Field Meas & Reg. Stations	3	-	-	-	-	-	-	-	-	-	-	-	-	-
9	336	Purification Equipment	3	-	-	-	-	-	-	-	-	-	-	-	-	-
10		Total Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11		Allocation Percentage	Prod. Plant	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		Transmission														
12	365	Land & Land Rights	1.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	365	Rights of Way	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
14	366	Structures-Compressor Stas.	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
15	366	Structures	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
16	367	Mains - Demand	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
17	367	Mains - Customer	4.0	-	-	-	-	-	-	-	-	-	-	-	-	-
18	367	Mains - Commodity	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-
19	367	Mains-Bridge	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
20	368	Compressor Stations	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
21	369	Measuring & Reg. Sta. Equip.	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
22	370	Communication Equip.	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
23	371	Other Equipment	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
24		Total Transmission		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25		Allocation Percentage	Trans. Plant	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		Distribution														
26	374	Land & Land Rights	1.0	$ 351,685	$ 193,288	$ -	$ -	$ 1,671	$ -	$ -	$ 25,214	$ -	$ -	$ 62,756	$ -	$ -
27	374	Rights of Way	1.0	445,985	245,116	-	-	2,119	-	-	31,974	-	-	79,584	-	-
28	375	Structures	1.0	47,682	26,206	-	-	227	-	-	3,419	-	-	8,509	-	-
29	376	Mains - Demand	1.0	208,461,866	114,571,685	-	-	990,384	-	-	14,945,473	-	-	37,199,001	-	-
30	376	Mains - Customer	5.0	307,811,910	-	293,123,754	-	-	67,379	-	-	11,690,781	-	-	2,473,169	-
31	376	Mains - Commodity	3.0	1	-	-	0	-	-	0	-	-	0	-	-	0
32	378	Measuring & Reg. Station	3.0	23,180,184	-	-	10,911,762	-	-	93,846	-	-	1,831,398	-	-	5,368,058
33	380	Services - Demand	1.0	0	0	-	-	0	-	-	0	-	-	0	-	-
34	380	Services - Customer	7.0	305,210,571	-	246,322,712	-	-	293,451	-	-	44,031,688	-	-	10,804,180	-
35	381	Meters	6.0	125,828,203	-	92,283,117	-	-	396,110	-	-	13,834,403	-	-	12,663,169	-
36	385	Industrial Meas. & Reg. Sta.	3.0	3,942,124	-	-	1,855,702	-	-	15,960	-	-	311,456	-	-	912,915
37	386	Other Prop. on Cust. Premises	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
38	387	Other Equipment	1.0	(39,455)	(21,685)	-	-	(187)	-	-	(2,829)	-	-	(7,041)	-	-
39		Total Distribution		$ 975,240,756	$ 115,014,611	$ 631,729,584	$ 12,767,464	$ 994,212	$ 756,940	$ 109,806	$ 15,003,251	$ 69,556,872	$ 2,142,853	$ 37,342,809	$ 25,940,518	$ 6,280,973
40		Allocation Percentage	Dist. Plant	100.00%	11.79%	64.78%	1.31%	0.10%	0.08%	0.01%	1.54%	7.13%	0.22%	3.83%	2.66%	0.64%
41	389-398	Total General Plant	1.1	$ 74,626,005	$ 8,800,987	$ 48,340,325	$ 976,974	$ 76,078	$ 57,921	$ 8,402	$ 1,148,058	$ 5,322,533	$ 163,972	$ 2,857,494	$ 1,984,984	$ 480,624
42		Total Net Plant-Direct		$1,051,372,747	$ 123,993,206	$ 681,045,438	$ 13,764,154	$ 1,071,825	$ 816,030	$ 118,378	$ 16,174,478	$ 74,986,816	$ 2,310,135	$ 40,257,969	$ 27,965,560	$ 6,771,296
		Systems Allocable Plant														
43	301-303	Intangible Plant	1.1	$ 26,400,863	$ 3,113,575	$ 17,101,629	$ 345,630	$ 26,914	$ 20,491	$ 2,973	$ 406,155	$ 1,882,983	$ 58,009	$ 1,010,912	$ 702,239	$ 170,033
44	389-398	General Plant	1.1	$ 14,188,530	$ 1,673,318	$ 9,190,873	$ 185,751	$ 14,465	$ 11,013	$ 1,598	$ 218,278	$ 1,011,965	$ 31,176	$ 543,291	$ 377,402	$ 91,380
45		Total Systems Allocable		40,589,393	4,786,893	26,292,503	531,380	41,379	31,504	4,570	624,433	2,894,948	89,185	1,554,203	1,079,641	261,413
46		Total Net Plant		$1,091,962,140	$ 128,780,099	$ 707,337,941	$ 14,295,534	$ 1,113,204	$ 847,534	$ 122,948	$ 16,798,911	$ 77,881,764	$ 2,399,320	$ 41,812,172	$ 29,045,201	$ 7,032,709

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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Residential Gas Service			MMMHP Gas Service			Small General Gas Service			Medium General Gas Service		
					Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
		Other Rate Base Items														
1		Cash Working Capital	11.2	(11,082,156)	(587,328)	(7,670,516)	(401,267)	(5,077)	(15,009)	(3,451)	(76,615)	(866,727)	(67,347)	(190,693)	(410,903)	(197,404)
2		Materials & Supplies	1.1	9,222,489	1,087,650	5,974,032	120,737	9,402	7,158	1,038	141,880	657,773	20,264	353,137	245,310	59,397
3		Prepayments	1.1	2,740,815	323,237	1,775,412	35,882	2,794	2,127	309	42,165	195,483	6,022	104,948	72,903	17,652
4		Gas Plant Acquisition Adjustment	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-
5		Customer Deposits	8.0	(23,912,141)	-	(22,804,948)	-	-	(5,242)	-	-	(909,540)	-	-	(192,412)	-
6		Customer Advances	8.0	(7,027,372)	-	(6,701,987)	-	-	(1,541)	-	-	(267,298)	-	-	(56,547)	-
7		Deferred Taxes	1.1	(136,691,328)	(16,120,635)	(88,544,244)	(1,789,509)	(139,350)	(106,094)	(15,391)	(2,102,880)	(9,749,204)	(300,346)	(5,234,029)	(3,635,865)	(880,351)
8		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-	-	-	-	-	-	-	-	-	-
9		Total Allocated Rate Base		925,212,447	113,483,024	589,365,690	12,261,378	980,973	728,934	105,453	14,803,461	66,942,251	2,057,913	36,845,535	25,067,688	6,032,003

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Line No.	Account No.	Description	Allocation Factor No.	Large General Gas Service Demand	Large General Gas Service Customer	Large General Gas Service Commodity	Gas Service to Armed Forces Demand	Gas Service to Armed Forces Customer	Gas Service to Armed Forces Commodity	Air-Conditioning Gas Service Demand	Air-Conditioning Gas Service Customer	Air-Conditioning Gas Service Commodity	CNG - Small Demand	CNG - Small Customer	CNG - Small Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Net Plant in Service - Direct													
		Intangible													
1	301	Organization	1.1	$ 1,315	$ 136	$ 144	$ 175	$ 5	$ 6	$ 6	$ 8	$ 4	$ 1	$ 1	$ 0
2	302	Franchise & Consent	1.1	36,548	3,791	4,008	4,860	149	172	169	220	100	34	21	10
3	303	Misc. Intangible	1.1	8,578	890	941	1,141	35	40	40	52	23	8	5	2
4		Total Intangible		$ 46,441	$ 4,817	$ 5,093	$ 6,176	$ 190	$ 219	$ 214	$ 280	$ 127	$ 43	$ 27	$ 13
5		Allocation Percentage	Intang. Plant	3.08%	0.32%	0.34%	0.41%	0.01%	0.01%	0.01%	0.02%	0.01%	0.00%	0.00%	0.00%
		Production													
6	326	Other Land & Land Rights	3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	332	Field Lines	3	-	-	-	-	-	-	-	-	-	-	-	-
8	334	Field Meas & Reg. Stations	3	-	-	-	-	-	-	-	-	-	-	-	-
9	336	Purification Equipment	3	-	-	-	-	-	-	-	-	-	-	-	-
10		Total Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11		Allocation Percentage	Prod. Plant	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		Transmission													
12	365	Land & Land Rights	1.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	365	Rights of Way	1.0	-	-	-	-	-	-	-	-	-	-	-	-
14	366	Structures-Compressor Stas.	1.0	-	-	-	-	-	-	-	-	-	-	-	-
15	366	Structures	1.0	-	-	-	-	-	-	-	-	-	-	-	-
16	367	Mains - Demand	1.0	-	-	-	-	-	-	-	-	-	-	-	-
17	367	Mains - Customer	4.0	-	-	-	-	-	-	-	-	-	-	-	-
18	367	Mains - Commodity	3.0	-	-	-	-	-	-	-	-	-	-	-	-
19	367	Mains-Bridge	1.0	-	-	-	-	-	-	-	-	-	-	-	-
20	368	Compressor Stations	1.0	-	-	-	-	-	-	-	-	-	-	-	-
21	369	Measuring & Reg. Sta. Equip.	1.0	-	-	-	-	-	-	-	-	-	-	-	-
22	370	Communication Equip.	1.0	-	-	-	-	-	-	-	-	-	-	-	-
23	371	Other Equipment	1.0	-	-	-	-	-	-	-	-	-	-	-	-
24		Total Transmission		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25		Allocation Percentage	Trans. Plant	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		Distribution													
26	374	Land & Land Rights	1.0	$ 50,542	$ -	$ -	$ 6,721	$ -	$ -	$ 233	$ -	$ -	$ 47	$ -	$ -
27	374	Rights of Way	1.0	64,094	-	-	8,523	-	-	296	-	-	60	-	-
28	375	Structures	1.0	6,853	-	-	911	-	-	32	-	-	6	-	-
29	376	Mains - Demand	1.0	29,958,581	-	-	3,983,935	-	-	138,294	-	-	28,012	-	-
30	376	Mains - Customer	5.0	-	53,832	-	-	3,209	-	-	13,339	-	-	7,843	-
31	376	Mains - Commodity	3.0	-	-	0	-	-	0	-	-	0	-	-	0
32	378	Measuring & Reg. Station	3.0	-	-	2,818,916	-	-	121,252	-	-	70,276	-	-	6,976
33	380	Services - Demand	1.0	0	-	-	0	-	-	0	-	-	0	-	-
34	380	Services - Customer	7.0	-	830,855	-	-	54,623	-	-	159,542	-	-	6,958	-
35	381	Meters	6.0	-	2,234,479	-	-	65,102	-	-	8,338	-	-	2,387	-
36	385	Industrial Meas. & Reg. Sta.	3.0	-	-	479,397	-	-	20,621	-	-	11,951	-	-	1,186
37	386	Other Prop. on Cust. Premises	1.0	-	-	-	-	-	-	-	-	-	-	-	-
38	387	Other Equipment	1.0	(5,670)	-	-	(754)	-	-	(26)	-	-	(5)	-	-
39		Total Distribution		$ 30,074,398	$ 3,119,166	$ 3,298,314	$ 3,999,336	$ 122,934	$ 141,872	$ 138,829	$ 181,220	$ 82,227	$ 28,120	$ 17,187	$ 8,163
40		Allocation Percentage	Dist. Plant	3.08%	0.32%	0.34%	0.41%	0.01%	0.01%	0.01%	0.02%	0.01%	0.00%	0.00%	0.00%
41	389-398	Total General Plant	1.1	$ 2,301,311	$ 238,680	$ 252,389	$ 306,032	$ 9,407	$ 10,856	$ 10,623	$ 13,867	$ 6,292	$ 2,152	$ 1,315	$ 625
42		Total Net Plant-Direct		$ 32,422,151	$ 3,362,663	$ 3,555,796	$ 4,311,544	$ 132,531	$ 152,947	$ 149,666	$ 195,367	$ 88,646	$ 30,315	$ 18,529	$ 8,800
		Systems Allocable Plant													
43	301-303	Intangible Plant	1.1	$ 814,148	$ 84,439	$ 89,289	$ 108,267	$ 3,328	$ 3,841	$ 3,758	$ 4,906	$ 2,226	$ 761	$ 465	$ 221
44	389-398	General Plant	1.1	$ 437,545	$ 45,380	$ 47,986	$ 58,185	$ 1,789	$ 2,064	$ 2,020	$ 2,637	$ 1,196	$ 409	$ 250	$ 119
45		Total Systems Allocable		1,251,693	129,819	137,275	166,452	5,116	5,905	5,778	7,542	3,422	1,170	715	340
46		Total Net Plant		$ 33,673,843	$ 3,492,483	$ 3,693,071	$ 4,477,996	$ 137,647	$ 158,852	$ 155,444	$ 202,909	$ 92,069	$ 31,485	$ 19,244	$ 9,140

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Line No.	Account No.	Description	Allocation Factor No.	Large General Gas Service Demand	Large General Gas Service Customer	Large General Gas Service Commodity	Gas Service to Armed Forces Demand	Gas Service to Armed Forces Customer	Gas Service to Armed Forces Commodity	Air-Conditioning Gas Service Demand	Air-Conditioning Gas Service Customer	Air-Conditioning Gas Service Commodity	CNG - Small Demand	CNG - Small Customer	CNG - Small Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Other Rate Base Items													
1		Cash Working Capital	11.2	(153,576)	(53,804)	(103,662)	(20,423)	(2,154)	(4,459)	(709)	(1,893)	(2,584)	(144)	(366)	(257)
2		Materials & Supplies	1.1	284,402	29,497	31,191	37,820	1,163	1,342	1,313	1,714	778	266	163	77
3		Prepayments	1.1	84,521	8,766	9,270	11,240	345	399	390	509	231	79	48	23
4		Gas Plant Acquisition Adjustment	1.1	-	-	-	-	-	-	-	-	-	-	-	-
5		Customer Deposits	8.0	-	-	-	-	-	-	-	-	-	-	-	-
6		Customer Advances	8.0	-	-	-	-	-	-	-	-	-	-	-	-
7		Deferred Taxes	1.1	(4,215,277)	(437,187)	(462,297)	(560,553)	(17,231)	(19,885)	(19,458)	(25,400)	(11,525)	(3,941)	(2,409)	(1,144)
8		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-	-	-	-	-	-	-	-	-
9		Total Allocated Rate Base		29,673,914	3,039,754	3,167,573	3,946,079	119,770	136,249	136,980	177,839	78,968	27,745	16,680	7,839

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Line No.	Account No.	Description	Allocation Factor No.	CNG - Large Demand	CNG - Large Customer	CNG - Large Commodity	CNG - Residential Demand	CNG - Residential Customer	CNG - Residential Commodity	Cogeneration Gas Service Demand	Cogeneration Gas Service Customer	Cogeneration Gas Service Commodity	Small Essential Agr. User Gas Service Demand	Small Essential Agr. User Gas Service Customer	Small Essential Agr. User Gas Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Net Plant in Service - Direct													
		Intangible													
1	301	Organization	1.1	$ 11	$ 19	$ 4	$ 1	$ 4	$ 0	$ 100	$ 8	$ 29	$ 143	$ 28	$ 25
2	302	Franchise & Consent	1.1	317	537	103	16	99	4	2,791	229	817	3,970	777	684
3	303	Misc. Intangible	1.1	75	126	24	4	23	1	655	54	192	932	182	161
4		Total Intangible		$ 403	$ 682	$ 131	$ 20	$ 126	$ 6	$ 3,547	$ 291	$ 1,038	$ 5,045	$ 988	$ 870
5		Allocation Percentage	Intang. Plant	0.03%	0.05%	0.01%	0.00%	0.01%	0.00%	0.24%	0.02%	0.07%	0.34%	0.07%	0.06%
		Production													
6	326	Other Land & Land Rights	3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	332	Field Lines	3	-	-	-	-	-	-	-	-	-	-	-	-
8	334	Field Meas & Reg. Stations	3	-	-	-	-	-	-	-	-	-	-	-	-
9	336	Purification Equipment	3	-	-	-	-	-	-	-	-	-	-	-	-
10		Total Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11		Allocation Percentage	Prod. Plant	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		Transmission													
12	365	Land & Land Rights	1.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	365	Rights of Way	1.0	-	-	-	-	-	-	-	-	-	-	-	-
14	366	Structures-Compressor Stas.	1.0	-	-	-	-	-	-	-	-	-	-	-	-
15	366	Structures	1.0	-	-	-	-	-	-	-	-	-	-	-	-
16	367	Mains - Demand	1.0	-	-	-	-	-	-	-	-	-	-	-	-
17	367	Mains - Customer	4.0	-	-	-	-	-	-	-	-	-	-	-	-
18	367	Mains - Commodity	3.0	-	-	-	-	-	-	-	-	-	-	-	-
19	367	Mains-Bridge	1.0	-	-	-	-	-	-	-	-	-	-	-	-
20	368	Compressor Stations	1.0	-	-	-	-	-	-	-	-	-	-	-	-
21	369	Measuring & Reg. Sta. Equip.	1.0	-	-	-	-	-	-	-	-	-	-	-	-
22	370	Communication Equip.	1.0	-	-	-	-	-	-	-	-	-	-	-	-
23	371	Other Equipment	1.0	-	-	-	-	-	-	-	-	-	-	-	-
24		Total Transmission		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25		Allocation Percentage	Trans. Plant	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		Distribution													
26	374	Land & Land Rights	1.0	$ 439	$ -	$ -	$ 22	$ -	$ -	$ 3,860	$ -	$ -	$ 5,491	$ -	$ -
27	374	Rights of Way	1.0	557	-	-	27	-	-	4,895	-	-	6,963	-	-
28	375	Structures	1.0	60	-	-	3	-	-	523	-	-	744	-	-
29	376	Mains - Demand	1.0	260,180	-	-	12,796	-	-	2,287,869	-	-	3,254,588	-	-
30	376	Mains - Customer	5.0	-	9,626	-	-	39,215	-	-	8,200	-	-	40,017	-
31	376	Mains - Commodity	3.0	-	-	0	-	-	0	-	-	0	-	-	0
32	378	Measuring & Reg. Station	3.0	-	-	72,658	-	-	3,050	-	-	574,275	-	-	481,347
33	380	Services - Demand	1.0	0	-	-	0	-	-	0	-	-	0	-	-
34	380	Services - Customer	7.0	-	167,146	-	-	30,998	-	-	119,187	-	-	349,122	-
35	381	Meters	6.0	-	264,930	-	-	11,272	-	-	61,329	-	-	250,633	-
36	385	Industrial Meas. & Reg. Sta.	3.0	-	-	12,357	-	-	519	-	-	97,664	-	-	81,860
37	386	Other Prop. on Cust. Premises	1.0	-	-	-	-	-	-	-	-	-	-	-	-
38	387	Other Equipment	1.0	(49)	-	-	(2)	-	-	(433)	-	-	(616)	-	-
39		Total Distribution		$ 261,186	$ 441,702	$ 85,015	$ 12,845	$ 81,486	$ 3,569	$ 2,296,714	$ 188,716	$ 671,938	$ 3,267,170	$ 639,773	$ 563,207
40		Allocation Percentage	Dist. Plant	0.03%	0.05%	0.01%	0.00%	0.01%	0.00%	0.24%	0.02%	0.07%	0.34%	0.07%	0.06%
41	389-398	Total General Plant	1.1	$ 19,986	$ 33,799	$ 6,505	$ 983	$ 6,235	$ 273	$ 175,746	$ 14,441	$ 51,417	$ 250,006	$ 48,956	$ 43,097
42		Total Net Plant-Direct		$ 281,575	$ 476,183	$ 91,652	$ 13,848	$ 87,847	$ 3,848	$ 2,476,006	$ 203,448	$ 724,393	$ 3,522,221	$ 689,716	$ 607,174
		Systems Allocable Plant													
43	301-303	Intangible Plant	1.1	$ 7,071	$ 11,957	$ 2,301	$ 348	$ 2,206	$ 97	$ 62,175	$ 5,109	$ 18,190	$ 88,446	$ 17,319	$ 15,247
44	389-398	General Plant	1.1	$ 3,800	$ 6,426	$ 1,237	$ 187	$ 1,186	$ 52	$ 33,414	$ 2,746	$ 9,776	$ 47,533	$ 9,308	$ 8,194
45		Total Systems Allocable		10,871	18,384	3,538	535	3,391	149	95,589	7,854	27,966	135,979	26,627	23,441
46		Total Net Plant		$ 292,446	$ 494,566	$ 95,190	$ 14,382	$ 91,238	$ 3,996	$ 2,571,595	$ 211,302	$ 752,359	$ 3,658,201	$ 716,343	$ 630,615

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Line No.	Account No.	Description	Allocation Factor No.		CNG - Large			CNG - Residential			Cogeneration Gas Service			Small Essential Agr. User Gas Service	
				Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Other Rate Base Items													
1		Cash Working Capital	11.2	(1,334)	(6,883)	(2,672)	(66)	(993)	(112)	(11,728)	(2,284)	(21,118)	(16,684)	(19,325)	(17,701)
2		Materials & Supplies	1.1	2,470	4,177	804	121	771	34	21,719	1,785	6,354	30,896	6,050	5,326
3		Prepayments	1.1	734	1,241	239	36	229	10	6,455	530	1,888	9,182	1,798	1,583
4		Gas Plant Acquisition Adjustment	1.1	-	-	-	-	-	-	-	-	-	-	-	-
5		Customer Deposits	8.0	-	-	-	-	-	-	-	-	-	-	-	-
6		Customer Advances	8.0	-	-	-	-	-	-	-	-	-	-	-	-
7		Deferred Taxes	1.1	(36,608)	(61,910)	(11,916)	(1,800)	(11,421)	(500)	(321,911)	(26,451)	(94,180)	(457,932)	(89,672)	(78,940)
8		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-	-	-	-	-	-	-	-	-
9		Total Allocated Rate Base		257,708	431,192	81,645	12,674	79,823	3,428	2,266,130	184,883	645,304	3,223,663	615,195	540,883

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Line No.	Account No.	Description	Allocation Factor No.	Natural Gas Engine Gas Service Demand	Natural Gas Engine Gas Service Customer	Natural Gas Engine Gas Service Commodity	Street Lighting Gas Service Demand	Street Lighting Gas Service Customer	Street Lighting Gas Service Commodity	Special Residential Gas Service - A/C Demand	Special Residential Gas Service - A/C Customer	Special Residential Gas Service - A/C Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		Net Plant in Service - Direct										
		Intangible										
1	301	Organization	1.1	$ 33	$ 261	$ 42	$ 1	$ 1	$ 0	$ 2	$ 3	$ 0
2	302	Franchise & Consent	1.1	927	7,261	1,157	21	25	5	66	96	12
3	303	Misc. Intangible	1.1	218	1,704	272	5	6	1	15	22	3
4		Total Intangible		$ 1,178	$ 9,227	$ 1,471	$ 27	$ 32	$ 7	$ 83	$ 122	$ 16
5		Allocation Percentage	Intang. Plant	0.08%	0.61%	0.10%	0.00%	0.00%	0.00%	0.01%	0.01%	0.00%
		Production										
6	326	Other Land & Land Rights	3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	332	Field Lines	3	-	-	-	-	-	-	-	-	-
8	334	Field Meas & Reg. Stations	3	-	-	-	-	-	-	-	-	-
9	336	Purification Equipment	3	-	-	-	-	-	-	-	-	-
10		Total Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11		Allocation Percentage	Prod. Plant	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		Transmission										
12	365	Land & Land Rights	1.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	365	Rights of Way	1.0	-	-	-	-	-	-	-	-	-
14	366	Structures-Compressor Stas.	1.0	-	-	-	-	-	-	-	-	-
15	366	Structures	1.0	-	-	-	-	-	-	-	-	-
16	367	Mains - Demand	1.0	-	-	-	-	-	-	-	-	-
17	367	Mains - Customer	4.0	-	-	-	-	-	-	-	-	-
18	367	Mains - Commodity	3.0	-	-	-	-	-	-	-	-	-
19	367	Mains-Bridge	1.0	-	-	-	-	-	-	-	-	-
20	368	Compressor Stations	1.0	-	-	-	-	-	-	-	-	-
21	369	Measuring & Reg. Sta. Equip.	1.0	-	-	-	-	-	-	-	-	-
22	370	Communication Equip.	1.0	-	-	-	-	-	-	-	-	-
23	371	Other Equipment	1.0	-	-	-	-	-	-	-	-	-
24		Total Transmission		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25		Allocation Percentage	Trans. Plant	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		Distribution										
26	374	Land & Land Rights	1.0	$ 1,282	$ -	$ -	$ 29	$ -	$ -	$ 91	$ -	$ -
27	374	Rights of Way	1.0	1,626	-	-	37	-	-	115	-	-
28	375	Structures	1.0	174	-	-	4	-	-	12	-	-
29	376	Mains - Demand	1.0	759,858	-	-	17,399	-	-	53,811	-	-
30	376	Mains - Customer	5.0	-	215,238	-	-	10,339	-	-	55,971	-
31	376	Mains - Commodity	3.0	-	-	0	-	-	0	-	-	0
32	378	Measuring & Reg. Station	3.0	-	-	813,954	-	-	3,822	-	-	8,593
33	380	Services - Demand	1.0	0	-	-	0	-	-	0	-	-
34	380	Services - Customer	7.0	-	2,029,991	-	-	10,116	-	-	-	-
35	381	Meters	6.0	-	3,730,102	-	-	-	-	-	22,831	-
36	385	Industrial Meas. & Reg. Sta.	3.0	-	-	138,425	-	-	650	-	-	1,461
37	386	Other Prop. on Cust. Premises	1.0	-	-	-	-	-	-	-	-	-
38	387	Other Equipment	1.0	(144)	-	-	(3)	-	-	(10)	-	-
39		Total Distribution		$ 762,796	$ 5,975,331	$ 952,379	$ 17,467	$ 20,455	$ 4,472	$ 54,019	$ 78,802	$ 10,055
40		Allocation Percentage	Dist. Plant	0.08%	0.61%	0.10%	0.00%	0.00%	0.00%	0.01%	0.01%	0.00%
41	389-398	Total General Plant	1.1	$ 58,370	$ 457,236	$ 72,877	$ 1,337	$ 1,565	$ 342	$ 4,134	$ 6,030	$ 769
42		Total Net Plant-Direct		$ 822,344	$ 6,441,794	$ 1,026,726	$ 18,830	$ 22,052	$ 4,821	$ 58,236	$ 84,953	$ 10,840
		Systems Allocable Plant										
43	301-303	Intangible Plant	1.1	$ 20,650	$ 161,759	$ 25,782	$ 473	$ 554	$ 121	$ 1,462	$ 2,133	$ 272
44	389-398	General Plant	1.1	$ 11,098	$ 86,934	$ 13,856	$ 254	$ 298	$ 65	$ 786	$ 1,146	$ 146
45		Total Systems Allocable		31,747	248,692	39,638	727	851	186	2,248	3,280	418
46		Total Net Plant		$ 854,091	$ 6,690,487	$ 1,066,364	$ 19,557	$ 22,903	$ 5,007	$ 60,484	$ 88,233	$ 11,258

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Line No.	Account No.	Description	Allocation Factor No.	Natural Gas Engine Gas Service			Street Lighting Gas Service			Special Residential Gas Service - A/C		
				Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		Other Rate Base Items										
1		Cash Working Capital	11.2	(3,895)	(106,449)	(29,932)	(89)	(1,888)	(141)	(276)	(1,900)	(316)
2		Materials & Supplies	1.1	7,213	56,506	9,006	165	193	42	511	745	95
3		Prepayments	1.1	2,144	16,793	2,677	49	57	13	152	221	28
4		Gas Plant Acquisition Adjustment	1.1	-	-	-	-	-	-	-	-	-
5		Customer Deposits	8.0	-	-	-	-	-	-	-	-	-
6		Customer Advances	8.0	-	-	-	-	-	-	-	-	-
7		Deferred Taxes	1.1	(106,915)	(837,512)	(133,487)	(2,448)	(2,867)	(627)	(7,571)	(11,045)	(1,409)
8		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-	-	-	-	-	-
9		Total Allocated Rate Base		752,638	5,819,825	914,627	17,234	18,399	4,295	53,299	76,255	9,656

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Line No.	Account No. (a)	Description (b)	Allocation Factor No. (c)	Total Amount (d)	Residential Gas Service Demand (e)	Residential Gas Service Customer (f)	Residential Gas Service Commodity (g)	MMMHP Gas Service Demand (h)	MMMHP Gas Service Customer (i)	MMMHP Gas Service Commodity (j)	Small General Gas Service Demand (k)	Small General Gas Service Customer (l)	Small General Gas Service Commodity (m)	Medium General Gas Service Demand (n)	Medium General Gas Service Customer (o)	Medium General Gas Service Commodity (p)
		Direct Depreciation Expense														
1	301-303	Intangible	Intang. Plant	$ 209,988	$ 24,765	$ 136,024	$ 2,749	$ 214	$ 163	$ 24	$ 3,230	$ 14,977	$ 461	$ 8,041	$ 5,585	$ 1,352
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 62,360,935	$ 7,354,511	$ 40,395,407	$ 816,405	$ 63,574	$ 48,402	$ 7,021	$ 959,370	$ 4,447,755	$ 137,023	$ 2,387,854	$ 1,658,744	$ 401,631
5	389-398	General	1.1	$ 4,820,934	$ 568,555	$ 3,122,846	$ 63,114	$ 4,915	$ 3,742	$ 543	$ 74,166	$ 343,842	$ 10,593	$ 184,598	$ 128,232	$ 31,049
6		Total Direct Dep. Exp.		$ 67,391,857	$ 7,947,831	$ 43,654,277	$ 882,267	$ 68,703	$ 52,307	$ 7,588	$ 1,036,767	$ 4,806,574	$ 148,077	$ 2,580,492	$ 1,792,562	$ 434,033
		Systems Allocable Depreciation Expense														
7	301-303	Intangible	Intang. Plant	$ 4,688,595	$ 552,947	$ 3,037,121	$ 61,381	$ 4,780	$ 3,639	$ 528	$ 72,130	$ 334,404	$ 10,302	$ 179,530	$ 124,712	$ 30,197
8	389-398	General	1.1	$ 2,373,988	$ 279,975	$ 1,537,793	$ 31,079	$ 2,420	$ 1,843	$ 267	$ 36,522	$ 169,319	$ 5,216	$ 90,902	$ 63,146	$ 15,290
		System Allocable Amortization														
9		Miscellaneous Intangible	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-
10		Structures-Leasehold Improvements	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-
11		Total System Allocable Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-
12		Total System Alloc Dep. Exp. & Amortization		7,062,583	832,923	4,574,914	92,461	7,200	5,482	795	108,652	503,723	15,518	270,432	187,858	45,486
13		Total Depreciation Expense		74,454,440	8,780,753	48,229,191	974,728	75,903	57,788	8,383	1,145,418	5,310,297	163,595	2,850,925	1,980,420	479,519
14		Amortization-Limited Term Gas Plant	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-
15		Amortization-Gas Plant Acquisition	1.1	(52,996)	(6,250)	(34,329)	(694)	(54)	(41)	(6)	(815)	(3,780)	(116)	(2,029)	(1,410)	(341)
16		Amortization of PBOP Costs	1.1	337,524	39,806	218,637	4,419	344	262	38	5,193	24,073	742	12,924	8,978	2,174
17		Amortization of Service Investigation	7.0	-	-	-	-	-	-	-	-	-	-	-	-	-
18		Amortization of TRIMP Costs	1.1	1,183,333	139,556	766,525	15,492	1,206	918	133	18,205	84,399	2,600	45,311	31,476	7,621
19		Amortization of SOX Implementation	1.1	27,346	3,225	17,714	358	28	21	3	421	1,950	60	1,047	727	176
20		Total Depreciation & Amortization Expense		$ 75,949,648	$ 8,957,090	$ 49,197,738	$ 994,303	$ 77,427	$ 58,949	$ 8,551	$ 1,168,421	$ 5,416,939	$ 166,881	$ 2,908,177	$ 2,020,192	$ 489,149

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Line No.	Account No. (a)	Description (b)	Allocation Factor No. (c)	Total Amount (d)	Residential Gas Service Demand (e)	Residential Gas Service Customer (f)	Residential Gas Service Commodity (g)	MMMHP Gas Service Demand (h)	MMMHP Gas Service Customer (i)	MMMHP Gas Service Commodity (j)	Small General Gas Service Demand (k)	Small General Gas Service Customer (l)	Small General Gas Service Commodity (m)	Medium General Gas Service Demand (n)	Medium General Gas Service Customer (o)	Medium General Gas Service Commodity (p)
		Operation and Maintenance Expense														
		Gas Supply Expense														
1	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-
3	805	Purchased Gas Cost Adj.	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-
4	810	Gas Used for Compressor Sta. Fuel--	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-
5	813	Other Gas Supply Expense	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-
6		Labor & Labor Loading	3.0	683,189	-	-	321,602	-	-	2,766	-	-	53,977	-	-	158,213
7		Materials & Expenses	3.0	57,202	-	-	26,927	-	-	232	-	-	4,519	-	-	13,247
8		Total Gas Supply Expense		$ 740,391	$ -	$ -	$ 348,529	$ -	$ -	$ 2,998	$ -	$ -	$ 58,496	$ -	$ -	$ 171,460
		Transmission Expenses														
9	850	Operation Supervision & Engin.														
10		Labor & Labor Loading	5.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11		Materials & Expenses	5.0	-	-	-	-	-	-	-	-	-	-	-	-	-
12	851	System Control & Load Dispatch														
13		Labor & Labor Loading	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-
14		Materials & Expenses	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-
15	852	Communication System Exp.														
16		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
17		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
18	853	Compressor Station														
19		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
20		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
21	854	Gas for Compressor Station Fuel	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-
22	856	Mains Expense														
23		Labor & Labor Loading	6.0	-	-	-	-	-	-	-	-	-	-	-	-	-
24		Materials & Expenses	6.0	-	-	-	-	-	-	-	-	-	-	-	-	-
25	857	Meas. & Res. Sta. Exp.														
26		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
27		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
28	858	Trans. & comp. of Gas by Others	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-
29	860	Rents	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
30	861	Maint. Supervision & Eng.														
31		Labor & Labor Loading	7.0	-	-	-	-	-	-	-	-	-	-	-	-	-
32		Materials & Expenses	7.0	-	-	-	-	-	-	-	-	-	-	-	-	-
33	862	Maint. of Struct. & Imp.	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
34	863	Maint. of Mains														
35		Labor & Labor Loading	6.0	-	-	-	-	-	-	-	-	-	-	-	-	-
36		Materials & Expenses	6.0	-	-	-	-	-	-	-	-	-	-	-	-	-
37	864	Maint. of Comp. Sta. Equip.														
38		Labor & Labor Loading	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-
39		Materials & Expenses	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-
40	865	Maint. of Meas. & Reg. Sta. Equip.														
41		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
42		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
43		Total Transmission Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Residential Gas Service Demand	Residential Gas Service Customer	Residential Gas Service Commodity	MMMHP Gas Service Demand	MMMHP Gas Service Customer	MMMHP Gas Service Commodity	Small General Gas Service Demand	Small General Gas Service Customer	Small General Gas Service Commodity	Medium General Gas Service Demand	Medium General Gas Service Customer	Medium General Gas Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
		Distribution Expenses														
1	870	Operation Supervision & Eng.														
2		Labor & Labor Loading	5.5	$ 7,314,234	$ 390,455	$ 4,522,517	$ 402,417	$ 3,375	$ 12,751	$ 3,461	$ 50,933	$ 592,281	$ 67,541	$ 126,772	$ 413,564	$ 197,970
3		Materials & Expenses	5.5	1,144,604	61,102	707,729	62,974	528	1,995	542	7,971	92,686	10,569	19,839	64,719	30,980
4	871	Distribution Load Dispatching														
5		Labor & Labor Loading	3.0	531,430	-	-	250,163	-	-	2,152	-	-	41,987	-	-	123,068
6		Materials & Expenses	3.0	128,930	-	-	60,692	-	-	522	-	-	10,186	-	-	29,858
7	874	Mains & Svcs. Expense														
8		Labor & Labor Loading	4.4	5,227,680	729,100	3,432,876	0	6,303	2,296	0	95,109	354,601	0	236,723	84,493	0
9		Materials & Expenses	4.4	5,914,196	824,848	3,883,692	0	7,130	2,598	0	107,598	401,168	0	267,811	95,589	0
10	875	Meas. & Reg. Sta. Exp.-Gen.														
11		Labor & Labor Loading	3.0	1,964,122	-	-	924,584	-	-	7,952	-	-	155,179	-	-	454,851
12		Materials & Expenses	3.0	777,755	-	-	366,118	-	-	3,149	-	-	61,448	-	-	180,112
13	878	Meter & House Reg. Exp.														
14		Labor & Labor Loading	6.0	5,796,552	-	4,251,224	-	-	18,248	-	-	637,312	-	-	583,357	-
15		Materials & Expenses	6.0	875,104	-	641,806	-	-	2,755	-	-	96,215	-	-	88,069	-
16	879	Customer Installation Exp.														
17		Labor & Labor Loading	6.0	6,850,542	-	5,024,226	-	-	21,566	-	-	753,195	-	-	689,429	-
18		Materials & Expenses	6.0	1,043,174	-	765,070	-	-	3,284	-	-	114,694	-	-	104,984	-
19	880	Other Expenses														
20		Labor & Labor Loading	5.5	6,293,097	335,943	3,891,130	346,236	2,904	10,971	2,978	43,823	509,593	58,111	109,074	355,827	170,331
21		Materials & Expenses	5.5	4,262,589	227,549	2,635,632	234,521	1,967	7,431	2,017	29,683	345,170	39,361	73,880	241,017	115,373
22	881	Rents	5.5	1,980,383	105,719	1,224,505	108,958	914	3,452	937	13,791	160,365	18,287	34,325	111,976	53,602
23		Total Distribution-Operations		$ 50,104,393	$ 2,674,716	$ 30,980,406	$ 2,756,664	$ 23,121	$ 87,346	$ 23,708	$ 348,907	$ 4,057,280	$ 462,670	$ 868,424	$ 2,833,023	$ 1,356,145
		Operation and Maintenance Expense														
		Distribution Expenses														
24	885	Maint. Supervision & Eng.														
25		Labor & Labor Loading	6.6	$ 2,374,262	$ 280,170	$ 1,454,107	$ 84,874	$ 2,422	$ 1,458	$ 730	$ 36,547	$ 157,768	$ 14,245	$ 90,965	$ 50,929	$ 41,754
26		Materials & Expenses	6.6	254,842	30,072	156,077	9,110	260	156	78	3,923	16,934	1,529	9,764	5,466	4,482
27	886	Maint. of Structures & Imp.														
28		Labor & Labor Loading	1.0	13,682	7,520	-	-	65	-	-	981	-	-	2,442	-	-
29		Materials & Expenses	1.0	50,707	27,869	-	-	241	-	-	3,635	-	-	9,048	-	-
30	887	Maint. of Mains														
31		Labor & Labor Loading	2.2	7,503,706	1,665,225	4,260,364	0	14,395	979	0	217,223	169,918	0	540,663	35,946	0
32		Materials & Expenses	2.2	5,977,097	1,326,440	3,393,605	0	11,466	780	0	173,029	135,349	0	430,667	28,633	0
33	889	Maint. of Meas. & Reg. Sta-Gen														
34		Labor & Labor Loading	3.0	1,118,151	-	-	526,355	-	-	4,527	-	-	88,342	-	-	258,941
35		Materials & Expenses	3.0	829,877	-	-	390,654	-	-	3,360	-	-	65,566	-	-	192,183
36	892	Maint. of Services														
37		Labor & Labor Loading	3.3	5,317,554	0	4,291,575	-	0	5,113	-	0	767,145	-	0	188,237	-
38		Materials & Expenses	3.3	2,909,486	0	2,348,125	-	0	2,797	-	0	419,742	-	0	102,993	-
39	893	Maint of Meter & House Reg.														
40		Labor & Labor Loading	6.0	1,126,714	-	826,339	-	-	3,547	-	-	123,879	-	-	113,391	-
41		Materials & Expenses	6.0	805,373	-	590,665	-	-	2,535	-	-	88,548	-	-	81,052	-
42	894	Maint of Other Equip.														
43		Labor & Labor Loading	6.6	150,319	17,738	92,062	5,374	153	92	46	2,314	9,989	902	5,759	3,224	2,644
44		Materials & Expenses	6.6	44,303	5,228	27,133	1,584	45	27	14	682	2,944	266	1,697	950	779
45		Total Distribution-Maintenance		$ 28,476,074	$ 3,360,262	$ 17,440,053	$ 1,017,950	$ 29,047	$ 17,486	$ 8,755	$ 438,334	$ 1,892,215	$ 170,850	$ 1,091,006	$ 610,821	$ 500,782
46		Total Distribution O & M		$ 78,580,466	$ 6,034,978	$ 48,420,459	$ 3,774,613	$ 52,168	$ 104,832	$ 32,463	$ 787,242	$ 5,949,495	$ 633,520	$ 1,959,430	$ 3,443,843	$ 1,856,927

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
AUGUST 31, 2004

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Residential Gas Service Demand	Residential Gas Service Customer	Residential Gas Service Commodity	MMMHP Gas Service Demand	MMMHP Gas Service Customer	MMMHP Gas Service Commodity	Small General Gas Service Demand	Small General Gas Service Customer	Small General Gas Service Commodity	Medium General Gas Service Demand	Medium General Gas Service Customer	Medium General Gas Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
		Customer Accounts Expenses														
1	901	Supervision														
2		Labor & Labor Loading	10.1	$ 3,574,463	$ -	$ 3,144,808	$ -	$ -	$ 5,106	$ -	$ -	$ 305,704	$ -	$ -	$ 80,475	$ -
3		Materials & Expenses	10.1	218,328	-	192,084	-	-	312	-	-	18,672	-	-	4,915	-
4	902	Meter Reading Exp.														
5		Labor & Labor Loading	13.0	5,130,538	-	4,494,167	-	-	7,657	-	-	451,691	-	-	119,438	-
6		Materials & Expenses	13.0	1,285,812	-	1,126,325	-	-	1,919	-	-	113,202	-	-	29,933	-
7	903	Customer Records & Collections														
8		Labor & Labor Loading	13.0	14,174,373	-	12,416,242	-	-	21,154	-	-	1,247,907	-	-	329,976	-
9		Materials & Expenses	13.0	6,602,396	-	5,783,462	-	-	9,853	-	-	581,273	-	-	153,702	-
10	903	Customer Records & Collections - LCS														
11		Labor & Labor Loading - LCS	13.0	1,077,228	-	943,613	-	-	1,608	-	-	94,839	-	-	25,078	-
12		Materials & Expenses - LCS	13.0	47,923	-	41,979	-	-	72	-	-	4,219	-	-	1,116	-
13	904	Uncollectible Accounts Exp.	4.0	1,498,151	-	1,426,662	-	-	328	-	-	56,900	-	-	12,037	-
14	905	Misc. Customer Accounts Exp.														
15		Labor & Labor Loading	10.1	372,869	-	328,049	-	-	533	-	-	31,889	-	-	8,395	-
16		Materials & Expenses	10.1	21,199	-	18,651	-	-	30	-	-	1,813	-	-	477	-
17		Total Customer Accounts Expenses		$ 34,003,279	$ -	$ 29,916,043	$ -	$ -	$ 48,570	$ -	$ -	$ 2,908,110	$ -	$ -	$ 765,542	$ -
		Customer Service & Info. Exp.														
18	908	Customer Assistance Exp.														
19		Labor & Labor Loading	13.0	$ 275,434	$ -	$ 241,270	$ -	$ -	$ 411	$ -	$ -	$ 24,249	$ -	$ -	$ 6,412	$ -
20		Materials & Expenses	13.0	248,457	-	217,640	-	-	371	-	-	21,874	-	-	5,784	-
21	909	Info. & Instructional Exp.														
22		Labor & Labor Loading	13.0	-	-	-	-	-	-	-	-	-	-	-	-	-
23		Materials & Expenses	13.0	-	-	-	-	-	-	-	-	-	-	-	-	-
24	910	Misc. C.S. & I. Expense														
25		Labor & Labor Loading	13.0	773	-	677	-	-	1	-	-	68	-	-	18	-
26		Materials & Expenses	13.0	23,832	-	20,876	-	-	36	-	-	2,098	-	-	555	-
27		Total Customer Service & Info. Exp.		$ 548,496	$ -	$ 480,462	$ -	$ -	$ 819	$ -	$ -	$ 48,289	$ -	$ -	$ 12,769	$ -
		Sales Expense														
28	911	Supervision														
29		Labor & Labor Loading	4.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30		Materials & Expenses	4.0	-	-	-	-	-	-	-	-	-	-	-	-	-
31	912	Demonstrating & Selling Exp.														
32		Labor & Labor Loading	4.0	-	-	-	-	-	-	-	-	-	-	-	-	-
33		Materials & Expenses	4.0	-	-	-	-	-	-	-	-	-	-	-	-	-
34	913	Advertising Expense														
35		Labor & Labor Loading	4.0	-	-	-	-	-	-	-	-	-	-	-	-	-
36		Materials & Expenses	4.0	-	-	-	-	-	-	-	-	-	-	-	-	-
37		Total Sales Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38		Total O & M Expense		$ 113,872,832	$ 6,034,978	$ 78,816,964	$ 4,123,143	$ 52,168	$ 154,220	$ 35,461	$ 787,242	$ 8,905,894	$ 692,016	$ 1,959,430	$ 4,222,155	$ 2,028,386
39		Allocation Percentage	Total O&M	100.00%	5.30%	69.22%	3.62%	0.05%	0.14%	0.03%	0.69%	7.82%	0.61%	1.72%	3.71%	1.78%
		Other Operating Deductions														
40		Administrative & General Expense	Total O&M	52,481,195	2,781,378	36,324,869	1,900,259	24,043	71,077	16,343	362,821	4,104,515	318,934	903,055	1,945,891	934,835
41		Interest on Customer Deposits	8.0	717,364	-	684,148	-	-	157	-	-	27,286	-	-	5,772	-
42		Taxes Other Than Income	1.1	33,455,124	3,945,516	21,671,153	437,981	34,106	25,966	3,767	514,679	2,386,112	73,509	1,281,026	889,876	215,465
43		Total Allocated Operating Deductions		$ 200,526,315	$ 12,761,872	$ 137,497,135	$ 6,461,382	$ 110,317	$ 251,421	$ 55,571	$ 1,664,741	$ 15,423,807	$ 1,084,459	$ 4,143,510	$ 7,063,694	$ 3,178,687
		Tax Adjustments														
44		Interest Expense	1.1	40,521,530	4,778,890	26,248,543	530,492	41,310	31,451	4,562	623,389	2,890,108	89,036	1,551,604	1,077,836	260,976
45		State South Georgia	1.1	77,020	9,083	49,891	1,008	79	60	9	1,185	5,493	169	2,949	2,049	496
46		Investment Tax Credit	1.1	(528,352)	(62,311)	(342,249)	(6,917)	(539)	(410)	(59)	(8,128)	(37,684)	(1,161)	(20,231)	(14,054)	(3,403)
47		Federal South Georgia	1.1	288,233	33,993	186,708	3,773	294	224	32	4,434	20,558	633	11,037	7,667	1,856

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
AUGUST 31, 2004

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Residential Gas Service Demand	Residential Gas Service Customer	Residential Gas Service Commodity	MMMHP Gas Service Demand	MMMHP Gas Service Customer	MMMHP Gas Service Commodity	Small General Gas Service Demand	Small General Gas Service Customer	Small General Gas Service Commodity	Medium General Gas Service Demand	Medium General Gas Service Customer	Medium General Gas Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
		Summary of Allocated Cost of Service														
		Rate Base														
1		Direct Net Plant		$1,051,372,747	$123,993,206	$ 681,045,438	$13,764,154	$ 1,071,825	$ 816,030	$ 118,378	$16,174,478	$ 74,986,816	$ 2,310,135	$40,257,969	$27,965,560	$ 6,771,296
2		Systems Allocable Net Plant		40,589,393	4,786,893	26,292,503	531,380	41,379	31,504	4,570	624,433	2,894,948	89,185	1,554,203	1,079,641	261,413
3		Cash Working Capital	1.1	(11,082,156)	(587,328)	(7,670,516)	(401,267)	(5,077)	(15,009)	(3,451)	(76,615)	(866,727)	(67,347)	(190,693)	(410,903)	(197,404)
4		Materials & Supplies	1.1	9,222,489	1,087,650	5,974,032	120,737	9,402	7,158	1,038	141,880	657,773	20,264	353,137	245,310	59,397
5		Prepayments	1.1	2,740,815	323,237	1,775,412	35,882	2,794	2,127	309	42,165	195,483	6,022	104,948	72,903	17,652
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-
7		Customer Deposits	8.0	(23,912,141)	-	(22,804,948)	-	-	(5,242)	-	-	(909,540)	-	-	(192,412)	-
8		Customer Advances	8.0	(7,027,372)	-	(6,701,987)	-	-	(1,541)	-	-	(267,298)	-	-	(56,547)	-
9		Deferred Taxes	1.1	(136,691,328)	(16,120,635)	(88,544,244)	(1,789,509)	(139,350)	(106,094)	(15,391)	(2,102,880)	(9,749,204)	(300,346)	(5,234,029)	(3,635,865)	(880,351)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-	-	-	-	-	-	-	-	-	-
11		Total Rate Base		$ 925,212,447	$113,483,024	$ 589,365,690	$12,261,378	$ 980,973	$ 728,934	$ 105,453	$14,803,461	$ 66,942,251	$ 2,057,913	$36,845,535	$25,067,688	$ 6,032,003
12		Net Operating Margin	Direct	$ 305,070,666	$131,352,292	$ 78,563,677	$ -	$ 770,456	$ 113,400	$ -	$18,198,521	$ 7,870,340	$ -	$38,173,087	$ 7,492,320	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 7,611,429	$ 3,277,204	$ 1,960,142	$ -	$ 19,223	$ 2,829	$ -	$ 454,048	$ 196,363	$ -	$ 952,408	$ 186,931	$ -
14		Late Charges	Direct	$ 1,386,957	597,173	357,178	-	3,503	516	-	82,737	35,781	-	173,548	34,063	-
15		Service Establishment Charges	Direct	$ 6,950,610	2,992,679	1,789,964	-	17,554	2,584	-	414,628	179,315	-	869,721	170,702	-
16		Reconnect / Reread Charges	Direct	$ 547,658	235,802	141,036	-	1,383	204	-	32,670	14,129	-	68,528	13,450	-
17		Other Revenue - Labor	Direct	$ 1,705	734	439	-	4	1	-	102	44	-	213	42	-
18		Other Revenue - Parts & Material	Direct	$ 5,764	2,482	1,484	-	15	2	-	344	149	-	721	142	-
19		Other Revenue - Field Collection Fee	Direct	$ 388,540	167,291	100,059	-	981	144	-	23,178	10,024	-	48,617	9,542	-
20		Other Revenue - Returned Item Fee	Direct	$ 135,450	58,320	34,882	-	342	50	-	8,080	3,494	-	16,949	3,327	-
21		Other Revenue - Rental Income	Net Op. Marg.	767,198	330,327	197,573	-	1,938	285	-	45,766	19,792	-	95,998	18,842	-
22		Total Revenue		322,865,978	139,014,304	83,146,435	-	815,398	120,015	-	19,260,073	8,329,431	-	40,399,791	7,929,360	-
23		O & M		(113,872,632)	(6,034,978)	(78,816,964)	(4,123,143)	(52,168)	(154,220)	(35,461)	(787,242)	(8,905,894)	(692,016)	(1,959,430)	(4,222,155)	(2,028,386)
24		A & G	Total O&M	(52,481,195)	(2,781,378)	(36,324,869)	(1,900,259)	(24,043)	(71,077)	(16,343)	(362,821)	(4,104,515)	(318,934)	(903,055)	(1,945,891)	(934,835)
25		Depreciation Expense		(75,949,648)	(8,957,090)	(49,197,738)	(994,303)	(77,427)	(58,949)	(8,551)	(1,168,421)	(5,416,939)	(166,881)	(2,908,177)	(2,020,192)	(489,149)
26		Interest on Customer Deposits	8.0	(717,364)	-	(684,148)	-	-	(157)	-	-	(27,286)	-	-	(5,772)	-
27		Taxes other than Income	1.1	(33,455,124)	(3,945,516)	(21,671,153)	(437,981)	(34,106)	(25,966)	(3,767)	(514,679)	(2,386,112)	(73,509)	(1,281,026)	(889,876)	(215,465)
		State Income Tax														
28		Taxable Income before Interest Exp.		$ 46,390,015	$117,295,342	$(103,548,437)	$(7,455,685)	$ 627,654	$(190,355)	$(64,122)	$16,426,911	$(12,511,315)	$(1,251,340)	$33,348,104	$(1,154,525)	$(3,667,835)
29		Interest Expense	1.1	(40,521,530)	(4,778,890)	(26,248,543)	(530,492)	(41,310)	(31,451)	(4,562)	(623,389)	(2,890,108)	(89,036)	(1,551,604)	(1,077,836)	(260,976)
30		State Taxable Income		$ 5,868,486	$112,516,452	$(129,796,981)	$(7,986,177)	$ 586,345	$(221,806)	$(68,685)	$15,803,521	$(15,401,423)	$(1,340,376)	$31,796,499	$(2,232,361)	$(3,928,811)
31		State Income Tax		408,916	7,840,146	(9,044,254)	(556,477)	40,856	(15,455)	(4,786)	1,101,189	(1,073,171)	(93,397)	2,215,580	(155,551)	(273,760)
32		South Georgia	1.1	77,020	9,083	49,891	1,008	79	60	9	1,185	5,493	169	2,949	2,049	496
33		State Income Tax		485,936	7,849,230	(8,994,363)	(555,468)	40,935	(15,396)	(4,777)	1,102,374	(1,067,678)	(93,228)	2,218,529	(153,502)	(273,264)
		Federal Income Tax														
34		Taxable Income before Interest Exp.		46,390,015	117,295,342	(103,548,437)	(7,455,685)	627,654	(190,355)	(64,122)	16,426,911	(12,511,315)	(1,251,340)	33,348,104	(1,154,525)	(3,667,835)
35		Interest Expense	1.1	(40,521,530)	(4,778,890)	(26,248,543)	(530,492)	(41,310)	(31,451)	(4,562)	(623,389)	(2,890,108)	(89,036)	(1,551,604)	(1,077,836)	(260,976)
36		Federal Taxable Income		5,868,486	112,516,452	(129,796,981)	(7,986,177)	586,345	(221,806)	(68,685)	15,803,521	(15,401,423)	(1,340,376)	31,796,499	(2,232,361)	(3,928,811)
37		Federal Income Tax		$ 1,910,849	$ 36,636,707	$(42,263,454)	$(2,600,395)	$ 190,921	$(72,223)	$(22,365)	$ 5,145,816	$(5,014,888)	$(436,443)	$10,353,322	$(726,884)	$(1,279,268)
38		I T C	1.1	(528,352)	(62,311)	(342,249)	(6,917)	(539)	(410)	(59)	(8,128)	(37,684)	(1,161)	(20,231)	(14,054)	(3,403)
39		South Georgia	1.1	288,233	33,993	186,708	3,773	294	224	32	4,434	20,558	633	11,037	7,667	1,856
40		Total Federal Income Tax		$ 1,670,730	$ 36,608,389	$(42,418,996)	$(2,603,538)	$ 190,676	$(72,409)	$(22,392)	$ 5,142,122	$(5,032,014)	$(436,970)	$10,344,127	$(733,271)	$(1,280,815)
41		Regulatory Amortization	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-
42		Net Income		$ 44,233,349	$ 72,837,723	$(52,135,079)	$(4,296,678)	$ 396,043	$(102,550)	$(36,953)	$10,182,414	$(6,411,623)	$(721,142)	$20,785,447	$(267,752)	$(2,113,757)
43		Rate of Return on Rate Base		4.78%	64.18%	(8.85%)	(35.04%)	40.37%	(14.07%)	(35.04%)	68.78%	(9.58%)	(35.04%)	56.41%	(1.07%)	(35.04%)
44		Rate of Return by Class Total				2.29%			14.13%			3.64%			27.09%	

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Line No.	Account No.	Description	Allocation Factor No.	Large General Gas Service Demand	Large General Gas Service Customer	Large General Gas Service Commodity	Gas Service to Armed Forces Demand	Gas Service to Armed Forces Customer	Gas Service to Armed Forces Commodity	Air-Conditioning Gas Service Demand	Air-Conditioning Gas Service Customer	Air-Conditioning Gas Service Commodity	CNG - Small Demand	CNG - Small Customer	CNG - Small Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Direct Depreciation Expense													
1	301-303	Intangible	Intang. Plant	$ 6,476	$ 672	$ 710	$ 861	$ 26	$ 31	$ 30	$ 39	$ 18	$ 6	$ 4	$ 2
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 1,923,082	$ 199,452	$ 210,908	$ 255,734	$ 7,861	$ 9,072	$ 8,877	$ 11,588	$ 5,258	$ 1,798	$ 1,099	$ 522
5	389-398	General	1.1	$ 148,668	$ 15,419	$ 16,305	$ 19,770	$ 608	$ 701	$ 686	$ 896	$ 406	$ 139	$ 85	$ 40
6		Total Direct Dep. Exp.		$ 2,078,225	$ 215,543	$ 227,923	$ 276,365	$ 8,495	$ 9,804	$ 9,593	$ 12,523	$ 5,682	$ 1,943	$ 1,188	$ 564
		Systems Allocable Depreciation Expense													
7	301-303	Intangible	Intang. Plant	$ 144,587	$ 14,996	$ 15,857	$ 19,227	$ 591	$ 682	$ 667	$ 871	$ 395	$ 135	$ 83	$ 39
8	389-398	General	1.1	$ 73,209	$ 7,593	$ 8,029	$ 9,735	$ 299	$ 345	$ 338	$ 441	$ 200	$ 68	$ 42	$ 20
		System Allocable Amortization													
9		Miscellaneous Intangible	1.1	-	-	-	-	-	-	-	-	-	-	-	-
10		Structures-Leasehold Improvements	1.1	-	-	-	-	-	-	-	-	-	-	-	-
11		Total System Allocable Amortization		-	-	-	-	-	-	-	-	-	-	-	-
12		Total System Alloc Dep. Exp. & Amortization		217,795	22,589	23,886	28,963	890	1,027	1,005	1,312	595	204	124	59
13		Total Depreciation Expense		2,296,020	238,132	251,809	305,328	9,385	10,831	10,599	13,835	6,278	2,147	1,312	623
14		Amortization-Limited Term Gas Plant	1.1	-	-	-	-	-	-	-	-	-	-	-	-
15		Amortization-Gas Plant Acquisition	1.1	(1,634)	(169)	(179)	(217)	(7)	(8)	(8)	(10)	(4)	(2)	(1)	(0)
16		Amortization of PBOP Costs	1.1	10,409	1,080	1,142	1,384	43	49	48	63	28	10	6	3
17		Amortization of Service Investigation	7.0	-	-	-	-	-	-	-	-	-	-	-	-
18		Amortization of TRIMP Costs	1.1	36,492	3,785	4,002	4,853	149	172	168	220	100	34	21	10
19		Amortization of SOX Implementation	1.1	843	87	92	112	3	4	4	5	2	1	0	0
20		Total Depreciation & Amortization Expense		$ 2,342,129	$ 242,914	$ 256,866	$ 311,460	$ 9,574	$ 11,049	$ 10,812	$ 14,113	$ 6,404	$ 2,190	$ 1,339	$ 636

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Line No.	Account No.	Description	Allocation Factor No.	Large General Gas Service Demand	Large General Gas Service Customer	Large General Gas Service Commodity	Gas Service to Armed Forces Demand	Gas Service to Armed Forces Customer	Gas Service to Armed Forces Commodity	Air-Conditioning Gas Service Demand	Air-Conditioning Gas Service Customer	Air-Conditioning Gas Service Commodity	Demand	CNG - Small Customer	CNG - Small Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Operation and Maintenance Expense													
		Gas Supply Expense													
1	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-	-	-	-	-	-	-	-	-
3	805	Purchased Gas Cost Adj.	3.0	-	-	-	-	-	-	-	-	-	-	-	-
4	810	Gas Used for Compressor Sta. Fuel--	3.0	-	-	-	-	-	-	-	-	-	-	-	-
5	813	Other Gas Supply Expense	3.0	-	-	-	-	-	-	-	-	-	-	-	-
6		Labor & Labor Loading	3.0	-	-	83,082	-	-	3,574	-	-	2,071	-	-	206
7		Materials & Expenses	3.0	-	-	6,956	-	-	299	-	-	173	-	-	17
8		Total Gas Supply Expense		$ -	$ -	$ 90,038	$ -	$ -	$ 3,873	$ -	$ -	$ 2,245	$ -	$ -	$ 223
		Transmission Expenses													
9	850	Operation Supervision & Engin.													
10		Labor & Labor Loading	5.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11		Materials & Expenses	5.0	-	-	-	-	-	-	-	-	-	-	-	-
12	851	System Control & Load Dispatch													
13		Labor & Labor Loading	3.0	-	-	-	-	-	-	-	-	-	-	-	-
14		Materials & Expenses	3.0	-	-	-	-	-	-	-	-	-	-	-	-
15	852	Communication System Exp.													
16		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-
17		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-
18	853	Compressor Station													
19		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-
20		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-
21	854	Gas for Compressor Station Fuel	3.0	-	-	-	-	-	-	-	-	-	-	-	-
22	856	Mains Expense													
23		Labor & Labor Loading	6.0	-	-	-	-	-	-	-	-	-	-	-	-
24		Materials & Expenses	6.0	-	-	-	-	-	-	-	-	-	-	-	-
25	857	Meas. & Res. Sta. Exp.													
26		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-
27		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-
28	858	Trans. & comp. of Gas by Others	3.0	-	-	-	-	-	-	-	-	-	-	-	-
29	860	Rents	1.0	-	-	-	-	-	-	-	-	-	-	-	-
30	861	Maint. Supervision & Eng.													
31		Labor & Labor Loading	7.0	-	-	-	-	-	-	-	-	-	-	-	-
32		Materials & Expenses	7.0	-	-	-	-	-	-	-	-	-	-	-	-
33	862	Maint. of Struct. & Imp.	1.0	-	-	-	-	-	-	-	-	-	-	-	-
34	863	Maint. of Mains													
35		Labor & Labor Loading	6.0	-	-	-	-	-	-	-	-	-	-	-	-
36		Materials & Expenses	6.0	-	-	-	-	-	-	-	-	-	-	-	-
37	864	Maint. of Comp. Sta. Equip.													
38		Labor & Labor Loading	3.0	-	-	-	-	-	-	-	-	-	-	-	-
39		Materials & Expenses	3.0	-	-	-	-	-	-	-	-	-	-	-	-
40	865	Maint. of Meas. & Reg. Sta. Equip.													
41		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-
42		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-
43		Total Transmission Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Distribution Expenses													
1	870	Operation Supervision & Eng.													
2		Labor & Labor Loading	5.5	$ 102,097	$ 68,006	$ 103,959	$ 13,577	$ 2,091	$ 4,472	$ 471	$ 832	$ 2,592	$ 95	$ 120	$ 257
3		Materials & Expenses	5.5	15,977	10,642	16,269	2,125	327	700	74	130	406	15	19	40
4	871	Distribution Load Dispatching													
5		Labor & Labor Loading	3.0	-	-	64,627	-	-	2,780	-	-	1,611	-	-	160
6		Materials & Expenses	3.0	-	-	15,679	-	-	674	-	-	391	-	-	39
7	874	Mains & Svcs. Expense													
8		Labor & Labor Loading	4.4	190,647	5,630	0	25,353	368	0	880	1,100	0	178	94	0
9		Materials & Expenses	4.4	215,684	6,369	0	28,682	416	0	996	1,245	0	202	107	0
10	875	Meas. & Reg. Sta. Exp.-Gen.													
11		Labor & Labor Loading	3.0	-	-	238,855	-	-	10,274	-	-	5,955	-	-	591
12		Materials & Expenses	3.0	-	-	94,582	-	-	4,068	-	-	2,358	-	-	234
13	878	Meter & House Reg. Exp.													
14		Labor & Labor Loading	6.0	-	102,936	-	-	2,999	-	-	384	-	-	110	-
15		Materials & Expenses	6.0	-	15,540	-	-	453	-	-	58	-	-	17	-
16	879	Customer Installation Exp.													
17		Labor & Labor Loading	6.0	-	121,653	-	-	3,544	-	-	454	-	-	130	-
18		Materials & Expenses	6.0	-	18,525	-	-	540	-	-	69	-	-	20	-
19	880	Other Expenses													
20		Labor & Labor Loading	5.5	87,844	58,512	89,446	11,682	1,799	3,847	406	716	2,230	82	103	221
21		Materials & Expenses	5.5	59,500	39,633	60,586	7,912	1,218	2,606	275	485	1,510	56	70	150
22	881	Rents	5.5	27,644	18,413	28,148	3,676	566	1,211	128	225	702	26	32	70
23		Total Distribution-Operations		$ 699,393	$ 465,860	$ 712,149	$ 93,006	$ 14,321	$ 30,632	$ 3,229	$ 5,697	$ 17,754	$ 654	$ 821	$ 1,762
		Operation and Maintenance Expense													
		Distribution Expenses													
24	885	Maint. Supervision & Eng.													
25		Labor & Labor Loading	6.6	$ 73,260	$ 5,379	$ 21,926	$ 9,742	$ 237	$ 943	$ 338	$ 442	$ 547	$ 68	$ 40	$ 54
26		Materials & Expenses	6.6	7,863	577	2,353	1,046	25	101	36	47	59	7	4	6
27	886	Maint. of Structures & Imp.													
28		Labor & Labor Loading	1.0	1,966	-	-	261	-	-	9	-	-	2	-	-
29		Materials & Expenses	1.0	7,287	-	-	969	-	-	34	-	-	7	-	-
30	887	Maint. of Mains													
31		Labor & Labor Loading	2.2	435,429	782	0	57,904	47	0	2,010	194	0	407	114	0
32		Materials & Expenses	2.2	346,842	623	0	46,124	37	0	1,601	154	0	324	91	0
33	889	Maint. of Meas. & Reg. Sta-Gen													
34		Labor & Labor Loading	3.0	-	-	135,977	-	-	5,849	-	-	3,390	-	-	337
35		Materials & Expenses	3.0	-	-	100,920	-	-	4,341	-	-	2,516	-	-	250
36	892	Maint. of Services													
37		Labor & Labor Loading	3.3	0	14,476	-	0	952	-	0	2,780	-	0	121	-
38		Materials & Expenses	3.3	0	7,920	-	0	521	-	0	1,521	-	0	66	-
39	893	Maint of Meter & House Reg.													
40		Labor & Labor Loading	6.0	-	20,008	-	-	583	-	-	75	-	-	21	-
41		Materials & Expenses	6.0	-	14,302	-	-	417	-	-	53	-	-	15	-
42	894	Maint of Other Equip.													
43		Labor & Labor Loading	6.6	4,638	341	1,388	617	15	60	21	28	35	4	3	3
44		Materials & Expenses	6.6	1,367	100	409	182	4	18	6	8	10	1	1	1
45		Total Distribution-Maintenance		$ 878,652	$ 64,509	$ 262,974	$ 116,844	$ 2,837	$ 11,311	$ 4,056	$ 5,303	$ 6,556	$ 822	$ 476	$ 651
46		Total Distribution O & M		$ 1,578,046	$ 530,368	$ 975,124	$ 209,851	$ 17,158	$ 41,944	$ 7,285	$ 11,000	$ 24,310	$ 1,475	$ 1,297	$ 2,413

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Customer Accounts Expenses													
1	901	Supervision													
2		Labor & Labor Loading	10.1	$ -	$ 2,325	$ -	$ -	$ 515	$ -	$ -	$ 874	$ -	$ -	$ 255	$ -
3		Materials & Expenses	10.1	-	142	-	-	31	-	-	53	-	-	16	-
4	902	Meter Reading Exp.													
5		Labor & Labor Loading	13.0	-	3,466	-	-	775	-	-	1,309	-	-	379	-
6		Materials & Expenses	13.0	-	869	-	-	194	-	-	328	-	-	95	-
7	903	Customer Records & Collections													
8		Labor & Labor Loading	13.0	-	9,577	-	-	2,141	-	-	3,615	-	-	1,046	-
9		Materials & Expenses	13.0	-	4,461	-	-	997	-	-	1,684	-	-	487	-
10	903	Customer Records & Collections - LCS													
11		Labor & Labor Loading - LCS	13.0	-	728	-	-	163	-	-	275	-	-	80	-
12		Materials & Expenses - LCS	13.0	-	32	-	-	7	-	-	12	-	-	4	-
13	904	Uncollectible Accounts Exp.	4.0	-	262	-	-	16	-	-	65	-	-	38	-
14	905	Misc. Customer Accounts Exp.													
15		Labor & Labor Loading	10.1	-	243	-	-	54	-	-	91	-	-	27	-
16		Materials & Expenses	10.1	-	14	-	-	3	-	-	5	-	-	2	-
17		Total Customer Accounts Expenses		$ -	$ 22,119	$ -	$ -	$ 4,895	$ -	$ -	$ 8,311	$ -	$ -	$ 2,428	$ -
		Customer Service & Info. Exp.													
18	908	Customer Assistance Exp.													
19		Labor & Labor Loading	13.0	$ -	$ 186	$ -	$ -	$ 42	$ -	$ -	$ 70	$ -	$ -	$ 20	$ -
20		Materials & Expenses	13.0	-	168	-	-	38	-	-	63	-	-	18	-
21	909	Info. & Instructional Exp.													
22		Labor & Labor Loading	13.0	-	-	-	-	-	-	-	-	-	-	-	-
23		Materials & Expenses	13.0	-	-	-	-	-	-	-	-	-	-	-	-
24	910	Misc. C.S. & I. Expense													
25		Labor & Labor Loading	13.0	-	1	-	-	0	-	-	0	-	-	0	-
26		Materials & Expenses	13.0	-	16	-	-	4	-	-	6	-	-	2	-
27		Total Customer Service & Info. Exp.		$ -	$ 371	$ -	$ -	$ 83	$ -	$ -	$ 140	$ -	$ -	$ 40	$ -
		Sales Expense													
28	911	Supervision													
29		Labor & Labor Loading	4.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30		Materials & Expenses	4.0	-	-	-	-	-	-	-	-	-	-	-	-
31	912	Demonstrating & Selling Exp.													
32		Labor & Labor Loading	4.0	-	-	-	-	-	-	-	-	-	-	-	-
33		Materials & Expenses	4.0	-	-	-	-	-	-	-	-	-	-	-	-
34	913	Advertising Expense													
35		Labor & Labor Loading	4.0	-	-	-	-	-	-	-	-	-	-	-	-
36		Materials & Expenses	4.0	-	-	-	-	-	-	-	-	-	-	-	-
37		Total Sales Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38		Total O & M Expense		$ 1,578,046	$ 552,858	$ 1,065,162	$ 209,851	$ 22,136	$ 45,816	$ 7,285	$ 19,451	$ 26,555	$ 1,475	$ 3,766	$ 2,636
39		Allocation Percentage	Total O&M	1.39%	0.49%	0.94%	0.18%	0.02%	0.04%	0.01%	0.02%	0.02%	0.00%	0.00%	0.00%
		Other Operating Deductions													
40		Administrative & General Expense	Total O&M	727,284	254,799	490,908	96,715	10,202	21,116	3,357	8,964	12,238	680	1,735	1,215
41		Interest on Customer Deposits	8.0	-	-	-	-	-	-	-	-	-	-	-	-
42		Taxes Other Than Income	1.1	1,031,686	107,001	113,147	137,195	4,217	4,867	4,762	6,217	2,821	965	590	280
43		Total Allocated Operating Deductions		$ 3,337,016	$ 914,658	$ 1,669,217	$ 443,761	$ 36,555	$ 71,799	$ 15,404	$ 34,632	$ 41,614	$ 3,120	$ 6,091	$ 4,131
		Tax Adjustments													
44		Interest Expense	1.1	1,249,600	129,602	137,046	166,174	5,108	5,895	5,768	7,530	3,417	1,168	714	339
45		State South Georgia	1.1	2,375	246	260	316	10	11	11	14	6	2	1	1
46		Investment Tax Credit	1.1	(16,293)	(1,690)	(1,787)	(2,167)	(67)	(77)	(75)	(98)	(45)	(15)	(9)	(4)
47		Federal South Georgia	1.1	8,889	922	975	1,182	36	42	41	54	24	8	5	2

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	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Summary of Allocated Cost of Service													
		Rate Base													
1		Direct Net Plant		$32,422,151	$ 3,362,663	$ 3,555,796	$ 4,311,544	$ 132,531	$ 152,947	$ 149,666	$ 195,367	$ 88,646	$ 30,315	$ 18,529	$ 8,800
2		Systems Allocable Net Plant		1,251,693	129,819	137,275	166,452	5,116	5,905	5,778	7,542	3,422	1,170	715	340
3		Cash Working Capital	1.1	(153,576)	(53,804)	(103,662)	(20,423)	(2,154)	(4,459)	(709)	(1,893)	(2,584)	(144)	(366)	(257)
4		Materials & Supplies	1.1	284,402	29,497	31,191	37,820	1,163	1,342	1,313	1,714	778	266	163	77
5		Prepayments	1.1	84,521	8,766	9,270	11,240	345	399	390	509	231	79	48	23
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-	-	-	-	-	-	-	-	-
7		Customer Deposits	8.0	-	-	-	-	-	-	-	-	-	-	-	-
8		Customer Advances	8.0	-	-	-	-	-	-	-	-	-	-	-	-
9		Deferred Taxes	1.1	(4,215,277)	(437,187)	(462,297)	(560,553)	(17,231)	(19,885)	(19,458)	(25,400)	(11,525)	(3,941)	(2,409)	(1,144)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-	-	-	-	-	-	-	-	-
11		Total Rate Base		$29,673,914	$ 3,039,754	$ 3,167,573	$ 3,946,079	$ 119,770	$ 136,249	$ 136,980	$ 177,839	$ 78,968	$ 27,745	$ 16,680	$ 7,839
12		Net Operating Margin	Direct	$12,641,232	$ 906,000	$ -	$ 600,979	$ 37,800	$ -	$ 139,816	$ 27,400	$ -	$ 24,257	$ 5,280	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 315,395	$ 22,604	$ -	$ 14,994	$ 943	$ -	$ 3,488	$ 684	$ -	$ 605	$ 132	$ -
14		Late Charges	Direct	57,471	4,119	-	2,732	172	-	636	125	-	110	24	-
15		Service Establishment Charges	Direct	288,013	20,642	-	13,692	861	-	3,186	624	-	553	120	-
16		Reconnect / Reread Charges	Direct	22,693	1,626	-	1,079	68	-	251	49	-	44	9	-
17		Other Revenue - Labor	Direct	71	5	-	3	0	-	1	0	-	0	0	-
18		Other Revenue - Parts & Material	Direct	239	17	-	11	1	-	3	1	-	0	0	-
19		Other Revenue - Field Collection Fee	Direct	16,100	1,154	-	765	48	-	178	35	-	31	7	-
20		Other Revenue - Returned Item Fee	Direct	5,613	402	-	267	17	-	62	12	-	11	2	-
21		Other Revenue - Rental Income	Net Op. Marg.	31,790	2,278	-	1,511	95	-	352	69	-	61	13	-
22		Total Revenue		13,378,617	958,849	-	636,035	40,005	-	147,972	28,998	-	25,672	5,588	-
23		O & M		(1,578,046)	(552,858)	(1,065,162)	(209,851)	(22,136)	(45,816)	(7,285)	(19,451)	(26,555)	(1,475)	(3,766)	(2,636)
24		A & G	Total O&M	(727,284)	(254,799)	(490,908)	(96,715)	(10,202)	(21,116)	(3,357)	(8,964)	(12,238)	(680)	(1,735)	(1,215)
25		Depreciation Expense		(2,342,129)	(242,914)	(256,866)	(311,460)	(9,574)	(11,049)	(10,812)	(14,113)	(6,404)	(2,190)	(1,339)	(636)
26		Interest on Customer Deposits	8.0	-	-	-	-	-	-	-	-	-	-	-	-
27		Taxes other than Income	1.1	(1,031,686)	(107,001)	(113,147)	(137,195)	(4,217)	(4,867)	(4,762)	(6,217)	(2,821)	(965)	(590)	(280)
		State Income Tax													
28		Taxable Income before Interest Exp.		$ 7,699,472	$(198,723)	$(1,926,082)	$(119,186)	$(6,124)	$(82,848)	$ 121,756	$(19,746)	$(48,017)	$ 20,362	$(1,841)	$(4,767)
29		Interest Expense	1.1	(1,249,600)	(129,602)	(137,046)	(166,174)	(5,108)	(5,895)	(5,768)	(7,530)	(3,417)	(1,168)	(714)	(339)
30		State Taxable Income		$ 6,449,872	$(328,326)	$(2,063,128)	$(285,359)	$(11,232)	$(88,743)	$ 115,987	$(27,276)	$(51,434)	$ 19,193	$(2,555)	$(5,106)
31		State Income Tax		449,427	(22,878)	(143,759)	(19,884)	(783)	(6,184)	8,082	(1,901)	(3,584)	1,337	(178)	(356)
32		South Georgia	1.1	2,375	246	260	316	10	11	11	14	6	2	1	1
33		State Income Tax		451,802	(22,631)	(143,498)	(19,568)	(773)	(6,172)	8,093	(1,886)	(3,577)	1,340	(177)	(355)
		Federal Income Tax													
34		Taxable Income before Interest Exp.		7,699,472	(198,723)	(1,926,082)	(119,186)	(6,124)	(82,848)	121,756	(19,746)	(48,017)	20,362	(1,841)	(4,767)
35		Interest Expense	1.1	(1,249,600)	(129,602)	(137,046)	(166,174)	(5,108)	(5,895)	(5,768)	(7,530)	(3,417)	(1,168)	(714)	(339)
36		Federal Taxable Income		6,449,872	(328,326)	(2,063,128)	(285,359)	(11,232)	(88,743)	115,987	(27,276)	(51,434)	19,193	(2,555)	(5,106)
37		Federal Income Tax		$ 2,100,156	$(106,907)	$(671,779)	$(92,916)	$(3,657)	$(28,896)	$ 37,767	$(8,881)	$(16,748)	$ 6,250	$(832)	$(1,663)
38		I T C	1.1	(16,293)	(1,690)	(1,787)	(2,167)	(67)	(77)	(75)	(98)	(45)	(15)	(9)	(4)
39		South Georgia	1.1	8,889	922	975	1,182	36	42	41	54	24	8	5	2
40		Total Federal Income Tax		$ 2,092,751	$(107,675)	$(672,591)	$(93,901)	$(3,688)	$(28,931)	$ 37,733	$(8,926)	$(16,768)	$ 6,243	$(836)	$(1,665)
41		Regulatory Amortization	1.1	-	-	-	-	-	-	-	-	-	-	-	-
42		Net Income		$ 5,154,919	$(68,417)	$(1,109,993)	$(5,717)	$(1,664)	$(47,745)	$ 75,930	$(8,934)	$(27,672)	$ 12,780	$(828)	$(2,747)
43		Rate of Return on Rate Base		17.37%	(2.25%)	(35.04%)	(0.14%)	(1.39%)	(35.04%)	55.43%	(5.02%)	(35.04%)	46.06%	(4.97%)	(35.04%)
44		Rate of Return by Class Total			11.08%			(1.31%)			9.99%			17.61%	

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
AUGUST 31, 2004

Line No.	Account No.	Description	Allocation Factor No.	CNG - Large Demand	CNG - Large Customer	CNG - Large Commodity	CNG - Residential Demand	CNG - Residential Customer	CNG - Residential Commodity	Cogeneration Gas Service Demand	Cogeneration Gas Service Customer	Cogeneration Gas Service Commodity	Small Essential Agr. User Gas Service Demand	Small Essential Agr. User Gas Service Customer	Small Essential Agr. User Gas Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Direct Depreciation Expense													
1	301-303	Intangible	Intang. Plant	$ 56	$ 95	$ 18	$ 3	$ 18	$ 1	$ 495	$ 41	$ 145	$ 703	$ 138	$ 121
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 16,701	$ 28,244	$ 5,436	$ 821	$ 5,211	$ 228	$ 146,861	$ 12,067	$ 42,967	$ 208,916	$ 40,910	$ 36,014
5	389-398	General	1.1	$ 1,291	$ 2,183	$ 420	$ 63	$ 403	$ 18	$ 11,353	$ 933	$ 3,322	$ 16,151	$ 3,163	$ 2,784
6		Total Direct Dep. Exp.		$ 18,049	$ 30,523	$ 5,875	$ 888	$ 5,631	$ 247	$ 158,709	$ 13,041	$ 46,433	$ 225,771	$ 44,210	$ 38,919
		Systems Allocable Depreciation Expense													
7	301-303	Intangible	Intang. Plant	$ 1,256	$ 2,124	$ 409	$ 62	$ 392	$ 17	$ 11,042	$ 907	$ 3,230	$ 15,707	$ 3,076	$ 2,708
8	389-398	General	1.1	$ 636	$ 1,075	$ 207	$ 31	$ 198	$ 9	$ 5,591	$ 459	$ 1,636	$ 7,953	$ 1,557	$ 1,371
		System Allocable Amortization													
9		Miscellaneous Intangible	1.1	-	-	-	-	-	-	-	-	-	-	-	-
10		Structures-Leasehold Improvements	1.1	-	-	-	-	-	-	-	-	-	-	-	-
11		Total System Allocable Amortization		-	-	-	-	-	-	-	-	-	-	-	-
12		Total System Alloc Dep. Exp. & Amortization		1,891	3,199	616	93	590	26	16,633	1,367	4,866	23,660	4,633	4,079
13		Total Depreciation Expense		19,940	33,722	6,490	981	6,221	272	175,342	14,407	51,299	249,431	48,843	42,998
14		Amortization-Limited Term Gas Plant	1.1	-	-	-	-	-	-	-	-	-	-	-	-
15		Amortization-Gas Plant Acquisition	1.1	(14)	(24)	(5)	(1)	(4)	(0)	(125)	(10)	(37)	(178)	(35)	(31)
16		Amortization of PBOP Costs	1.1	90	153	29	4	28	1	795	65	233	1,131	221	195
17		Amortization of Service Investigation	7.0	-	-	-	-	-	-	-	-	-	-	-	-
18		Amortization of TRIMP Costs	1.1	317	536	103	16	99	4	2,787	229	815	3,964	776	683
19		Amortization of SOX Implementation	1.1	7	12	2	0	2	0	64	5	19	92	18	16
20		Total Depreciation & Amortization Expense		$ 20,341	$ 34,399	$ 6,621	$ 1,000	$ 6,346	$ 278	$ 178,863	$ 14,697	$ 52,329	$ 254,440	$ 49,824	$ 43,861

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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AUGUST 31, 2004

Line No.	Account No.	Description	Allocation Factor No.	CNG - Large Demand	CNG - Large Customer	CNG - Large Commodity	CNG - Residential Demand	CNG - Residential Customer	CNG - Residential Commodity	Cogeneration Gas Service Demand	Cogeneration Gas Service Customer	Cogeneration Gas Service Commodity	Small Essential Agr. User Gas Service Demand	Small Essential Agr. User Gas Service Customer	Small Essential Agr. User Gas Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Operation and Maintenance Expense													
		Gas Supply Expense													
1	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-	-	-	-	-	-	-	-	-
3	805	Purchased Gas Cost Adj.	3.0	-	-	-	-	-	-	-	-	-	-	-	-
4	810	Gas Used for Compressor Sta. Fuel--	3.0	-	-	-	-	-	-	-	-	-	-	-	-
5	813	Other Gas Supply Expense	3.0	-	-	-	-	-	-	-	-	-	-	-	-
6		Labor & Labor Loading	3.0	-	-	2,141	-	-	90	-	-	16,926	-	-	14,187
7		Materials & Expenses	3.0	-	-	179	-	-	8	-	-	1,417	-	-	1,188
8		Total Gas Supply Expense		$ -	$ -	$ 2,321	$ -	$ -	$ 97	$ -	$ -	$ 18,343	$ -	$ -	$ 15,375
		Transmission Expenses													
9	850	Operation Supervision & Engin.													
10		Labor & Labor Loading	5.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11		Materials & Expenses	5.0	-	-	-	-	-	-	-	-	-	-	-	-
12	851	System Control & Load Dispatch													
13		Labor & Labor Loading	3.0	-	-	-	-	-	-	-	-	-	-	-	-
14		Materials & Expenses	3.0	-	-	-	-	-	-	-	-	-	-	-	-
15	852	Communication System Exp.													
16		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-
17		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-
18	853	Compressor Station													
19		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-
20		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-
21	854	Gas for Compressor Station Fuel	3.0	-	-	-	-	-	-	-	-	-	-	-	-
22	856	Mains Expense													
23		Labor & Labor Loading	6.0	-	-	-	-	-	-	-	-	-	-	-	-
24		Materials & Expenses	6.0	-	-	-	-	-	-	-	-	-	-	-	-
25	857	Meas. & Res. Sta. Exp.													
26		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-
27		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-
28	858	Trans. & comp. of Gas by Others	3.0	-	-	-	-	-	-	-	-	-	-	-	-
29	860	Rents	1.0	-	-	-	-	-	-	-	-	-	-	-	-
30	861	Maint. Supervision & Eng.													
31		Labor & Labor Loading	7.0	-	-	-	-	-	-	-	-	-	-	-	-
32		Materials & Expenses	7.0	-	-	-	-	-	-	-	-	-	-	-	-
33	862	Maint. of Struct. & Imp.	1.0	-	-	-	-	-	-	-	-	-	-	-	-
34	863	Maint. of Mains													
35		Labor & Labor Loading	6.0	-	-	-	-	-	-	-	-	-	-	-	-
36		Materials & Expenses	6.0	-	-	-	-	-	-	-	-	-	-	-	-
37	864	Maint. of Comp. Sta. Equip.													
38		Labor & Labor Loading	3.0	-	-	-	-	-	-	-	-	-	-	-	-
39		Materials & Expenses	3.0	-	-	-	-	-	-	-	-	-	-	-	-
40	865	Maint. of Meas. & Reg. Sta. Equip.													
41		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-
42		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-
43		Total Transmission Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
AUGUST 31, 2004

Line No.	Account No.	Description	Allocation Factor No.	CNG - Large Demand	CNG - Large Customer	CNG - Large Commodity	CNG - Residential Demand	CNG - Residential Customer	CNG - Residential Commodity	Cogeneration Gas Service Demand	Cogeneration Gas Service Customer	Cogeneration Gas Service Commodity	Small Essential Agr. User Gas Service Demand	Small Essential Agr. User Gas Service Customer	Small Essential Agr. User Gas Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Distribution Expenses													
1	870	Operation Supervision & Eng.													
2		Labor & Labor Loading	5.5	$ 887	$ 8,308	$ 2,680	$ 44	$ 567	$ 112	$ 7,797	$ 2,218	$ 21,179	$ 11,091	$ 8,616	$ 17,752
3		Materials & Expenses	5.5	139	1,300	419	7	89	18	1,220	347	3,314	1,736	1,348	2,778
4	871	Distribution Load Dispatching													
5		Labor & Labor Loading	3.0	-	-	1,666	-	-	70	-	-	13,166	-	-	11,035
6		Materials & Expenses	3.0	-	-	404	-	-	17	-	-	3,194	-	-	2,677
7	874	Mains & Svcs. Expense													
8		Labor & Labor Loading	4.4	1,656	1,125	0	81	447	0	14,559	811	0	20,711	2,476	0
9		Materials & Expenses	4.4	1,873	1,273	0	92	505	0	16,471	917	0	23,431	2,802	0
10	875	Meas. & Reg. Sta. Exp.-Gen.													
11		Labor & Labor Loading	3.0	-	-	6,157	-	-	258	-	-	48,660	-	-	40,786
12		Materials & Expenses	3.0	-	-	2,438	-	-	102	-	-	19,268	-	-	16,150
13	878	Meter & House Reg. Exp.													
14		Labor & Labor Loading	6.0	-	12,205	-	-	519	-	-	2,825	-	-	11,546	-
15		Materials & Expenses	6.0	-	1,843	-	-	78	-	-	427	-	-	1,743	-
16	879	Customer Installation Exp.													
17		Labor & Labor Loading	6.0	-	14,424	-	-	614	-	-	3,339	-	-	13,645	-
18		Materials & Expenses	6.0	-	2,196	-	-	93	-	-	508	-	-	2,078	-
19	880	Other Expenses													
20		Labor & Labor Loading	5.5	763	7,148	2,305	38	488	97	6,708	1,908	18,222	9,543	7,413	15,273
21		Materials & Expenses	5.5	517	4,842	1,562	25	331	66	4,544	1,293	12,343	6,464	5,021	10,345
22	881	Rents	5.5	240	2,249	726	12	154	30	2,111	601	5,734	3,003	2,333	4,806
23		Total Distribution-Operations		$ 6,074	$ 56,913	$ 18,356	$ 299	$ 3,885	$ 771	$ 53,411	$ 15,193	$ 145,080	$ 75,979	$ 59,022	$ 121,604
		Operation and Maintenance Expense													
		Distribution Expenses													
24	885	Maint. Supervision & Eng.													
25		Labor & Labor Loading	6.6	$ 636	$ 817	$ 565	$ 31	$ 188	$ 24	$ 5,595	$ 404	$ 4,467	$ 7,959	$ 1,324	$ 3,744
26		Materials & Expenses	6.6	68	88	61	3	20	3	601	43	479	854	142	402
27	886	Maint. of Structures & Imp.													
28		Labor & Labor Loading	1.0	17	-	-	1	-	-	150	-	-	214	-	-
29		Materials & Expenses	1.0	63	-	-	3	-	-	557	-	-	792	-	-
30	887	Maint. of Mains													
31		Labor & Labor Loading	2.2	3,782	140	0	186	570	0	33,253	119	0	47,303	582	0
32		Materials & Expenses	2.2	3,012	111	0	148	454	0	26,488	95	0	37,680	463	0
33	889	Maint. of Meas. & Reg. Sta-Gen													
34		Labor & Labor Loading	3.0	-	-	3,505	-	-	147	-	-	27,701	-	-	23,219
35		Materials & Expenses	3.0	-	-	2,601	-	-	109	-	-	20,560	-	-	17,233
36	892	Maint. of Services													
37		Labor & Labor Loading	3.3	0	2,912	-	0	540	-	0	2,077	-	0	6,083	-
38		Materials & Expenses	3.3	0	1,593	-	0	295	-	0	1,136	-	0	3,328	-
39	893	Maint of Meter & House Reg.													
40		Labor & Labor Loading	6.0	-	2,372	-	-	101	-	-	549	-	-	2,244	-
41		Materials & Expenses	6.0	-	1,696	-	-	72	-	-	393	-	-	1,604	-
42	894	Maint of Other Equip.													
43		Labor & Labor Loading	6.6	40	52	36	2	12	2	354	26	283	504	84	237
44		Materials & Expenses	6.6	12	15	11	1	4	0	104	8	83	149	25	70
45		Total Distribution-Maintenance		$ 7,631	$ 9,796	$ 6,778	$ 375	$ 2,256	$ 285	$ 67,101	$ 4,849	$ 53,574	$ 95,454	$ 15,879	$ 44,905
46		Total Distribution O & M		$ 13,705	$ 66,709	$ 25,134	$ 674	$ 6,141	$ 1,055	$ 120,512	$ 20,043	$ 198,654	$ 171,433	$ 74,900	$ 166,508

SOUTHWEST GAS CORPORATION
ARIZONA
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Line No.	Account No. (a)	Description (b)	Allocation Factor No. (c)	CNG - Large Demand (d)	CNG - Large Customer (e)	CNG - Large Commodity (f)	CNG - Residential Demand (g)	CNG - Residential Customer (h)	CNG - Residential Commodity (i)	Cogeneration Gas Service Demand (j)	Cogeneration Gas Service Customer (k)	Cogeneration Gas Service Commodity (l)	Small Essential Agr. User Gas Service Demand (m)	Small Essential Agr. User Gas Service Customer (n)	Small Essential Agr. User Gas Service Commodity (o)
		Customer Accounts Expenses													
1	901	Supervision													
2		Labor & Labor Loading	10.1	$ -	$ 416	$ -	$ -	$ 421	$ -	$ -	$ 354	$ -	$ -	$ 12,783	$ -
3		Materials & Expenses	10.1	-	25	-	-	26	-	-	22	-	-	781	-
4	902	Meter Reading Exp.													
5		Labor & Labor Loading	13.0	-	620	-	-	601	-	-	528	-	-	19,284	-
6		Materials & Expenses	13.0	-	155	-	-	151	-	-	132	-	-	4,833	-
7	903	Customer Records & Collections													
8		Labor & Labor Loading	13.0	-	1,712	-	-	1,661	-	-	1,459	-	-	53,276	-
9		Materials & Expenses	13.0	-	798	-	-	774	-	-	679	-	-	24,816	-
10	903	Customer Records & Collections - LCS													
11		Labor & Labor Loading - LCS	13.0	-	130	-	-	126	-	-	111	-	-	4,049	-
12		Materials & Expenses - LCS	13.0	-	6	-	-	6	-	-	5	-	-	180	-
13	904	Uncollectible Accounts Exp.	4.0	-	47	-	-	191	-	-	40	-	-	195	-
14	905	Misc. Customer Accounts Exp.													
15		Labor & Labor Loading	10.1	-	43	-	-	44	-	-	37	-	-	1,333	-
16		Materials & Expenses	10.1	-	2	-	-	2	-	-	2	-	-	76	-
17		Total Customer Accounts Expenses		$ -	$ 3,955	$ -	$ -	$ 4,002	$ -	$ -	$ 3,369	$ -	$ -	$ 121,605	$ -
		Customer Service & Info. Exp.													
18	908	Customer Assistance Exp.													
19		Labor & Labor Loading	13.0	$ -	$ 33	$ -	$ -	$ 32	$ -	$ -	$ 28	$ -	$ -	$ 1,035	$ -
20		Materials & Expenses	13.0	-	30	-	-	29	-	-	26	-	-	934	-
21	909	Info. & Instructional Exp.													
22		Labor & Labor Loading	13.0	-	-	-	-	-	-	-	-	-	-	-	-
23		Materials & Expenses	13.0	-	-	-	-	-	-	-	-	-	-	-	-
24	910	Misc. C.S. & I. Expense													
25		Labor & Labor Loading	13.0	-	0	-	-	0	-	-	0	-	-	3	-
26		Materials & Expenses	13.0	-	3	-	-	3	-	-	2	-	-	90	-
27		Total Customer Service & Info. Exp.		$ -	$ 66	$ -	$ -	$ 64	$ -	$ -	$ 56	$ -	$ -	$ 2,062	$ -
		Sales Expense													
28	911	Supervision													
29		Labor & Labor Loading	4.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30		Materials & Expenses	4.0	-	-	-	-	-	-	-	-	-	-	-	-
31	912	Demonstrating & Selling Exp.													
32		Labor & Labor Loading	4.0	-	-	-	-	-	-	-	-	-	-	-	-
33		Materials & Expenses	4.0	-	-	-	-	-	-	-	-	-	-	-	-
34	913	Advertising Expense													
35		Labor & Labor Loading	4.0	-	-	-	-	-	-	-	-	-	-	-	-
36		Materials & Expenses	4.0	-	-	-	-	-	-	-	-	-	-	-	-
37		Total Sales Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38		Total O & M Expense		$ 13,705	$ 70,730	$ 27,455	$ 674	$ 10,208	$ 1,153	$ 120,512	$ 23,468	$ 216,997	$ 171,433	$ 198,567	$ 181,883
39		Allocation Percentage	Total O&M	0.01%	0.06%	0.02%	0.00%	0.01%	0.00%	0.11%	0.02%	0.19%	0.15%	0.17%	0.16%
		Other Operating Deductions													
40		Administrative & General Expense	Total O&M	6,316	32,598	12,653	311	4,705	531	55,541	10,816	100,009	79,009	91,515	83,826
41		Interest on Customer Deposits	8.0	-	-	-	-	-	-	-	-	-	-	-	-
42		Taxes Other Than Income	1.1	8,960	15,152	2,916	441	2,795	122	78,788	6,474	23,050	112,079	21,947	19,321
43		Total Allocated Operating Deductions		$ 28,981	$ 118,480	$ 43,025	$ 1,425	$ 17,708	$ 1,806	$ 254,840	$ 40,758	$ 340,056	$ 362,521	$ 312,029	$ 285,029
		Tax Adjustments													
44		Interest Expense	1.1	10,852	18,353	3,532	534	3,386	148	95,429	7,841	27,919	135,752	26,583	23,401
45		State South Georgia	1.1	21	35	7	1	6	0	181	15	53	258	51	44
46		Investment Tax Credit	1.1	(142)	(239)	(46)	(7)	(44)	(2)	(1,244)	(102)	(364)	(1,770)	(347)	(305)
47		Federal South Georgia	1.1	77	131	25	4	24	1	679	56	199	966	189	166

SOUTHWEST GAS CORPORATION
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Line No.	Account No. (a)	Description (b)	Allocation Factor No. (c)	CNG - Large Demand (d)	CNG - Large Customer (e)	CNG - Large Commodity (f)	CNG - Residential Demand (g)	CNG - Residential Customer (h)	CNG - Residential Commodity (i)	Cogeneration Gas Service Demand (j)	Cogeneration Gas Service Customer (k)	Cogeneration Gas Service Commodity (l)	Small Essential Agr. User Gas Service Demand (m)	Small Essential Agr. User Gas Service Customer (n)	Small Essential Agr. User Gas Service Commodity (o)
		Summary of Allocated Cost of Service													
		Rate Base													
1		Direct Net Plant		$ 281,575	$ 476,183	$ 91,652	$ 13,848	$ 87,847	$ 3,848	$ 2,476,006	$ 203,448	$ 724,393	$ 3,522,221	$ 689,716	$ 607,174
2		Systems Allocable Net Plant		10,871	18,384	3,538	535	3,391	149	95,589	7,854	27,966	135,979	26,627	23,441
3		Cash Working Capital	1.1	(1,334)	(6,883)	(2,672)	(66)	(993)	(112)	(11,728)	(2,284)	(21,118)	(16,684)	(19,325)	(17,701)
4		Materials & Supplies	1.1	2,470	4,177	804	121	771	34	21,719	1,785	6,354	30,896	6,050	5,326
5		Prepayments	1.1	734	1,241	239	36	229	10	6,455	530	1,888	9,182	1,798	1,583
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-	-	-	-	-	-	-	-	-
7		Customer Deposits	8.0	-	-	-	-	-	-	-	-	-	-	-	-
8		Customer Advances	8.0	-	-	-	-	-	-	-	-	-	-	-	-
9		Deferred Taxes	1.1	(36,608)	(61,910)	(11,916)	(1,800)	(11,421)	(500)	(321,911)	(26,451)	(94,180)	(457,932)	(89,672)	(78,940)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-	-	-	-	-	-	-	-	-
11		Total Rate Base		$ 257,708	$ 431,192	$ 81,645	$ 12,674	$ 79,823	$ 3,428	$ 2,266,130	$ 184,883	$ 645,304	$ 3,223,663	$ 615,195	$ 540,883
12		Net Operating Margin	Direct	$ 252,636	$ 55,080	$ -	$ 10,607	$ 10,560	$ -	$ 1,340,792	$ 64,560	$ -	$ 2,448,925	$ 101,025	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 6,303	$ 1,374	$ -	$ 265	$ 263	$ -	$ 33,452	$ 1,611	$ -	$ 61,100	$ 2,521	$ -
14		Late Charges	Direct	1,149	250	-	48	48	-	6,096	294	-	11,134	459	-
15		Service Establishment Charges	Direct	5,756	1,255	-	242	241	-	30,548	1,471	-	55,795	2,302	-
16		Reconnect / Reread Charges	Direct	454	99	-	19	19	-	2,407	116	-	4,396	181	-
17		Other Revenue - Labor	Direct	1	0	-	0	0	-	7	0	-	14	1	-
18		Other Revenue - Parts & Material	Direct	5	1	-	0	0	-	25	1	-	46	2	-
19		Other Revenue - Field Collection Fee	Direct	322	70	-	14	13	-	1,708	82	-	3,119	129	-
20		Other Revenue - Returned Item Fee	Direct	112	24	-	5	5	-	595	29	-	1,087	45	-
21		Other Revenue - Rental Income	Net Op. Marg.	635	139	-	27	27	-	3,372	162	-	6,159	254	-
22		Total Revenue		267,373	58,293	-	11,226	11,176	-	1,419,003	68,326	-	2,591,775	106,918	-
23		O & M		(13,705)	(70,730)	(27,455)	(674)	(10,208)	(1,153)	(120,512)	(23,468)	(216,997)	(171,433)	(198,567)	(181,883)
24		A & G	Total O&M	(6,316)	(32,598)	(12,653)	(311)	(4,705)	(531)	(55,541)	(10,816)	(100,009)	(79,009)	(91,515)	(83,826)
25		Depreciation Expense		(20,341)	(34,399)	(6,621)	(1,000)	(6,346)	(278)	(178,863)	(14,697)	(52,329)	(254,440)	(49,824)	(43,861)
26		Interest on Customer Deposits	8.0	-	-	-	-	-	-	-	-	-	-	-	-
27		Taxes other than Income	1.1	(8,960)	(15,152)	(2,916)	(441)	(2,795)	(122)	(78,788)	(6,474)	(23,050)	(112,079)	(21,947)	(19,321)
		State Income Tax													
28		Taxable Income before Interest Exp.		218,051	(94,586)	(49,645)	8,800	(12,878)	(2,084)	985,299	12,871	(392,385)	1,974,814	(254,935)	(328,890)
29		Interest Expense	1.1	(10,852)	(18,353)	(3,532)	(534)	(3,386)	(148)	(95,429)	(7,841)	(27,919)	(135,752)	(26,583)	(23,401)
30		State Taxable Income		207,199	(112,939)	(53,178)	8,266	(16,264)	(2,233)	889,870	5,030	(420,304)	1,839,062	(281,517)	(352,292)
31		State Income Tax		14,438	(7,870)	(3,705)	576	(1,133)	(156)	62,006	350	(29,287)	128,146	(19,616)	(24,548)
32		South Georgia	1.1	21	35	7	1	6	0	181	15	53	258	51	44
33		State Income Tax		14,458	(7,835)	(3,699)	577	(1,127)	(155)	62,188	365	(29,234)	128,404	(19,566)	(24,503)
		Federal Income Tax													
34		Taxable Income before Interest Exp.		218,051	(94,586)	(49,645)	8,800	(12,878)	(2,084)	985,299	12,871	(392,385)	1,974,814	(254,935)	(328,890)
35		Interest Expense	1.1	(10,852)	(18,353)	(3,532)	(534)	(3,386)	(148)	(95,429)	(7,841)	(27,919)	(135,752)	(26,583)	(23,401)
36		Federal Taxable Income		207,199	(112,939)	(53,178)	8,266	(16,264)	(2,233)	889,870	5,030	(420,304)	1,839,062	(281,517)	(352,292)
37		Federal Income Tax		67,466	(36,774)	(17,315)	2,692	(5,296)	(727)	289,752	1,638	(136,856)	598,821	(91,665)	(114,710)
38		I T C	1.1	(142)	(239)	(46)	(7)	(44)	(2)	(1,244)	(102)	(364)	(1,770)	(347)	(305)
39		South Georgia	1.1	77	131	25	4	24	1	679	56	199	966	189	166
40		Total Federal Income Tax		67,402	(36,883)	(17,336)	2,688	(5,316)	(728)	289,187	1,591	(137,022)	598,016	(91,823)	(114,849)
41		Regulatory Amortization	1.1	-	-	-	-	-	-	-	-	-	-	-	-
42		Net Income		$ 136,191	$ (49,868)	$ (28,610)	$ 5,535	$ (6,435)	$ (1,201)	$ 633,925	$ 10,914	$ (226,130)	$ 1,248,394	$ (143,546)	$ (189,538)
43		Rate of Return on Rate Base		52.85%	(11.57%)	(35.04%)	43.67%	(8.06%)	(35.04%)	27.97%	5.90%	(35.04%)	38.73%	(23.33%)	(35.04%)
44		Rate of Return by Class Total			7.49%			(2.19%)			13.52%			20.90%	

SCHEDULE G-4A
SHEET 15 of 20

SOUTHWEST GAS CORPORATION
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Line No.	Account No.	Description	Allocation Factor No.	Natural Gas Engine Gas Service Demand	Natural Gas Engine Gas Service Customer	Natural Gas Engine Gas Service Commodity	Street Lighting Gas Service Demand	Street Lighting Gas Service Customer	Street Lighting Gas Service Commodity	Special Residential Gas Service - A/C Demand	Special Residential Gas Service - A/C Customer	Special Residential Gas Service - A/C Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		Direct Depreciation Expense										
1	301-303	Intangible	Intang. Plant	$ 164	$ 1,287	$ 205	$ 4	$ 4	$ 1	$ 12	$ 17	$ 2
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 48,776	$ 382,087	$ 60,899	$ 1,117	$ 1,308	$ 286	$ 3,454	$ 5,039	$ 643
5	389-398	General	1.1	$ 3,771	$ 29,538	$ 4,708	$ 86	$ 101	$ 22	$ 267	$ 390	$ 50
6		Total Direct Dep. Exp.		$ 52,711	$ 412,912	$ 65,812	$ 1,207	$ 1,413	$ 309	$ 3,733	$ 5,445	$ 695
		Systems Allocable Depreciation Expense										
7	301-303	Intangible	Intang. Plant	$ 3,667	$ 28,727	$ 4,579	$ 84	$ 98	$ 21	$ 260	$ 379	$ 48
8	389-398	General	1.1	$ 1,857	$ 14,546	$ 2,318	$ 43	$ 50	$ 11	$ 131	$ 192	$ 24
		System Allocable Amortization										
9		Miscellaneous Intangible	1.1	-	-	-	-	-	-	-	-	-
10		Structures-Leasehold Improvements	1.1	-	-	-	-	-	-	-	-	-
11		Total System Allocable Amortization		-	-	-	-	-	-	-	-	-
12		Total System Alloc Dep. Exp. & Amortization		5,524	43,273	6,897	126	148	32	391	571	73
13		Total Depreciation Expense		58,235	456,185	72,709	1,333	1,562	341	4,124	6,016	768
14		Amortization-Limited Term Gas Plant	1.1	-	-	-	-	-	-	-	-	-
15		Amortization-Gas Plant Acquisition	1.1	(41)	(325)	(52)	(1)	(1)	(0)	(3)	(4)	(1)
16		Amortization of PBOP Costs	1.1	264	2,068	330	6	7	2	19	27	3
17		Amortization of Service Investigation	7.0	-	-	-	-	-	-	-	-	-
18		Amortization of TRIMP Costs	1.1	926	7,250	1,156	21	25	5	66	96	12
19		Amortization of SOX Implementation	1.1	21	168	27	0	1	0	2	2	0
20		Total Depreciation & Amortization Expense		$ 59,405	$ 465,346	$ 74,169	$ 1,360	$ 1,593	$ 348	$ 4,207	$ 6,137	$ 783

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Line No.	Account No.	Description	Allocation Factor No.	Natural Gas Engine Gas Service Demand	Natural Gas Engine Gas Service Customer	Natural Gas Engine Gas Service Commodity	Street Lighting Gas Service Demand	Street Lighting Gas Service Customer	Street Lighting Gas Service Commodity	Special Residential Gas Service - A/C Demand	Special Residential Gas Service - A/C Customer	Special Residential Gas Service - A/C Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		Operation and Maintenance Expense										
		Gas Supply Expense										
1	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-	-	-	-	-	-
3	805	Purchased Gas Cost Adj.	3.0	-	-	-	-	-	-	-	-	-
4	810	Gas Used for Compressor Sta. Fuel--	3.0	-	-	-	-	-	-	-	-	-
5	813	Other Gas Supply Expense	3.0	-	-	-	-	-	-	-	-	-
6		Labor & Labor Loading	3.0	-	-	23,990	-	-	113	-	-	253
7		Materials & Expenses	3.0	-	-	2,009	-	-	9	-	-	21
8		Total Gas Supply Expense		$ -	$ -	$ 25,998	$ -	$ -	$ 122	$ -	$ -	$ 274
		Transmission Expenses										
9	850	Operation Supervision & Engin.										
10		Labor & Labor Loading	5.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11		Materials & Expenses	5.0	-	-	-	-	-	-	-	-	-
12	851	System Control & Load Dispatch										
13		Labor & Labor Loading	3.0	-	-	-	-	-	-	-	-	-
14		Materials & Expenses	3.0	-	-	-	-	-	-	-	-	-
15	852	Communication System Exp.										
16		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-
17		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-
18	853	Compressor Station										
19		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-
20		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-
21	854	Gas for Compressor Station Fuel	3.0	-	-	-	-	-	-	-	-	-
22	856	Mains Expense										
23		Labor & Labor Loading	6.0	-	-	-	-	-	-	-	-	-
24		Materials & Expenses	6.0	-	-	-	-	-	-	-	-	-
25	857	Meas. & Res. Sta. Exp.										
26		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-
27		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-
28	858	Trans. & comp. of Gas by Others	3.0	-	-	-	-	-	-	-	-	-
29	860	Rents	1.0	-	-	-	-	-	-	-	-	-
30	861	Maint. Supervision & Eng.										
31		Labor & Labor Loading	7.0	-	-	-	-	-	-	-	-	-
32		Materials & Expenses	7.0	-	-	-	-	-	-	-	-	-
33	862	Maint. of Struct. & Imp.	1.0	-	-	-	-	-	-	-	-	-
34	863	Maint. of Mains										
35		Labor & Labor Loading	6.0	-	-	-	-	-	-	-	-	-
36		Materials & Expenses	6.0	-	-	-	-	-	-	-	-	-
37	864	Maint. of Comp. Sta. Equip.										
38		Labor & Labor Loading	3.0	-	-	-	-	-	-	-	-	-
39		Materials & Expenses	3.0	-	-	-	-	-	-	-	-	-
40	865	Maint. of Meas. & Reg. Sta. Equip.										
41		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-
42		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-
43		Total Transmission Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

SOUTHWEST GAS CORPORATION
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Line No.	Account No.	Description	Allocation Factor No.	Natural Gas Engine Gas Service Demand	Natural Gas Engine Gas Service Customer	Natural Gas Engine Gas Service Commodity	Street Lighting Gas Service Demand	Street Lighting Gas Service Customer	Street Lighting Gas Service Commodity	Special Residential Gas Service - A/C Demand	Special Residential Gas Service - A/C Customer	Special Residential Gas Service - A/C Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		Distribution Expenses										
1	870	Operation Supervision & Eng.										
2		Labor & Labor Loading	5.5	$ 2,590	$ 116,144	$ 30,018	$ 59	$ 70	$ 141	$ 183	$ 855	$ 317
3		Materials & Expenses	5.5	405	18,175	4,698	9	11	22	29	134	50
4	871	Distribution Load Dispatching										
5		Labor & Labor Loading	3.0	-	-	18,661	-	-	88	-	-	197
6		Materials & Expenses	3.0	-	-	4,527	-	-	21	-	-	48
7	874	Mains & Svcs. Expense										
8		Labor & Labor Loading	4.4	4,836	14,288	0	111	130	0	342	356	0
9		Materials & Expenses	4.4	5,471	16,164	0	125	147	0	387	403	0
10	875	Meas. & Reg. Sta. Exp.-Gen.										
11		Labor & Labor Loading	3.0	-	-	68,969	-	-	324	-	-	728
12		Materials & Expenses	3.0	-	-	27,310	-	-	128	-	-	288
13	878	Meter & House Reg. Exp.										
14		Labor & Labor Loading	6.0	-	171,835	-	-	-	-	-	1,052	-
15		Materials & Expenses	6.0	-	25,942	-	-	-	-	-	159	-
16	879	Customer Installation Exp.										
17		Labor & Labor Loading	6.0	-	203,080	-	-	-	-	-	1,243	-
18		Materials & Expenses	6.0	-	30,924	-	-	-	-	-	189	-
19	880	Other Expenses										
20		Labor & Labor Loading	5.5	2,228	99,929	25,827	51	60	121	158	735	273
21		Materials & Expenses	5.5	1,509	67,686	17,494	35	41	82	107	498	185
22	881	Rents	5.5	701	31,447	8,128	16	19	38	50	231	86
23		Total Distribution-Operations		$ 17,739	$ 795,615	$ 205,631	$ 406	$ 478	$ 966	$ 1,256	$ 5,856	$ 2,171
		Operation and Maintenance Expense										
		Distribution Expenses										
24	885	Maint. Supervision & Eng.										
25		Labor & Labor Loading	6.6	$ 1,858	$ 10,886	$ 6,331	$ 43	$ 50	$ 30	$ 132	$ 168	$ 67
26		Materials & Expenses	6.6	199	1,168	680	5	5	3	14	18	7
27	886	Maint. of Structures & Imp.										
28		Labor & Labor Loading	1.0	50	-	-	1	-	-	4	-	-
29		Materials & Expenses	1.0	185	-	-	4	-	-	13	-	-
30	887	Maint. of Mains										
31		Labor & Labor Loading	2.2	11,044	3,128	0	253	150	0	782	813	0
32		Materials & Expenses	2.2	8,797	2,492	0	201	120	0	623	648	0
33	889	Maint. of Meas. & Reg. Sta-Gen										
34		Labor & Labor Loading	3.0	-	-	39,263	-	-	184	-	-	415
35		Materials & Expenses	3.0	-	-	29,140	-	-	137	-	-	308
36	892	Maint. of Services										
37		Labor & Labor Loading	3.3	0	35,368	-	0	176	-	0	-	-
38		Materials & Expenses	3.3	0	19,351	-	0	96	-	0	-	-
39	893	Maint of Meter & House Reg.										
40		Labor & Labor Loading	6.0	-	33,401	-	-	-	-	-	204	-
41		Materials & Expenses	6.0	-	23,875	-	-	-	-	-	146	-
42	894	Maint of Other Equip.										
43		Labor & Labor Loading	6.6	118	689	401	3	3	2	8	11	4
44		Materials & Expenses	6.6	35	203	118	1	1	1	2	3	1
45		Total Distribution-Maintenance		$ 22,286	$ 130,561	$ 75,933	$ 510	$ 602	$ 357	$ 1,578	$ 2,012	$ 802
46		Total Distribution O & M		$ 40,025	$ 926,177	$ 281,564	$ 917	$ 1,080	$ 1,322	$ 2,834	$ 7,867	$ 2,973

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
AUGUST 31, 2004

Line No.	Account No.	Description	Allocation Factor No.	Natural Gas Engine Gas Service Demand	Natural Gas Engine Gas Service Customer	Natural Gas Engine Gas Service Commodity	Street Lighting Gas Service Demand	Street Lighting Gas Service Customer	Street Lighting Gas Service Commodity	Special Residential Gas Service - A/C Demand	Special Residential Gas Service - A/C Customer	Special Residential Gas Service - A/C Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		Customer Accounts Expenses										
1	901	Supervision										
2		Labor & Labor Loading	10.1	$ -	$ 17,329	$ -	$ -	$ 1,894	$ -	$ -	$ 1,206	$
3		Materials & Expenses	10.1	-	1,058	-	-	116	-	-	74	-
4	902	Meter Reading Exp.										
5		Labor & Labor Loading	13.0	-	25,998	-	-	2,853	-	-	1,773	-
6		Materials & Expenses	13.0	-	6,516	-	-	715	-	-	444	-
7	903	Customer Records & Collections										
8		Labor & Labor Loading	13.0	-	71,827	-	-	7,883	-	-	4,897	-
9		Materials & Expenses	13.0	-	33,457	-	-	3,672	-	-	2,281	-
10	903	Customer Records & Collections - LCS										
11		Labor & Labor Loading - LCS	13.0	-	5,459	-	-	599	-	-	372	-
12		Materials & Expenses - LCS	13.0	-	243	-	-	27	-	-	17	-
13	904	Uncollectible Accounts Exp.	4.0	-	1,048	-	-	50	-	-	272	-
14	905	Misc. Customer Accounts Exp.										
15		Labor & Labor Loading	10.1	-	1,808	-	-	198	-	-	126	-
16		Materials & Expenses	10.1	-	103	-	-	11	-	-	7	-
17		Total Customer Accounts Expenses		$ -	$ 164,845	$ -	$ -	$ 18,017	$ -	$ -	$ 11,468	$
		Customer Service & Info. Exp.										
18	908	Customer Assistance Exp.										
19		Labor & Labor Loading	13.0	$ -	$ 1,396	$ -	$ -	$ 153	$ -	$ -	$ 95	$
20		Materials & Expenses	13.0	-	1,259	-	-	138	-	-	86	-
21	909	Info. & Instructional Exp.										
22		Labor & Labor Loading	13.0	-	-	-	-	-	-	-	-	-
23		Materials & Expenses	13.0	-	-	-	-	-	-	-	-	-
24	910	Misc. C.S. & I. Expense										
25		Labor & Labor Loading	13.0	-	4	-	-	0	-	-	0	-
26		Materials & Expenses	13.0	-	121	-	-	13	-	-	8	-
27		Total Customer Service & Info. Exp.		$ -	$ 2,779	$ -	$ -	$ 305	$ -	$ -	$ 190	$
		Sales Expense										
28	911	Supervision										
29		Labor & Labor Loading	4.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
30		Materials & Expenses	4.0	-	-	-	-	-	-	-	-	-
31	912	Demonstrating & Selling Exp.										
32		Labor & Labor Loading	4.0	-	-	-	-	-	-	-	-	-
33		Materials & Expenses	4.0	-	-	-	-	-	-	-	-	-
34	913	Advertising Expense										
35		Labor & Labor Loading	4.0	-	-	-	-	-	-	-	-	-
36		Materials & Expenses	4.0	-	-	-	-	-	-	-	-	-
37		Total Sales Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
38		Total O & M Expense		$ 40,025	$ 1,093,801	$ 307,562	$ 917	$ 19,402	$ 1,444	$ 2,834	$ 19,525	$ 3,247
39		Allocation Percentage	Total O&M	0.04%	0.96%	0.27%	0.00%	0.02%	0.00%	0.00%	0.02%	0.00%
		Other Operating Deductions										
40		Administrative & General Expense	Total O&M	18,447	504,107	141,748	422	8,942	666	1,306	8,999	1,497
41		Interest on Customer Deposits	8.0	-	-	-	-	-	-	-	-	-
42		Taxes Other Than Income	1.1	26,167	204,981	32,671	599	702	153	1,853	2,703	345
43		Total Allocated Operating Deductions		$ 84,639	$ 1,802,889	$ 481,982	$ 1,938	$ 29,046	$ 2,263	$ 5,994	$ 31,227	$ 5,089
		Tax Adjustments										
44		Interest Expense	1.1	31,694	248,277	39,572	726	850	186	2,244	3,274	418
45		State South Georgia	1.1	60	472	75	1	2	0	4	6	1
46		Investment Tax Credit	1.1	(413)	(3,237)	(516)	(9)	(11)	(2)	(29)	(43)	(5)
47		Federal South Georgia	1.1	225	1,766	281	5	6	1	16	23	3

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
AUGUST 31, 2004

Line No.	Account No.	Description	Allocation Factor No.	Natural Gas Engine Gas Service			Street Lighting Gas Service			Special Residential Gas Service - A/C		
				Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		Summary of Allocated Cost of Service										
		Rate Base										
1		Direct Net Plant		$ 822,344	$ 6,441,794	$ 1,026,726	$ 18,830	$ 22,052	$ 4,821	$ 58,236	$ 84,953	$ 10,840
2		Systems Allocable Net Plant		31,747	248,692	39,638	727	851	186	2,248	3,280	418
3		Cash Working Capital	1.1	(3,895)	(106,449)	(29,932)	(89)	(1,888)	(141)	(276)	(1,900)	(316)
4		Materials & Supplies	1.1	7,213	56,506	9,006	165	193	42	511	745	95
5		Prepayments	1.1	2,144	16,793	2,677	49	57	13	152	221	28
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-	-	-	-	-	-
7		Customer Deposits	8.0	-	-	-	-	-	-	-	-	-
8		Customer Advances	8.0	-	-	-	-	-	-	-	-	-
9		Deferred Taxes	1.1	(106,915)	(837,512)	(133,487)	(2,448)	(2,867)	(627)	(7,571)	(11,045)	(1,409)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-	-	-	-	-	-
11		Total Rate Base		$ 752,638	$ 5,819,825	$ 914,627	$ 17,234	$ 18,399	$ 4,295	$ 53,299	$ 76,255	$ 9,656
12		Net Operating Margin	Direct	$ 3,443,622	$ 289,800	$ -	$ 47,592	$ -	$ -	$ 73,539	$ 15,072	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 85,917	$ 7,230	$ -	$ 1,187	$ -	$ -	$ 1,835	$ 376	$ -
14		Late Charges	Direct	15,656	1,318	-	216	-	-	334	69	-
15		Service Establishment Charges	Direct	78,458	6,603	-	1,084	-	-	1,675	343	-
16		Reconnect / Reread Charges	Direct	6,182	520	-	85	-	-	132	27	-
17		Other Revenue - Labor	Direct	19	2	-	0	-	-	0	0	-
18		Other Revenue - Parts & Material	Direct	65	5	-	1	-	-	1	0	-
19		Other Revenue - Field Collection Fee	Direct	4,386	369	-	61	-	-	94	19	-
20		Other Revenue - Returned Item Fee	Direct	1,529	129	-	21	-	-	33	7	-
21		Other Revenue - Rental Income	Net Op. Marg.	8,660	729	-	120	-	-	185	38	-
22		Total Revenue		3,644,495	306,705	-	50,368	-	-	77,829	15,951	-
23		O & M		(40,025)	(1,093,801)	(307,562)	(917)	(19,402)	(1,444)	(2,834)	(19,525)	(3,247)
24		A & G	Total O&M	(18,447)	(504,107)	(141,748)	(422)	(8,942)	(666)	(1,306)	(8,999)	(1,497)
25		Depreciation Expense		(59,405)	(465,346)	(74,169)	(1,360)	(1,593)	(348)	(4,207)	(6,137)	(783)
26		Interest on Customer Deposits	8.0	-	-	-	-	-	-	-	-	-
27		Taxes other than Income	1.1	(26,167)	(204,981)	(32,671)	(599)	(702)	(153)	(1,853)	(2,703)	(345)
		State Income Tax										
28		Taxable Income before Interest Exp.		$ 3,500,451	$(1,961,530)	$(556,151)	$ 47,070	$(30,639)	$(2,611)	$ 67,628	$(21,412)	$(5,872)
29		Interest Expense	1.1	(31,694)	(248,277)	(39,572)	(726)	(850)	(186)	(2,244)	(3,274)	(418)
30		State Taxable Income		$ 3,468,756	$(2,209,807)	$(595,722)	$ 46,344	$(31,489)	$(2,797)	$ 65,383	$(24,687)	$(6,289)
31		State Income Tax		241,703	(153,979)	(41,510)	3,229	(2,194)	(195)	4,556	(1,720)	(438)
32		South Georgia	1.1	60	472	75	1	2	0	4	6	1
33		State Income Tax		241,763	(153,507)	(41,435)	3,231	(2,193)	(195)	4,560	(1,714)	(437)
		Federal Income Tax										
34		Taxable Income before Interest Exp.		3,500,451	(1,961,530)	(556,151)	47,070	(30,639)	(2,611)	67,628	(21,412)	(5,872)
35		Interest Expense	1.1	(31,694)	(248,277)	(39,572)	(726)	(850)	(186)	(2,244)	(3,274)	(418)
36		Federal Taxable Income		3,468,756	(2,209,807)	(595,722)	46,344	(31,489)	(2,797)	65,383	(24,687)	(6,289)
37		Federal Income Tax		$ 1,129,469	$(719,540)	$(193,974)	$ 15,090	$(10,253)	$(911)	$ 21,290	$(8,038)	$(2,048)
38		I T C	1.1	(413)	(3,237)	(516)	(9)	(11)	(2)	(29)	(43)	(5)
39		South Georgia	1.1	225	1,766	281	5	6	1	16	23	3
40		Total Federal Income Tax		$ 1,129,281	$(721,011)	$(194,209)	$ 15,086	$(10,258)	$(912)	$ 21,276	$(8,058)	$(2,050)
41		Regulatory Amortization	1.1	-	-	-	-	-	-	-	-	-
42		Net Income		$ 2,129,407	$(1,087,012)	$(320,507)	$ 28,753	$(18,188)	$(1,505)	$ 41,791	$(11,641)	$(3,384)
43		Rate of Return on Rate Base		282.93%	(18.68%)	(35.04%)	166.84%	(98.86%)	(35.04%)	78.41%	(15.27%)	(35.04%)
44		Rate of Return by Class Total			9.64%			22.69%			19.23%	

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
DATA ENTRY AND CLASSIFICATION OF COSTS

Line No.	Acct No.	Description	Production Specific	Production Demand	Production Customer	Production Commodity	Transmission Specific	Transmission Demand	Transmission Customer	Transmission Commodity	Distribution Specific	Distribution Demand	Distribution Customer	Distribution Commodity	Customer Accounting Specific	Customer Accounting Demand	Customer Accounting Customer
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
		Net Plant in Service															
		Direct															
		Intangible															
1	301	Organization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,152	$ 32,314	$ 1,186	$ -	$ -	$ -
2	302	Franchise & Consent	-	-	-	-	-	-	-	-	-	254,311	897,884	32,960	-	-	-
3	303	Misc. Intangible	-	-	-	-	-	-	-	-	-	59,692	210,750	7,736	-	-	-
		Total Intangible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 323,156	$ 1,140,948	$ 41,883	$ -	$ -	$ -
		Production															
4	326	Other Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	332	Field Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	334	Field Meas & Reg. Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	336	Purification Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8		Total Production	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Transmission															
9	365	Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	365	Rights of Way	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	366	Structures-Compressor Stas.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	366	Structures	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	367	Mains	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	367	Mains-Bridge	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	368	Compressor Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	369	Measuring & Reg. Sta. Equip.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	370	Communication Equip.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	371	Other Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19		Total Transmission	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Distribution															
20	374.1	Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 351,685	$ -	$ -	$ -	$ -	$ -
21	374.2	Rights of Way	-	-	-	-	-	-	-	-	-	445,985	-	-	-	-	-
22	375	Structures	-	-	-	-	-	-	-	-	-	47,682	-	-	-	-	-
23	376	Mains	-	-	-	-	-	-	-	-	-	208,461,866	307,811,910	1	-	-	-
24	378	Measuring & Reg. Station	-	-	-	-	-	-	-	-	-	-	-	23,180,184	-	-	-
25	380	Services	-	-	-	-	-	-	-	-	-	0	305,210,571	0	-	-	-
26	381	Meters	-	-	-	-	-	-	-	-	-	-	125,828,203	-	-	-	-
27	385	Industrial Meas. & Reg. Sta.	-	-	-	-	-	-	-	-	-	-	-	3,942,124	-	-	-
28	386	Other Prop. on Cust. Premises	-	-	-	-	-	-	-	-	-	-		-	-	-	-
29	387	Other Equipment	-	-	-	-	-	-	-	-	-	(39,455)	-	-	-	-	-
30		Total Distribution	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 209,267,764	$ 738,850,684	$ 27,122,308	$ -	$ -	$ -
31		Total Trans., Dist., Prod.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 209,267,764	$ 738,850,684	$ 27,122,308	$ -	$ -	$ -

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
DATA ENTRY AND CLASSIFICATION OF COSTS

Line No.	Acct No.	Description	Production Specific	Production Demand	Production Customer	Production Commodity	Transmission Specific	Transmission Demand	Transmission Customer	Transmission Commodity	Distribution Specific	Distribution Demand	Distribution Customer	Distribution Commodity	Customer Accounting Specific	Customer Accounting Demand	Customer Accounting Customer
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
		General															
1	389	Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,385,030	$ 4,890,051	$ 179,508	$ -	$ -	$ -
2	390.1	Structures & Improvements	-	-	-	-	-	-	-	-	-	4,079,343	14,402,723	528,706	-	-	-
3	390.2	Struct. & Imp.-Leasehold	-	-	-	-	-	-	-	-	-	87,079	307,446	11,286	-	-	-
4	391.0	Office Furn. & Equip.	-	-	-	-	-	-	-	-	-	899,784	3,176,819	116,617	-	-	-
5	391.1	Office Furn. & Computer Equip.	-	-	-	-	-	-	-	-	-	1,568,636	5,538,302	203,304	-	-	-
6	392.1	Transp. Equip.-Light	-	-	-	-	-	-	-	-	-	5,397,476	19,056,585	699,544	-	-	-
7	392.0	Transp. Equip.-Heavy	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	393	Stores Equipment	-	-	-	-	-	-	-	-	-	100,392	354,448	13,011	-	-	-
9	394	Tools, Shop, & Garage Equip.	-	-	-	-	-	-	-	-	-	1,616,856	5,708,549	209,554	-	-	-
10	395	Laboratory Equip.	-	-	-	-	-	-	-	-	-	123,476	435,951	16,003	-	-	-
11	396	Power Operated Equip.	-	-	-	-	-	-	-	-	-	576,947	2,036,995	74,776	-	-	-
12	397.1	Comm. Equip.-General	-	-	-	-	-	-	-	-	-	(23,321)	(82,338)	(3,023)	-	-	-
13	397.2	Comm. Equip.-Telemetering	-	-	-	-	-	-	-	-	-	27,493	97,067	3,563	-	-	-
14	398	Miscellaneous Equip.	-	-	-	-	-	-	-	-	-	174,104	614,699	22,565	-	-	-
15		Total General	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 16,013,294	$ 56,537,296	$ 2,075,415	$ -	$ -	$ -
		Systems Allocable															
		Intangible															
16	301	Organization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,638	$ 26,966	$ 990	$ -	$ -	$ -
17	302	Franchise & Consent	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	303	Miscellaneous Intang.	-	-	-	-	-	-	-	-	-	5,657,476	19,974,552	733,241	-	-	-
19		Total Intangible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,665,113	$ 20,001,518	$ 734,231	$ -	$ -	$ -
		General															
20	389	Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 48,348	$ 170,699	$ 6,266	$ -	$ -	$ -
21	390.10	Structures & Improvements	-	-	-	-	-	-	-	-	-	1,021,293	3,605,824	132,365	-	-	-
22	390.20	Struct. & Imp.-Leasehold	-	-	-	-	-	-	-	-	-	30,802	108,752	3,992	-	-	-
23	391.00	Office Furn. & Equip.	-	-	-	-	-	-	-	-	-	728,309	2,571,403	94,393	-	-	-
24	391.10	Office Furn. & Computer Equip.	-	-	-	-	-	-	-	-	-	373,712	1,319,446	48,435	-	-	-
25	392.11	Transp. Equip.-Light	-	-	-	-	-	-	-	-	-	283,401	1,000,590	36,730	-	-	-
26	392.21	Airframe	-	-	-	-	-	-	-	-	-	18,014	63,601	2,335	-	-	-
27	392.22	Aircraft-Left Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	392.23	Aircraft-Right Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	393	Stores Equipment	-	-	-	-	-	-	-	-	-	3,597	12,699	466	-	-	-
30	394	Tools, Shop, & Garage Equip.	-	-	-	-	-	-	-	-	-	54,906	193,855	7,116	-	-	-
31	395	Laboratory Equip.	-	-	-	-	-	-	-	-	-	23,033	81,322	2,985	-	-	-
32	397.1	Comm. Equip.-General	-	-	-	-	-	-	-	-	-	257,709	909,879	33,401	-	-	-
33	397.2	Telemetering Equipment	-	-	-	-	-	-	-	-	-	72,650	256,500	9,416	-	-	-
34	398	Miscellaneous Equip.	-	-	-	-	-	-	-	-	-	128,809	454,779	16,694	-	-	-
35		Total General	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,044,584	$ 10,749,351	$ 394,596	$ -	$ -	$ -
36		Total Net Plant-Direct	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 225,604,214	$ 796,528,928	$ 29,239,606	$ -	$ -	$ -
37		Total Net Plant-Systems Alloc.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,709,697	$ 30,750,869	$ 1,128,827	$ -	$ -	$ -
38		Total Net Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 234,313,911	$ 827,279,797	$ 30,368,433	$ -	$ -	$ -
39		Cash Working Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$(2,378,016)	$(8,395,936)	$(308,205)	$ -	$ -	$ -
40		Materials and Supplies	-	-	-	-	-	-	-	-	-	1,978,967	6,987,036	256,486	-	-	-
41		Prepayments	-	-	-	-	-	-	-	-	-	588,126	2,076,465	76,224	-	-	-
42		Gas Plant Acquisition Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43		Customer Deposits	-	-	-	-	-	-	-	-	-	-	(23,912,141)	-	-	-	-
44		Customer Advances	-	-	-	-	-	-	-	-	-	-	(7,027,372)	-	-	-	-
45		Deferred Taxes	-	-	-	-	-	-	-	-	-	(29,331,310)	(103,558,512)	(3,801,507)	-	-	-
46		Deferred Gain Headquarters Bldg.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47		Total Rate Base	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 205,171,678	$ 693,449,337	$ 26,591,432	$ -	$ -	$ -

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
DATA ENTRY AND CLASSIFICATION OF COSTS

Line No.	Acct No.	Description	Production Specific	Production Demand	Production Customer	Production Commodity	Transmission Specific	Transmission Demand	Transmission Customer	Transmission Commodity	Distribution Specific	Distribution Demand	Distribution Customer	Distribution Commodity	Customer Accounting Specific	Customer Accounting Demand	Customer Accounting Customer
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
		Depreciation Expense & Amortizatio															
		Direct															
		Intangible															
1	301	Organization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	302	Franchise & Consent	-	-	-	-	-	-	-	-	-	16,657	58,810	2,159	-	-	-
3	303	Misc. Intangible	-	-	-	-	-	-	-	-	-	28,402	100,278	3,681	-	-	-
4		Total Intangible Dep. Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 45,059	$ 159,089	$ 5,840	$ -	$ -	$ -
		Production															
5	326	Other Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	332	Field Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	334	Field Meas & Reg. Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	336	Purification Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9		Total Production Dep. Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Transmission															
10	365	Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	365	Rights of Way	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	366	Structures-Compressor Stas.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	366	Structures	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	367	Mains	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	367	Mains-Bridge	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	368	Compressor Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	369	Measuring & Reg. Sta. Equip.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	370	Communication Equip.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	371	Other Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20		Total Transmission Dep. Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	# $ -	$ -	$ -	$ -	$ -	$ -	$ -
		Distribution															
21	374	Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	374.2	Rights of Way	-	-	-	-	-	-	-	-	-	15,501	-	-	-	-	-
23	375	Structures	-	-	-	-	-	-	-	-	-	1,271	-	-	-	-	-
24	376	Mains	-	-	-	-	-	-	-	-	-	12,179,878	17,984,640	0	-	-	-
25	378	Measuring & Reg. Station	-	-	-	-	-	-	-	-	-	-	-	1,007,546	-	-	-
26	380	Services	-	-	-	-	-	-	-	-	-	0	27,761,544	0	-	-	-
27	381	Meters	-	-	-	-	-	-	-	-	-	-	3,104,837	-	-	-	-
28	385	Industrial Meas. & Reg. Sta.	-	-	-	-	-	-	-	-	-	-	-	281,378	-	-	-
29	386	Other Prop. on Cust. Premises															
30	387	Other Equipment	-	-	-	-	-	-	-	-	-	24,340	-	-	-	-	-
31		Total Distribution Dep. Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,220,990	$ 48,851,021	$ 1,288,924	$ -	$ -	$ -

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
DATA ENTRY AND CLASSIFICATION OF COSTS

Line No.	Acct No.	Description	Production Specific	Production Demand	Production Customer	Production Commodity	Transmission Specific	Transmission Demand	Transmission Customer	Transmission Commodity	Distribution Specific	Distribution Demand	Distribution Customer	Distribution Commodity	Customer Accounting Specific	Customer Accounting Demand	Customer Accounting Customer
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
		General															
1	389	Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	390.1	Structures & Improvements	-	-	-	-	-	-	-	-	-	103,781	366,415	13,451	-	-	-
3	390.2	Struct. & Imp.-Leasehold	-	-	-	-	-	-	-	-	-	13,378	47,233	1,734	-	-	-
4	391	Office Furn. & Equip.	-	-	-	-	-	-	-	-	-	28,411	100,308	3,682	-	-	-
5	391	Office Furn. & Computer Equip.	-	-	-	-	-	-	-	-	-	270,869	956,344	35,106	-	-	-
6	392	Transp. Equip.	-	-	-	-	-	-	-	-	-	499,803	1,764,627	64,777	-	-	-
7	393	Stores Equipment	-	-	-	-	-	-	-	-	-	2,151	7,594	279	-	-	-
8	394	Tools, Shop, & Garage Equip.	-	-	-	-	-	-	-	-	-	22,779	80,425	2,952	-	-	-
9	395	Laboratory Equip.	-	-	-	-	-	-	-	-	-	3,587	12,664	465	-	-	-
10	396	Power Operated Equip.	-	-	-	-	-	-	-	-	-	31,701	111,924	4,109	-	-	-
11	397.1	Comm. Equip.-General	-	-	-	-	-	-	-	-	-	42,372	149,600	5,492	-	-	-
12	397.2	Comm. Equip.-Telemetering	-	-	-	-	-	-	-	-	-	7,442	26,276	965	-	-	-
13	398	Miscellaneous Equip.	-	-	-	-	-	-	-	-	-	8,206	28,972	1,064	-	-	-
14		Total General Dep. Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,034,479	$ 3,652,381	$ 134,074	$ -	$ -	$ -
		Systems Allocable															
		Intangible															
15	301	Organization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	302	Franchise & Consent															
17	303	Miscellaneous Intang.	-	-	-	-	-	-	-	-	-	1,006,082	3,552,119	130,394	-	-	-
18		Total Intangible Dep. Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,006,082	$ 3,552,119	$ 130,394	$ -	$ -	$ -
		General															
19	389	Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	390.1	Structures	-	-	-	-	-	-	-	-	-	36,545	129,027	4,736	-	-	-
21	390.2	Structures - Leasehold Improvements	-	-	-	-	-	-	-	-	-	3,673	12,969	476	-	-	-
22	391	Office Furniture & Equipment	-	-	-	-	-	-	-	-	-	78,195	276,078	10,134	-	-	-
23	391.1	Computer Equipment	-	-	-	-	-	-	-	-	-	270,856	956,296	35,104	-	-	-
24	392.11	Transportation Equipment - Light	-	-	-	-	-	-	-	-	-	30,152	106,456	3,908	-	-	-
25	392.12	Transportation Equipment - Heavy	-	-	-	-	-	-	-	-	-	990	3,496	128	-	-	-
26	393	Stores Equipment	-	-	-	-	-	-	-	-	-	477	1,686	62	-	-	-
27	394	Tools, Shop, & Garage Equipment	-	-	-	-	-	-	-	-	-	5,718	20,189	741	-	-	-
28	395	Laboratory Equipment	-	-	-	-	-	-	-	-	-	1,585	5,595	205	-	-	-
29	396	Power Operated Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	397.1	Communication Equipment	-	-	-	-	-	-	-	-	-	48,427	170,977	6,276	-	-	-
31	397.2	Telemetering Equipment	-	-	-	-	-	-	-	-	-	19,954	70,449	2,586	-	-	-
32	398	Miscellaneous Equipment	-	-	-	-	-	-	-	-	-	12,841	45,337	1,664	-	-	-
33		Total General Dep. Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 509,412	$ 1,798,554	$ 66,023	$ -	$ -	$ -
		System Allocable Amortization															
34		Miscellaneous Intangible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35		Structures-Leasehold Improvements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36		Total System Allocable Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
37		Total Depreciation Exp.-Direct	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,300,529	$ 52,662,490	$ 1,428,838	$ -	$ -	$ -
38		Total Dep. Exp.-Systems Alloc.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,515,493	$ 5,350,673	$ 196,417	$ -	$ -	$ -
39		Amortization-Limited Term Gas Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40		Amortization-Gas Plant Acquisition	-	-	-	-	-	-	-	-	-	(10,459)	(41,413)	(1,124)	-	-	-
41		Amortization of PBOP Costs	-	-	-	-	-	-	-	-	-	66,614	263,754	7,156	-	-	-
42		Amortization of Service Investigation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43		Amortization of TRIMP Costs	-	-	-	-	-	-	-	-	-	233,544	924,700	25,089	-	-	-
44		Amortization of SOX Implementation	-	-	-	-	-	-	-	-	-	5,397	21,369	580	-	-	-
45		Total Depreciation Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,111,118	$ 59,181,574	$ 1,656,956	$ -	$ -	$ -

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
DATA ENTRY AND CLASSIFICATION OF COSTS

Line No.	Acct No.	Description	Production				Transmission				Distribution				Customer Accounting		
			Specific	Demand	Customer	Commodity	Specific	Demand	Customer	Commodity	Specific	Demand	Customer	Commodity	Specific	Demand	Customer
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
		Operation and Maintenance Expense															
		Gas Supply Expense															
1	800	Natural Gas Wellhead Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	803	Natural Gas Transmission Line Pur	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	805.1	Purchased Gas Cost Adj.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	810	Gas Used for Compressor Sta. Fue	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	813	Other Gas Supply Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6		Labor & Labor Loading	-	-	-	683,189	-	-	-	-	-	-	-	-	-	-	-
7		Materials & Expenses	-	-	-	57,202	-	-	-	-	-	-	-	-	-	-	-
8		Total Gas Supply Expense	$ -	$ -	$ -	$ 740,391	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Transmission Expenses															
9	850	Operation Supervision & Engin.															
10		Labor & Labor Loading	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	851	System Control & Load Dispatch															
13		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	852	Communication System Exp.															
16		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	853	Compressor Station															
19		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	854	Gas for Compressor Station Fuel															
22	856	Mains Expense															
23		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	857	Meas. & Res. Sta. Exp.															
26		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	858	Trans. & comp. of Gas by Others	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	860	Rents	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	861	Maint. Supervision & Eng.															
31		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
33	862	Maint. of Struct. & Imp.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	863	Maint. of Mains															
35		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	864	Maint. of Comp. Sta. Equip.															
38		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
39		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40	865	Maint. of Meas. & Reg. Sta. Equip.															
41		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43		Total Transmission Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
DATA ENTRY AND CLASSIFICATION OF COSTS

Line No.	Acct No.	Description	Production Specific	Production Demand	Production Customer	Production Commodity	Transmission Specific	Transmission Demand	Transmission Customer	Transmission Commodity	Distribution Specific	Distribution Demand	Distribution Customer	Distribution Commodity	Customer Accounting Specific	Customer Accounting Demand	Customer Accounting Customer
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
		Distribution Expenses															
1	870	Operation Supervision & Eng.															
2		Labor & Labor Loading	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 793,391	$ 5,748,939	$ 771,904	$ -	$ -	$ -
3		Materials & Expenses	-	-	-	-	-	-	-	-	-	124,158	899,651	120,795	-	-	-
4	871	Distribution Load Dispatching															
5		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	265,715	-	265,715	-	-	-
6		Materials & Expenses	-	-	-	-	-	-	-	-	-	64,465	-	64,465	-	-	-
7	874	Mains & Svcs. Expense															
8		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	1,326,589	3,901,091	0	-	-	-
9		Materials & Expenses	-	-	-	-	-	-	-	-	-	1,500,801	4,413,395	0	-	-	-
10	875	Meas. & Reg. Sta. Exp.-Gen.															
11		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	1,964,122	-	-	-
12		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	777,755	-	-	-
13	878	Meter & House Reg. Exp.															
14		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	5,796,552	-	-	-	-
15		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	875,104	-	-	-	-
16	879	Customer Installation Exp.															
17		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	6,850,542	-	-	-	-
18		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	1,043,174	-	-	-	-
19	880	Other Expenses															
20		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	682,626	4,946,332	664,139	-	-	-
21		Materials & Expenses	-	-	-	-	-	-	-	-	-	462,372	3,350,367	449,851	-	-	-
22	881	Rents	-	-	-	-	-	-	-	-	-	214,817	1,556,568	208,999	-	-	-
23		Total Distribution-Operations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,434,933	$ 39,381,715	$ 5,287,745	$ -	$ -	$ -
24	885	Maint. Supervision & Eng.															
25		Labor & Labor Loading	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 509,766	$ 1,684,195	$ 180,300	$ -	$ -	$ -
26		Materials & Expenses	-	-	-	-	-	-	-	-	-	54,716	180,774	19,353	-	-	-
27	886	Maint. of Structures & Imp.															
28		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	13,682	-	-	-	-	-
29		Materials & Expenses	-	-	-	-	-	-	-	-	-	50,707	-	-	-	-	-
30	887	Maint. of Mains															
31		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	3,029,859	4,473,847	0	-	-	-
32		Materials & Expenses	-	-	-	-	-	-	-	-	-	2,413,442	3,563,655	0	-	-	-
33	889	Maint. of Meas. & Reg. Sta-Gen															
34		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	1,118,151	-	-	-
35		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	829,877	-	-	-
36	892	Maint. of Services															
37		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	0	5,317,554	0	-	-	-
38		Materials & Expenses	-	-	-	-	-	-	-	-	-	0	2,909,486	0	-	-	-
39	893	Maint of Meter & House Reg.															
40		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	1,126,714	-	-	-	-
41		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	805,373	-	-	-	-
42	894	Maint of Other Equip.															
43		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	32,274	106,629	11,415	-	-	-
44		Materials & Expenses	-	-	-	-	-	-	-	-	-	9,512	31,426	3,364	-	-	-
45		Total Distribution-Maintenance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,113,958	$ 20,199,655	$ 2,162,461	$ -	$ -	$ -
46		Total Distribution O & M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,548,891	$ 59,581,369	$ 7,450,206	$ -	$ -	$ -

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
DATA ENTRY AND CLASSIFICATION OF COSTS

Line No.	Acct No.	Description	Production Specific	Production Demand	Production Customer	Production Commodity	Transmission Specific	Transmission Demand	Transmission Customer	Transmission Commodity	Distribution Specific	Distribution Demand	Distribution Customer	Distribution Commodity	Customer Accounting Specific	Customer Accounting Demand	Customer Accounting Customer
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
		Customer Accounts Expenses															
1	901	Supervision															
2		Labor & Labor Loading	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,574,463
3		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	218,328
4	902	Meter Reading Exp.															
5		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,130,538
6		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,285,812
7	903	Customer Records & Collections															
8		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14,174,373
9		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6,602,396
10	903	Customer Records & Collections - L															
11		Labor & Labor Loading - LCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,077,228
12		Materials & Expenses - LCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	47,923
13	904	Uncollectible Accounts Exp.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,498,151
14	905	Misc. Customer Accounts Exp.															
15		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	372,869
16		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21,199
17		Total Customer Accounts Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 34,003,279
		Customer Service & Info. Exp.															
18	908	Customer Assistance Exp.															
19		Labor & Labor Loading	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 275,434
20		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,457
21	909	Info. & Instructional Exp.															
22		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	910	Misc. C.S. & I. Expense															
25		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	773
26		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23,832
27		Total Customer Service & Info. Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 548,496
		Sales Expense															
28	911	Supervision															
29		Labor & Labor Loading	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	912	Demonstrating & Selling Exp.															
32		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
33		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	913	Advertising Expense															
35		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37		Total Sales Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38		Total O & M Expense	$ -	$ -	$ -	$ 740,391	$ -	$ -	$ -	$ -	$ -	$ 11,548,891	$ 59,581,369	$ 7,450,206	$ -	$ -	$ 34,551,775

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
DATA ENTRY AND CLASSIFICATION OF COSTS

Line No.	Acct No.	Description	Production				Transmission				Distribution				Customer Accounting		
			Specific	Demand	Customer	Commodity	Specific	Demand	Customer	Commodity	Specific	Demand	Customer	Commodity	Specific	Demand	Customer
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1		Administrative & General Expense	$ -	$ -	$ -	$ 341,229	$ -	$ -	$ -	$ -	$ -	$ 5,322,610	$ 27,459,640	$ 3,433,623	$ -	$ -	$ 15,924,093
2		Interest on Customer Deposits	-	-	-	-	-	-	-	-	-	-	-	-	-	-	717,364
3		Taxes other than Income	-	-	-	-	-	-	-	-	-	7,418,884	25,074,709	961,530	-	-	-
4		Interest Expense	-	-	-	-	-	-	-	-	-	8,985,904	30,371,001	1,164,625	-	-	-
5		South Georgia - State	-	-	-	-	-	-	-	-	-	17,080	57,727	2,214	-	-	-
6		Investment Tas Credit (I T C)	-	-	-	-	-	-	-	-	-	(117,165)	(396,001)	(15,185)	-	-	-
7		South Georgia - Federal	-	-	-	-	-	-	-	-	-	63,917	216,031	8,284	-	-	-
8		Regulatory Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9		SIT Rate															
10		FIT Rate															
		Rate Base															
11		Direct Net Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 225,604,214	$ 796,528,928	$ 29,239,606	$ -	$ -	$ -
12		Systems Allocable Net Plant	-	-	-	-	-	-	-	-	-	8,709,697	30,750,869	1,128,827	-	-	-
13		Cash Working Capital	-	-	-	-	-	-	-	-	-	(2,378,016)	(8,395,936)	(308,205)	-	-	-
14		Materials & Supplies	-	-	-	-	-	-	-	-	-	1,978,967	6,987,036	256,486	-	-	-
15		Prepayments	-	-	-	-	-	-	-	-	-	588,126	2,076,465	76,224	-	-	-
16		Gas Plant Acquisition Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17		Customer Deposits	-	-	-	-	-	-	-	-	-	-	(23,912,141)	-	-	-	-
18		Customer Advances	-	-	-	-	-	-	-	-	-	-	(7,027,372)	-	-	-	-
19		Deferred Taxes	-	-	-	-	-	-	-	-	-	(29,331,310)	(103,558,512)	(3,801,507)	-	-	-
20		Deferred Gain Hdqtrs Bldg	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21		Total Rate Base	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 205,171,678	$ 693,449,337	$ 26,591,432	$ -	$ -	$ -
22		Net Operating Margin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 67,651,339	$ 228,651,324	$ 8,768,003	$ -	$ -	$ -
23		Special Contract & Optional	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,687,882	$ 5,704,788	$ 218,759	$ -	$ -	$ -
24		Late Charges	-	-	-	-	-	-	-	-	-	307,566	1,039,528	39,862	-	-	-
25		Service Establishment Charges	-	-	-	-	-	-	-	-	-	1,541,341	5,209,502	199,767	-	-	-
26		Reconnect / Reread Charges	-	-	-	-	-	-	-	-	-	121,447	410,471	15,740	-	-	-
27		Other Revenue - Labor	-	-	-	-	-	-	-	-	-	378	1,278	49	-	-	-
28		Other Revenue - Parts & Materials	-	-	-	-	-	-	-	-	-	1,278	4,320	166	-	-	-
29		Other Revenue - Field Collection Fee	-	-	-	-	-	-	-	-	-	86,161	291,212	11,167	-	-	-
30		Other Revenue - Returned Item Fee	-	-	-	-	-	-	-	-	-	30,037	101,520	3,893	-	-	-
31		Other Revenue - Rental Income	-	-	-	-	-	-	-	-	-	170,131	575,017	22,050	-	-	-
32		Total Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 71,597,561	$ 241,988,961	$ 9,279,457	$ -	$ -	$ -
		Operating Deductions															
33		O & M	$ -	$ -	$ -	$(740,391)	$ -	$ -	$ -	$ -	$ -	$(11,548,891)	$(59,581,369)	$(7,450,206)	$ -	$ -	$(34,551,775)
34		A & G	-	-	-	(341,229)	-	-	-	-	-	(5,322,610)	(27,459,640)	(3,433,623)	-	-	(15,924,093)
35		Depreciation Expense	-	-	-	-	-	-	-	-	-	(15,111,118)	(59,181,574)	(1,656,956)	-	-	-
36		Interest on Customer Deposits	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(717,364)
37		Taxes other than Income	-	-	-	-	-	-	-	-	-	(7,418,884)	(25,074,709)	(961,530)	-	-	-

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
DATA ENTRY AND CLASSIFICATION OF COSTS

Line No.	Acct No.	Description	Production Specific	Production Demand	Production Customer	Production Commodity	Transmission Specific	Transmission Demand	Transmission Customer	Transmission Commodity	Distribution Specific	Distribution Demand	Distribution Customer	Distribution Commodity	Customer Accounting Specific	Customer Accounting Demand	Customer Accounting Customer
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
		State Income Tax															
1		Taxable Income before Interest Exp.	$ -	$ -	$ -	$(1,081,620)	$ -	$ -	$ -	$ -	$ -	$ 32,196,058	$ 70,691,668	$(4,222,859)	$ -	$ -	$(51,193,232)
2		Interest Expense	-	-	-	-	-	-	-	-	-	(8,985,904)	(30,371,001)	(1,164,625)	-	-	-
3		State Taxable Income	$ -	$ -	$ -	$(1,081,620)	$ -	$ -	$ -	$ -	$ -	$ 23,210,154	$ 40,320,668	$(5,387,484)	$ -	$ -	$(51,193,232)
4		State Income Tax @ 6.9680%	$ -	$ -	$ -	$(75,367)	$ -	$ -	$ -	$ -	$ -	$ 1,617,284	$ 2,809,544	$(375,400)	$ -	$ -	$(3,567,144)
5		South Georgia	-	-	-	-	-	-	-	-	-	17,080	57,727	2,214	-	-	-
6		State Income Tax	$ -	$ -	$ -	$(75,367)	$ -	$ -	$ -	$ -	$ -	$ 1,634,363	$ 2,867,271	$(373,186)	$ -	$ -	$(3,567,144)
		Federal Income Tax															
7		Taxable Income before Interest Exp.	$ -	$ -	$ -	$(1,081,620)	$ -	$ -	$ -	$ -	$ -	$ 32,196,058	$ 70,691,668	$(4,222,859)	$ -	$ -	$(51,193,232)
8		Interest Expense	-	-	-	-	-	-	-	-	-	(8,985,904)	(30,371,001)	(1,164,625)	-	-	-
9		Federal Taxable Income	$ -	$ -	$ -	$(1,081,620)	$ -	$ -	$ -	$ -	$ -	$ 23,210,154	$ 40,320,668	$(5,387,484)	$ -	$ -	$(51,193,232)
10		Federal Income Tax @ 32.5612%	$ -	$ -	$ -	$(352,188)	$ -	$ -	$ -	$ -	$ -	$ 7,557,505	$ 13,128,893	$(1,754,229)	$ -	$ -	$(16,669,131)
11		I T C	-	-	-	-	-	-	-	-	-	(117,165)	(396,001)	(15,185)	-	-	-
12		South Georgia	-	-	-	-	-	-	-	-	-	63,917	216,031	8,284	-	-	-
13		Total Federal Income Tax	$ -	$ -	$ -	$(352,188)	$ -	$ -	$ -	$ -	$ -	$ 7,504,257	$ 12,948,923	$(1,761,131)	$ -	$ -	$(16,669,131)
14		Regulatory Amortization	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15		Net Income	$ -	$ -	$ -	$(654,064)	$ -	$ -	$ -	$ -	$ -	$ 23,057,438	$ 54,875,474	$(2,088,542)	$ -	$ -	$(30,956,957)

SCHEDULE G-7A
SHEET 1 of 4

SOUTHWEST GAS CORPORATION
ARIZONA
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDING
AUGUST 31, 2004

Line No.	Description	Allocation Factor No.	Total	Residential Gas Service Demand	Residential Gas Service Customer	Residential Gas Service Commodity	MMMHP Gas Service Demand	MMMHP Gas Service Customer	MMMHP Gas Service Commodity	Small General Gas Service Demand	Small General Gas Service Customer	Small General Gas Service Commodity	Medium General Gas Service Demand	Medium General Gas Service Customer	Medium General Gas Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	CP Demand		1,212,685	666,498			5,761			86,942			216,398		
		1	100.0000%	54.960501%	0.000000%	0.000000%	0.475091%	0.000000%	0.000000%	7.169404%	0.000000%	0.000000%	17.844511%	0.000000%	0.000000%
2	NCP Demand		1,363,797	666,498			5,761			86,942			216,398		
		2	100.0000%	48.870737%	0.000000%	0.000000%	0.422450%	0.000000%	0.000000%	6.375016%	0.000000%	0.000000%	15.867294%	0.000000%	0.000000%
3	Throughput		605,776,598	0		285,161,248			2,452,509			47,860,619			140,285,500
		3	100.0000%	0.000000%	0.000000%	47.073665%	0.000000%	0.000000%	0.404854%	0.000000%	0.000000%	7.900705%	0.000000%	0.000000%	23.157960%
4	Customers		863,424		822,223			189			32,793			6,937	
		4	100.0000%	0.000000%	95.228204%	0.000000%	0.000000%	0.021890%	0.000000%	0.000000%	3.798027%	0.000000%	0.000000%	0.803468%	0.000000%
5	Customers With Mains		863,424	0	822,223	0	0	189	0	0	32,793	0	0	6,937	0
		5	100.0000%	0.000000%	95.228204%	0.000000%	0.000000%	0.021890%	0.000000%	0.000000%	3.798027%	0.000000%	0.000000%	0.803468%	0.000000%
6	Meters for Customers		1,121,103		822,223			3,529			123,262			112,826	
		6	100.0000%	0.000000%	73.340567%	0.000000%	0.000000%	0.314802%	0.000000%	0.000000%	10.994676%	0.000000%	0.000000%	10.063856%	0.000000%
7	Service Lines for Customers		1,018,790		822,223			980			146,977			36,064	
		7	100.0000%	0.000000%	80.705826%	0.000000%	0.000000%	0.096147%	0.000000%	0.000000%	14.426659%	0.000000%	0.000000%	3.539910%	0.000000%
8	Residential & General Service(Sm & Med)		862,143	0	822,223	0	0	189	0	0	32,793	0	0	6,937	
		8	100.0000%	0.000000%	95.369744%	0.000000%	0.000000%	0.021922%	0.000000%	0.000000%	3.803672%	0.000000%	0.000000%	0.804662%	0.000000%
9	Extra		0	0	0	0	0	0	0	0	0	0	0	0	0
		9	0.0000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
10	Extra		0	0	0	0	0	0	0	0	0	0	0	0	0
		10	0.0000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0	0	0	0	0	0	0	0	0	0
		11	0.0000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		151	0	0	0	0	0	0	0	0	0	0	0	0
		12	100.0000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		938,649	0	822,223	0	0	1,401	0	0	82,638	0	0	21,852	0
		13	100.0000%	0.000000%	87.596412%	0.000000%	0.000000%	0.149238%	0.000000%	0.000000%	8.803967%	0.000000%	0.000000%	2.327978%	0.000000%
14	Extra		0	0	0	0	0	0	0	0	0	0	0	0	0
		14	0.0000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0	0	0	0	0	0	0	0	0	0
		15	0.0000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors														
	Net Production, Transmission, & Distribution Plant		975,240,756	115,014,611	631,729,584	12,767,464	994,212	756,940	109,806	15,003,251	69,556,872	2,142,853	37,342,809	25,940,518	6,280,973
16		1.1	100.0000%	11.793458%	64.776783%	1.309160%	0.101945%	0.077616%	0.011259%	1.538415%	7.132277%	0.219726%	3.829086%	2.659909%	0.644043%
	Distribution Mains		516,273,776	114,571,685	293,123,754	0	990,384	67,379	0	14,945,473	11,690,781	0	37,199,001	2,473,169	0
17		2.2	100.0000%	22.192040%	56.776805%	0.000000%	0.191833%	0.013051%	0.000000%	2.894874%	2.264454%	0.000000%	7.205286%	0.479042%	0.000000%
	Distribution Services		305,210,571	0	246,322,712	0	0	293,451	0	0	44,031,688	0	0	10,804,180	0
18		3.3	100.0000%	0.000000%	80.705826%	0.000000%	0.000000%	0.096147%	0.000000%	0.000000%	14.426659%	0.000000%	0.000000%	3.539910%	0.000000%
	Distribution Mains & Services		821,484,347	114,571,686	539,446,466	0	990,384	360,830	0	14,945,473	55,722,469	0	37,199,001	13,277,349	0
19		4.4	100.0000%	13.946910%	65.667285%	0.000000%	0.120560%	0.043924%	0.000000%	1.819325%	6.783144%	0.000000%	4.528267%	1.616263%	0.000000%
	Allocable Distribution Operating Expenses		29,109,484	1,553,947	17,998,894	1,601,557	13,433	50,746	13,774	202,707	2,357,185	268,801	504,534	1,645,920	787,889
20		5.5	100.0000%	5.338286%	61.831716%	5.501840%	0.046145%	0.174328%	0.047318%	0.696361%	8.097653%	0.923413%	1.733228%	5.654240%	2.706639%
	Allocable Distribution Maintenance Expenses		25,652,348	3,027,054	15,710,674	917,008	26,167	15,752	7,887	394,869	1,704,580	153,908	982,820	550,251	451,124
21		6.6	100.0000%	11.800300%	61.244583%	3.574754%	0.102004%	0.061404%	0.030744%	1.539308%	6.644929%	0.599976%	3.831308%	2.145032%	1.758605%
	Transmission Operating Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
22		7.7	0.0000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Transmission Mains		0	0	0	0	0	0	0	0	0	0	0	0	0
23		8.8	0.0000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Transmission Maintenance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
24		9.9	0.0000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Customer Accounting Expense		29,816,420	0	26,232,450	0	0	42,590	0	0	2,550,031	0	0	671,280	0
25		10.1	100.0000%	0.000000%	87.979878%	0.000000%	0.000000%	0.142840%	0.000000%	0.000000%	8.552439%	0.000000%	0.000000%	2.251378%	0.000000%
	Total O & M Expense		113,872,632	6,034,978	78,816,964	4,123,143	52,168	154,220	35,461	787,242	8,905,894	692,016	1,959,430	4,222,155	2,028,386
		11.2	100.0000%	5.299761%	69.215019%	3.620837%	0.045812%	0.135432%	0.031141%	0.691335%	7.820925%	0.607711%	1.720720%	3.707787%	1.781276%

SOUTHWEST GAS CORPORATION
ARIZONA
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDING
AUGUST 31, 2004

Line No.	Description	Allocation Factor No.	Large General Gas Service Demand	Large General Gas Service Customer	Large General Gas Service Commodity	Gas Service to Armed Forces Demand	Gas Service to Armed Forces Customer	Gas Service to Armed Forces Commodity	Air-Conditioning Gas Service Demand	Air-Conditioning Gas Service Customer	Air-Conditioning Gas Service Commodity	CNG - Small Demand	CNG - Small Customer	CNG - Small Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	CP Demand		174,278			23,176			804			163		
		1	14.371252%	0.000000%	0.000000%	1.911110%	0.000000%	0.000000%	0.066340%	0.000000%	0.000000%	0.013437%	0.000000%	0.000000%
2	NCP Demand		174,278			23,176			5,469			614		
		2	12.778881%	0.000000%	0.000000%	1.699354%	0.000000%	0.000000%	0.401028%	0.000000%	0.000000%	0.045054%	0.000000%	0.000000%
3	Throughput				73,667,816			3,168,716			1,836,544			182,313
		3	0.000000%	0.000000%	12.160888%	0.000000%	0.000000%	0.523083%	0.000000%	0.000000%	0.303172%	0.000000%	0.000000%	0.030096%
4	Customers			151			9			37			22	
		4	0.000000%	0.017489%	0.000000%	0.000000%	0.001042%	0.000000%	0.000000%	0.004334%	0.000000%	0.000000%	0.002548%	0.000000%
5	Customers With Mains		0	151	0	0	9	0	0	37	0	0	22	0
		5	0.000000%	0.017489%	0.000000%	0.000000%	0.001042%	0.000000%	0.000000%	0.004334%	0.000000%	0.000000%	0.002548%	0.000000%
6	Meters for Customers			19,909			580			74			21	
		6	0.000000%	1.775818%	0.000000%	0.000000%	0.051739%	0.000000%	0.000000%	0.006627%	0.000000%	0.000000%	0.001897%	0.000000%
7	Service Lines for Customers			2,773			182			533			23	
		7	0.000000%	0.272224%	0.000000%	0.000000%	0.017897%	0.000000%	0.000000%	0.052273%	0.000000%	0.000000%	0.002280%	0.000000%
8	Residential & General Service(Sm & Med)													
		8	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
9	Extra		0	0	0	0	0	0	0	0	0	0	0	0
		9	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
10	Extra		0	0	0	0	0	0	0	0	0	0	0	0
		10	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0	0	0	0	0	0	0	0	0
		11	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		0	151	0	0	0	0	0	0	0	0	0	0
		12	0.000000%	100.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		0	634	0	0	142	0	0	239	0	0	69	0
		13	0.000000%	0.067565%	0.000000%	0.000000%	0.015101%	0.000000%	0.000000%	0.025505%	0.000000%	0.000000%	0.007383%	0.000000%
14	Extra		0	0	0	0	0	0	0	0	0	0	0	0
		14	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0	0	0	0	0	0	0	0	0
		15	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors													
16	Net Production, Transmission, & Distribution Plant		30,074,398	3,119,166	3,298,314	3,999,336	122,934	141,872	138,829	181,220	82,227	28,120	17,187	8,163
		1.1	3.083792%	0.319836%	0.338205%	0.410087%	0.012605%	0.014547%	0.014235%	0.018582%	0.008431%	0.002883%	0.001762%	0.000837%
17	Distribution Mains		29,958,581	53,832	0	3,983,935	3,209	0	138,294	13,339	0	28,012	7,843	0
		2.2	5.802848%	0.010427%	0.000000%	0.771671%	0.000621%	0.000000%	0.026787%	0.002584%	0.000000%	0.005426%	0.001519%	0.000000%
18	Distribution Services		0	830,855	0	0	54,623	0	0	159,542	0	0	6,958	0
		3.3	0.000000%	0.272224%	0.000000%	0.000000%	0.017897%	0.000000%	0.000000%	0.052273%	0.000000%	0.000000%	0.002280%	0.000000%
19	Distribution Mains & Services		29,958,581	884,687	0	3,983,935	57,832	0	138,294	172,881	0	28,012	14,801	0
		4.4	3.646884%	0.107694%	0.000000%	0.484968%	0.007040%	0.000000%	0.016835%	0.021045%	0.000000%	0.003410%	0.001802%	0.000000%
20	Allocable Distribution Operating Expenses		406,331	270,654	413,742	54,035	8,320	17,797	1,876	3,310	10,315	380	477	1,024
		5.5	1.395872%	0.929778%	1.421331%	0.185625%	0.028583%	0.061137%	0.006444%	0.011371%	0.035434%	0.001305%	0.001639%	0.003518%
21	Allocable Distribution Maintenance Expenses		791,524	58,112	236,898	105,258	2,556	10,190	3,654	4,777	5,906	740	429	586
		6.6	3.085581%	0.226537%	0.923493%	0.410325%	0.009963%	0.039723%	0.014244%	0.018621%	0.023023%	0.002885%	0.001672%	0.002285%
22	Transmission Operating Expense		0	0	0	0	0	0	0	0	0	0	0	0
		7.7	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
23	Transmission Mains		0	0	0	0	0	0	0	0	0	0	0	0
		8.8	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
24	Transmission Maintenance Expense		0	0	0	0	0	0	0	0	0	0	0	0
		9.9	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
25	Customer Accounting Expense		0	19,395	0	0	4,292	0	0	7,287	0	0	2,129	0
		10.1	0.000000%	0.065049%	0.000000%	0.000000%	0.014395%	0.000000%	0.000000%	0.024441%	0.000000%	0.000000%	0.007140%	0.000000%
	Total O & M Expense		1,578,046	552,858	1,065,162	209,851	22,136	45,816	7,285	19,451	26,555	1,475	3,766	2,636
		11.2	1.385799%	0.485505%	0.935398%	0.184286%	0.019439%	0.040235%	0.006397%	0.017081%	0.023320%	0.001296%	0.003307%	0.002315%

SCHEDULE G-7A
SHEET 3 of 4

SOUTHWEST GAS CORPORATION
ARIZONA
DEVELOPMENT OF ALLOCATION FACTORS
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Line No.	Description	Allocation Factor No.	Demand	CNG - Large Customer	Commodity	Demand	CNG - Residential Customer	Commodity	Demand	Cogeneration Gas Service Customer	Commodity	Demand	Small Essential Agr. User Gas Service Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	CP Demand		1,514			74			13,309			18,933		
		1	0.124809%	0.000000%	0.000000%	0.006138%	0.000000%	0.000000%	1.097500%	0.000000%	0.000000%	1.561239%	0.000000%	0.000000%
2	NCP Demand		13,309			265			45,747			18,933		
		2	0.975894%	0.000000%	0.000000%	0.019400%	0.000000%	0.000000%	3.354378%	0.000000%	0.000000%	1.388250%	0.000000%	0.000000%
3	Throughput				1,898,808			79,719			15,007,742			12,579,235
		3	0.000000%	0.000000%	0.313450%	0.000000%	0.000000%	0.013160%	0.000000%	0.000000%	2.477438%	0.000000%	0.000000%	2.076547%
4	Customers			27			110			23			112	
		4	0.000000%	0.003127%	0.000000%	0.000000%	0.012740%	0.000000%	0.000000%	0.002664%	0.000000%	0.000000%	0.013001%	0.000000%
5	Customers With Mains		0	27	0	0	110	0	0	23	0	0	112	0
		5	0.000000%	0.003127%	0.000000%	0.000000%	0.012740%	0.000000%	0.000000%	0.002664%	0.000000%	0.000000%	0.013001%	0.000000%
6	Meters for Customers			2,360			100			546			2,233	
		6	0.000000%	0.210549%	0.000000%	0.000000%	0.008958%	0.000000%	0.000000%	0.048741%	0.000000%	0.000000%	0.199186%	0.000000%
7	Service Lines for Customers			558			103			398			1,165	
		7	0.000000%	0.054764%	0.000000%	0.000000%	0.010156%	0.000000%	0.000000%	0.039051%	0.000000%	0.000000%	0.114387%	0.000000%
8	Residential & General Service(Sm & Med)													
		8	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
9	Extra		0	0	0	0	0	0	0	0	0	0	0	0
		9	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
10	Extra		0	0	0	0	0	0	0	0	0	0	0	0
		10	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0	0	0	0	0	0	0	0	0
		11	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		0	0	0	0	0	0	0	0	0	0	0	0
		12	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		0	113	0	0	110	0	0	97	0	0	3,528	0
		13	0.000000%	0.012081%	0.000000%	0.000000%	0.011719%	0.000000%	0.000000%	0.010291%	0.000000%	0.000000%	0.375859%	0.000000%
14	Extra		0	0	0	0	0	0	0	0	0	0	0	0
		14	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0	0	0	0	0	0	0	0	0
		15	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors													
	Net Production, Transmission, & Distribution Plant		261,186	441,702	85,015	12,845	81,486	3,569	2,296,714	188,716	671,938	3,267,170	639,773	563,207
16		1.1	0.026782%	0.045292%	0.008717%	0.001317%	0.008355%	0.000366%	0.235502%	0.019351%	0.068900%	0.335012%	0.065601%	0.057751%
	Distribution Mains		260,180	9,626	0	12,796	39,215	0	2,287,869	8,200	0	3,254,588	40,017	0
17		2.2	0.050396%	0.001864%	0.000000%	0.002478%	0.007596%	0.000000%	0.443150%	0.001588%	0.000000%	0.630400%	0.007751%	0.000000%
	Distribution Services		0	167,146	0	0	30,998	0	0	119,187	0	0	349,122	0
18		3.3	0.000000%	0.054764%	0.000000%	0.000000%	0.010156%	0.000000%	0.000000%	0.039051%	0.000000%	0.000000%	0.114387%	0.000000%
	Distribution Mains & Services		260,180	176,771	0	12,796	70,213	0	2,287,869	127,386	0	3,254,588	389,140	0
19		4.4	0.031672%	0.021518%	0.000000%	0.001558%	0.008547%	0.000000%	0.278504%	0.015507%	0.000000%	0.396184%	0.047370%	0.000000%
	Allocable Distribution Operating Expenses		3,529	33,065	10,664	174	2,257	448	31,031	8,827	84,288	44,142	34,290	70,649
20		5.5	0.012123%	0.113588%	0.036635%	0.000596%	0.007754%	0.001538%	0.106600%	0.030323%	0.289556%	0.151642%	0.117797%	0.242701%
	Allocable Distribution Maintenance Expenses		6,874	8,825	6,106	338	2,033	256	60,447	4,369	48,261	85,988	14,304	40,452
21		6.6	0.026797%	0.034402%	0.023803%	0.001318%	0.007924%	0.000999%	0.235639%	0.017030%	0.188136%	0.335206%	0.055761%	0.157692%
	Transmission Operating Expense		0	0	0	0	0	0	0	0	0	0	0	0
22		7.7	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Transmission Mains		0	0	0	0	0	0	0	0	0	0	0	0
23		8.8	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Transmission Maintenance Expense		0	0	0	0	0	0	0	0	0	0	0	0
24		9.9	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Customer Accounting Expense		0	3,468	0	0	3,509	0	0	2,954	0	0	106,632	0
25		10.1	0.000000%	0.011631%	0.000000%	0.000000%	0.011770%	0.000000%	0.000000%	0.009908%	0.000000%	0.000000%	0.357627%	0.000000%
	Total O & M Expense		13,705	70,730	27,455	674	10,208	1,153	120,512	23,468	216,997	171,433	198,567	181,883
		11.2	0.012035%	0.062113%	0.024110%	0.000592%	0.008964%	0.001012%	0.105830%	0.020609%	0.190561%	0.150548%	0.174376%	0.159725%

SOUTHWEST GAS CORPORATION
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Line No.	Description	Allocation Factor No.	Natural Gas Engine Gas Service Demand	Natural Gas Engine Gas Service Customer	Natural Gas Engine Gas Service Commodity	Street Lighting Gas Service Demand	Street Lighting Gas Service Customer	Street Lighting Gas Service Commodity	Special Residential Gas Service - A/C Demand	Special Residential Gas Service - A/C Customer	Special Residential Gas Service - A/C Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	CP Demand		4,420			101			313		
		1	0.364507%	0.000000%	0.000000%	0.008347%	0.000000%	0.000000%	0.025813%	0.000000%	0.000000%
2	NCP Demand		105,993			101			313		
		2	7.771891%	0.000000%	0.000000%	0.007422%	0.000000%	0.000000%	0.022953%	0.000000%	0.000000%
3	Throughput				21,271,370			99,883			224,576
		3	0.000000%	0.000000%	3.511422%	0.000000%	0.000000%	0.016488%	0.000000%	0.000000%	0.037072%
4	Customers			604			29			157	
		4	0.000000%	0.069925%	0.000000%	0.000000%	0.003359%	0.000000%	0.000000%	0.018183%	0.000000%
5	Customers With Mains		0	604	0	0	29	0	0	157	0
		5	0.000000%	0.069925%	0.000000%	0.000000%	0.003359%	0.000000%	0.000000%	0.018183%	0.000000%
6	Meters for Customers			33,234			0			203	
		6	0.000000%	2.964440%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.018145%	0.000000%
7	Service Lines for Customers			6,776			34			0	
		7	0.000000%	0.665112%	0.000000%	0.000000%	0.003315%	0.000000%	0.000000%	0.000000%	0.000000%
8	Residential & General Service(Sm & Med)										
		8	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
9	Extra		0	0	0	0	0	0	0	0	0
		9	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
10	Extra		0	0	0	0	0	0	0	0	0
		10	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0	0	0	0	0	0
		11	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		0	0	0	0	0	0	0	0	0
		12	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		0	4,757	0	0	522	0	0	324	0
		13	0.000000%	0.506739%	0.000000%	0.000000%	0.055612%	0.000000%	0.000000%	0.034549%	0.000000%
14	Extra		0	0	0	0	0	0	0	0	0
		14	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0	0	0	0	0	0
		15	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors										
16	Net Production, Transmission, & Distribution Plant		762,796	5,975,331	952,379	17,467	20,455	4,472	54,019	78,802	10,055
		1.1	0.078216%	0.612703%	0.097656%	0.001791%	0.002097%	0.000459%	0.005539%	0.008080%	0.001031%
17	Distribution Mains		759,858	215,238	0	17,399	10,339	0	53,811	55,971	0
		2.2	0.147181%	0.041691%	0.000000%	0.003370%	0.002003%	0.000000%	0.010423%	0.010841%	0.000000%
18	Distribution Services		0	2,029,991	0	0	10,116	0	0	0	0
		3.3	0.000000%	0.665112%	0.000000%	0.000000%	0.003315%	0.000000%	0.000000%	0.000000%	0.000000%
19	Distribution Mains & Services		759,858	2,245,229	0	17,399	20,455	0	53,811	55,971	0
		4.4	0.092498%	0.273314%	0.000000%	0.002118%	0.002490%	0.000000%	0.006550%	0.006813%	0.000000%
20	Allocable Distribution Operating Expenses		10,306	462,234	119,467	236	277	561	730	3,402	1,261
		5.5	0.035404%	1.587915%	0.410405%	0.000811%	0.000953%	0.001927%	0.002507%	0.011687%	0.004333%
21	Allocable Distribution Maintenance Expenses		20,076	117,615	68,403	460	543	321	1,422	1,812	722
		6.6	0.078262%	0.458495%	0.266656%	0.001792%	0.002115%	0.001252%	0.005542%	0.007064%	0.002815%
22	Transmission Operating Expense		0	0	0	0	0	0	0	0	0
		7.7	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
23	Transmission Mains		0	0	0	0	0	0	0	0	0
		8.8	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
24	Transmission Maintenance Expense		0	0	0	0	0	0	0	0	0
		9.9	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
25	Customer Accounting Expense		0	144,547	0	0	15,799	0	0	10,056	0
		10.1	0.000000%	0.484791%	0.000000%	0.000000%	0.052986%	0.000000%	0.000000%	0.033727%	0.000000%
	Total O & M Expense		40,025	1,093,801	307,562	917	19,402	1,444	2,834	19,525	3,247
		11.2	0.035149%	0.960548%	0.270093%	0.000805%	0.017038%	0.001268%	0.002489%	0.017146%	0.002852%

SCHEDULE G-1 IS NOT APPLICABLE IN THE CLASS COST OF SERVICE STUDY AT PROPOSED RATES

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY SUMMARY
PROPOSED RATE SCHEDULES AT PRESENT RATES
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Description (a)	Allocation Factor No. (b)	Total Amount (c)	Total	Single Family Residential (d)	Multi-Family Residential (e)	MMMHP (f)	Small Gen. Service (g)	Medium Gen. Service (h)
	Rate Base								
1	Direct Net Plant		$1,051,372,747	$1,051,372,747	$ 778,840,783	$ 44,462,430	$ 1,991,380	$40,877,420	$55,797,181
2	Systems Allocable Net Plant		40,589,393	40,589,393	30,060,278	1,716,521	76,879	1,578,117	2,154,111
3	Cash Working Capital	11.2	(11,082,156)	(11,082,156)	(8,072,938)	(565,054)	(23,368)	(453,498)	(609,724)
4	Materials & Supplies	1.1	9,222,489	9,222,489	6,830,124	390,018	17,468	358,571	489,445
5	Prepayments	Direct Net Plant	2,740,815	2,740,815	2,029,832	115,909	5,191	106,563	145,457
6	Gas Plant Acquisition Adjustment	Direct Net Plant	-	-	-	-	-	-	-
7	Customer Deposits	8	(23,912,141)	(23,912,141)	(21,263,793)	(1,726,035)	(5,284)	(461,380)	(455,649)
8	Customer Advances	8	(7,027,372)	(7,027,372)	(6,249,068)	(507,252)	(1,553)	(135,592)	(133,908)
9	Deferred Taxes	1.1	(136,891,328)	(136,891,328)	(101,232,834)	(5,780,660)	(258,904)	(5,314,565)	(7,254,317)
10	Deferred Gain Hdqtrs Bldg	4	-	-	-	-	-	-	-
11	Total Rate Base		$ 925,212,447	$ 925,212,447	$ 680,742,385	$ 38,105,876	$ 1,801,811	$36,555,636	$50,132,597
	Margin								
12	Net Operating Margin	Direct	$ 305,070,666	$ 305,070,666	$ 196,580,278	$ 13,424,301	$ 883,856	$ 5,415,035	$20,350,243
13	Special Contract Margin	Net Op. Marg.	$ 7,611,429	$ 7,611,429	$ 4,904,624	$ 334,933	$ 22,052	$ 135,104	$ 507,733
14	Other Revenue	Net Op. Marg.	10,183,882	10,183,882	6,562,251	448,131	29,505	180,765	679,333
15	Total Revenue		$ 322,865,978	$ 322,865,978	$ 208,047,153	$ 14,207,364	$ 935,413	$ 5,730,904	$21,537,309
	Operating Deductions								
16	O & M		$(113,872,632)	$(113,872,632)	$(82,951,970)	$(5,806,106)	$(240,114)	$(4,659,834)	$(6,265,102)
17	A & G	O & M	(52,481,195)	(52,481,195)	(38,230,595)	(2,675,896)	(110,663)	(2,147,607)	(2,887,437)
18	Depreciation Expense		(75,949,648)	(75,949,648)	(56,247,885)	(3,211,902)	(143,854)	(2,952,926)	(4,030,708)
19	Interest on Customer Deposits	8	(717,364)	(717,364)	(637,914)	(51,781)	(159)	(13,841)	(13,669)
20	Taxes other than Income	1.1	(33,455,124)	(33,455,124)	(24,776,678)	(1,414,813)	(63,367)	(1,300,737)	(1,775,490)
21	Total Operating Deductions		$(276,475,963)	$(276,475,963)	$(202,845,042)	$(13,160,498)	$(558,157)	$(11,074,945)	$(14,972,406)
	State Income Tax								
22	Taxable Income before Interest Exp.		$ 46,390,015	$ 46,390,015	$ 5,202,111	$ 1,046,866	$ 377,256	$(5,344,041)	$ 6,564,903
23	Interest Expense	1.1	(40,521,530)	(40,521,530)	(30,010,018)	(1,713,651)	(76,751)	(1,575,479)	(2,150,510)
24	State Taxable Income		$ 5,868,486	$ 5,868,486	$(24,807,907)	$(666,785)	$ 300,505	$(6,919,520)	$ 4,414,394
25	State Income Tax		408,916	408,916	(1,728,615)	(46,462)	20,939	(482,152)	307,595
26	South Georgia	1.1	77,020	77,020	57,041	3,257	146	2,995	4,088
27	Total State Income Tax		$ 485,936	$ 485,936	$(1,671,574)	$(43,204)	$ 21,085	$(479,158)	$ 311,682
	Federal Income Tax								
28	Taxable Income before Interest Exp.		$ 46,390,015	$ 46,390,015	$ 5,202,111	$ 1,046,866	$ 377,256	$(5,344,041)	$ 6,564,903
29	Interest Expense		(40,521,530)	(40,521,530)	(30,010,018)	(1,713,651)	(76,751)	(1,575,479)	(2,150,510)
30	Federal Taxable Income		$ 5,868,486	$ 5,868,486	$(24,807,907)	$(666,785)	$ 300,505	$(6,919,520)	$ 4,414,394
31	Federal Income Tax		$ 1,910,849	$ 1,910,849	$(8,077,752)	$(217,113)	$ 97,848	$(2,253,079)	$ 1,437,380
32	I T C	1.1	(528,352)	(528,352)	(391,295)	(22,344)	(1,001)	(20,542)	(28,040)
33	South Georgia	1.1	288,233	288,233	213,464	12,189	546	11,207	15,297
34	Total Federal Income Tax		$ 1,670,730	$ 1,670,730	$(8,255,583)	$(227,268)	$ 97,393	$(2,262,415)	$ 1,424,636
35	Regulatory Amortization	Depr. Exp.	-	-	-	-	-	-	-
36	Net Income		$ 44,233,349	$ 44,233,349	$ 15,129,269	$ 1,317,338	$ 258,778	$(2,602,469)	$ 4,828,584
37	Rate of Return on Rate Base		4.78%	4.78%	2.22%	3.46%	14.36%	(7.12%)	9.63%

Line No.	Description (a)	Large Gen. Service (i)	Trans. Eligible Service (j)	Air Conditioning (k)	CNG Small (l)	CNG Large (m)	CNG Residential (n)	Electric Generation (o)	Small Ess. Agr. (p)	Natural Gas Engines (q)	Street Lighting (r)	Line No.
	Rate Base											
1	Direct Net Plant	$ 87,369,001	$ 27,209,107	$ 428,699	$ 57,198	$ 849,187	$ 89,186	$ 3,346,035	$1,857,095	$ 8,352,328	$ 45,716	1
2	Systems Allocable Net Plant	3,372,976	1,050,437	16,550	2,208	32,784	3,443	129,177	71,695	322,451	1,765	2
3	Cash Working Capital	(878,596)	(268,640)	(5,150)	(761)	(10,865)	(1,086)	(34,848)	(15,456)	(140,079)	(2,091)	3
4	Materials & Supplies	766,388	238,674	3,760	502	7,449	782	29,351	16,290	73,265	401	4
5	Prepayments	227,762	70,931	1,118	149	2,214	232	8,723	4,841	21,774	119	5
6	Gas Plant Acquisition Adjustment	-	-	-	-	-	-	-	-	-	-	6
7	Customer Deposits	-	-	-	-	-	-	-	-	-	-	7
8	Customer Advances	-	-	-	-	-	-	-	-	-	-	8
9	Deferred Taxes	(11,359,040)	(3,537,517)	(55,736)	(7,436)	(110,405)	(11,595)	(435,025)	(241,445)	(1,085,905)	(5,944)	9
10	Deferred Gain Hdqtrs Bldg	-	-	-	-	-	-	-	-	-	-	10
11	Total Rate Base	$ 79,498,488	$ 24,762,993	$ 389,242	$ 51,860	$ 770,364	$ 80,963	$ 3,043,412	$1,693,020	$ 7,543,834	$ 39,966	11
	Margin											
12	Net Operating Margin	$ 46,243,388	$ 15,855,591	$ 167,216	$ 29,537	$ 307,716	$ 21,167	$ 1,405,352	$ 605,972	$ 3,733,422	$ 47,592	12
13	Special Contract Margin	$ 1,153,760	$ 395,593	$ 4,172	$ 737	$ 7,677	$ 528	$ 35,063	$ 15,119	$ 93,148	$ 1,187	13
14	Other Revenue	1,543,699	529,292	5,582	986	10,272	707	46,914	20,229	124,629	1,589	14
15	Total Revenue	$ 48,940,847	$ 16,780,476	$ 176,970	$ 31,260	$ 325,666	$ 22,402	$ 1,487,329	$ 641,319	$ 3,951,199	$ 50,368	15
	Operating Deductions											
16	O & M	$(9,027,873)	$(2,760,364)	$(52,919)	$(7,817)	$(111,643)	$(11,160)	$(358,074)	$(158,819)	$(1,439,354)	$(21,484)	16
17	A & G	(4,160,733)	(1,272,186)	(24,389)	(3,603)	(51,454)	(5,143)	(165,028)	(73,196)	(663,364)	(9,901)	17
18	Depreciation Expense	(6,311,410)	(1,965,547)	(30,969)	(4,132)	(61,344)	(6,443)	(241,713)	(134,154)	(603,360)	(3,302)	18
19	Interest on Customer Deposits	-	-	-	-	-	-	-	-	-	-	19
20	Taxes other than Income	(2,780,118)	(865,805)	(13,641)	(1,820)	(27,021)	(2,838)	(106,472)	(59,094)	(265,775)	(1,455)	20
21	Total Operating Deductions	$(22,280,134)	$(6,863,902)	$(121,918)	$(17,371)	$(251,462)	$(25,584)	$(871,286)	$(425,263)	$(2,971,852)	$(36,142)	21
	State Income Tax											
22	Taxable Income before Interest Exp.	$ 26,660,712	$ 9,916,574	$ 55,052	$ 13,889	$ 74,203	$(3,182)	$ 616,042	$ 216,056	$ 979,347	$ 14,226	22
23	Interest Expense	(3,367,336)	(1,048,681)	(16,523)	(2,204)	(32,729)	(3,437)	(128,961)	(71,575)	(321,912)	(1,762)	23
24	State Taxable Income	$ 23,293,376	$ 8,867,893	$ 38,529	$ 11,684	$ 41,474	$(6,620)	$ 487,081	$ 144,481	$ 657,435	$ 12,464	24
25	State Income Tax	1,623,082	617,915	2,685	814	2,890	(461)	33,940	10,067	45,810	869	25
26	South Georgia	6,400	1,993	31	4	62	7	245	136	612	3	26
27	Total State Income Tax	$ 1,629,483	$ 619,908	$ 2,716	$ 818	$ 2,952	$(455)	$ 34,185	$ 10,203	$ 46,422	$ 872	27
	Federal Income Tax											
28	Taxable Income before Interest Exp.	$ 26,660,712	$ 9,916,574	$ 55,052	$ 13,889	$ 74,203	$(3,182)	$ 616,042	$ 216,056	$ 979,347	$ 14,226	28
29	Interest Expense	(3,367,336)	(1,048,681)	(16,523)	(2,204)	(32,729)	(3,437)	(128,961)	(71,575)	(321,912)	(1,762)	29
30	Federal Taxable Income	$ 23,293,376	$ 8,867,893	$ 38,529	$ 11,684	$ 41,474	$(6,620)	$ 487,081	$ 144,481	$ 657,435	$ 12,464	30
31	Federal Income Tax	$ 7,584,603	$ 2,887,492	$ 12,546	$ 3,804	$ 13,505	$(2,155)	$ 158,599	$ 47,045	$ 214,069	$ 4,058	31
32	I T C	(43,906)	(13,674)	(215)	(29)	(427)	(45)	(1,682)	(933)	(4,197)	(23)	32
33	South Georgia	23,952	7,459	118	16	233	24	917	509	2,290	13	33
34	Total Federal Income Tax	$ 7,564,649	$ 2,881,278	$ 12,448	$ 3,791	$ 13,311	$(2,176)	$ 157,835	$ 46,621	$ 212,161	$ 4,048	34
35	Regulatory Amortization	-	-	-	-	-	-	-	-	-	-	35
36	Net Income	$ 17,466,581	$ 6,415,388	$ 39,888	$ 9,279	$ 57,941	$(562)	$ 424,022	$ 159,232	$ 720,764	$ 9,306	36
37	Rate of Return on Rate Base	21.97%	25.91%	10.25%	17.89%	7.52%	(0.68%)	13.93%	9.41%	9.55%	23.29%	37

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY SUMMARY
PROPOSED RATE SCHEDULES AT PROPOSED RATES
TEST YEAR ENDING AUGUST 31, 2004

Line No.	Description (a)	Allocation Factor No. (b)	Total Amount (c)	Total	Single Family Residential (d)	Multi-Family Residential (e)	MMMHP (f)	Small Gen. Service (g)	Medium Gen. Service (h)
	Rate Base								
1	Direct Net Plant		$1,051,372,747	$1,051,372,747	$ 778,640,783	$ 44,462,430	$ 1,991,380	$40,877,420	$55,797,181
2	Systems Allocable Net Plant		40,589,393	40,589,393	30,060,278	1,716,521	76,879	1,578,117	2,154,111
3	Cash Working Capital	11.2	(11,082,156)	(11,082,156)	(8,072,938)	(565,054)	(23,368)	(453,498)	(509,724)
4	Materials & Supplies	1.1	9,222,489	9,222,489	6,830,124	390,018	17,468	358,571	489,445
5	Prepayments	Direct Net Plant	2,740,815	2,740,815	2,029,832	115,909	5,191	106,563	145,457
6	Gas Plant Acquisition Adjustment	Direct Net Plant	-	-	-	-	-	-	-
7	Customer Deposits	8	(23,912,141)	(23,912,141)	(21,263,793)	(1,726,035)	(5,284)	(461,380)	(455,649)
8	Customer Advances	8	(7,027,372)	(7,027,372)	(6,249,068)	(507,252)	(1,553)	(135,592)	(133,908)
9	Deferred Taxes	1.1	(136,691,328)	(136,691,328)	(101,232,834)	(5,780,680)	(258,904)	(5,314,565)	(7,254,317)
10	Deferred Gain Hdqtrs Bldg	4	-	-	-	-	-	-	-
11	Total Rate Base		$ 925,212,447	$ 925,212,447	$ 680,742,385	$ 38,105,876	$ 1,801,811	$38,555,636	$50,132,597
12	Net Operating Margin	Direct	$ 374,561,561	$ 374,561,561	$ 249,459,371	$ 16,740,546	$ 1,018,249	$ 7,567,224	$24,095,859
13	Special Contract&Optional&Resale N	Net Op. Marg.	$ 7,678,169	$ 7,678,169	$ 5,113,689	$ 343,166	$ 20,873	$ 155,121	$ 493,943
14	Other Revenue	Net Op. Marg.	11,434,480	11,434,480	7,368,107	503,162	33,128	202,963	762,756
15	Total Revenue		$ 393,674,210	$ 393,674,210	$ 261,941,167	$ 17,586,874	$ 1,072,250	$ 7,925,308	$25,352,558
	Operating Deductions								
16	O & M		$(114,028,490)	$(114,028,490)	$(83,089,274)	$(5,817,251)	$(240,148)	$(4,662,813)	$(6,268,044)
17	A & G	O & M	(52,481,195)	(52,481,195)	(38,230,595)	(2,675,896)	(110,663)	(2,147,607)	(2,887,437)
18	Depreciation Expense		(75,949,648)	(75,949,648)	(56,247,885)	(3,211,902)	(143,854)	(2,952,926)	(4,030,708)
19	Interest on Customer Deposits	8	(717,364)	(717,364)	(637,914)	(51,781)	(159)	(13,841)	(13,669)
20	Taxes other than Income	1.1	(33,455,124)	(33,455,124)	(24,776,678)	(1,414,813)	(63,367)	(1,300,737)	(1,775,490)
21	Total Operating Deductions		$(276,631,821)	$(276,631,821)	$(202,982,346)	$(13,171,644)	$(558,191)	$(11,077,924)	$(14,975,348)
	State Income Tax								
22	Taxable Income before Interest Exp.		$ 117,042,389	$ 117,042,389	$ 58,958,820	$ 4,415,230	$ 514,059	$(3,152,616)	$10,377,210
23	Interest Expense	1.1	(40,521,530)	(40,521,530)	(30,010,018)	(1,713,651)	(76,751)	(1,575,479)	(2,150,510)
24	State Taxable Income		$ 76,520,860	$ 76,520,860	$ 28,948,802	$ 2,701,579	$ 437,309	$(4,728,094)	$ 8,226,701
25	State Income Tax		$ 5,331,974	5,331,974	$ 2,017,153	$ 188,246	$ 30,472	$(329,454)	$ 573,237
26	South Georgia	1.1	77,020	77,020	57,041	3,257	146	2,995	4,088
27	Total State Income Tax		$ 5,408,994	$ 5,408,994	$ 2,074,193	$ 191,503	$ 30,618	$(326,459)	$ 577,324
	Federal Income Tax								
28	Taxable Income before Interest Exp.		$ 117,042,389	117,042,389	$ 58,958,820	$ 4,415,230	$ 514,059	$(3,152,616)	$10,377,210
29	Interest Expense		(40,521,530)	(40,521,530)	(30,010,018)	(1,713,651)	(76,751)	(1,575,479)	(2,150,510)
30	Net Taxable Income		$ 76,520,860	$ 76,520,860	$ 28,948,802	$ 2,701,579	$ 437,309	$(4,728,094)	$ 8,226,701
31	Federal Income Tax		$ 24,916,110	$ 24,916,110	$ 9,426,077	$ 879,667	$ 142,393	$(1,539,524)	$ 2,678,712
32	I T C	1.1	(528,352)	(528,352)	(391,295)	(22,344)	(1,001)	(20,542)	(28,040)
33	South Georgia	1.1	288,233	288,233	213,464	12,189	546	11,207	15,297
34	Total Federal Income Tax		$ 24,675,991	$ 24,675,991	$ 9,248,247	$ 869,512	$ 141,938	$(1,548,860)	$ 2,665,969
35	Regulatory Amortization	Depr. Exp.	-	0	-	-	-	-	-
36	Net Income		$ 86,957,405	$ 86,957,405	$ 47,636,381	$ 3,354,215	$ 341,504	$(1,277,296)	$ 7,133,917
37	Rate of Return on Rate Base		9.40%	9.40%	7.00%	8.80%	18.95%	(3.49%)	14.23%

Line No.	Description (a)	Large Gen. Service (i)	Trans. Eligible Service (j)	Air Conditioning (k)	CNG Small (l)	CNG Large (m)	CNG Residential (n)	Electric Generation (o)	Small Ess. Agr. (p)	Gas Engines (q)	Street Lighting (r)	Line No.
	Rate Base											
1	Direct Net Plant	$ 87,369,001	$ 27,209,107	$ 428,699	$ 57,198	$ 849,187	$ 89,186	$ 3,346,035	$1,857,095	$ 8,352,328	$ 45,716	1
2	Systems Allocable Net Plant	3,372,976	1,050,437	16,550	2,208	32,784	3,443	129,177	71,695	322,451	1,765	2
3	Cash Working Capital	(878,598)	(268,640)	(5,150)	(761)	(10,865)	(1,086)	(34,848)	(15,456)	(140,079)	(2,091)	3
4	Materials & Supplies	766,388	238,674	3,760	502	7,449	782	29,351	16,290	73,265	401	4
5	Prepayments	227,762	70,931	1,118	149	2,214	232	8,723	4,841	21,774	119	5
6	Gas Plant Acquisition Adjustment	-	-	-	-	-	-	-	-	-	-	6
7	Customer Deposits	-	-	-	-	-	-	-	-	-	-	7
8	Customer Advances	-	-	-	-	-	-	-	-	-	-	8
9	Deferred Taxes	(11,359,040)	(3,537,517)	(55,736)	(7,436)	(110,405)	(11,595)	(435,025)	(241,445)	(1,085,905)	(5,944)	9
10	Deferred Gain Hdqtrs Bldg	-	-	-	-	-	-	-	-	-	-	10
11	Total Rate Base	$ 79,498,488	$ 24,762,993	$ 389,242	$ 51,860	$ 770,364	$ 80,963	$ 3,043,412	$1,693,020	$ 7,543,834	$ 39,966	11
12	Net Operating Margin	$ 51,491,636	$ 17,433,222	$ 197,199	$ 31,520	$ 372,948	$ 26,737	$ 1,620,489	$ 718,644	$ 3,733,337	$ 54,580	12
13	Special Contract&Optional&Resale N	$ 1,055,531	$ 357,365	$ 4,042	$ 646	$ 7,645	$ 548	$ 33,219	$ 14,732	$ 76,530	$ 1,119	13
14	Other Revenue	1,733,268	594,290	6,267	1,107	11,534	793	52,675	22,713	139,934	1,784	14
15	Total Revenue	$ 54,280,435	$ 18,384,877	$ 207,509	$ 33,273	$ 392,127	$ 28,078	$ 1,706,362	$ 756,088	$ 3,949,801	$ 57,483	15
	Operating Deductions											
16	O & M	$(9,029,135)	$(2,760,395)	$(52,926)	$(7,821)	$(111,648)	$(11,180)	$(358,078)	$(158,826)	$(1,439,463)	$(21,489)	16
17	A & G	(4,160,733)	(1,272,186)	(24,389)	(3,603)	(51,454)	(5,143)	(165,028)	(73,196)	(663,364)	(9,901)	17
18	Depreciation Expense	(6,311,410)	(1,965,547)	(30,969)	(4,132)	(61,344)	(6,443)	(241,713)	(134,154)	(603,380)	(3,302)	18
19	Interest on Customer Deposits	-	-	-	-	-	-	-	-	-	-	19
20	Taxes other than Income	(2,780,118)	(865,805)	(13,641)	(1,820)	(27,021)	(2,838)	(106,472)	(59,094)	(265,775)	(1,455)	20
21	Total Operating Deductions	$(22,281,396)	$(6,863,933)	$(121,925)	$(17,375)	$(251,467)	$(25,604)	$(871,290)	$(425,270)	$(2,971,961)	$(36,147)	21
	State Income Tax											
22	Taxable Income before Interest Exp.	$ 31,999,039	$ 11,520,944	$ 85,584	$ 15,898	$ 140,660	$ 2,475	$ 835,092	$ 330,819	$ 977,840	$ 21,335	22
23	Interest Expense	(3,367,336)	(1,048,681)	(16,523)	(2,204)	(32,729)	(3,437)	(128,961)	(71,575)	(321,912)	(1,762)	23
24	State Taxable Income	$ 28,631,702	$ 10,472,263	$ 69,061	$ 13,693	$ 107,931	$(963)	$ 706,130	$ 259,243	$ 655,928	$ 19,574	24
25	State Income Tax	$ 1,995,057	$ 729,707	$ 4,812	$ 954	$ 7,521	$(67)	$ 49,203	$ 18,064	$ 45,705	$ 1,364	25
26	South Georgia	6,400	1,993	31	4	62	7	245	136	612	3	26
27	Total State Income Tax	$ 2,001,457	$ 731,701	$ 4,844	$ 958	$ 7,583	$(61)	$ 49,448	$ 18,200	$ 46,317	$ 1,367	27
	Federal Income Tax											
28	Taxable Income before Interest Exp.	$ 31,999,039	$ 11,520,944	$ 85,584	$ 15,898	$ 140,660	$ 2,475	$ 835,092	$ 330,819	$ 977,840	$ 21,335	28
29	Interest Expense	(3,367,336)	(1,048,681)	(16,523)	(2,204)	(32,729)	(3,437)	(128,961)	(71,575)	(321,912)	(1,762)	29
30	Net Taxable Income	$ 28,631,702	$ 10,472,263	$ 69,061	$ 13,693	$ 107,931	$(963)	$ 706,130	$ 259,243	$ 655,928	$ 19,574	30
31	Federal Income Tax	$ 9,322,826	$ 3,409,895	$ 22,487	$ 4,459	$ 35,143	$(314)	$ 229,925	$ 84,413	$ 213,578	$ 6,373	31
32	I T C	(43,906)	(13,674)	(215)	(29)	(427)	(45)	(1,682)	(933)	(4,197)	(23)	32
33	South Georgia	23,952	7,459	118	16	233	24	917	509	2,290	13	33
34	Total Federal Income Tax	$ 9,302,872	$ 3,403,680	$ 22,389	$ 4,446	$ 34,950	$(334)	$ 229,160	$ 83,989	$ 211,671	$ 6,363	34
35	Regulatory Amortization	-	-	-	-	-	-	-	-	-	-	35
36	Net Income	$ 20,694,709	$ 7,385,563	$ 58,351	$ 10,494	$ 98,127	$ 2,869	$ 556,483	$ 228,630	$ 719,852	$ 13,605	36
37	Rate of Return on Rate Base	26.03%	29.83%	14.99%	20.24%	12.74%	3.54%	18.28%	13.50%	9.54%	34.04%	37

SOUTHWEST GAS CORPORATION
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Residential Gas Service Demand	Residential Gas Service Customer	Residential Gas Service Commodity	Multi-Family Residential Demand	Multi-Family Residential Customer	Multi-Family Residential Commodity	MMMHP Gas Service Demand	MMMHP Gas Service Customer	MMMHP Gas Service Commodity	Small General Gas Service Demand	Small General Gas Service Customer	Small General Gas Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
		Net Plant in Service - Direct														
		Intangible														
1	301	Organization	1.1	$ 42,653	$ 5,064	$ 25,996	$ 528	$ 252	$ 1,521	$ 31	$ 42	$ 34	$ 5	$ 75	$ 1,576	$ 7
2	302	Franchise & Consent	1.1	1,185,155	140,722	722,332	14,665	6,990	42,267	863	1,177	934	133	2,076	43,797	206
3	303	Misc. Intangible	1.1	278,178	33,030	169,545	3,442	1,641	9,921	203	276	219	31	487	10,280	48
4		Total Intangible		$ 1,505,987	$ 178,817	$ 917,873	$ 18,635	$ 8,883	$ 53,709	$ 1,097	$ 1,496	$ 1,187	$ 170	$ 2,638	$ 55,653	$ 262
5		Allocation Percentage	Intang. Plant	100.00%	11.87%	60.95%	1.24%	0.59%	3.57%	0.07%	0.10%	0.08%	0.01%	0.18%	3.70%	0.02%
		Production														
6	326	Other Land & Land Rights	3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	332	Field Lines	3	-	-	-	-	-	-	-	-	-	-	-	-	-
8	334	Field Meas & Reg. Stations	3	-	-	-	-	-	-	-	-	-	-	-	-	-
9	336	Purification Equipment	3	-	-	-	-	-	-	-	-	-	-	-	-	-
10		Total Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11		Allocation Percentage	Prod. Plant	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		Transmission														
12	365	Land & Land Rights	1.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	365	Rights of Way	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
14	366	Structures-Compressor Stas.	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
15	366	Structures	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
16	367	Mains - Demand	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
17	367	Mains - Customer	4.0	-	-	-	-	-	-	-	-	-	-	-	-	-
18	367	Mains - Commodity	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-
19	367	Mains-Bridge	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
20	368	Compressor Stations	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
21	369	Measuring & Reg. Sta. Equip.	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
22	370	Communication Equip.	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
23	371	Other Equipment	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
24		Total Transmission		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25		Allocation Percentage	Trans. Plant	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		Distribution														
26	374	Land & Land Rights	1.0	$ 351,685	$ 194,604	$ -	$ -	$ 9,667	$ -	$ -	$ 1,628	$ -	$ -	$ 2,871	$ -	$ -
27	374	Rights of Way	1.0	445,985	246,785	-	-	12,259	-	-	2,065	-	-	3,640	-	-
28	375	Structures	1.0	47,682	26,385	-	-	1,311	-	-	221	-	-	389	-	-
29	376	Mains - Demand	1.0	208,461,866	115,351,773	-	-	5,729,984	-	-	965,044	-	-	1,701,513	-	-
30	376	Mains - Customer	5.0	307,811,910	-	271,168,317	-	-	22,011,408	-	-	67,379	-	-	5,883,789	-
31	376	Mains - Commodity	3.0	1	-	-	0	-	-	0	-	-	0	-	-	0
32	378	Measuring & Reg. Station	3.0	23,180,184	-	-	10,313,459	-	-	606,897	-	-	93,846	-	-	144,913
33	380	Services - Demand	1.0	0	0	-	-	0	-	-	0	-	-	0	-	-
34	380	Services - Customer	7.0	305,210,571	-	238,209,289	-	-	5,448,226	-	-	306,762	-	-	23,189,801	-
35	381	Meters	6.0	125,828,203	-	85,015,123	-	-	7,320,940	-	-	394,459	-	-	6,966,167	-
36	385	Industrial Meas. & Reg. Sta.	3.0	3,942,124	-	-	1,753,952	-	-	103,211	-	-	15,960	-	-	24,644
37	386	Other Prop. on Cust. Premises	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
38	387	Other Equipment	1.0	(39,455)	(21,832)	-	-	(1,084)	-	-	(183)	-	-	(322)	-	-
39		Total Distribution		$ 975,240,756	$ 115,797,715	$ 594,392,729	$ 12,067,411	$ 5,752,136	$ 34,780,573	$ 710,108	$ 968,775	$ 768,600	$ 109,806	$ 1,708,091	$ 36,039,757	$ 169,557
40		Allocation Percentage	Dist. Plant	100.00%	11.87%	60.95%	1.24%	0.59%	3.57%	0.07%	0.10%	0.08%	0.01%	0.18%	3.70%	0.02%
41	389-398	Total General Plant	1.1	$ 74,626,005	$ 8,860,910	$ 45,483,287	$ 923,406	$ 440,157	$ 2,661,430	$ 54,338	$ 74,131	$ 58,814	$ 8,402	$ 130,704	$ 2,757,784	$ 12,975
42		Total Net Plant-Direct		$ 1,051,372,747	$ 124,837,442	$ 640,793,889	$ 13,009,452	$ 6,201,175	$ 37,495,712	$ 765,543	$ 1,044,402	$ 828,601	$ 118,378	$ 1,841,433	$ 38,853,194	$ 182,794
		Systems Allocable Plant														
43	301-303	Intangible Plant	1.1	$ 26,400,863	$ 3,134,774	$ 16,090,879	$ 326,678	$ 155,717	$ 941,549	$ 19,223	$ 26,226	$ 20,807	$ 2,973	$ 46,240	$ 975,637	$ 4,590
44	389-398	General Plant	1.1	$ 14,188,530	$ 1,684,712	$ 8,647,669	$ 175,566	$ 83,686	$ 506,014	$ 10,331	$ 14,094	$ 11,182	$ 1,598	$ 24,851	$ 524,333	$ 2,467
45		Total Systems Allocable		40,589,393	4,819,486	24,738,548	502,244	239,403	1,447,563	29,555	40,320	31,989	4,570	71,091	1,499,970	7,057
46		Total Net Plant		$ 1,091,962,140	$ 129,656,928	$ 665,532,437	$ 13,511,696	$ 6,440,579	$ 38,943,275	$ 795,097	$ 1,084,722	$ 860,590	$ 122,948	$ 1,912,523	$ 40,353,164	$ 189,851

SOUTHWEST GAS CORPORATION
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Residential Gas Service Demand	Residential Gas Service Customer	Residential Gas Service Commodity	Multi-Family Residential Demand	Multi-Family Residential Customer	Multi-Family Residential Commodity	MMMHP Gas Service Demand	MMMHP Gas Service Customer	MMMHP Gas Service Commodity	Small General Gas Service Demand	Small General Gas Service Customer	Small General Gas Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
		Other Rate Base Items														
1		Cash Working Capital	11.2	(11,082,156)	(591,327)	(7,102,346)	(379,265)	(29,374)	(513,362)	(22,318)	(4,947)	(14,970)	(3,451)	(8,722)	(439,447)	(5,329)
2		Materials & Supplies	1.1	9,222,489	1,095,056	5,620,951	114,117	54,396	328,907	6,715	9,161	7,268	1,038	16,153	340,815	1,603
3		Prepayments	1.1	2,740,815	325,438	1,670,480	33,914	16,166	97,747	1,996	2,723	2,160	309	4,800	101,286	477
4		Gas Plant Acquisition Adjustment	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-
5		Customer Deposits	8.0	(23,912,141)	-	(21,263,793)	-	-	(1,726,035)	-	-	(5,284)	-	-	(461,380)	-
6		Customer Advances	8.0	(7,027,372)	-	(6,249,068)	-	-	(507,252)	-	-	(1,553)	-	-	(135,592)	-
7		Deferred Taxes	1.1	(136,691,328)	(16,230,396)	(83,311,050)	(1,691,388)	(806,229)	(4,874,902)	(99,530)	(135,785)	(107,728)	(15,391)	(239,409)	(5,051,391)	(23,765)
8		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-	-	-	-	-	-	-	-	-	-
9		Total Allocated Rate Base		925,212,447	114,255,699	554,897,612	11,589,074	5,675,538	31,748,378	681,960	955,874	740,484	105,453	1,685,345	34,707,455	162,836

SOUTHWEST GAS CORPORATION
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Line No.	Account No.	Description	Allocation Factor No.	Medium General Gas Service Demand	Medium General Gas Service Customer	Medium General Gas Service Commodity	Large General Gas Service Demand	Large General Gas Service Customer	Large General Gas Service Commodity	Transportation Eligible Service Demand	Transportation Eligible Service Customer	Transportation Eligible Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		Net Plant in Service - Direct										
		Intangible										
1	301	Organization	1.1	$ 595	$ 1,584	$ 84	$ 2,121	$ 1,145	$ 276	$ 793	$ 143	$ 168
2	302	Franchise & Consent	1.1	16,536	44,020	2,341	58,939	31,822	7,726	22,038	3,965	4,668
3	303	Misc. Intangible	1.1	3,881	10,332	550	13,834	7,469	1,813	5,173	931	1,096
4		Total Intangible		$ 21,012	$ 55,936	$ 2,975	$ 74,894	$ 40,436	$ 9,818	$ 28,004	$ 5,038	$ 5,932
5		Allocation Percentage	Intang. Plant	1.40%	3.71%	0.20%	4.97%	2.69%	0.65%	1.86%	0.33%	0.39%
		Production										
6	326	Other Land & Land Rights	3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	332	Field Lines	3	-	-	-	-	-	-	-	-	-
8	334	Field Meas & Reg. Stations	3	-	-	-	-	-	-	-	-	-
9	336	Purification Equipment	3	-	-	-	-	-	-	-	-	-
10		Total Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11		Allocation Percentage	Prod. Plant	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		Transmission										
12	365	Land & Land Rights	1.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	365	Rights of Way	1.0	-	-	-	-	-	-	-	-	-
14	366	Structures-Compressor Stas.	1.0	-	-	-	-	-	-	-	-	-
15	366	Structures	1.0	-	-	-	-	-	-	-	-	-
16	367	Mains - Demand	1.0	-	-	-	-	-	-	-	-	-
17	367	Mains - Customer	4.0	-	-	-	-	-	-	-	-	-
18	367	Mains - Commodity	3.0	-	-	-	-	-	-	-	-	-
19	367	Mains-Bridge	1.0	-	-	-	-	-	-	-	-	-
20	368	Compressor Stations	1.0	-	-	-	-	-	-	-	-	-
21	369	Measuring & Reg. Sta. Equip.	1.0	-	-	-	-	-	-	-	-	-
22	370	Communication Equip.	1.0	-	-	-	-	-	-	-	-	-
23	371	Other Equipment	1.0	-	-	-	-	-	-	-	-	-
24		Total Transmission		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25		Allocation Percentage	Trans. Plant	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		Distribution										
26	374	Land & Land Rights	1.0	$ 22,868	$ -	$ -	$ 81,506	$ -	$ -	$ 30,476	$ -	$ -
27	374	Rights of Way	1.0	28,999	-	-	103,360	-	-	38,648	-	-
28	375	Structures	1.0	3,100	-	-	11,051	-	-	4,132	-	-
29	376	Mains - Demand	1.0	13,554,761	-	-	48,312,628	-	-	18,064,891	-	-
30	376	Mains - Customer	5.0	-	5,810,706	-	-	2,492,628	-	-	60,962	-
31	376	Mains - Commodity	3.0	-	-	0	-	-	0	-	-	0
32	378	Measuring & Reg. Station	3.0	-	-	1,646,541	-	-	5,433,608	-	-	3,283,214
33	380	Services - Demand	1.0	0	-	-	0	-	-	0	-	-
34	380	Services - Customer	7.0	-	23,028,521	-	-	11,352,122	-	-	935,661	-
35	381	Meters	6.0	-	7,383,848	-	-	12,340,615	-	-	2,265,918	-
36	385	Industrial Meas. & Reg. Sta.	3.0	-	-	280,018	-	-	924,063	-	-	558,358
37	386	Other Prop. on Cust. Premises	1.0	-	-	-	-	-	-	-	-	-
38	387	Other Equipment	1.0	(2,565)	-	-	(9,144)	-	-	(3,419)	-	-
39		Total Distribution		$ 13,607,163	$ 36,223,075	$ 1,926,560	$ 48,499,401	$ 26,185,365	$ 6,357,672	$ 18,134,728	$ 3,262,541	$ 3,841,572
40		Allocation Percentage	Dist. Plant	1.40%	3.71%	0.20%	4.97%	2.69%	0.65%	1.86%	0.33%	0.39%
41	389-398	Total General Plant	1.1	$ 1,041,228	$ 2,771,811	$ 147,421	$ 3,711,203	$ 2,003,720	$ 486,493	$ 1,387,680	$ 249,652	$ 293,959
42		Total Net Plant-Direct		$ 14,869,403	$ 39,050,822	$ 2,076,956	$ 52,285,498	$ 28,229,521	$ 6,853,982	$ 19,550,413	$ 3,517,231	$ 4,141,464
		Systems Allocable Plant										
43	301-303	Intangible Plant	1.1	$ 368,361	$ 980,599	$ 52,154	$ 1,312,933	$ 708,867	$ 172,109	$ 490,927	$ 88,321	$ 103,996
44	389-398	General Plant	1.1	$ 197,967	$ 527,000	$ 28,029	$ 705,605	$ 380,964	$ 92,496	$ 263,838	$ 47,466	$ 55,890
45		Total Systems Allocable		566,328	1,507,600	80,183	2,018,539	1,089,831	264,605	754,765	135,787	159,886
46		Total Net Plant		$ 15,235,731	$ 40,558,422	$ 2,157,139	$ 54,304,037	$ 29,319,352	$ 7,118,587	$ 20,305,178	$ 3,653,017	$ 4,301,350

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Line No.	Account No.	Description	Allocation Factor No.	Medium General Gas Service			Large General Gas Service			Transportation Eligible Service		
				Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		Other Rate Base Items										
1		Cash Working Capital	11.2	(69,486)	(479,688)	(60,550)	(247,665)	(431,119)	(199,814)	(92,606)	(55,298)	(120,736)
2		Materials & Supplies	1.1	128,678	342,548	18,219	458,641	247,625	60,122	171,493	30,853	36,328
3		Prepayments	1.1	38,242	101,801	5,414	136,303	73,591	17,868	50,966	9,169	10,796
4		Gas Plant Acquisition Adjustment	1.1	-	-	-	-	-	-	-	-	-
5		Customer Deposits	8.0	-	(455,649)	-	-	-	-	-	-	-
6		Customer Advances	8.0	-	(133,908)	-	-	-	-	-	-	-
7		Deferred Taxes	1.1	(1,907,202)	(5,077,085)	(270,030)	(6,797,755)	(3,670,183)	(891,102)	(2,541,793)	(457,283)	(538,441)
8		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-	-	-	-	-	-
9		Total Allocated Rate Base		13,425,963	34,856,441	1,850,193	47,853,561	25,539,266	6,105,661	17,893,238	3,180,457	3,689,297

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Line No.	Account No.	Description	Allocation Factor No.	Air-Conditioning Gas Service Demand	Air-Conditioning Gas Service Customer	Air-Conditioning Gas Service Commodity	CNG - Small Demand	CNG - Small Customer	CNG - Small Commodity	CNG - Large Demand	CNG - Large Customer	CNG - Large Commodity	CNG - Residential Demand	CNG - Residential Customer	CNG - Residential Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Net Plant in Service - Direct													
		Intangible													
1	301	Organization	1.1	$ 6	$ 8	$ 4	$ 1	$ 1	$ 0	$ 11	$ 20	$ 4	$ 1	$ 3	$ 0
2	302	Franchise & Consent	1.1	154	229	100	33	21	10	309	545	103	15	81	4
3	303	Misc. Intangible	1.1	36	54	23	8	5	2	73	128	24	4	19	1
4		Total Intangible		$ 196	$ 291	$ 127	$ 42	$ 27	$ 13	$ 393	$ 692	$ 131	$ 19	$ 103	$ 6
5		Allocation Percentage	Intang. Plant	0.01%	0.02%	0.01%	0.00%	0.00%	0.00%	0.03%	0.05%	0.01%	0.00%	0.01%	0.00%
		Production													
6	326	Other Land & Land Rights	3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
7	332	Field Lines	3	-	-	-	-	-	-	-	-	-	-	-	-
8	334	Field Meas & Reg. Stations	3	-	-	-	-	-	-	-	-	-	-	-	-
9	336	Purification Equipment	3	-	-	-	-	-	-	-	-	-	-	-	-
10		Total Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11		Allocation Percentage	Prod. Plant	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		Transmission													
12	365	Land & Land Rights	1.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
13	365	Rights of Way	1.0	-	-	-	-	-	-	-	-	-	-	-	-
14	366	Structures-Compressor Stas.	1.0	-	-	-	-	-	-	-	-	-	-	-	-
15	366	Structures	1.0	-	-	-	-	-	-	-	-	-	-	-	-
16	367	Mains - Demand	1.0	-	-	-	-	-	-	-	-	-	-	-	-
17	367	Mains - Customer	4.0	-	-	-	-	-	-	-	-	-	-	-	-
18	367	Mains - Commodity	3.0	-	-	-	-	-	-	-	-	-	-	-	-
19	367	Mains-Bridge	1.0	-	-	-	-	-	-	-	-	-	-	-	-
20	368	Compressor Stations	1.0	-	-	-	-	-	-	-	-	-	-	-	-
21	369	Measuring & Reg. Sta. Equip.	1.0	-	-	-	-	-	-	-	-	-	-	-	-
22	370	Communication Equip.	1.0	-	-	-	-	-	-	-	-	-	-	-	-
23	371	Other Equipment	1.0	-	-	-	-	-	-	-	-	-	-	-	-
24		Total Transmission		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25		Allocation Percentage	Trans. Plant	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		Distribution													
26	374	Land & Land Rights	1.0	$ 213	$ -	$ -	$ 46	$ -	$ -	$ 428	$ -	$ -	$ 21	$ -	$ -
27	374	Rights of Way	1.0	271	-	-	58	-	-	542	-	-	27	-	-
28	375	Structures	1.0	29	-	-	6	-	-	58	-	-	3	-	-
29	376	Mains - Demand	1.0	126,518	-	-	27,295	-	-	253,522	-	-	12,468	-	-
30	376	Mains - Customer	5.0	-	13,339	-	-	7,843	-	-	9,626	-	-	39,215	-
31	376	Mains - Commodity	3.0	-	-	0	-	-	0	-	-	0	-	-	0
32	378	Measuring & Reg. Station	3.0	-	-	70,276	-	-	6,976	-	-	72,658	-	-	3,050
33	380	Services - Demand	1.0	0	-	-	0	-	-	0	-	-	0	-	-
34	380	Services - Customer	7.0	-	166,779	-	-	7,273	-	-	174,727	-	-	16,202	-
35	381	Meters	6.0	-	8,304	-	-	2,377	-	-	263,826	-	-	11,225	-
36	385	Industrial Meas. & Reg. Sta.	3.0	-	-	11,951	-	-	1,186	-	-	12,357	-	-	519
37	386	Other Prop. on Cust. Premises	1.0	-	-	-	-	-	-	-	-	-	-	-	-
38	387	Other Equipment	1.0	(24)	-	-	(5)	-	-	(48)	-	-	(2)	-	-
39		Total Distribution		$ 127,007	$ 188,422	$ 82,227	$ 27,400	$ 17,493	$ 8,163	$ 254,502	$ 448,179	$ 85,015	$ 12,516	$ 66,642	$ 3,569
40		Allocation Percentage	Dist. Plant	0.01%	0.02%	0.01%	0.00%	0.00%	0.00%	0.03%	0.05%	0.01%	0.00%	0.01%	0.00%
41	389-398	Total General Plant	1.1	$ 9,719	$ 14,418	$ 6,292	$ 2,097	$ 1,339	$ 625	$ 19,475	$ 34,295	$ 6,505	$ 958	$ 5,100	$ 273
42		Total Net Plant-Direct		$ 136,922	$ 203,131	$ 88,646	$ 29,539	$ 18,859	$ 8,800	$ 274,369	$ 483,166	$ 91,652	$ 13,493	$ 71,845	$ 3,848
		Systems Allocable Plant													
43	301-303	Intangible Plant	1.1	$ 3,438	$ 5,101	$ 2,226	$ 742	$ 474	$ 221	$ 6,890	$ 12,133	$ 2,301	$ 339	$ 1,804	$ 97
44	389-398	General Plant	1.1	$ 1,848	$ 2,741	$ 1,196	$ 399	$ 255	$ 119	$ 3,703	$ 6,520	$ 1,237	$ 182	$ 970	$ 52
45		Total Systems Allocable		5,286	7,842	3,422	1,140	728	340	10,592	18,653	3,538	521	2,774	149
46		Total Net Plant		$ 142,208	$ 210,973	$ 92,069	$ 30,680	$ 19,587	$ 9,140	$ 284,962	$ 501,819	$ 95,190	$ 14,014	$ 74,618	$ 3,996

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Line No.	Account No.	Description	Allocation Factor No.	Air-Conditioning Gas Service			CNG - Small			CNG - Large			CNG - Residential		
				Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Other Rate Base Items													
1		Cash Working Capital	11.2	(649)	(1,917)	(2,584)	(140)	(364)	(257)	(1,300)	(6,894)	(2,672)	(64)	(910)	(112)
2		Materials & Supplies	1.1	1,201	1,782	778	259	165	77	2,407	4,238	804	118	630	34
3		Prepayments	1.1	357	530	231	77	49	23	715	1,260	239	35	187	10
4		Gas Plant Acquisition Adjustment	1.1	-	-	-	-	-	-	-	-	-	-	-	-
5		Customer Deposits	8.0	-	-	-	-	-	-	-	-	-	-	-	-
6		Customer Advances	8.0	-	-	-	-	-	-	-	-	-	-	-	-
7		Deferred Taxes	1.1	(17,802)	(26,410)	(11,525)	(3,840)	(2,452)	(1,144)	(35,671)	(62,818)	(11,916)	(1,754)	(9,341)	(500)
8		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-	-	-	-	-	-	-	-	-
9		Total Allocated Rate Base		125,316	184,958	78,968	27,035	16,985	7,839	251,113	437,606	81,645	12,350	65,185	3,428

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Line No.	Account No.	Description	Allocation Factor No.	Electric Generation Gas Service Demand	Electric Generation Gas Service Customer	Electric Generation Gas Service Commodity	Small Essential Agr. User Gas Service Demand	Small Essential Agr. User Gas Service Customer	Small Essential Agr. User Gas Service Commodity	Natural Gas Engine Gas Service Demand	Natural Gas Engine Gas Service Customer	Natural Gas Engine Gas Service Commodity	Street Lighting Gas Service Demand	Street Lighting Gas Service Customer	Street Lighting Gas Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Net Plant in Service - Direct													
		Intangible													
1	301	Organization	1.1	$ 98	$ 8	$ 29	$ 60	$ 9	$ 6	$ 33	$ 265	$ 42	$ 1	$ 1	$ 0
2	302	Franchise & Consent	1.1	2,720	236	817	1,677	256	160	903	7,354	1,157	21	25	5
3	303	Misc. Intangible	1.1	638	55	192	394	60	38	212	1,726	272	5	6	1
4		Total Intangible		$ 3,456	$ 299	$ 1,038	$ 2,131	$ 325	$ 204	$ 1,148	$ 9,345	$ 1,471	$ 26	$ 32	$ 7
5		Allocation Percentage	Intang. Plant	0.23%	0.02%	0.07%	0.14%	0.02%	0.01%	0.08%	0.62%	0.10%	0.00%	0.00%	0.00%
		Production													
6	326	Other Land & Land Rights	3	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	332	Field Lines	3	-	-	-	-	-	-	-	-	-	-	-	
8	334	Field Meas & Reg. Stations	3	-	-	-	-	-	-	-	-	-	-	-	
9	336	Purification Equipment	3	-	-	-	-	-	-	-	-	-	-	-	
10		Total Production		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11		Allocation Percentage	Prod. Plant	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		Transmission													
12	365	Land & Land Rights	1.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	365	Rights of Way	1.0	-	-	-	-	-	-	-	-	-	-	-	
14	366	Structures-Compressor Stas.	1.0	-	-	-	-	-	-	-	-	-	-	-	
15	366	Structures	1.0	-	-	-	-	-	-	-	-	-	-	-	
16	367	Mains - Demand	1.0	-	-	-	-	-	-	-	-	-	-	-	
17	367	Mains - Customer	4.0	-	-	-	-	-	-	-	-	-	-	-	
18	367	Mains - Commodity	3.0	-	-	-	-	-	-	-	-	-	-	-	
19	367	Mains-Bridge	1.0	-	-	-	-	-	-	-	-	-	-	-	
20	368	Compressor Stations	1.0	-	-	-	-	-	-	-	-	-	-	-	
21	369	Measuring & Reg. Sta. Equip.	1.0	-	-	-	-	-	-	-	-	-	-	-	
22	370	Communication Equip.	1.0	-	-	-	-	-	-	-	-	-	-	-	
23	371	Other Equipment	1.0	-	-	-	-	-	-	-	-	-	-	-	
24		Total Transmission		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25		Allocation Percentage	Trans. Plant	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		Distribution													
26	374	Land & Land Rights	1.0	$ 3,761	$ -	$ -	$ 2,319	$ -	$ -	$ 1,249	$ -	$ -	$ 29	$ -	$ -
27	374	Rights of Way	1.0	4,769	-	-	2,941	-	-	1,584	-	-	36	-	
28	375	Structures	1.0	510	-	-	314	-	-	169	-	-	4	-	
29	376	Mains - Demand	1.0	2,229,318	-	-	1,374,784	-	-	740,412	-	-	16,954	-	
30	376	Mains - Customer	5.0	-	8,200	-	-	12,923	-	-	215,238	-	-	10,339	
31	376	Mains - Commodity	3.0	-	-	0	-	-	0	-	-	0	-	-	0
32	378	Measuring & Reg. Station	3.0	-	-	574,275	-	-	112,694	-	-	813,954	-	-	3,822
33	380	Services - Demand	1.0	0	-	-	0	-	-	0	-	-	0	-	
34	380	Services - Customer	7.0	-	124,593	-	-	117,964	-	-	2,122,074	-	-	10,575	
35	381	Meters	6.0	-	61,074	-	-	79,774	-	-	3,714,554	-	-	-	
36	385	Industrial Meas. & Reg. Sta.	3.0	-	-	97,664	-	-	19,165	-	-	138,425	-	-	650
37	386	Other Prop. on Cust. Premises	1.0	-	-	-	-	-	-	-	-	-	-	-	
38	387	Other Equipment	1.0	(422)	-	-	(260)	-	-	(140)	-	-	(3)	-	
39		Total Distribution		$ 2,237,937	$ 193,867	$ 671,938	$ 1,380,098	$ 210,662	$ 131,859	$ 743,275	$ 6,051,866	$ 952,379	$ 17,020	$ 20,914	$ 4,472
40		Allocation Percentage	Dist. Plant	0.23%	0.02%	0.07%	0.14%	0.02%	0.01%	0.08%	0.62%	0.10%	0.00%	0.00%	0.00%
41	389-398	Total General Plant	1.1	$ 171,248	$ 14,835	$ 51,417	$ 105,606	$ 16,120	$ 10,090	$ 56,876	$ 463,092	$ 72,877	$ 1,302	$ 1,600	$ 342
42		Total Net Plant-Direct		$ 2,412,641	$ 209,001	$ 724,393	$ 1,487,835	$ 227,107	$ 142,153	$ 801,298	$ 6,524,304	$ 1,026,726	$ 18,348	$ 22,546	$ 4,821
		Systems Allocable Plant													
43	301-303	Intangible Plant	1.1	$ 60,583	$ 5,248	$ 18,190	$ 37,361	$ 5,703	$ 3,570	$ 20,121	$ 163,831	$ 25,782	$ 461	$ 566	$ 121
44	389-398	General Plant	1.1	$ 32,559	$ 2,821	$ 9,776	$ 20,079	$ 3,065	$ 1,918	$ 10,814	$ 88,047	$ 13,856	$ 248	$ 304	$ 65
45		Total Systems Allocable		93,143	8,069	27,966	57,440	8,768	5,488	30,935	251,878	39,638	708	870	186
46		Total Net Plant		$ 2,505,783	$ 217,070	$ 752,359	$ 1,545,275	$ 235,875	$ 147,641	$ 832,233	$ 6,776,181	$ 1,066,364	$ 19,057	$ 23,417	$ 5,007

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Line No.	Account No.	Description	Allocation Factor No.	Electric Generation Gas Service			Small Essential Agr. User Gas Service			Natural Gas Engine Gas Service			Street Lighting Gas Service		
				Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Other Rate Base Items													
1		Cash Working Capital	11.2	(11,428)	(2,302)	(21,118)	(7,048)	(4,265)	(4,144)	(3,796)	(106,351)	(29,932)	(87)	(1,863)	(141)
2		Materials & Supplies	1.1	21,163	1,833	6,354	13,051	1,992	1,247	7,029	57,230	9,006	161	198	42
3		Prepayments	1.1	6,289	545	1,888	3,879	592	371	2,089	17,008	2,677	48	59	13
4		Gas Plant Acquisition Adjustment	1.1	-	-	-	-	-	-	-	-	-	-	-	-
5		Customer Deposits	8.0	-	-	-	-	-	-	-	-	-	-	-	-
6		Customer Advances	8.0	-	-	-	-	-	-	-	-	-	-	-	-
7		Deferred Taxes	1.1	(313,673)	(27,173)	(94,180)	(193,437)	(29,527)	(18,482)	(104,179)	(848,239)	(133,487)	(2,386)	(2,931)	(627)
8		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-	-	-	-	-	-	-	-	-
9		Total Allocated Rate Base		2,208,135	189,973	645,304	1,361,720	204,667	126,633	733,377	5,895,829	914,627	16,793	18,879	4,295

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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Residential Gas Service Demand	Residential Gas Service Customer	Residential Gas Service Commodity	Multi-Family Residential Demand	Multi-Family Residential Customer	Multi-Family Residential Commodity	MMMHP Gas Service Demand	MMMHP Gas Service Customer	MMMHP Gas Service Commodity	Small General Gas Service Demand	Small General Gas Service Customer	Small General Gas Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
		Direct Depreciation Expense														
1	301-303	Intangible	Intang. Plant	$ 209,988	$ 24,933	$ 127,984	$ 2,598	$ 1,239	$ 7,489	$ 153	$ 209	$ 165	$ 24	$ 368	$ 7,760	$ 37
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 62,360,935	$ 7,404,586	$ 38,007,934	$ 771,640	$ 367,815	$ 2,224,014	$ 45,407	$ 61,947	$ 49,147	$ 7,021	$ 109,222	$ 2,304,531	$ 10,842
5	389-398	General	1.1	$ 4,820,934	$ 572,426	$ 2,938,278	$ 59,653	$ 28,435	$ 171,932	$ 3,510	$ 4,789	$ 3,799	$ 543	$ 8,444	$ 178,156	$ 838
6		Total Direct Dep. Exp.		$ 67,391,857	$ 8,001,945	$ 41,074,196	$ 833,892	$ 397,489	$ 2,403,435	$ 49,070	$ 66,945	$ 53,112	$ 7,588	$ 118,034	$ 2,490,448	$ 11,717
		Systems Allocable Depreciation Expense														
7	301-303	Intangible	Intang. Plant	$ 4,688,595	$ 556,712	$ 2,857,619	$ 58,016	$ 27,654	$ 167,212	$ 3,414	$ 4,658	$ 3,695	$ 528	$ 8,212	$ 173,266	$ 815
8	389-398	General	1.1	$ 2,373,988	$ 281,882	$ 1,446,906	$ 29,375	$ 14,002	$ 84,665	$ 1,729	$ 2,358	$ 1,871	$ 267	$ 4,158	$ 87,730	$ 413
		System Allocable Amortization														
9		Miscellaneous Intangible	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-
10		Structures-Leasehold Improvements	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-
11		Total System Allocable Amortization		-	-	-	-	-	-	-	-	-	-	-	-	-
12		Total System Alloc Dep. Exp. & Amortization		7,062,583	838,594	4,304,525	87,391	41,656	251,877	5,143	7,016	5,566	795	12,370	260,996	1,228
13		Total Depreciation Expense		74,454,440	8,840,539	45,378,721	921,283	439,145	2,655,312	54,213	73,961	58,679	8,383	130,404	2,751,444	12,945
14		Amortization-Limited Term Gas Plant	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-
15		Amortization-Gas Plant Acquisition	1.1	(52,996)	(6,293)	(32,300)	(656)	(313)	(1,890)	(39)	(53)	(42)	(6)	(93)	(1,958)	(9)
16		Amortization of PBOP Costs	1.1	337,524	40,077	205,715	4,176	1,991	12,037	246	335	266	38	591	12,473	59
17		Amortization of Service Investigation	7.0	-	-	-	-	-	-	-	-	-	-	-	-	-
18		Amortization of TRIMP Costs	1.1	1,183,333	140,506	721,222	14,642	6,980	42,202	862	1,175	933	133	2,073	43,730	206
19		Amortization of SOX Implementation	1.1	27,346	3,247	16,667	338	161	975	20	27	22	3	48	1,011	5
20		Total Depreciation & Amortization Expense		$ 75,949,648	$ 9,018,076	$ 46,290,025	$ 939,784	$ 447,964	$ 2,708,636	$ 55,302	$ 75,446	$ 59,857	$ 8,551	$ 133,022	$ 2,806,699	$ 13,205

SCHEDULE G-4B
SHEET 1 of 20

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
AUGUST 31, 2004

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Residential Gas Service			Multi-Family Residential			MMMHP Gas Service			Small General Gas Service		
					Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
		Operation and Maintenance Expense														
		Gas Supply Expense														
1	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-
3	805	Purchased Gas Cost Adj.	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-
4	810	Gas Used for Compressor Sta. Fuel--	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-
5	813	Other Gas Supply Expense	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-
6		Labor & Labor Loading	3.0	683,189	-	-	303,968	-	-	17,887	-	-	2,766	-	-	4,271
7		Materials & Expenses	3.0	57,202	-	-	25,451	-	-	1,498	-	-	232	-	-	358
8		Total Gas Supply Expense		$ 740,391	$ -	$ -	$ 329,419	$ -	$ -	$ 19,385	$ -	$ -	$ 2,998	$ -	$ -	$ 4,629
		Transmission Expenses														
9	850	Operation Supervision & Engin.														
10		Labor & Labor Loading	5.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11		Materials & Expenses	5.0	-	-	-	-	-	-	-	-	-	-	-	-	-
12	851	System Control & Load Dispatch														
13		Labor & Labor Loading	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-
14		Materials & Expenses	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-
15	852	Communication System Exp.														
16		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
17		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
18	853	Compressor Station														
19		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
20		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
21	854	Gas for Compressor Station Fuel	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-
22	856	Mains Expense														
23		Labor & Labor Loading	6.0	-	-	-	-	-	-	-	-	-	-	-	-	-
24		Materials & Expenses	6.0	-	-	-	-	-	-	-	-	-	-	-	-	-
25	857	Meas. & Res. Sta. Exp.														
26		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
27		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
28	858	Trans. & comp. of Gas by Others	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-
29	860	Rents	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
30	861	Maint. Supervision & Eng.														
31		Labor & Labor Loading	7.0	-	-	-	-	-	-	-	-	-	-	-	-	-
32		Materials & Expenses	7.0	-	-	-	-	-	-	-	-	-	-	-	-	-
33	862	Maint. of Struct. & Imp.	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
34	863	Maint. of Mains														
35		Labor & Labor Loading	6.0	-	-	-	-	-	-	-	-	-	-	-	-	-
36		Materials & Expenses	6.0	-	-	-	-	-	-	-	-	-	-	-	-	-
37	864	Maint. of Comp. Sta. Equip.														
38		Labor & Labor Loading	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-
39		Materials & Expenses	3.0	-	-	-	-	-	-	-	-	-	-	-	-	-
40	865	Maint. of Meas. & Reg. Sta. Equip.														
41		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
42		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-	-
43		Total Transmission Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

SCHEDULE G-4B
SHEET 3 of 20

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
AUGUST 31, 2004

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Residential Gas Service Demand	Residential Gas Service Customer	Residential Gas Service Commodity	Multi-Family Residential Demand	Multi-Family Residential Customer	Multi-Family Residential Commodity	MMMHP Gas Service Demand	MMMHP Gas Service Customer	MMMHP Gas Service Commodity	Small General Gas Service Demand	Small General Gas Service Customer	Small General Gas Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
		Distribution Expenses														
1	870	Operation Supervision & Eng.														
2		Labor & Labor Loading	5.5	$ 7,314,234	$ 393,113	$ 4,208,649	$ 380,353	$ 19,528	$ 306,515	$ 22,382	$ 3,289	$ 12,748	$ 3,461	$ 5,799	$ 301,696	$ 5,344
3		Materials & Expenses	5.5	1,144,604	61,518	658,612	59,521	3,056	47,967	3,503	515	1,995	542	907	47,212	836
4	871	Distribution Load Dispatching														
5		Labor & Labor Loading	3.0	531,430	-	-	236,447	-	-	13,914	-	-	2,152	-	-	3,322
6		Materials & Expenses	3.0	128,930	-	-	57,364	-	-	3,376	-	-	522	-	-	806
7	874	Mains & Svcs. Expense														
8		Labor & Labor Loading	4.4	5,227,680	734,064	3,241,526	0	36,464	174,745	0	6,141	2,381	0	10,828	185,016	0
9		Materials & Expenses	4.4	5,914,196	830,464	3,667,214	0	41,252	197,693	0	6,948	2,694	0	12,250	209,312	0
10	875	Meas. & Reg. Sta. Exp.-Gen.														
11		Labor & Labor Loading	3.0	1,964,122	-	-	873,888	-	-	51,424	-	-	7,952	-	-	12,279
12		Materials & Expenses	3.0	777,755	-	-	346,043	-	-	20,363	-	-	3,149	-	-	4,862
13	878	Meter & House Reg. Exp.														
14		Labor & Labor Loading	6.0	5,796,552	-	3,916,408	-	-	337,255	-	-	18,172	-	-	320,912	-
15		Materials & Expenses	6.0	875,104	-	591,259	-	-	50,915	-	-	2,743	-	-	48,448	-
16	879	Customer Installation Exp.														
17		Labor & Labor Loading	6.0	6,850,542	-	4,628,530	-	-	398,578	-	-	21,476	-	-	379,263	-
18		Materials & Expenses	6.0	1,043,174	-	704,815	-	-	60,694	-	-	3,270	-	-	57,753	-
19	880	Other Expenses														
20		Labor & Labor Loading	5.5	6,293,097	338,231	3,621,082	327,252	16,801	263,723	19,257	2,830	10,968	2,978	4,989	259,577	4,598
21		Materials & Expenses	5.5	4,262,589	229,099	2,452,717	221,662	11,380	178,631	13,044	1,917	7,429	2,017	3,379	175,823	3,115
22	881	Rents	5.5	1,980,383	106,438	1,139,523	102,983	5,287	82,991	6,060	890	3,452	937	1,570	81,687	1,447
23		Total Distribution-Operations		$ 50,104,393	$ 2,692,927	$ 28,830,335	$ 2,605,513	$ 133,768	$ 2,099,707	$ 153,322	$ 22,529	$ 87,328	$ 23,708	$ 39,722	$ 2,066,699	$ 36,610
		Operation and Maintenance Expense														
		Distribution Expenses														
24	885	Maint. Supervision & Eng.														
25		Labor & Labor Loading	6.6	$ 2,374,262	$ 282,078	$ 1,370,474	$ 80,220	$ 14,012	$ 77,194	$ 4,721	$ 2,360	$ 1,489	$ 730	$ 4,161	$ 81,975	$ 1,127
26		Materials & Expenses	6.6	254,842	30,277	147,100	8,610	1,504	8,286	507	253	160	78	447	8,799	121
27	886	Maint. of Structures & Imp.														
28		Labor & Labor Loading	1.0	13,682	7,571	-	-	376	-	-	63	-	-	112	-	-
29		Materials & Expenses	1.0	50,707	28,059	-	-	1,394	-	-	235	-	-	414	-	-
30	887	Maint. of Mains														
31		Labor & Labor Loading	2.2	7,503,706	1,676,563	3,941,256	0	83,282	319,922	0	14,026	979	0	24,730	85,517	0
32		Materials & Expenses	2.2	5,977,097	1,335,471	3,139,419	0	66,338	254,834	0	11,173	780	0	19,699	68,119	0
33	889	Maint. of Meas. & Reg. Sta-Gen														
34		Labor & Labor Loading	3.0	1,118,151	-	-	497,494	-	-	29,275	-	-	4,527	-	-	6,990
35		Materials & Expenses	3.0	829,877	-	-	369,234	-	-	21,728	-	-	3,360	-	-	5,188
36	892	Maint. of Services														
37		Labor & Labor Loading	3.3	5,317,554	0	4,150,219	-	0	94,922	-	0	5,345	-	0	404,026	-
38		Materials & Expenses	3.3	2,909,486	0	2,270,782	-	0	51,936	-	0	2,924	-	0	221,062	-
39	893	Maint of Meter & House Reg.														
40		Labor & Labor Loading	6.0	1,126,714	-	761,258	-	-	65,555	-	-	3,532	-	-	62,378	-
41		Materials & Expenses	6.0	805,373	-	544,146	-	-	46,858	-	-	2,525	-	-	44,588	-
42	894	Maint of Other Equip.														
43		Labor & Labor Loading	6.6	150,319	17,859	86,767	5,079	887	4,887	299	149	94	46	263	5,190	71
44		Materials & Expenses	6.6	44,303	5,263	25,572	1,497	261	1,440	88	44	28	14	78	1,530	21
45		Total Distribution-Maintenance		$ 28,476,074	$ 3,383,141	$ 16,436,994	$ 962,134	$ 168,054	$ 925,834	$ 56,617	$ 28,304	$ 17,856	$ 8,755	$ 49,904	$ 983,183	$ 13,519
46		Total Distribution O & M		$ 78,580,466	$ 6,076,068	$ 45,267,329	$ 3,567,647	$ 301,823	$ 3,025,541	$ 209,939	$ 50,833	$ 105,184	$ 32,463	$ 89,626	$ 3,049,882	$ 50,128

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
AUGUST 31, 2004

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Residential Gas Service Demand	Residential Gas Service Customer	Residential Gas Service Commodity	Multi-Family Residential Demand	Multi-Family Residential Customer	Multi-Family Residential Commodity	MMMHP Gas Service Demand	MMMHP Gas Service Customer	MMMHP Gas Service Commodity	Small General Gas Service Demand	Small General Gas Service Customer	Small General Gas Service Commodity
(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
		Customer Accounts Expenses														
1	901	Supervision														
2		Labor & Labor Loading	10.1	$ 3,574,463	$ -	$ 2,867,058	$ -	$ -	$ 232,727	$ -	$ -	$ 5,028	$ -	$ -	$ 151,547	$ -
3		Materials & Expenses	10.1	218,328	-	175,119	-	-	14,215	-	-	307	-	-	9,256	-
4	902	Meter Reading Exp.														
5		Labor & Labor Loading	13.0	5,130,538	-	4,093,773	-	-	332,303	-	-	7,539	-	-	223,839	-
6		Materials & Expenses	13.0	1,285,812	-	1,025,979	-	-	83,282	-	-	1,889	-	-	56,098	-
7	903	Customer Records & Collections														
8		Labor & Labor Loading	13.0	14,174,373	-	11,310,053	-	-	918,068	-	-	20,829	-	-	618,411	-
9		Materials & Expenses	13.0	6,602,396	-	5,268,201	-	-	427,634	-	-	9,702	-	-	288,055	-
10	903	Customer Records & Collections - LCS														
11		Labor & Labor Loading - LCS	13.0	1,077,228	-	859,545	-	-	69,772	-	-	1,583	-	-	46,998	-
12		Materials & Expenses - LCS	13.0	47,923	-	38,239	-	-	3,104	-	-	70	-	-	2,091	-
13	904	Uncollectible Accounts Exp.	4.0	1,498,151	-	1,319,803	-	-	107,132	-	-	328	-	-	28,637	-
14	905	Misc. Customer Accounts Exp.														
15		Labor & Labor Loading	10.1	372,869	-	299,076	-	-	24,277	-	-	524	-	-	15,809	-
16		Materials & Expenses	10.1	21,199	-	17,004	-	-	1,380	-	-	30	-	-	899	-
17		Total Customer Accounts Expenses		$ 34,003,279	$ -	$ 27,273,850	$ -	$ -	$ 2,213,893	$ -	$ -	$ 47,831	$ -	$ -	$ 1,441,639	$ -
		Customer Service & Info. Exp.														
18	908	Customer Assistance Exp.														
19		Labor & Labor Loading	13.0	$ 275,434	$ -	$ 219,775	$ -	$ -	$ 17,840	$ -	$ -	$ 405	$ -	$ -	$ 12,017	$ -
20		Materials & Expenses	13.0	248,457	-	198,250	-	-	16,092	-	-	365	-	-	10,840	-
21	909	Info. & Instructional Exp.														
22		Labor & Labor Loading	13.0	-	-	-	-	-	-	-	-	-	-	-	-	-
23		Materials & Expenses	13.0	-	-	-	-	-	-	-	-	-	-	-	-	-
24	910	Misc. C.S. & I. Expense														
25		Labor & Labor Loading	13.0	773	-	617	-	-	50	-	-	1	-	-	34	-
26		Materials & Expenses	13.0	23,832	-	19,016	-	-	1,544	-	-	35	-	-	1,040	-
27		Total Customer Service & Info. Exp.		$ 548,496	$ -	$ 437,657	$ -	$ -	$ 35,526	$ -	$ -	$ 806	$ -	$ -	$ 23,930	$ -
		Sales Expense														
28	911	Supervision														
29		Labor & Labor Loading	4.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30		Materials & Expenses	4.0	-	-	-	-	-	-	-	-	-	-	-	-	-
31	912	Demonstrating & Selling Exp.														
32		Labor & Labor Loading	4.0	-	-	-	-	-	-	-	-	-	-	-	-	-
33		Materials & Expenses	4.0	-	-	-	-	-	-	-	-	-	-	-	-	-
34	913	Advertising Expense														
35		Labor & Labor Loading	4.0	-	-	-	-	-	-	-	-	-	-	-	-	-
36		Materials & Expenses	4.0	-	-	-	-	-	-	-	-	-	-	-	-	-
37		Total Sales Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38		Total O & M Expense		$ 113,872,632	$ 6,076,068	$ 72,978,836	$ 3,897,066	$ 301,823	$ 5,274,960	$ 229,323	$ 50,833	$ 153,821	$ 35,461	$ 89,626	$ 4,515,451	$ 54,757
39		Allocation Percentage	Total O&M	100.00%	5.34%	64.09%	3.42%	0.27%	4.63%	0.20%	0.04%	0.14%	0.03%	0.08%	3.97%	0.05%
		Other Operating Deductions														
40		Administrative & General Expense	Total O&M	52,481,195	2,800,316	33,634,214	1,796,065	139,103	2,431,104	105,690	23,428	70,892	16,343	41,306	2,081,064	25,236
41		Interest on Customer Deposits	8.0	717,364	-	637,914	-	-	51,781	-	-	159	-	-	13,841	-
42		Taxes Other Than Income	1.1	33,455,124	3,972,380	20,390,331	413,966	197,324	1,193,129	24,360	33,233	26,366	3,767	58,595	1,236,325	5,817
43		Total Allocated Operating Deductions		$ 200,526,315	$ 12,848,764	$ 127,641,295	$ 6,107,098	$ 638,250	$ 8,950,974	$ 359,373	$ 107,494	$ 251,238	$ 55,571	$ 189,528	$ 7,846,682	$ 85,810
		Tax Adjustments														
44		Interest Expense	1.1	40,521,530	4,811,428	24,897,186	501,404	239,003	1,445,143	29,505	40,253	31,936	4,562	70,972	1,497,462	7,045
45		State South Georgia	1.1	77,020	9,145	46,942	953	454	2,747	56	77	61	9	135	2,846	13
46		Investment Tax Credit	1.1	(528,352)	(62,735)	(322,022)	(6,538)	(3,116)	(18,843)	(385)	(525)	(416)	(59)	(925)	(19,525)	(92)
47		Federal South Georgia	1.1	288,233	34,224	175,673	3,567	1,700	10,279	210	286	227	32	505	10,652	50

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
AUGUST 31, 2004

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Residential Gas Service			Multi-Family Residential			MMMHP Gas Service			Small General Gas Service		
					Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
		Summary of Allocated Cost of Service														
		Rate Base														
1		Direct Net Plant		$ 1,051,372,747	$ 124,837,442	$ 640,793,889	$ 13,009,452	$ 6,201,175	$ 37,495,712	$ 765,543	$ 1,044,402	$ 828,601	$ 118,378	$ 1,841,433	$ 38,853,194	$ 182,794
2		Systems Allocable Net Plant		40,589,393	4,819,486	24,738,548	502,244	239,403	1,447,563	29,555	40,320	31,989	4,570	71,091	1,499,970	7,057
3		Cash Working Capital	1.1	(11,082,156)	(591,327)	(7,102,346)	(379,265)	(29,374)	(513,362)	(22,318)	(4,947)	(14,970)	(3,451)	(8,722)	(439,447)	(5,329)
4		Materials & Supplies	1.1	9,222,489	1,095,056	5,620,951	114,117	54,396	328,907	6,715	9,161	7,268	1,038	16,153	340,815	1,603
5		Prepayments	1.1	2,740,815	325,438	1,670,480	33,914	16,166	97,747	1,996	2,723	2,160	309	4,800	101,286	477
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-
7		Customer Deposits	8.0	(23,912,141)	-	(21,263,793)	-	-	(1,726,035)	-	-	(5,284)	-	-	(461,380)	-
8		Customer Advances	8.0	(7,027,372)	-	(6,249,068)	-	-	(507,252)	-	-	(1,553)	-	-	(135,592)	-
9		Deferred Taxes	1.1	(136,691,328)	(16,230,396)	(83,311,050)	(1,691,388)	(806,229)	(4,874,902)	(99,530)	(135,785)	(107,728)	(15,391)	(239,409)	(5,051,391)	(23,765)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-	-	-	-	-	-	-	-	-	-
11		Total Rate Base		$ 925,212,447	$ 114,255,699	$ 554,897,612	$ 11,589,074	$ 5,675,538	$ 31,748,378	$ 681,960	$ 955,874	$ 740,484	$ 105,453	$ 1,685,345	$ 34,707,455	$ 162,836
12		Net Operating Margin	Direct	$ 305,070,666	$ 123,877,754	$ 72,702,524	$ -	$ 7,548,076	$ 5,876,225	$ -	$ 770,456	$ 113,400	$ -	$ 1,439,375	$ 3,975,660	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 7,611,429	$ 3,090,716	$ 1,813,908	$ -	$ 188,322	$ 146,610	$ -	$ 19,223	$ 2,829	$ -	$ 35,912	$ 99,192	$ -
14		Late Charges	Direct	$ 1,386,957	$ 563,191	$ 330,531	$ -	$ 34,316	$ 26,715	$ -	$ 3,503	$ 516	$ -	$ 6,544	$ 18,075	$ -
15		Service Establishment Charges	Direct	$ 6,950,610	$ 2,822,382	$ 1,656,426	$ -	$ 171,972	$ 133,882	$ -	$ 17,554	$ 2,584	$ -	$ 32,794	$ 90,580	$ -
16		Reconnect / Reread Charges	Direct	$ 547,658	$ 222,383	$ 130,514	$ -	$ 13,550	$ 10,549	$ -	$ 1,383	$ 204	$ -	$ 2,584	$ 7,137	$ -
17		Other Revenue - Labor	Direct	$ 1,705	$ 693	$ 406	$ -	$ 42	$ 33	$ -	$ 4	$ 1	$ -	$ 8	$ 22	$ -
18		Other Revenue - Parts & Material	Direct	$ 5,764	$ 2,341	$ 1,374	$ -	$ 143	$ 111	$ -	$ 15	$ 2	$ -	$ 27	$ 75	$ -
19		Other Revenue - Field Collection Fee	Direct	$ 388,540	$ 157,772	$ 92,594	$ -	$ 9,613	$ 7,484	$ -	$ 981	$ 144	$ -	$ 1,833	$ 5,063	$ -
20		Other Revenue - Returned Item Fee	Direct	$ 135,450	$ 55,001	$ 32,280	$ -	$ 3,351	$ 2,609	$ -	$ 342	$ 50	$ -	$ 639	$ 1,765	$ -
21		Other Revenue - Rental Income	Direct	$ 767,198	$ 311,530	$ 182,834	$ -	$ 18,982	$ 14,778	$ -	$ 1,938	$ 285	$ -	$ 3,620	$ 9,998	$ -
22		Total Revenue		322,865,978	131,103,763	76,943,391	-	7,988,369	6,218,996	-	815,398	120,015	-	1,523,336	4,207,567	-
23		O & M		(113,872,632)	(6,076,068)	(72,978,836)	(3,897,066)	(301,823)	(5,274,960)	(229,323)	(50,833)	(153,821)	(35,461)	(89,626)	(4,515,451)	(54,757)
24		A & G	Total O&M	(52,481,195)	(2,800,316)	(33,634,214)	(1,796,065)	(139,103)	(2,431,104)	(105,690)	(23,428)	(70,892)	(16,343)	(41,306)	(2,081,064)	(25,236)
25		Depreciation Expense		(75,949,648)	(9,018,076)	(46,290,025)	(939,784)	(447,964)	(2,708,636)	(55,302)	(75,446)	(59,857)	(8,551)	(133,022)	(2,806,699)	(13,205)
26		Interest on Customer Deposits	8.0	(717,364)	-	(637,914)	-	-	(51,781)	-	-	(159)	-	-	(13,841)	-
27		Taxes other than Income	1.1	(33,455,124)	(3,972,380)	(20,390,331)	(413,966)	(197,324)	(1,193,129)	(24,360)	(33,233)	(26,366)	(3,767)	(58,595)	(1,236,325)	(5,817)
		State Income Tax														
28		Taxable Income before Interest Exp.		$ 46,390,015	$ 109,236,922	$(96,987,929)	$(7,046,882)	$ 6,902,155	$(5,440,615)	$(414,674)	$ 632,458	$(191,080)	$(64,122)	$ 1,200,786	$(6,445,813)	$(99,015)
29		Interest Expense	1.1	(40,521,530)	(4,811,428)	(24,697,186)	(501,404)	(239,003)	(1,445,143)	(29,505)	(40,253)	(31,936)	(4,562)	(70,972)	(1,497,462)	(7,045)
30		State Taxable Income		$ 5,868,486	$ 104,425,494	$(121,685,115)	$(7,548,286)	$ 6,663,152	$(6,885,757)	$(444,180)	$ 592,205	$(223,015)	$(68,685)	$ 1,129,815	$(7,943,275)	$(106,060)
31		State Income Tax		408,916	7,276,368	(8,479,019)	(525,965)	464,288	(479,800)	(30,950)	41,265	(15,540)	(4,786)	78,725	(553,487)	(7,390)
32		South Georgia	1.1	77,020	9,145	46,942	953	454	2,747	56	77	61	9	135	2,846	13
33		State Income Tax		485,936	7,285,514	(8,432,076)	(525,012)	464,743	(477,053)	(30,894)	41,341	(15,479)	(4,777)	78,860	(550,641)	(7,377)
		Federal Income Tax														
34		Taxable Income before Interest Exp.		46,390,015	109,236,922	(96,987,929)	(7,046,882)	6,902,155	(5,440,615)	(414,674)	632,458	(191,080)	(64,122)	1,200,786	(6,445,813)	(99,015)
35		Interest Expense	1.1	(40,521,530)	(4,811,428)	(24,697,186)	(501,404)	(239,003)	(1,445,143)	(29,505)	(40,253)	(31,936)	(4,562)	(70,972)	(1,497,462)	(7,045)
36		Federal Taxable Income		5,868,486	104,425,494	(121,685,115)	(7,548,286)	6,663,152	(6,885,757)	(444,180)	592,205	(223,015)	(68,685)	1,129,815	(7,943,275)	(106,060)
37		Federal Income Tax		$ 1,910,849	$ 34,002,194	$(39,622,134)	$(2,457,813)	$ 2,169,602	$(2,242,085)	$(144,630)	$ 192,829	$(72,616)	$(22,365)	$ 367,881	$(2,586,426)	$(34,534)
38		I T C	1.1	(528,352)	(62,735)	(322,022)	(6,538)	(3,116)	(18,843)	(385)	(525)	(416)	(59)	(925)	(19,525)	(92)
39		South Georgia	1.1	288,233	34,224	175,673	3,567	1,700	10,279	210	286	227	32	505	10,652	50
40		Total Federal Income Tax		$ 1,670,730	$ 33,973,683	$(39,768,482)	$(2,460,784)	$ 2,168,186	$(2,250,649)	$(144,805)	$ 192,591	$(72,806)	$(22,392)	$ 367,461	$(2,595,299)	$(34,576)
41		Regulatory Amortization	1.1	-	-	-	-	-	-	-	-	-	-	-	-	-
42		Net Income		$ 44,233,349	$ 67,977,726	$(48,787,370)	$(4,061,087)	$ 4,269,226	$(2,712,913)	$(238,975)	$ 398,526	$(102,795)	$(36,953)	$ 754,465	$(3,299,873)	$(57,062)
43		Rate of Return on Rate Base		4.78%	59.50%	(8.79%)	(35.04%)	75.22%	(8.55%)	(35.04%)	41.69%	(13.88%)	(35.04%)	44.77%	(9.51%)	(35.04%)
44		Rate of Return by Class Total				2.22%			3.46%			14.36%			(7.12%)	

SOUTHWEST GAS CORPORATION
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Line No.	Account No.	Description	Allocation Factor No.	Medium General Gas Service Demand	Medium General Gas Service Customer	Medium General Gas Service Commodity	Large General Gas Service Demand	Large General Gas Service Customer	Large General Gas Service Commodity	Transportation Eligible Service Demand	Transportation Eligible Service Customer	Transportation Eligible Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		Direct Depreciation Expense										
1	301-303	Intangible	Intang. Plant	$ 2,930	$ 7,800	$ 415	$ 10,443	$ 5,638	$ 1,369	$ 3,905	$ 702	$ 827
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 870,098	$ 2,316,253	$ 123,192	$ 3,101,253	$ 1,674,401	$ 406,536	$ 1,159,610	$ 208,620	$ 245,646
5	389-398	General	1.1	$ 67,265	$ 179,063	$ 9,524	$ 239,748	$ 129,443	$ 31,428	$ 89,646	$ 16,128	$ 18,990
6		Total Direct Dep. Exp.		$ 940,293	$ 2,503,116	$ 133,131	$ 3,351,444	$ 1,809,482	$ 439,333	$ 1,253,160	$ 225,451	$ 265,463
		Systems Allocable Depreciation Expense										
7	301-303	Intangible	Intang. Plant	$ 65,418	$ 174,147	$ 9,262	$ 233,167	$ 125,889	$ 30,565	$ 87,185	$ 15,685	$ 18,469
8	389-398	General	1.1	$ 33,123	$ 88,176	$ 4,690	$ 118,060	$ 63,742	$ 15,476	$ 44,145	$ 7,942	$ 9,351
		System Allocable Amortization										
9		Miscellaneous Intangible	1.1	-	-	-	-	-	-	-	-	-
10		Structures-Leasehold Improvements	1.1	-	-	-	-	-	-	-	-	-
11		Total System Allocable Amortization		-	-	-	-	-	-	-	-	-
12		Total System Alloc Dep. Exp. & Amortization		98,542	262,323	13,952	351,227	189,631	46,042	131,330	23,627	27,820
13		Total Depreciation Expense		1,038,834	2,765,439	147,083	3,702,671	1,999,113	485,374	1,384,490	249,078	293,284
14		Amortization-Limited Term Gas Plant	1.1	-	-	-	-	-	-	-	-	-
15		Amortization-Gas Plant Acquisition	1.1	(739)	(1,968)	(105)	(2,636)	(1,423)	(345)	(985)	(177)	(209)
16		Amortization of PBOP Costs	1.1	4,709	12,537	667	16,785	9,063	2,200	6,276	1,129	1,330
17		Amortization of Service Investigation	7.0	-	-	-	-	-	-	-	-	-
18		Amortization of TRIMP Costs	1.1	16,511	43,952	2,338	58,848	31,773	7,714	22,004	3,959	4,661
19		Amortization of SOX Implementation	1.1	382	1,016	54	1,360	734	178	509	91	108
20		Total Depreciation & Amortization Expense		$ 1,059,696	$ 2,820,975	$ 150,036	$ 3,777,029	$ 2,039,260	$ 495,122	$ 1,412,294	$ 254,080	$ 299,173

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Line No.	Account No.	Description	Allocation Factor No.	Medium General Gas Service Demand	Medium General Gas Service Customer	Medium General Gas Service Commodity	Large General Gas Service Demand	Large General Gas Service Customer	Large General Gas Service Commodity	Transportation Eligible Service Demand	Transportation Eligible Service Customer	Transportation Eligible Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		Operation and Maintenance Expense										
		Gas Supply Expense										
1	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-	-	-	-	-	-
3	805	Purchased Gas Cost Adj.	3.0	-	-	-	-	-	-	-	-	-
4	810	Gas Used for Compressor Sta. Fuel--	3.0	-	-	-	-	-	-	-	-	-
5	813	Other Gas Supply Expense	3.0	-	-	-	-	-	-	-	-	-
6		Labor & Labor Loading	3.0	-	-	48,528	-	-	160,145	-	-	96,766
7		Materials & Expenses	3.0	-	-	4,063	-	-	13,409	-	-	8,102
8		Total Gas Supply Expense		$ -	$ -	$ 52,592	$ -	$ -	$ 173,553	$ -	$ -	$ 104,868
		Transmission Expenses										
9	850	Operation Supervision & Engin.										
10		Labor & Labor Loading	5.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11		Materials & Expenses	5.0	-	-	-	-	-	-	-	-	-
12	851	System Control & Load Dispatch										
13		Labor & Labor Loading	3.0	-	-	-	-	-	-	-	-	-
14		Materials & Expenses	3.0	-	-	-	-	-	-	-	-	-
15	852	Communication System Exp.										
16		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-
17		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-
18	853	Compressor Station										
19		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-
20		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-
21	854	Gas for Compressor Station Fuel	3.0	-	-	-	-	-	-	-	-	-
22	856	Mains Expense										
23		Labor & Labor Loading	6.0	-	-	-	-	-	-	-	-	-
24		Materials & Expenses	6.0	-	-	-	-	-	-	-	-	-
25	857	Meas. & Res. Sta. Exp.										
26		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-
27		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-
28	858	Trans. & comp. of Gas by Others	3.0	-	-	-	-	-	-	-	-	-
29	860	Rents	1.0	-	-	-	-	-	-	-	-	-
30	861	Maint. Supervision & Eng.										
31		Labor & Labor Loading	7.0	-	-	-	-	-	-	-	-	-
32		Materials & Expenses	7.0	-	-	-	-	-	-	-	-	-
33	862	Maint. of Struct. & Imp.	1.0	-	-	-	-	-	-	-	-	-
34	863	Maint. of Mains										
35		Labor & Labor Loading	6.0	-	-	-	-	-	-	-	-	-
36		Materials & Expenses	6.0	-	-	-	-	-	-	-	-	-
37	864	Maint. of Comp. Sta. Equip.										
38		Labor & Labor Loading	3.0	-	-	-	-	-	-	-	-	-
39		Materials & Expenses	3.0	-	-	-	-	-	-	-	-	-
40	865	Maint. of Meas. & Reg. Sta. Equip.										
41		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-
42		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-
43		Total Transmission Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

SOUTHWEST GAS CORPORATION
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Line No.	Account No.	Description	Allocation Factor No.	Medium General Gas Service Demand	Medium General Gas Service Customer	Medium General Gas Service Commodity	Large General Gas Service Demand	Large General Gas Service Customer	Large General Gas Service Commodity	Transportation Eligible Service Demand	Transportation Eligible Service Customer	Transportation Eligible Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		Distribution Expenses										
1	870	Operation Supervision & Eng.										
2		Labor & Labor Loading	5.5	$ 46,194	$ 313,046	$ 60,723	$ 164,647	$ 406,116	$ 200,387	$ 61,564	$ 69,302	$ 121,082
3		Materials & Expenses	5.5	7,229	48,989	9,503	25,766	63,553	31,359	9,634	10,845	18,948
4	871	Distribution Load Dispatching										
5		Labor & Labor Loading	3.0	-	-	37,749	-	-	124,571	-	-	75,271
6		Materials & Expenses	3.0	-	-	9,158	-	-	30,222	-	-	18,261
7	874	Mains & Svcs. Expense										
8		Labor & Labor Loading	4.4	86,258	183,524	0	307,447	88,104	0	114,960	6,342	0
9		Materials & Expenses	4.4	97,586	207,625	0	347,822	99,674	0	130,056	7,175	0
10	875	Meas. & Reg. Sta. Exp.-Gen.										
11		Labor & Labor Loading	3.0	-	-	139,516	-	-	460,405	-	-	278,196
12		Materials & Expenses	3.0	-	-	55,246	-	-	182,312	-	-	110,160
13	878	Meter & House Reg. Exp.										
14		Labor & Labor Loading	6.0	-	340,153	-	-	568,498	-	-	104,385	-
15		Materials & Expenses	6.0	-	51,353	-	-	85,826	-	-	15,759	-
16	879	Customer Installation Exp.										
17		Labor & Labor Loading	6.0	-	402,003	-	-	671,868	-	-	123,365	-
18		Materials & Expenses	6.0	-	61,216	-	-	102,309	-	-	18,786	-
19	880	Other Expenses										
20		Labor & Labor Loading	5.5	39,745	269,342	52,246	141,661	349,419	172,411	52,969	59,627	104,178
21		Materials & Expenses	5.5	26,921	182,437	35,388	95,953	236,676	116,782	35,878	40,388	70,564
22	881	Rents	5.5	12,507	84,760	16,441	44,579	109,959	54,256	16,669	18,764	32,784
23		Total Distribution-Operations		$ 316,441	$ 2,144,448	$ 415,970	$ 1,127,875	$ 2,782,002	$ 1,372,705	$ 421,731	$ 474,737	$ 829,446
		Operation and Maintenance Expense										
		Distribution Expenses										
24	885	Maint. Supervision & Eng.										
25		Labor & Labor Loading	6.6	$ 33,146	$ 81,990	$ 12,807	$ 118,142	$ 51,884	$ 42,264	$ 44,175	$ 5,702	$ 25,538
26		Materials & Expenses	6.6	3,558	8,800	1,375	12,681	5,569	4,536	4,742	612	2,741
27	886	Maint. of Structures & Imp.										
28		Labor & Labor Loading	1.0	890	-	-	3,171	-	-	1,186	-	-
29		Materials & Expenses	1.0	3,297	-	-	11,752	-	-	4,394	-	-
30	887	Maint. of Mains										
31		Labor & Labor Loading	2.2	197,010	84,455	0	702,193	36,229	0	262,562	886	0
32		Materials & Expenses	2.2	156,929	67,273	0	559,334	28,858	0	209,144	706	0
33	889	Maint. of Meas. & Reg. Sta-Gen										
34		Labor & Labor Loading	3.0	-	-	79,425	-	-	262,103	-	-	158,374
35		Materials & Expenses	3.0	-	-	58,948	-	-	194,529	-	-	117,543
36	892	Maint. of Services										
37		Labor & Labor Loading	3.3	0	401,216	-	0	197,783	-	0	16,302	-
38		Materials & Expenses	3.3	0	219,524	-	0	108,217	-	0	8,919	-
39	893	Maint of Meter & House Reg.										
40		Labor & Labor Loading	6.0	-	66,118	-	-	110,503	-	-	20,290	-
41		Materials & Expenses	6.0	-	47,261	-	-	78,987	-	-	14,503	-
42	894	Maint of Other Equip.										
43		Labor & Labor Loading	6.6	2,099	5,191	811	7,480	3,285	2,676	2,797	361	1,617
44		Materials & Expenses	6.6	618	1,530	239	2,204	968	789	824	106	477
45		Total Distribution-Maintenance		$ 397,546	$ 983,358	$ 153,605	$ 1,416,956	$ 622,283	$ 506,897	$ 529,823	$ 68,387	$ 306,288
46		Total Distribution O & M		$ 713,987	$ 3,127,806	$ 569,574	$ 2,544,832	$ 3,404,285	$ 1,879,602	$ 951,555	$ 543,124	$ 1,135,734

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Line No.	Account No.	Description	Allocation Factor No.	Medium General Gas Service Demand	Medium General Gas Service Customer	Medium General Gas Service Commodity	Large General Gas Service Demand	Large General Gas Service Customer	Large General Gas Service Commodity	Transportation Eligible Service Demand	Transportation Eligible Service Customer	Transportation Eligible Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		Customer Accounts Expenses										
1	901	Supervision										
2		Labor & Labor Loading	10.1	$ -	$ 186,233	$ -	$ -	$ 106,036	$ -	$ -	$ 2,593	$ -
3		Materials & Expenses	10.1	-	11,375	-	-	6,477	-	-	158	-
4	902	Meter Reading Exp.										
5		Labor & Labor Loading	13.0	-	276,323	-	-	158,051	-	-	3,865	-
6		Materials & Expenses	13.0	-	69,252	-	-	39,611	-	-	969	-
7	903	Customer Records & Collections										
8		Labor & Labor Loading	13.0	-	763,412	-	-	436,654	-	-	10,679	-
9		Materials & Expenses	13.0	-	355,596	-	-	203,393	-	-	4,974	-
10	903	Customer Records & Collections - LCS										
11		Labor & Labor Loading - LCS	13.0	-	58,018	-	-	33,185	-	-	812	-
12		Materials & Expenses - LCS	13.0	-	2,581	-	-	1,476	-	-	36	-
13	904	Uncollectible Accounts Exp.	4.0	-	28,281	-	-	12,132	-	-	297	-
14	905	Misc. Customer Accounts Exp.										
15		Labor & Labor Loading	10.1	-	19,427	-	-	11,061	-	-	271	-
16		Materials & Expenses	10.1	-	1,104	-	-	629	-	-	15	-
17		Total Customer Accounts Expenses		$ -	$ 1,771,602	$ -	$ -	$ 1,008,705	$ -	$ -	$ 24,669	$ -
		Customer Service & Info. Exp.										
18	908	Customer Assistance Exp.										
19		Labor & Labor Loading	13.0	$ -	$ 14,834	$ -	$ -	$ 8,485	$ -	$ -	$ 208	$ -
20		Materials & Expenses	13.0	-	13,382	-	-	7,654	-	-	187	-
21	909	Info. & Instructional Exp.										
22		Labor & Labor Loading	13.0	-	-	-	-	-	-	-	-	-
23		Materials & Expenses	13.0	-	-	-	-	-	-	-	-	-
24	910	Misc. C.S. & I. Expense										
25		Labor & Labor Loading	13.0	-	42	-	-	24	-	-	1	-
26		Materials & Expenses	13.0	-	1,284	-	-	734	-	-	18	-
27		Total Customer Service & Info. Exp.		$ -	$ 29,541	$ -	$ -	$ 16,897	$ -	$ -	$ 413	$ -
		Sales Expense										
28	911	Supervision										
29		Labor & Labor Loading	4.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30		Materials & Expenses	4.0	-	-	-	-	-	-	-	-	-
31	912	Demonstrating & Selling Exp.										
32		Labor & Labor Loading	4.0	-	-	-	-	-	-	-	-	-
33		Materials & Expenses	4.0	-	-	-	-	-	-	-	-	-
34	913	Advertising Expense										
35		Labor & Labor Loading	4.0	-	-	-	-	-	-	-	-	-
36		Materials & Expenses	4.0	-	-	-	-	-	-	-	-	-
37		Total Sales Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38		Total O & M Expense		$ 713,987	$ 4,928,949	$ 622,166	$ 2,544,832	$ 4,429,886	$ 2,053,155	$ 951,555	$ 568,207	$ 1,240,603
39		Allocation Percentage	Total O&M	0.63%	4.33%	0.55%	2.23%	3.89%	1.80%	0.84%	0.50%	1.09%
		Other Operating Deductions										
40		Administrative & General Expense	Total O&M	329,060	2,271,636	286,741	1,172,852	2,041,630	946,251	438,549	261,873	571,764
41		Interest on Customer Deposits	8.0	-	13,669	-	-	-	-	-	-	-
42		Taxes Other Than Income	1.1	466,787	1,242,614	66,090	1,663,747	898,275	218,097	622,102	111,920	131,783
43		Total Allocated Operating Deductions		$ 1,509,833	$ 8,456,868	$ 974,997	$ 5,381,431	$ 7,369,791	$ 3,217,502	$ 2,012,206	$ 941,999	$ 1,944,150
		Tax Adjustments										
44		Interest Expense	1.1	565,381	1,505,079	80,049	2,015,164	1,088,009	264,163	753,503	135,559	159,618
45		State South Georgia	1.1	1,075	2,861	152	3,830	2,068	502	1,432	258	303
46		Investment Tax Credit	1.1	(7,372)	(19,624)	(1,044)	(26,275)	(14,186)	(3,444)	(9,825)	(1,768)	(2,081)
47		Federal South Georgia	1.1	4,022	10,706	569	14,334	7,739	1,879	5,360	964	1,135

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Line No.	Account No.	Description	Allocation Factor No.	Medium General Gas Service Demand	Medium General Gas Service Customer	Medium General Gas Service Commodity	Large General Gas Service Demand	Large General Gas Service Customer	Large General Gas Service Commodity	Transportation Eligible Service Demand	Transportation Eligible Service Customer	Transportation Eligible Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
		Summary of Allocated Cost of Service										
		Rate Base										
1		Direct Net Plant		$14,669,403	$ 39,050,822	$ 2,076,956	$52,285,498	$ 28,229,521	$ 6,853,982	$19,550,413	$ 3,517,231	$ 4,141,464
2		Systems Allocable Net Plant		566,328	1,507,600	80,183	2,018,539	1,089,831	264,605	754,765	135,787	159,886
3		Cash Working Capital	1.1	(69,486)	(479,688)	(60,550)	(247,665)	(431,119)	(199,814)	(92,606)	(55,298)	(120,736)
4		Materials & Supplies	1.1	128,678	342,548	18,219	458,641	247,625	60,122	171,493	30,853	36,328
5		Prepayments	1.1	38,242	101,801	5,414	136,303	73,591	17,868	50,966	9,169	10,796
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-	-	-	-	-	-
7		Customer Deposits	8.0	-	(455,649)	-	-	-	-	-	-	-
8		Customer Advances	8.0	-	(133,908)	-	-	-	-	-	-	-
9		Deferred Taxes	1.1	(1,907,202)	(5,077,085)	(270,030)	(6,797,755)	(3,670,183)	(891,102)	(2,541,793)	(457,283)	(538,441)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-	-	-	-	-	-
11		Total Rate Base		$13,425,963	$ 34,856,441	$ 1,850,193	$47,853,561	$ 25,539,266	$ 6,105,661	$17,893,238	$ 3,180,457	$ 3,689,297
12		Net Operating Margin	Direct	$16,136,803	$ 4,213,440	$ -	$38,942,928	$ 7,300,460	$ -	$14,970,291	$ 885,300	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 402,609	$ 105,124	$ -	$ 971,615	$ 182,144	$ -	$ 373,505	$ 22,088	$ -
14		Late Charges	Direct	$ 73,364	$ 19,156	$ -	$ 177,048	$ 33,190	$ -	$ 68,060	$ 4,025	$ -
15		Service Establishment Charges	Direct	$ 387,655	$ 95,997	$ -	$ 887,260	$ 166,331	$ -	$ 341,077	$ 20,170	$ -
16		Reconnect / Reread Charges	Direct	$ 28,969	$ 7,564	$ -	$ 69,910	$ 13,106	$ -	$ 26,874	$ 1,589	$ -
17		Other Revenue - Labor	Direct	$ 90	$ 24	$ -	$ 218	$ 41	$ -	$ 84	$ 5	$ -
18		Other Revenue - Parts & Material	Direct	$ 305	$ 80	$ -	$ 736	$ 138	$ -	$ 283	$ 17	$ -
19		Other Revenue - Field Collection Fee	Direct	$ 20,552	$ 5,366	$ -	$ 49,598	$ 9,298	$ -	$ 19,066	$ 1,128	$ -
20		Other Revenue - Returned Item Fee	Direct	$ 7,165	$ 1,871	$ -	$ 17,290	$ 3,241	$ -	$ 6,647	$ 393	$ -
21		Other Revenue - Rental Income	Direct	$ 40,581	$ 10,596	$ -	$ 97,934	$ 18,359	$ -	$ 37,648	$ 2,226	$ -
22		Total Revenue		17,076,091	4,459,217	-	41,214,538	7,726,309	-	15,843,535	936,941	-
23		O & M		(713,987)	(4,928,949)	(622,166)	(2,544,832)	(4,429,886)	(2,053,155)	(951,555)	(568,207)	(1,240,603)
24		A & G	Total O&M	(329,060)	(2,271,636)	(286,741)	(1,172,852)	(2,041,630)	(946,251)	(438,549)	(261,873)	(571,764)
25		Depreciation Expense		(1,059,696)	(2,820,975)	(150,036)	(3,777,029)	(2,039,260)	(495,122)	(1,412,294)	(254,080)	(299,173)
26		Interest on Customer Deposits	8.0	-	(13,669)	-	-	-	-	-	-	-
27		Taxes other than Income	1.1	(466,787)	(1,242,614)	(66,090)	(1,663,747)	(898,275)	(218,097)	(622,102)	(111,920)	(131,783)
		State Income Tax										
28		Taxable Income before Interest Exp.		$14,508,562	$(6,818,625)	$(1,125,033)	$32,056,079	$(1,682,742)	$(3,712,624)	$12,419,035	$(259,138)	$(2,243,323)
29		Interest Expense	1.1	(565,381)	(1,505,079)	(80,049)	(2,015,164)	(1,088,009)	(264,163)	(753,503)	(135,559)	(159,618)
30		State Taxable Income		$13,943,180	$(8,323,704)	$(1,205,082)	$30,040,915	$(2,770,751)	$(3,976,787)	$11,665,532	$(394,697)	$(2,402,942)
31		State Income Tax		971,561	(579,996)	(83,970)	2,093,251	(193,066)	(277,103)	812,854	(27,503)	(167,437)
32		South Georgia	1.1	1,075	2,861	152	3,830	2,068	502	1,432	258	303
33		State Income Tax		972,635	(577,135)	(83,818)	2,097,081	(190,998)	(276,600)	814,286	(27,245)	(167,134)
		Federal Income Tax										
34		Taxable Income before Interest Exp.		14,508,562	(6,818,625)	(1,125,033)	32,056,079	(1,682,742)	(3,712,624)	12,419,035	(259,138)	(2,243,323)
35		Interest Expense	1.1	(565,381)	(1,505,079)	(80,049)	(2,015,164)	(1,088,009)	(264,163)	(753,503)	(135,559)	(159,618)
36		Federal Taxable Income		13,943,180	(8,323,704)	(1,205,082)	30,040,915	(2,770,751)	(3,976,787)	11,665,532	(394,697)	(2,402,942)
37		Federal Income Tax		$ 4,540,067	$(2,710,298)	$(392,389)	$ 9,781,682	$(902,190)	$(1,294,890)	$ 3,798,437	$(128,518)	$(782,427)
38		I T C	1.1	(7,372)	(19,624)	(1,044)	(26,275)	(14,186)	(3,444)	(9,825)	(1,768)	(2,081)
39		South Georgia	1.1	4,022	10,706	569	14,334	7,739	1,879	5,360	964	1,135
40		Total Federal Income Tax		$ 4,536,717	$(2,719,217)	$(392,864)	$ 9,769,741	$(908,637)	$(1,296,455)	$ 3,793,972	$(129,322)	$(783,373)
41		Regulatory Amortization	1.1	-	-	-	-	-	-	-	-	-
42		Net Income		$ 8,999,210	$(3,522,274)	$(648,352)	$20,189,256	$(583,107)	$(2,139,569)	$ 7,810,776	$(102,572)	$(1,292,817)
43		Rate of Return on Rate Base		67.03%	(10.11%)	(35.04%)	42.19%	(2.28%)	(35.04%)	43.65%	(3.23%)	(35.04%)
44		Rate of Return by Class Total			9.63%			21.97%			25.91%	

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Line No.	Account No.	Description	Allocation Factor No.	Air-Conditioning Gas Service Demand	Air-Conditioning Gas Service Customer	Air-Conditioning Gas Service Commodity	CNG - Small Demand	CNG - Small Customer	CNG - Small Commodity	CNG - Large Demand	CNG - Large Customer	CNG - Large Commodity	CNG - Residential Demand	CNG - Residential Customer	CNG - Residential Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Direct Depreciation Expense													
1	301-303	Intangible	Intang. Plant	$ 27	$ 41	$ 18	$ 6	$ 4	$ 2	$ 55	$ 97	$ 18	$ 3	$ 14	$ 1
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 8,121	$ 12,048	$ 5,258	$ 1,752	$ 1,119	$ 522	$ 16,274	$ 28,658	$ 5,436	$ 800	$ 4,261	$ 228
5	389-398	General	1.1	$ 628	$ 931	$ 406	$ 135	$ 86	$ 40	$ 1,258	$ 2,215	$ 420	$ 62	$ 329	$ 18
6		Total Direct Dep. Exp.		$ 8,777	$ 13,020	$ 5,682	$ 1,893	$ 1,209	$ 564	$ 17,587	$ 30,970	$ 5,875	$ 865	$ 4,605	$ 247
		Systems Allocable Depreciation Expense													
7	301-303	Intangible	Intang. Plant	$ 611	$ 906	$ 395	$ 132	$ 84	$ 39	$ 1,224	$ 2,155	$ 409	$ 60	$ 320	$ 17
8	389-398	General	1.1	$ 309	$ 459	$ 200	$ 67	$ 43	$ 20	$ 620	$ 1,091	$ 207	$ 30	$ 162	$ 9
		System Allocable Amortization													
9		Miscellaneous Intangible	1.1	-	-	-	-	-	-	-	-	-	-	-	-
10		Structures-Leasehold Improvements	1.1	-	-	-	-	-	-	-	-	-	-	-	-
11		Total System Allocable Amortization		-	-	-	-	-	-	-	-	-	-	-	-
12		Total System Alloc Dep. Exp. & Amortization		920	1,365	595	198	127	59	1,843	3,246	616	91	483	26
13		Total Depreciation Expense		9,696	14,385	6,278	2,092	1,336	623	19,430	34,216	6,490	956	5,088	272
14		Amortization-Limited Term Gas Plant	1.1	-	-	-	-	-	-	-	-	-	-	-	-
15		Amortization-Gas Plant Acquisition	1.1	(7)	(10)	(4)	(1)	(1)	(0)	(14)	(24)	(5)	(1)	(4)	(0)
16		Amortization of PBOP Costs	1.1	44	65	28	9	6	3	88	155	29	4	23	1
17		Amortization of Service Investigation	7.0	-	-	-	-	-	-	-	-	-	-	-	-
18		Amortization of TRIMP Costs	1.1	154	229	100	33	21	10	309	544	103	15	81	4
19		Amortization of SOX Implementation	1.1	4	5	2	1	0	0	7	13	2	0	2	0
20		Total Depreciation & Amortization Expense		$ 9,891	$ 14,674	$ 6,404	$ 2,134	$ 1,362	$ 636	$ 19,820	$ 34,903	$ 6,621	$ 975	$ 5,190	$ 278

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Line No.	Account No.	Description	Allocation Factor No.	Air-Conditioning Gas Service Demand	Air-Conditioning Gas Service Customer	Air-Conditioning Gas Service Commodity	CNG - Small Demand	CNG - Small Customer	CNG - Small Commodity	CNG - Large Demand	CNG - Large Customer	CNG - Large Commodity	CNG - Residential Demand	CNG - Residential Customer	CNG - Residential Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Operation and Maintenance Expense													
		Gas Supply Expense													
1	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-	-	-	-	-	-	-	-	-
3	805	Purchased Gas Cost Adj.	3.0	-	-	-	-	-	-	-	-	-	-	-	-
4	810	Gas Used for Compressor Sta. Fuel--	3.0	-	-	-	-	-	-	-	-	-	-	-	-
5	813	Other Gas Supply Expense	3.0	-	-	-	-	-	-	-	-	-	-	-	-
6		Labor & Labor Loading	3.0	-	-	2,071	-	-	206	-	-	2,141	-	-	90
7		Materials & Expenses	3.0	-	-	173	-	-	17	-	-	179	-	-	8
8		Total Gas Supply Expense		$ -	$ -	$ 2,245	$ -	$ -	$ 223	$ -	$ -	$ 2,321	$ -	$ -	$ 97
		Transmission Expenses													
9	850	Operation Supervision & Engin.													
10		Labor & Labor Loading	5.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11		Materials & Expenses	5.0	-	-	-	-	-	-	-	-	-	-	-	-
12	851	System Control & Load Dispatch													
13		Labor & Labor Loading	3.0	-	-	-	-	-	-	-	-	-	-	-	-
14		Materials & Expenses	3.0	-	-	-	-	-	-	-	-	-	-	-	-
15	852	Communication System Exp.													
16		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-
17		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-
18	853	Compressor Station													
19		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-
20		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-
21	854	Gas for Compressor Station Fuel	3.0	-	-	-	-	-	-	-	-	-	-	-	-
22	856	Mains Expense													
23		Labor & Labor Loading	6.0	-	-	-	-	-	-	-	-	-	-	-	-
24		Materials & Expenses	6.0	-	-	-	-	-	-	-	-	-	-	-	-
25	857	Meas. & Res. Sta. Exp.													
26		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-
27		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-
28	858	Trans. & comp. of Gas by Others	3.0	-	-	-	-	-	-	-	-	-	-	-	-
29	860	Rents	1.0	-	-	-	-	-	-	-	-	-	-	-	-
30	861	Maint. Supervision & Eng.													
31		Labor & Labor Loading	7.0	-	-	-	-	-	-	-	-	-	-	-	-
32		Materials & Expenses	7.0	-	-	-	-	-	-	-	-	-	-	-	-
33	862	Maint. of Struct. & Imp.	1.0	-	-	-	-	-	-	-	-	-	-	-	-
34	863	Maint. of Mains													
35		Labor & Labor Loading	6.0	-	-	-	-	-	-	-	-	-	-	-	-
36		Materials & Expenses	6.0	-	-	-	-	-	-	-	-	-	-	-	-
37	864	Maint. of Comp. Sta. Equip.													
38		Labor & Labor Loading	3.0	-	-	-	-	-	-	-	-	-	-	-	-
39		Materials & Expenses	3.0	-	-	-	-	-	-	-	-	-	-	-	-
40	865	Maint. of Meas. & Reg. Sta. Equip.													
41		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-
42		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-
43		Total Transmission Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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Line No.	Account No.	Description	Allocation Factor No.	Air-Conditioning Gas Service Demand	Air-Conditioning Gas Service Customer	Air-Conditioning Gas Service Commodity	CNG - Small Demand	CNG - Small Customer	CNG - Small Commodity	CNG - Large Demand	CNG - Large Customer	CNG - Large Commodity	CNG - Residential Demand	CNG - Residential Customer	CNG - Residential Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Distribution Expenses													
1	870	Operation Supervision & Eng.													
2		Labor & Labor Loading	5.5	$ 431	$ 855	$ 2,592	$ 93	$ 121	$ 257	$ 864	$ 8,302	$ 2,680	$ 42	$ 515	$ 112
3		Materials & Expenses	5.5	67	134	406	15	19	40	135	1,299	419	7	81	18
4	871	Distribution Load Dispatching													
5		Labor & Labor Loading	3.0	-	-	1,611	-	-	160	-	-	1,666	-	-	70
6		Materials & Expenses	3.0	-	-	391	-	-	39	-	-	404	-	-	17
7	874	Mains & Svcs. Expense													
8		Labor & Labor Loading	4.4	805	1,146	0	174	96	0	1,613	1,173	0	79	353	0
9		Materials & Expenses	4.4	911	1,297	0	197	109	0	1,825	1,327	0	90	399	0
10	875	Meas. & Reg. Sta. Exp.-Gen.													
11		Labor & Labor Loading	3.0	-	-	5,955	-	-	591	-	-	6,157	-	-	258
12		Materials & Expenses	3.0	-	-	2,358	-	-	234	-	-	2,438	-	-	102
13	878	Meter & House Reg. Exp.													
14		Labor & Labor Loading	6.0	-	383	-	-	109	-	-	12,154	-	-	517	-
15		Materials & Expenses	6.0	-	58	-	-	17	-	-	1,835	-	-	78	-
16	879	Customer Installation Exp.													
17		Labor & Labor Loading	6.0	-	452	-	-	129	-	-	14,364	-	-	611	-
18		Materials & Expenses	6.0	-	69	-	-	20	-	-	2,187	-	-	93	-
19	880	Other Expenses													
20		Labor & Labor Loading	5.5	371	736	2,230	80	104	221	743	7,143	2,305	37	443	97
21		Materials & Expenses	5.5	251	498	1,510	54	70	150	504	4,838	1,562	25	300	66
22	881	Rents	5.5	117	232	702	25	33	70	234	2,248	726	12	140	30
23		Total Distribution-Operations		$ 2,954	$ 5,859	$ 17,754	$ 637	$ 826	$ 1,762	$ 5,919	$ 56,870	$ 18,356	$ 291	$ 3,530	$ 771
		Operation and Maintenance Expense													
		Distribution Expenses													
24	885	Maint. Supervision & Eng.													
25		Labor & Labor Loading	6.6	$ 309	$ 460	$ 547	$ 67	$ 40	$ 54	$ 620	$ 834	$ 565	$ 30	$ 151	$ 24
26		Materials & Expenses	6.6	33	49	59	7	4	6	67	90	61	3	16	3
27	886	Maint. of Structures & Imp.													
28		Labor & Labor Loading	1.0	8	-	-	2	-	-	17	-	-	1	-	-
29		Materials & Expenses	1.0	31	-	-	7	-	-	62	-	-	3	-	-
30	887	Maint. of Mains													
31		Labor & Labor Loading	2.2	1,839	194	0	397	114	0	3,685	140	0	181	570	0
32		Materials & Expenses	2.2	1,465	154	0	316	91	0	2,935	111	0	144	454	0
33	889	Maint. of Meas. & Reg. Sta-Gen													
34		Labor & Labor Loading	3.0	-	-	3,390	-	-	337	-	-	3,505	-	-	147
35		Materials & Expenses	3.0	-	-	2,516	-	-	250	-	-	2,601	-	-	109
36	892	Maint. of Services													
37		Labor & Labor Loading	3.3	0	2,906	-	0	127	-	0	3,044	-	0	282	-
38		Materials & Expenses	3.3	0	1,590	-	0	69	-	0	1,666	-	0	154	-
39	893	Maint of Meter & House Reg.													
40		Labor & Labor Loading	6.0	-	74	-	-	21	-	-	2,362	-	-	101	-
41		Materials & Expenses	6.0	-	53	-	-	15	-	-	1,689	-	-	72	-
42	894	Maint of Other Equip.													
43		Labor & Labor Loading	6.6	20	29	35	4	3	3	39	53	36	2	10	2
44		Materials & Expenses	6.6	6	9	10	1	1	1	12	16	11	1	3	0
45		Total Distribution-Maintenance		$ 3,711	$ 5,519	$ 6,556	$ 801	$ 485	$ 651	$ 7,436	$ 10,004	$ 6,778	$ 366	$ 1,813	$ 285
46		Total Distribution O & M		$ 6,664	$ 11,378	$ 24,310	$ 1,438	$ 1,312	$ 2,413	$ 13,354	$ 66,874	$ 25,134	$ 657	$ 5,343	$ 1,055

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Air-Conditioning Gas Service Demand	Air-Conditioning Gas Service Customer	Air-Conditioning Gas Service Commodity	CNG - Small Demand	CNG - Small Customer	CNG - Small Commodity	CNG - Large Demand	CNG - Large Customer	CNG - Large Commodity	CNG - Residential Demand	CNG - Residential Customer	CNG - Residential Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Customer Accounts Expenses													
1	901	Supervision													
2		Labor & Labor Loading	10.1	$ -	$ 860	$ -	$ -	$ 251	$ -	$ -	$ 409	$ -	$ -	$ 415	$ -
3		Materials & Expenses	10.1	-	53	-	-	15	-	-	25	-	-	25	-
4	902	Meter Reading Exp.													
5		Labor & Labor Loading	13.0	-	1,288	-	-	373	-	-	610	-	-	592	-
6		Materials & Expenses	13.0	-	323	-	-	93	-	-	153	-	-	148	-
7	903	Customer Records & Collections													
8		Labor & Labor Loading	13.0	-	3,560	-	-	1,030	-	-	1,686	-	-	1,636	-
9		Materials & Expenses	13.0	-	1,658	-	-	480	-	-	785	-	-	762	-
10	903	Customer Records & Collections - LCS													
11		Labor & Labor Loading - LCS	13.0	-	271	-	-	78	-	-	128	-	-	124	-
12		Materials & Expenses - LCS	13.0	-	12	-	-	3	-	-	6	-	-	6	-
13	904	Uncollectible Accounts Exp.	4.0	-	65	-	-	38	-	-	47	-	-	191	-
14	905	Misc. Customer Accounts Exp.													
15		Labor & Labor Loading	10.1	-	90	-	-	26	-	-	43	-	-	43	-
16		Materials & Expenses	10.1	-	5	-	-	1	-	-	2	-	-	2	-
17		Total Customer Accounts Expenses		$ -	$ 8,184	$ -	$ -	$ 2,391	$ -	$ -	$ 3,895	$ -	$ -	$ 3,944	$ -
		Customer Service & Info. Exp.													
18	908	Customer Assistance Exp.													
19		Labor & Labor Loading	13.0	$ -	$ 69	$ -	$ -	$ 20	$ -	$ -	$ 33	$ -	$ -	$ 32	$ -
20		Materials & Expenses	13.0	-	62	-	-	18	-	-	30	-	-	29	-
21	909	Info. & Instructional Exp.													
22		Labor & Labor Loading	13.0	-	-	-	-	-	-	-	-	-	-	-	-
23		Materials & Expenses	13.0	-	-	-	-	-	-	-	-	-	-	-	-
24	910	Misc. C.S. & I. Expense													
25		Labor & Labor Loading	13.0	-	0	-	-	0	-	-	0	-	-	0	-
26		Materials & Expenses	13.0	-	6	-	-	2	-	-	3	-	-	3	-
27		Total Customer Service & Info. Exp.		$ -	$ 138	$ -	$ -	$ 40	$ -	$ -	$ 65	$ -	$ -	$ 63	$ -
		Sales Expense													
28	911	Supervision													
29		Labor & Labor Loading	4.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30		Materials & Expenses	4.0	-	-	-	-	-	-	-	-	-	-	-	-
31	912	Demonstrating & Selling Exp.													
32		Labor & Labor Loading	4.0	-	-	-	-	-	-	-	-	-	-	-	-
33		Materials & Expenses	4.0	-	-	-	-	-	-	-	-	-	-	-	-
34	913	Advertising Expense													
35		Labor & Labor Loading	4.0	-	-	-	-	-	-	-	-	-	-	-	-
36		Materials & Expenses	4.0	-	-	-	-	-	-	-	-	-	-	-	-
37		Total Sales Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38		Total O & M Expense		$ 6,664	$ 19,700	$ 26,555	$ 1,438	$ 3,743	$ 2,636	$ 13,354	$ 70,834	$ 27,455	$ 657	$ 9,351	$ 1,153
39		Allocation Percentage	Total O&M	0.01%	0.02%	0.02%	0.00%	0.00%	0.00%	0.01%	0.06%	0.02%	0.00%	0.01%	0.00%
		Other Operating Deductions													
40		Administrative & General Expense	Total O&M	3,071	9,079	12,238	663	1,725	1,215	6,155	32,646	12,653	303	4,309	531
41		Interest on Customer Deposits	8.0	-	-	-	-	-	-	-	-	-	-	-	-
42		Taxes Other Than Income	1.1	4,357	6,464	2,821	940	600	280	8,731	15,375	2,916	429	2,288	122
43		Total Allocated Operating Deductions		$ 14,093	$ 35,243	$ 41,614	$ 3,040	$ 6,068	$ 4,131	$ 28,239	$ 118,855	$ 43,025	$ 1,389	$ 15,946	$ 1,806
		Tax Adjustments													
44		Interest Expense	1.1	5,277	7,829	3,417	1,138	727	339	10,575	18,622	3,532	520	2,769	148
45		State South Georgia	1.1	10	15	6	2	1	1	20	35	7	1	5	0
46		Investment Tax Credit	1.1	(69)	(102)	(45)	(15)	(9)	(4)	(138)	(243)	(46)	(7)	(36)	(2)
47		Federal South Georgia	1.1	38	56	24	8	5	2	75	132	25	4	20	1

SOUTHWEST GAS CORPORATION
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Line No.	Account No.	Description	Allocation Factor No.	Air-Conditioning Gas Service Demand	Air-Conditioning Gas Service Customer	Air-Conditioning Gas Service Commodity	CNG - Small Demand	CNG - Small Customer	CNG - Small Commodity	CNG - Large Demand	CNG - Large Customer	CNG - Large Commodity	CNG - Residential Demand	CNG - Residential Customer	CNG - Residential Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Summary of Allocated Cost of Service													
		Rate Base													
1		Direct Net Plant		$ 136,922	$ 203,131	$ 88,646	$ 29,539	$ 18,859	$ 8,800	$ 274,369	$ 483,166	$ 91,652	$ 13,493	$ 71,845	$ 3,848
2		Systems Allocable Net Plant		5,286	7,842	3,422	1,140	728	340	10,592	18,653	3,538	521	2,774	149
3		Cash Working Capital	1.1	(649)	(1,917)	(2,584)	(140)	(364)	(257)	(1,300)	(6,894)	(2,672)	(64)	(910)	(112)
4		Materials & Supplies	1.1	1,201	1,782	778	259	165	77	2,407	4,238	804	118	630	34
5		Prepayments	1.1	357	530	231	77	49	23	715	1,260	239	35	187	10
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-	-	-	-	-	-	-	-	-
7		Customer Deposits	8.0	-	-	-	-	-	-	-	-	-	-	-	-
8		Customer Advances	8.0	-	-	-	-	-	-	-	-	-	-	-	-
9		Deferred Taxes	1.1	(17,802)	(26,410)	(11,525)	(3,840)	(2,452)	(1,144)	(35,671)	(62,818)	(11,916)	(1,754)	(9,341)	(500)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-	-	-	-	-	-	-	-	-
11		Total Rate Base		$ 125,316	$ 184,958	$ 78,968	$ 27,035	$ 16,985	$ 7,839	$ 251,113	$ 437,606	$ 81,645	$ 12,350	$ 65,185	$ 3,428
12		Net Operating Margin	Direct	$ 139,816	$ 27,400	$ -	$ 24,257	$ 5,280	$ -	$ 252,636	$ 55,080	$ -	$ 10,607	$ 10,560	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 3,488	$ 684	$ -	$ 605	$ 132	$ -	$ 6,303	$ 1,374	$ -	$ 265	$ 263	$ -
14		Late Charges	Direct	$ 636	$ 125	$ -	$ 110	$ 24	$ -	$ 1,149	$ 250	$ -	$ 48	$ 48	$ -
15		Service Establishment Charges	Direct	$ 3,186	$ 624	$ -	$ 553	$ 120	$ -	$ 5,756	$ 1,255	$ -	$ 242	$ 241	$ -
16		Reconnect / Reread Charges	Direct	$ 251	$ 49	$ -	$ 44	$ 9	$ -	$ 454	$ 99	$ -	$ 19	$ 19	$ -
17		Other Revenue - Labor	Direct	$ 1	$ 0	$ -	$ 0	$ 0	$ -	$ 1	$ 0	$ -	$ 0	$ 0	$ -
18		Other Revenue - Parts & Material	Direct	$ 3	$ 1	$ -	$ 0	$ 0	$ -	$ 5	$ 1	$ -	$ 0	$ 0	$ -
19		Other Revenue - Field Collection Fee	Direct	$ 178	$ 35	$ -	$ 31	$ 7	$ -	$ 322	$ 70	$ -	$ 14	$ 13	$ -
20		Other Revenue - Returned Item Fee	Direct	$ 62	$ 12	$ -	$ 11	$ 2	$ -	$ 112	$ 24	$ -	$ 5	$ 5	$ -
21		Other Revenue - Rental Income	Direct	$ 352	$ 69	$ -	$ 61	$ 13	$ -	$ 635	$ 139	$ -	$ 27	$ 27	$ -
22		Total Revenue		147,972	28,998	-	25,672	5,588	-	267,373	58,293	-	11,226	11,176	-
23		O & M		(6,664)	(19,700)	(26,555)	(1,438)	(3,743)	(2,636)	(13,354)	(70,834)	(27,455)	(657)	(9,351)	(1,153)
24		A & G	Total O&M	(3,071)	(9,079)	(12,238)	(663)	(1,725)	(1,215)	(6,155)	(32,646)	(12,653)	(303)	(4,309)	(531)
25		Depreciation Expense		(9,891)	(14,674)	(6,404)	(2,134)	(1,362)	(636)	(19,820)	(34,903)	(6,621)	(975)	(5,190)	(278)
26		Interest on Customer Deposits	8.0	-	-	-	-	-	-	-	-	-	-	-	-
27		Taxes other than Income	1.1	(4,357)	(6,464)	(2,821)	(940)	(600)	(280)	(8,731)	(15,375)	(2,916)	(429)	(2,286)	(122)
		State Income Tax													
28		Taxable Income before Interest Exp.		$ 123,988	$(20,919)	$(48,017)	$ 20,498	$(1,843)	$(4,767)	$ 219,313	$(95,465)	$(49,645)	$ 8,862	$(9,960)	$(2,084)
29		Interest Expense	1.1	(5,277)	(7,829)	(3,417)	(1,138)	(727)	(339)	(10,575)	(18,622)	(3,532)	(520)	(2,769)	(148)
30		State Taxable Income		$ 118,711	$(28,748)	$(51,434)	$ 19,359	$(2,569)	$(5,106)	$ 208,739	$(114,087)	$(53,178)	$ 8,342	$(12,729)	$(2,233)
31		State Income Tax		8,272	(2,003)	(3,584)	1,349	(179)	(356)	14,545	(7,950)	(3,705)	581	(887)	(156)
32		South Georgia	1.1	10	15	6	2	1	1	20	35	7	1	5	0
33		State Income Tax		8,282	(1,988)	(3,577)	1,351	(178)	(355)	14,565	(7,914)	(3,699)	582	(882)	(155)
		Federal Income Tax													
34		Taxable Income before Interest Exp.		123,988	(20,919)	(48,017)	20,498	(1,843)	(4,767)	219,313	(95,465)	(49,645)	8,862	(9,960)	(2,084)
35		Interest Expense	1.1	(5,277)	(7,829)	(3,417)	(1,138)	(727)	(339)	(10,575)	(18,622)	(3,532)	(520)	(2,769)	(148)
36		Federal Taxable Income		118,711	(28,748)	(51,434)	19,359	(2,569)	(5,106)	208,739	(114,087)	(53,178)	8,342	(12,729)	(2,233)
37		Federal Income Tax		$ 38,654	$(9,361)	$(16,748)	$ 6,304	$(837)	$(1,663)	$ 67,968	$(37,148)	$(17,315)	$ 2,716	$(4,145)	$(727)
38		I T C	1.1	(69)	(102)	(45)	(15)	(9)	(4)	(138)	(243)	(46)	(7)	(36)	(2)
39		South Georgia	1.1	38	56	24	8	5	2	75	132	25	4	20	1
40		Total Federal Income Tax		$ 38,622	$(9,407)	$(16,768)	$ 6,297	$(841)	$(1,665)	$ 67,905	$(37,258)	$(17,336)	$ 2,713	$(4,161)	$(728)
41		Regulatory Amortization	1.1	-	-	-	-	-	-	-	-	-	-	-	-
42		Net Income		$ 77,084	$(9,524)	$(27,672)	$ 12,850	$(824)	$(2,747)	$ 136,843	$(50,292)	$(28,610)	$ 5,567	$(4,917)	$(1,201)
43		Rate of Return on Rate Base		61.51%	(5.15%)	(35.04%)	47.53%	(4.85%)	(35.04%)	54.49%	(11.49%)	(35.04%)	45.08%	(7.54%)	(35.04%)
44		Rate of Return by Class Total			10.25%			17.89%			7.52%			(0.68%)	

SOUTHWEST GAS CORPORATION
ARIZONA
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Line No.	Account No.	Description	Allocation Factor No.	Electric Generation Gas Service Demand	Electric Generation Gas Service Customer	Electric Generation Gas Service Commodity	Small Essential Agr. User Gas Service Demand	Small Essential Agr. User Gas Service Customer	Small Essential Agr. User Gas Service Commodity	Natural Gas Engine Gas Service Demand	Natural Gas Engine Gas Service Customer	Natural Gas Engine Gas Service Commodity	Street Lighting Gas Service Demand	Street Lighting Gas Service Customer	Street Lighting Gas Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Direct Depreciation Expense													
1	301-303	Intangible	Intang. Plant	$ 482	$ 42	$ 145	$ 297	$ 45	$ 28	$ 160	$ 1,303	$ 205	$ 4	$ 5	$ 1
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 143,103	$ 12,397	$ 42,967	$ 88,249	$ 13,471	$ 8,432	$ 47,528	$ 386,981	$ 60,899	$ 1,088	$ 1,337	$ 286
5	389-398	General	1.1	$ 11,063	$ 958	$ 3,322	$ 6,822	$ 1,041	$ 652	$ 3,674	$ 29,916	$ 4,708	$ 84	$ 103	$ 22
6		Total Direct Dep. Exp.		$ 154,648	$ 13,397	$ 46,433	$ 95,369	$ 14,557	$ 9,112	$ 51,362	$ 418,201	$ 65,812	$ 1,176	$ 1,445	$ 309
		Systems Allocable Depreciation Expense													
7	301-303	Intangible	Intang. Plant	$ 10,759	$ 932	$ 3,230	$ 6,635	$ 1,013	$ 634	$ 3,573	$ 29,095	$ 4,579	$ 82	$ 101	$ 21
8	389-398	General	1.1	$ 5,448	$ 472	$ 1,636	$ 3,360	$ 513	$ 321	$ 1,809	$ 14,732	$ 2,318	$ 41	$ 51	$ 11
		System Allocable Amortization													
9		Miscellaneous Intangible	1.1	-	-	-	-	-	-	-	-	-	-	-	-
10		Structures-Leasehold Improvements	1.1	-	-	-	-	-	-	-	-	-	-	-	-
11		Total System Allocable Amortization		-	-	-	-	-	-	-	-	-	-	-	-
12		Total System Alloc Dep. Exp. & Amortization		16,207	1,404	4,866	9,995	1,526	955	5,383	43,827	6,897	123	151	32
13		Total Depreciation Expense		170,855	14,801	51,299	105,363	16,083	10,067	56,745	462,028	72,709	1,299	1,597	341
14		Amortization-Limited Term Gas Plant	1.1	-	-	-	-	-	-	-	-	-	-	-	-
15		Amortization-Gas Plant Acquisition	1.1	(122)	(11)	(37)	(75)	(11)	(7)	(40)	(329)	(52)	(1)	(1)	(0)
16		Amortization of PBOP Costs	1.1	775	67	233	478	73	46	257	2,095	330	6	7	2
17		Amortization of Service Investigation	7.0	-	-	-	-	-	-	-	-	-	-	-	-
18		Amortization of TRIMP Costs	1.1	2,715	235	815	1,675	256	160	902	7,343	1,156	21	25	5
19		Amortization of SOX Implementation	1.1	63	5	19	39	6	4	21	170	27	0	1	0
20		Total Depreciation & Amortization Expense		$ 174,286	$ 15,098	$ 52,329	$ 107,479	$ 16,406	$ 10,269	$ 57,885	$ 471,306	$ 74,169	$ 1,325	$ 1,629	$ 348

SOUTHWEST GAS CORPORATION
ARIZONA
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Line No.	Account No.	Description	Allocation Factor No.	Electric Generation Gas Service Demand	Electric Generation Gas Service Customer	Electric Generation Gas Service Commodity	Small Essential Agr. User Gas Service Demand	Small Essential Agr. User Gas Service Customer	Small Essential Agr. User Gas Service Commodity	Natural Gas Engine Gas Service Demand	Natural Gas Engine Gas Service Customer	Natural Gas Engine Gas Service Commodity	Street Lighting Gas Service Demand	Street Lighting Gas Service Customer	Street Lighting Gas Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Operation and Maintenance Expense													
		Gas Supply Expense													
1	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-	-	-	-	-	-	-	-	-
3	805	Purchased Gas Cost Adj.	3.0	-	-	-	-	-	-	-	-	-	-	-	-
4	810	Gas Used for Compressor Sta. Fuel--	3.0	-	-	-	-	-	-	-	-	-	-	-	-
5	813	Other Gas Supply Expense	3.0	-	-	-	-	-	-	-	-	-	-	-	-
6		Labor & Labor Loading	3.0	-	-	16,926	-	-	3,321	-	-	23,990	-	-	113
7		Materials & Expenses	3.0	-	-	1,417	-	-	278	-	-	2,009	-	-	9
8		Total Gas Supply Expense		$ -	$ -	$ 18,343	$ -	$ -	$ 3,600	$ -	$ -	$ 25,998	$ -	$ -	$ 122
		Transmission Expenses													
9	850	Operation Supervision & Engin.													
10		Labor & Labor Loading	5.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11		Materials & Expenses	5.0	-	-	-	-	-	-	-	-	-	-	-	-
12	851	System Control & Load Dispatch													
13		Labor & Labor Loading	3.0	-	-	-	-	-	-	-	-	-	-	-	-
14		Materials & Expenses	3.0	-	-	-	-	-	-	-	-	-	-	-	-
15	852	Communication System Exp.													
16		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-
17		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-
18	853	Compressor Station													
19		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-
20		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-
21	854	Gas for Compressor Station Fuel	3.0	-	-	-	-	-	-	-	-	-	-	-	-
22	856	Mains Expense													
23		Labor & Labor Loading	6.0	-	-	-	-	-	-	-	-	-	-	-	-
24		Materials & Expenses	6.0	-	-	-	-	-	-	-	-	-	-	-	-
25	857	Meas. & Res. Sta. Exp.													
26		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-
27		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-
28	858	Trans. & comp. of Gas by Others	3.0	-	-	-	-	-	-	-	-	-	-	-	-
29	860	Rents	1.0	-	-	-	-	-	-	-	-	-	-	-	-
30	861	Maint. Supervision & Eng.													
31		Labor & Labor Loading	7.0	-	-	-	-	-	-	-	-	-	-	-	-
32		Materials & Expenses	7.0	-	-	-	-	-	-	-	-	-	-	-	-
33	862	Maint. of Struct. & Imp.	1.0	-	-	-	-	-	-	-	-	-	-	-	-
34	863	Maint. of Mains													
35		Labor & Labor Loading	6.0	-	-	-	-	-	-	-	-	-	-	-	-
36		Materials & Expenses	6.0	-	-	-	-	-	-	-	-	-	-	-	-
37	864	Maint. of Comp. Sta. Equip.													
38		Labor & Labor Loading	3.0	-	-	-	-	-	-	-	-	-	-	-	-
39		Materials & Expenses	3.0	-	-	-	-	-	-	-	-	-	-	-	-
40	865	Maint. of Meas. & Reg. Sta. Equip.													
41		Labor & Labor Loading	1.0	-	-	-	-	-	-	-	-	-	-	-	-
42		Materials & Expenses	1.0	-	-	-	-	-	-	-	-	-	-	-	-
43		Total Transmission Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
AUGUST 31, 2004

Line No.	Account No.	Description	Allocation Factor No.	Electric Generation Gas Service Demand	Electric Generation Gas Service Customer	Electric Generation Gas Service Commodity	Small Essential Agr. User Gas Service Demand	Small Essential Agr. User Gas Service Customer	Small Essential Agr. User Gas Service Commodity	Natural Gas Engine Gas Service Demand	Natural Gas Engine Gas Service Customer	Natural Gas Engine Gas Service Commodity	Street Lighting Gas Service Demand	Street Lighting Gas Service Customer	Street Lighting Gas Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Distribution Expenses													
1	870	Operation Supervision & Eng.													
2		Labor & Labor Loading	5.5	$ 7,597	$ 2,229	$ 21,179	$ 4,685	$ 2,766	$ 4,156	$ 2,523	$ 116,005	$ 30,018	$ 58	$ 71	$ 141
3		Materials & Expenses	5.5	1,189	349	3,314	733	433	650	395	18,154	4,698	9	11	22
4	871	Distribution Load Dispatching													
5		Labor & Labor Loading	3.0	-	-	13,166	-	-	2,584	-	-	18,661	-	-	88
6		Materials & Expenses	3.0	-	-	3,194	-	-	627	-	-	4,527	-	-	21
7	874	Mains & Svcs. Expense													
8		Labor & Labor Loading	4.4	14,187	845	0	8,749	833	0	4,712	14,874	0	108	133	0
9		Materials & Expenses	4.4	16,050	956	0	9,898	942	0	5,331	16,827	0	122	151	0
10	875	Meas. & Reg. Sta. Exp.-Gen.													
11		Labor & Labor Loading	3.0	-	-	48,660	-	-	9,549	-	-	68,969	-	-	324
12		Materials & Expenses	3.0	-	-	19,268	-	-	3,781	-	-	27,310	-	-	128
13	878	Meter & House Reg. Exp.													
14		Labor & Labor Loading	6.0	-	2,813	-	-	3,675	-	-	171,119	-	-	-	-
15		Materials & Expenses	6.0	-	425	-	-	555	-	-	25,834	-	-	-	-
16	879	Customer Installation Exp.													
17		Labor & Labor Loading	6.0	-	3,325	-	-	4,343	-	-	202,234	-	-	-	-
18		Materials & Expenses	6.0	-	506	-	-	661	-	-	30,795	-	-	-	-
19	880	Other Expenses													
20		Labor & Labor Loading	5.5	6,537	1,918	18,222	4,031	2,380	3,576	2,171	99,810	25,827	50	61	121
21		Materials & Expenses	5.5	4,428	1,299	12,343	2,730	1,612	2,422	1,471	67,606	17,494	34	42	82
22	881	Rents	5.5	2,057	603	5,734	1,269	749	1,125	683	31,409	8,128	16	19	38
23		Total Distribution-Operations		$ 52,044	$ 15,269	$ 145,080	$ 32,095	$ 18,950	$ 28,470	$ 17,285	$ 794,667	$ 205,631	$ 396	$ 488	$ 966
		Operation and Maintenance Expense													
		Distribution Expenses													
24	885	Maint. Supervision & Eng.													
25		Labor & Labor Loading	6.6	$ 5,452	$ 417	$ 4,467	$ 3,362	$ 439	$ 877	$ 1,811	$ 11,094	$ 6,331	$ 41	$ 51	$ 30
26		Materials & Expenses	6.6	585	45	479	361	47	94	194	1,191	680	4	6	3
27	886	Maint. of Structures & Imp.													
28		Labor & Labor Loading	1.0	146	-	-	90	-	-	49	-	-	1	-	-
29		Materials & Expenses	1.0	542	-	-	334	-	-	180	-	-	4	-	-
30	887	Maint. of Mains													
31		Labor & Labor Loading	2.2	32,402	119	0	19,982	188	0	10,761	3,128	0	246	150	0
32		Materials & Expenses	2.2	25,810	95	0	15,916	150	0	8,572	2,492	0	196	120	0
33	889	Maint. of Meas. & Reg. Sta-Gen													
34		Labor & Labor Loading	3.0	-	-	27,701	-	-	5,436	-	-	39,263	-	-	184
35		Materials & Expenses	3.0	-	-	20,560	-	-	4,035	-	-	29,140	-	-	137
36	892	Maint. of Services													
37		Labor & Labor Loading	3.3	0	2,171	-	0	2,055	-	0	36,972	-	0	184	-
38		Materials & Expenses	3.3	0	1,188	-	0	1,125	-	0	20,229	-	0	101	-
39	893	Maint of Meter & House Reg.													
40		Labor & Labor Loading	6.0	-	547	-	-	714	-	-	33,262	-	-	-	-
41		Materials & Expenses	6.0	-	391	-	-	511	-	-	23,775	-	-	-	-
42	894	Maint of Other Equip.													
43		Labor & Labor Loading	6.6	345	26	283	213	28	55	115	702	401	3	3	2
44		Materials & Expenses	6.6	102	8	83	63	8	16	34	207	118	1	1	1
45		Total Distribution-Maintenance		$ 65,383	$ 5,007	$ 53,574	$ 40,321	$ 5,264	$ 10,513	$ 21,715	$ 133,052	$ 75,933	$ 497	$ 616	$ 357
46		Total Distribution O & M		$ 117,428	$ 20,275	$ 198,654	$ 72,416	$ 24,214	$ 38,983	$ 39,001	$ 927,719	$ 281,564	$ 893	$ 1,104	$ 1,322

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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AUGUST 31, 2004

Line No.	Account No.	Description	Allocation Factor No.	Electric Generation Gas Service Demand	Electric Generation Gas Service Customer	Electric Generation Gas Service Commodity	Small Essential Agr. User Gas Service Demand	Small Essential Agr. User Gas Service Customer	Small Essential Agr. User Gas Service Commodity	Natural Gas Engine Gas Service Demand	Natural Gas Engine Gas Service Customer	Natural Gas Engine Gas Service Commodity	Street Lighting Gas Service Demand	Street Lighting Gas Service Customer	Street Lighting Gas Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
		Customer Accounts Expenses													
1	901	Supervision													
2		Labor & Labor Loading	10.1	$ -	$ 349	$ -	$ -	$ 2,027	$ -	$ -	$ 17,065	$ -	$ -	$ 1,865	$ -
3		Materials & Expenses	10.1	-	21	-	-	124	-	-	1,042	-	-	114	
4	902	Meter Reading Exp.													
5		Labor & Labor Loading	13.0	-	520	-	-	3,052	-	-	25,600	-	-	2,809	
6		Materials & Expenses	13.0	-	130	-	-	765	-	-	6,416	-	-	704	
7	903	Customer Records & Collections													
8		Labor & Labor Loading	13.0	-	1,436	-	-	8,431	-	-	70,725	-	-	7,762	
9		Materials & Expenses	13.0	-	669	-	-	3,927	-	-	32,944	-	-	3,615	
10	903	Customer Records & Collections - LCS													
11		Labor & Labor Loading - LCS	13.0	-	109	-	-	641	-	-	5,375	-	-	590	
12		Materials & Expenses - LCS	13.0	-	5	-	-	29	-	-	239	-	-	26	
13	904	Uncollectible Accounts Exp.	4.0	-	40	-	-	63	-	-	1,048	-	-	50	
14	905	Misc. Customer Accounts Exp.													
15		Labor & Labor Loading	10.1	-	36	-	-	211	-	-	1,780	-	-	195	
16		Materials & Expenses	10.1	-	2	-	-	12	-	-	101	-	-	11	
17		Total Customer Accounts Expenses		$ -	$ 3,318	$ -	$ -	$ 19,280	$ -	$ -	$ 162,335	$ -	$ -	$ 17,742	$ -
		Customer Service & Info. Exp.													
18	908	Customer Assistance Exp.													
19		Labor & Labor Loading	13.0	$ -	$ 28	$ -	$ -	$ 164	$ -	$ -	$ 1,374	$ -	$ -	$ 151	$ -
20		Materials & Expenses	13.0	-	25	-	-	148	-	-	1,240	-	-	136	
21	909	Info. & Instructional Exp.													
22		Labor & Labor Loading	13.0	-	-	-	-	-	-	-	-	-	-	-	
23		Materials & Expenses	13.0	-	-	-	-	-	-	-	-	-	-	-	
24	910	Misc. C.S. & I. Expense													
25		Labor & Labor Loading	13.0	-	0	-	-	0	-	-	4	-	-	0	
26		Materials & Expenses	13.0	-	2	-	-	14	-	-	119	-	-	13	
27		Total Customer Service & Info. Exp.		$ -	$ 56	$ -	$ -	$ 326	$ -	$ -	$ 2,737	$ -	$ -	$ 300	$ -
		Sales Expense													
28	911	Supervision													
29		Labor & Labor Loading	4.0	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30		Materials & Expenses	4.0	-	-	-	-	-	-	-	-	-	-	-	
31	912	Demonstrating & Selling Exp.													
32		Labor & Labor Loading	4.0	-	-	-	-	-	-	-	-	-	-	-	
33		Materials & Expenses	4.0	-	-	-	-	-	-	-	-	-	-	-	
34	913	Advertising Expense													
35		Labor & Labor Loading	4.0	-	-	-	-	-	-	-	-	-	-	-	
36		Materials & Expenses	4.0	-	-	-	-	-	-	-	-	-	-	-	
37		Total Sales Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38		Total O & M Expense		$ 117,428	$ 23,649	$ 216,997	$ 72,416	$ 43,821	$ 42,583	$ 39,001	$ 1,092,790	$ 307,562	$ 893	$ 19,146	$ 1,444
39		Allocation Percentage	Total O&M	0.10%	0.02%	0.19%	0.06%	0.04%	0.04%	0.03%	0.96%	0.27%	0.00%	0.02%	0.00%
		Other Operating Deductions													
40		Administrative & General Expense	Total O&M	54,120	10,899	100,009	33,375	20,196	19,625	17,974	503,641	141,748	412	8,824	666
41		Interest on Customer Deposits	8.0	-	-	-	-	-	-	-	-	-	-	-	
42		Taxes Other Than Income	1.1	76,771	6,650	23,050	47,344	7,227	4,523	25,498	207,606	32,671	584	717	153
43		Total Allocated Operating Deductions		$ 248,319	$ 41,199	$ 340,056	$ 153,134	$ 71,244	$ 66,732	$ 82,473	$ 1,804,038	$ 481,982	$ 1,888	$ 28,688	$ 2,263
		Tax Adjustments													
44		Interest Expense	1.1	92,987	8,055	27,919	57,343	8,753	5,479	30,883	251,457	39,572	707	869	186
45		State South Georgia	1.1	177	15	53	109	17	10	59	478	75	1	2	0
46		Investment Tax Credit	1.1	(1,212)	(105)	(364)	(748)	(114)	(71)	(403)	(3,279)	(516)	(9)	(11)	(2)
47		Federal South Georgia	1.1	661	57	199	408	62	39	220	1,789	281	5	6	1

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
AUGUST 31, 2004

Line No.	Account No. (a)	Description (b)	Allocation Factor No. (c)	Electric Generation Gas Service Demand (d)	Electric Generation Gas Service Customer (e)	Electric Generation Gas Service Commodity (f)	Small Essential Agr. User Gas Service Demand (g)	Small Essential Agr. User Gas Service Customer (h)	Small Essential Agr. User Gas Service Commodity (i)	Natural Gas Engine Gas Service Demand (j)	Natural Gas Engine Gas Service Customer (k)	Natural Gas Engine Gas Service Commodity (l)	Street Lighting Gas Service Demand (m)	Street Lighting Gas Service Customer (n)	Street Lighting Gas Service Commodity (o)
		Summary of Allocated Cost of Service													
		Rate Base													
1		Direct Net Plant		$ 2,412,641	$ 209,001	$ 724,393	$ 1,487,835	$ 227,107	$ 142,153	$ 801,298	$ 6,524,304	$ 1,026,726	$ 18,348	$ 22,546	$ 4,821
2		Systems Allocable Net Plant		93,143	8,069	27,966	57,440	8,768	5,488	30,935	251,878	39,638	708	870	186
3		Cash Working Capital	1.1	(11,428)	(2,302)	(21,118)	(7,048)	(4,265)	(4,144)	(3,796)	(106,351)	(29,932)	(87)	(1,863)	(141)
4		Materials & Supplies	1.1	21,163	1,833	6,354	13,051	1,992	1,247	7,029	57,230	9,006	161	198	42
5		Prepayments	1.1	6,289	545	1,888	3,879	592	371	2,089	17,008	2,677	48	59	13
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-	-	-	-	-	-	-	-	
7		Customer Deposits	8.0	-	-	-	-	-	-	-	-	-	-	-	
8		Customer Advances	8.0	-	-	-	-	-	-	-	-	-	-	-	
9		Deferred Taxes	1.1	(313,673)	(27,173)	(94,180)	(193,437)	(29,527)	(18,482)	(104,179)	(848,239)	(133,487)	(2,386)	(2,931)	(627)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-	-	-	-	-	-	-	-	
11		Total Rate Base		$ 2,208,135	$ 189,973	$ 645,304	$ 1,361,720	$ 204,667	$ 126,633	$ 733,377	$ 5,895,829	$ 914,627	$ 16,793	$ 18,879	$ 4,295
12		Net Operating Margin	Direct	$ 1,340,792	$ 64,560	$ -	$ 573,347	$ 32,625	$ -	$ 3,443,622	$ 289,800	$ -	$ 47,592	$ -	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 33,452	$ 1,611	$ -	$ 14,305	$ 814	$ -	$ 85,917	$ 7,230	$ -	$ 1,187	$ -	$ -
14		Late Charges	Direct	$ 6,096	$ 294	$ -	$ 2,607	$ 148	$ -	$ 15,656	$ 1,318	$ -	$ 216	$ -	$ -
15		Service Establishment Charges	Direct	$ 30,548	$ 1,471	$ -	$ 13,063	$ 743	$ -	$ 78,458	$ 6,603	$ -	$ 1,084	$ -	$ -
16		Reconnect / Reread Charges	Direct	$ 2,407	$ 116	$ -	$ 1,029	$ 59	$ -	$ 6,182	$ 520	$ -	$ 85	$ -	$ -
17		Other Revenue - Labor	Direct	$ 7	$ 0	$ -	$ 3	$ 0	$ -	$ 19	$ 2	$ -	$ 0	$ -	$ -
18		Other Revenue - Parts & Material	Direct	$ 25	$ 1	$ -	$ 11	$ 1	$ -	$ 65	$ 5	$ -	$ 1	$ -	$ -
19		Other Revenue - Field Collection Fee	Direct	$ 1,708	$ 82	$ -	$ 730	$ 42	$ -	$ 4,386	$ 369	$ -	$ 61	$ -	$ -
20		Other Revenue - Returned Item Fee	Direct	$ 595	$ 29	$ -	$ 255	$ 14	$ -	$ 1,529	$ 129	$ -	$ 21	$ -	$ -
21		Other Revenue - Rental Income	Direct	$ 3,372	$ 162	$ -	$ 1,442	$ 82	$ -	$ 8,660	$ 729	$ -	$ 120	$ -	$ -
22		Total Revenue		1,419,003	68,326	-	606,791	34,528	-	3,644,495	306,705	-	50,368	-	
23		O & M		(117,428)	(23,649)	(216,997)	(72,416)	(43,821)	(42,583)	(39,001)	(1,092,790)	(307,562)	(893)	(19,146)	(1,444)
24		A & G	Total O&M	(54,120)	(10,899)	(100,009)	(33,375)	(20,196)	(19,625)	(17,974)	(503,641)	(141,748)	(412)	(8,824)	(666)
25		Depreciation Expense		(174,286)	(15,098)	(52,329)	(107,479)	(16,406)	(10,269)	(57,885)	(471,306)	(74,169)	(1,325)	(1,629)	(348)
26		Interest on Customer Deposits	8.0	-	-	-	-	-	-	-	-	-	-	-	
27		Taxes other than Income	1.1	(76,771)	(6,650)	(23,050)	(47,344)	(7,227)	(4,523)	(25,498)	(207,606)	(32,671)	(584)	(717)	(153)
		State Income Tax													
28		Taxable Income before Interest Exp.		$ 996,399	$ 12,029	$ (392,385)	$ 346,178	$ (53,121)	$ (77,000)	$ 3,504,137	$ (1,968,639)	$ (556,151)	$ 47,154	$ (30,317)	$ (2,611)
29		Interest Expense	1.1	(92,987)	(8,055)	(27,919)	(57,343)	(8,753)	(5,479)	(30,883)	(251,457)	(39,572)	(707)	(869)	(186)
30		State Taxable Income		$ 903,412	$ 3,974	$ (420,304)	$ 288,835	$ (61,874)	$ (82,479)	$ 3,473,254	$ (2,220,096)	$ (595,722)	$ 46,447	$ (31,185)	$ (2,797)
31		State Income Tax		62,950	277	(29,287)	20,126	(4,311)	(5,747)	242,016	(154,696)	(41,510)	3,236	(2,173)	(195)
32		South Georgia	1.1	177	15	53	109	17	10	59	478	75	1	2	0
33		State Income Tax		63,126	292	(29,234)	20,235	(4,295)	(5,737)	242,075	(154,218)	(41,435)	3,238	(2,171)	(195)
		Federal Income Tax													
34		Taxable Income before Interest Exp.		996,399	12,029	(392,385)	346,178	(53,121)	(77,000)	3,504,137	(1,968,639)	(556,151)	47,154	(30,317)	(2,611)
35		Interest Expense	1.1	(92,987)	(8,055)	(27,919)	(57,343)	(8,753)	(5,479)	(30,883)	(251,457)	(39,572)	(707)	(869)	(186)
36		Federal Taxable Income		903,412	3,974	(420,304)	288,835	(61,874)	(82,479)	3,473,254	(2,220,096)	(595,722)	46,447	(31,185)	(2,797)
37		Federal Income Tax		$ 294,162	$ 1,294	$ (136,856)	$ 94,048	$ (20,147)	$ (26,856)	$ 1,130,933	$ (722,890)	$ (193,974)	$ 15,124	$ (10,154)	$ (911)
38		I T C	1.1	(1,212)	(105)	(364)	(748)	(114)	(71)	(403)	(3,279)	(516)	(9)	(11)	(2)
39		South Georgia	1.1	661	57	199	408	62	39	220	1,789	281	5	6	1
40		Total Federal Income Tax		$ 293,611	$ 1,246	$ (137,022)	$ 93,708	$ (20,199)	$ (26,889)	$ 1,130,750	$ (724,380)	$ (194,209)	$ 15,120	$ (10,160)	$ (912)
41		Regulatory Amortization	1.1	-	-	-	-	-	-	-	-	-	-	-	
42		Net Income		$ 639,661	$ 10,491	$ (226,130)	$ 232,235	$ (28,628)	$ (44,375)	$ 2,131,312	$ (1,090,041)	$ (320,507)	$ 28,797	$ (17,986)	$ (1,505)
43		Rate of Return on Rate Base		28.97%	5.52%	(35.04%)	17.05%	(13.99%)	(35.04%)	290.62%	(18.49%)	(35.04%)	171.48%	(95.27%)	(35.04%)
44		Rate of Return by Class Total			13.93%			9.41%			9.55%			23.29%	

SCHEDULE G-5B
SHEET 1 of 2

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
DATA ENTRY AND CLASSIFICATION OF COSTS

Line No.	Acct No.	Description	Production Specific	Production Demand	Production Customer	Production Commodity	Transmission Specific	Transmission Demand	Transmission Customer	Transmission Commodity	Distribution Specific	Distribution Demand	Distribution Customer	Distribution Commodity	Customer Accounting Specific	Customer Accounting Demand	Customer Accounting Customer
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
		Net Plant in Service															
		Direct															
		Intangible															
1	301	Organization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,152	$ 32,314	$ 1,186	$ -	$ -	$ -
2	302	Franchise & Consent	-	-	-	-	-	-	-	-	-	254,311	897,884	32,960	-	-	-
3	303	Misc. Intangible	-	-	-	-	-	-	-	-	-	59,692	210,750	7,736	-	-	-
		Total Intangible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 323,156	$ 1,140,948	$ 41,883	$ -	$ -	$ -
		Production															
4	326	Other Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	332	Field Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	334	Field Meas & Reg. Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	336	Purification Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8		Total Production	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Transmission															
9	365	Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	365	Rights of Way	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	366	Structures-Compressor Stas.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	366	Structures	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	367	Mains	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	367	Mains-Bridge	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	368	Compressor Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	369	Measuring & Reg. Sta. Equip.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	370	Communication Equip.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	371	Other Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19		Total Transmission	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Distribution															
20	374.1	Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 351,685	$ -	$ -	$ -	$ -	$ -
21	374.2	Rights of Way	-	-	-	-	-	-	-	-	-	445,985	-	-	-	-	-
22	375	Structures	-	-	-	-	-	-	-	-	-	47,682	-	-	-	-	-
23	376	Mains	-	-	-	-	-	-	-	-	-	208,461,866	307,811,910	1	-	-	-
24	378	Measuring & Reg. Station	-	-	-	-	-	-	-	-	-	-	-	23,180,184	-	-	-
25	380	Services	-	-	-	-	-	-	-	-	-	0	305,210,571	0	-	-	-
26	381	Meters	-	-	-	-	-	-	-	-	-	-	125,828,203	-	-	-	-
27	385	Industrial Meas. & Reg. Sta.	-	-	-	-	-	-	-	-	-	-	-	3,942,124	-	-	-
28	386	Other Prop. on Cust. Premises	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	387	Other Equipment	-	-	-	-	-	-	-	-	-	(39,455)	-	-	-	-	-
30		Total Distribution	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 209,267,764	$ 738,850,684	$ 27,122,308	$ -	$ -	$ -
31		Total Trans., Dist., Prod.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 209,267,764	$ 738,850,684	$ 27,122,308	$ -	$ -	$ -

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
DATA ENTRY AND CLASSIFICATION OF COSTS

Line No.	Acct No.	Description	Production Specific	Production Demand	Production Customer	Production Commodity	Transmission Specific	Transmission Demand	Transmission Customer	Transmission Commodity	Distribution Specific	Distribution Demand	Distribution Customer	Distribution Commodity	Customer Accounting Specific	Customer Accounting Demand	Customer Accounting Customer
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
		General															
1	389	Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,385,030	$ 4,890,051	$ 179,508	$ -	$ -	$ -
2	390.1	Structures & Improvements	-	-	-	-	-	-	-	-	-	4,079,343	14,402,723	528,706	-	-	-
3	390.2	Struct. & Imp.-Leasehold	-	-	-	-	-	-	-	-	-	87,079	307,446	11,286	-	-	-
4	391.0	Office Furn. & Equip.	-	-	-	-	-	-	-	-	-	899,784	3,176,819	116,617	-	-	-
5	391.1	Office Furn. & Computer Equip.	-	-	-	-	-	-	-	-	-	1,568,636	5,538,302	203,304	-	-	-
6	392.1	Transp. Equip.-Light	-	-	-	-	-	-	-	-	-	5,397,476	19,056,585	699,544	-	-	-
7	392.0	Transp. Equip.-Heavy	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	393	Stores Equipment	-	-	-	-	-	-	-	-	-	100,392	354,448	13,011	-	-	-
9	394	Tools, Shop, & Garage Equip.	-	-	-	-	-	-	-	-	-	1,616,856	5,708,549	209,554	-	-	-
10	395	Laboratory Equip.	-	-	-	-	-	-	-	-	-	123,476	435,951	16,003	-	-	-
11	396	Power Operated Equip.	-	-	-	-	-	-	-	-	-	576,947	2,036,995	74,776	-	-	-
12	397.1	Comm. Equip.-General	-	-	-	-	-	-	-	-	-	(23,321)	(82,338)	(3,023)	-	-	-
13	397.2	Comm. Equip.-Telemetering	-	-	-	-	-	-	-	-	-	27,493	97,067	3,563	-	-	-
14	398	Miscellaneous Equip.	-	-	-	-	-	-	-	-	-	174,104	614,699	22,565	-	-	-
15		Total General	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 16,013,294	$ 56,537,296	$ 2,075,415	$ -	$ -	$ -
		Systems Allocable															
		Intangible															
16	301	Organization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,638	$ 26,966	$ 990	$ -	$ -	$ -
17	302	Franchise & Consent	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	303	Miscellaneous Intang.	-	-	-	-	-	-	-	-	-	5,657,476	19,974,552	733,241	-	-	-
19		Total Intangible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,665,113	$ 20,001,518	$ 734,231	$ -	$ -	$ -
		General															
20	389	Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 48,348	$ 170,699	$ 6,266	$ -	$ -	$ -
21	390.10	Structures & Improvements	-	-	-	-	-	-	-	-	-	1,021,293	3,605,824	132,365	-	-	-
22	390.20	Struct. & Imp.-Leasehold	-	-	-	-	-	-	-	-	-	30,802	108,752	3,992	-	-	-
23	391.00	Office Furn. & Equip.	-	-	-	-	-	-	-	-	-	728,309	2,571,403	94,393	-	-	-
24	391.10	Office Furn. & Computer Equip.	-	-	-	-	-	-	-	-	-	373,712	1,319,446	48,435	-	-	-
25	392.11	Transp. Equip.-Light	-	-	-	-	-	-	-	-	-	283,401	1,000,590	36,730	-	-	-
26	392.12	Transp. Equip.-Heavy	-	-	-	-	-	-	-	-	-	18,014	63,601	2,335	-	-	-
27	392.22	Aircraft-Left Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	392.23	Aircraft-Right Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	393	Stores Equipment	-	-	-	-	-	-	-	-	-	3,597	12,699	466	-	-	-
30	394	Tools, Shop, & Garage Equip.	-	-	-	-	-	-	-	-	-	54,906	193,855	7,116	-	-	-
31	395	Laboratory Equip.	-	-	-	-	-	-	-	-	-	23,033	81,322	2,985	-	-	-
32	397.0	Comm. Equip.-General	-	-	-	-	-	-	-	-	-	257,709	909,879	33,401	-	-	-
33	397.2	Telemetering Equipment	-	-	-	-	-	-	-	-	-	72,650	256,500	9,416	-	-	-
34	398	Miscellaneous Equip.	-	-	-	-	-	-	-	-	-	128,809	454,779	16,694	-	-	-
35		Total General	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,044,584	$ 10,749,351	$ 394,596	$ -	$ -	$ -
36		Total Net Plant-Direct	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 225,604,214	$ 796,528,928	$ 29,239,606	$ -	$ -	$ -
37		Total Net Plant-Systems Alloc.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,709,697	$ 30,750,869	$ 1,128,827	$ -	$ -	$ -
38		Total Net Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 234,313,911	$ 827,279,797	$ 30,368,433	$ -	$ -	$ -
39		Cash Working Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$(2,378,016)	$(8,395,936)	$(308,205)	$ -	$ -	$ -
40		Materials and Supplies	-	-	-	-	-	-	-	-	-	1,978,967	6,987,036	256,486	-	-	-
41		Prepayments	-	-	-	-	-	-	-	-	-	588,126	2,076,465	76,224	-	-	-
42		Gas Plant Acquisition Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43		Customer Deposits	-	-	-	-	-	-	-	-	-	-	(23,912,141)	-	-	-	-
44		Customer Advances	-	-	-	-	-	-	-	-	-	-	(7,027,372)	-	-	-	-
45		Deferred Taxes	-	-	-	-	-	-	-	-	-	(29,331,310)	(103,558,512)	(3,801,507)	-	-	-
46		Deferred Gain Headquarters Bldg.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47		Total Rate Base	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 205,171,678	$ 693,449,337	$ 26,591,432	$ -	$ -	$ -

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
DATA ENTRY AND CLASSIFICATION OF COSTS

Line No.	Acct No.	Description	Production Specific	Production Demand	Production Customer	Production Commodity	Transmission Specific	Transmission Demand	Transmission Customer	Transmission Commodity	Distribution Specific	Distribution Demand	Distribution Customer	Distribution Commodity	Customer Accounting Specific	Customer Accounting Demand	Customer Accounting Customer
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
		Depreciation Expense & Amortizatic															
		Direct															
		Intangible															
1	301	Organization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	302	Franchise & Consent	-	-	-	-	-	-	-	-	-	16,657	58,810	2,159	-	-	-
3	303	Misc. Intangible	-	-	-	-	-	-	-	-	-	28,402	100,278	3,681	-	-	-
4		Total Intangible Dep. Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 45,059	$ 159,089	$ 5,840	$ -	$ -	$ -
		Production															
5	326	Other Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	332	Field Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	334	Field Meas & Reg. Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	336	Purification Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9		Total Production Dep. Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Transmission															
10	365	Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	365	Rights of Way	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	366	Structures-Compressor Stas.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	366	Structures	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	367	Mains	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	367	Mains-Bridge	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	368	Compressor Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	369	Measuring & Reg. Sta. Equip.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	370	Communication Equip.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	371	Other Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20		Total Transmission Dep. Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	# $ -	$ -	$ -	$ -	$ -	$ -	$ -
		Distribution															
21	374	Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	374.2	Rights of Way	-	-	-	-	-	-	-	-	-	15,501	-	-	-	-	-
23	375	Structures	-	-	-	-	-	-	-	-	-	1,271	-	-	-	-	-
24	376	Mains	-	-	-	-	-	-	-	-	-	12,179,878	17,984,640	0	-	-	-
25	378	Measuring & Reg. Station	-	-	-	-	-	-	-	-	-	-	-	1,007,546	-	-	-
26	380	Services	-	-	-	-	-	-	-	-	-	0	27,761,544	0	-	-	-
27	381	Meters	-	-	-	-	-	-	-	-	-	-	3,104,837	-	-	-	-
28	385	Industrial Meas. & Reg. Sta.	-	-	-	-	-	-	-	-	-	-	-	281,378	-	-	-
29	386	Other Prop. on Cust. Premises															
30	387	Other Equipment	-	-	-	-	-	-	-	-	-	24,340	-	-	-	-	-
31		Total Distribution Dep. Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,220,990	$ 48,851,021	$ 1,288,924	$ -	$ -	$ -

SCHEDULE G-6B
SHEET 1 of 7

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
DATA ENTRY AND CLASSIFICATION OF COSTS

Line No.	Acct No.	Description	Production Specific	Production Demand	Production Customer	Production Commodity	Transmission Specific	Transmission Demand	Transmission Customer	Transmission Commodity	Distribution Specific	Distribution Demand	Distribution Customer	Distribution Commodity	Customer Accounting Specific	Customer Accounting Demand	Customer Accounting Customer
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
		General															
1	389	Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	390.1	Structures & Improvements	-	-	-	-	-	-	-	-	-	103,781	366,415	13,451	-	-	-
3	390.2	Struct. & Imp.-Leasehold	-	-	-	-	-	-	-	-	-	13,378	47,233	1,734	-	-	-
4	391	Office Furn. & Equip.	-	-	-	-	-	-	-	-	-	28,411	100,308	3,682	-	-	-
5	391	Office Furn. & Computer Equip.	-	-	-	-	-	-	-	-	-	270,869	956,344	35,106	-	-	-
6	392	Transp. Equip.	-	-	-	-	-	-	-	-	-	499,803	1,764,627	64,777	-	-	-
7	393	Stores Equipment	-	-	-	-	-	-	-	-	-	2,151	7,594	279	-	-	-
8	394	Tools, Shop, & Garage Equip.	-	-	-	-	-	-	-	-	-	22,779	80,425	2,952	-	-	-
9	395	Laboratory Equip.	-	-	-	-	-	-	-	-	-	3,587	12,664	465	-	-	-
10	396	Power Operated Equip.	-	-	-	-	-	-	-	-	-	31,701	111,924	4,109	-	-	-
11	397.1	Comm. Equip.-General	-	-	-	-	-	-	-	-	-	42,372	149,600	5,492	-	-	-
12	397.2	Comm. Equip.-Telemetering	-	-	-	-	-	-	-	-	-	7,442	26,276	965	-	-	-
13	398	Miscellaneous Equip.	-	-	-	-	-	-	-	-	-	8,206	28,972	1,064	-	-	-
14		Total General Dep. Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,034,479	$ 3,652,381	$ 134,074	$ -	$ -	$ -
		Systems Allocable															
		Intangible															
15	301	Organization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	302	Franchise & Consent															
17	303	Miscellaneous Intang.	-	-	-	-	-	-	-	-	-	1,006,082	3,552,119	130,394	-	-	-
18		Total Intangible Dep. Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,006,082	$ 3,552,119	$ 130,394	$ -	$ -	$ -
		General															
19	389	Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	390.1	Structures	-	-	-	-	-	-	-	-	-	36,545	129,027	4,736	-	-	-
21	390.2	Structures - Leasehold Improvements	-	-	-	-	-	-	-	-	-	3,673	12,969	476	-	-	-
22	391	Office Furniture & Equipment	-	-	-	-	-	-	-	-	-	78,195	276,078	10,134	-	-	-
23	391.1	Computer Equipment	-	-	-	-	-	-	-	-	-	270,856	956,296	35,104	-	-	-
24	392.11	Transportation Equipment - Light	-	-	-	-	-	-	-	-	-	30,152	106,456	3,908	-	-	-
25	392.12	Transportation Equipment - Heavy	-	-	-	-	-	-	-	-	-	990	3,496	128	-	-	-
26	393	Stores Equipment	-	-	-	-	-	-	-	-	-	477	1,686	62	-	-	-
27	394	Tools, Shop, & Garage Equipment	-	-	-	-	-	-	-	-	-	5,718	20,189	741	-	-	-
28	395	Laboratory Equipment	-	-	-	-	-	-	-	-	-	1,585	5,595	205	-	-	-
29	396	Power Operated Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	397.1	Communication Equipment	-	-	-	-	-	-	-	-	-	48,427	170,977	6,276	-	-	-
31	397.2	Telemetering Equipment	-	-	-	-	-	-	-	-	-	19,954	70,449	2,586	-	-	-
32	398	Miscellaneous Equipment	-	-	-	-	-	-	-	-	-	12,841	45,337	1,664	-	-	-
33		Total General Dep. Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 509,412	$ 1,798,554	$ 66,023	$ -	$ -	$ -
		System Allocable Amortization															
34		Miscellaneous Intangible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35		Structures-Leasehold Improvements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36		Total System Allocable Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
37		Total Depreciation Exp.-Direct	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 13,300,529	$ 52,662,490	$ 1,428,838	$ -	$ -	$ -
38		Total Dep. Exp.-Systems Alloc.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,515,493	$ 5,350,673	$ 196,417	$ -	$ -	$ -
39		Amortization-Limited Term Gas Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40		Amortization-Gas Plant Acquisition	-	-	-	-	-	-	-	-	-	(10,459)	(41,413)	(1,124)	-	-	-
41		Amortization of PBOP Costs	-	-	-	-	-	-	-	-	-	66,614	263,754	7,156	-	-	-
42		Amortization of Service Investigation	-	-	-	-	-	-	-	-	-	66,614	263,754	7,156	-	-	-
43		Amortization of TRIMP Costs															
44		Amortization of SOX Implementation	-	-	-	-	-	-	-	-	-	5,397	21,369	580	-	-	-
45		Total Depreciation Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 14,944,188	$ 58,520,627	$ 1,639,024	$ -	$ -	$ -

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
DATA ENTRY AND CLASSIFICATION OF COSTS

Line	Acct		Production				Transmission				Distribution				Customer Accounting		
No.	No.	Description	Specific	Demand	Customer	Commodity	Specific	Demand	Customer	Commodity	Specific	Demand	Customer	Commodity	Specific	Demand	Customer
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
		Operation and Maintenance Expense															
		Gas Supply Expense															
1	800	Natural Gas Wellhead Purchases	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	803	Natural Gas Transmission Line Pur	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	805.1	Purchased Gas Cost Adj.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	810	Gas Used for Compressor Sta. Fue	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	813	Other Gas Supply Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6		Labor & Labor Loading	-	-	-	683,189	-	-	-	-	-	-	-	-	-	-	-
7		Materials & Expenses	-	-	-	57,202	-	-	-	-	-	-	-	-	-	-	-
8		Total Gas Supply Expense	$ -	$ -	$ -	$ 740,391	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Transmission Expenses															
9	850	Operation Supervision & Engin.															
10		Labor & Labor Loading	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	851	System Control & Load Dispatch															
13		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	852	Communication System Exp.															
16		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	853	Compressor Station															
19		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	854	Gas for Compressor Station Fuel															
22	856	Mains Expense															
23		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25	857	Meas. & Res. Sta. Exp.															
26		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	858	Trans. & comp. of Gas by Others	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	860	Rents	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	861	Maint. Supervision & Eng.															
31		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
33	862	Maint. of Struct. & Imp.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	863	Maint. of Mains															
35		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	864	Maint. of Comp. Sta. Equip.															
38		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
39		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40	865	Maint. of Meas. & Reg. Sta. Equip.															
41		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43		Total Transmission Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
DATA ENTRY AND CLASSIFICATION OF COSTS

Line No.	Acct No.	Description	Production Specific	Production Demand	Production Customer	Production Commodity	Transmission Specific	Transmission Demand	Transmission Customer	Transmission Commodity	Distribution Specific	Distribution Demand	Distribution Customer	Distribution Commodity	Customer Accounting Specific	Customer Accounting Demand	Customer Accounting Customer
(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
		Distribution Expenses															
1	870	Operation Supervision & Eng.															
2		Labor & Labor Loading	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 793,391	$ 5,748,939	$ 771,904	$ -	$ -	$ -
3		Materials & Expenses	-	-	-	-	-	-	-	-	-	124,158	899,651	120,795	-	-	-
4	871	Distribution Load Dispatching															
5		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	265,715	-	265,715	-	-	-
6		Materials & Expenses	-	-	-	-	-	-	-	-	-	64,465	-	64,465	-	-	-
7	874	Mains & Svcs. Expense															
8		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	1,326,589	3,901,091	0	-	-	-
9		Materials & Expenses	-	-	-	-	-	-	-	-	-	1,500,801	4,413,395	0	-	-	-
10	875	Meas. & Reg. Sta. Exp.-Gen.															
11		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	1,964,122	-	-	-
12		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	777,755	-	-	-
13	878	Meter & House Reg. Exp.															
14		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	5,796,552	-	-	-	-
15		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	875,104	-	-	-	-
16	879	Customer Installation Exp.															
17		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	6,850,542	-	-	-	-
18		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	1,043,174	-	-	-	-
19	880	Other Expenses															
20		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	682,626	4,946,332	664,139	-	-	-
21		Materials & Expenses	-	-	-	-	-	-	-	-	-	462,372	3,350,367	449,851	-	-	-
22	881	Rents	-	-	-	-	-	-	-	-	-	214,817	1,556,568	208,999	-	-	-
23		Total Distribution-Operations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,434,933	$ 39,381,715	$ 5,287,745	$ -	$ -	$ -
24	885	Maint. Supervision & Eng.															
25		Labor & Labor Loading	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 509,766	$ 1,684,195	$ 180,300	$ -	$ -	$ -
26		Materials & Expenses	-	-	-	-	-	-	-	-	-	54,716	180,774	19,353	-	-	-
27	886	Maint. of Structures & Imp.															
28		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	13,682	-	-	-	-	-
29		Materials & Expenses	-	-	-	-	-	-	-	-	-	50,707	-	-	-	-	-
30	887	Maint. of Mains															
31		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	3,029,859	4,473,847	0	-	-	-
32		Materials & Expenses	-	-	-	-	-	-	-	-	-	2,413,442	3,563,655	0	-	-	-
33	889	Maint. of Meas. & Reg. Sta-Gen															
34		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	1,118,151	-	-	-
35		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	829,877	-	-	-
36	892	Maint. of Services															
37		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	0	5,317,554	0	-	-	-
38		Materials & Expenses	-	-	-	-	-	-	-	-	-	0	2,909,486	0	-	-	-
39	893	Maint of Meter & House Reg.															
40		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	1,126,714	-	-	-	-
41		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	805,373	-	-	-	-
42	894	Maint of Other Equip.															
43		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	32,274	106,629	11,415	-	-	-
44		Materials & Expenses	-	-	-	-	-	-	-	-	-	9,512	31,426	3,364	-	-	-
45		Total Distribution-Maintenance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,113,958	$ 20,199,655	$ 2,162,461	$ -	$ -	$ -
46		Total Distribution O & M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11,548,891	$ 59,581,369	$ 7,450,206	$ -	$ -	$ -

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
DATA ENTRY AND CLASSIFICATION OF COSTS

Line No.	Acct No.	Description	Production Specific	Production Demand	Production Customer	Production Commodity	Transmission Specific	Transmission Demand	Transmission Customer	Transmission Commodity	Distribution Specific	Distribution Demand	Distribution Customer	Distribution Commodity	Customer Accounting Specific	Customer Accounting Demand	Customer Accounting Customer
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
		Customer Accounts Expenses															
1	901	Supervision															
2		Labor & Labor Loading	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,574,463
3		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	218,328
4	902	Meter Reading Exp.															
5		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,130,538
6		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,285,812
7	903	Customer Records & Collections															
8		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14,174,373
9		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6,602,396
10	903	Customer Records & Collections - L															
11		Labor & Labor Loading - LCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,077,228
12		Materials & Expenses - LCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	47,923
13	904	Uncollectible Accounts Exp.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,498,151
14	905	Misc. Customer Accounts Exp.															
15		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	372,869
16		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21,199
17		Total Customer Accounts Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 34,003,279
		Customer Service & Info. Exp.															
18	908	Customer Assistance Exp.															
19		Labor & Labor Loading	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 275,434
20		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	248,457
21	909	Info. & Instructional Exp.															
22		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	910	Misc. C.S. & I. Expense															
25		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	773
26		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	23,832
27		Total Customer Service & Info. Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 548,496
		Sales Expense															
28	911	Supervision															
29		Labor & Labor Loading	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	912	Demonstrating & Selling Exp.															
32		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
33		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	913	Advertising Expense															
35		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37		Total Sales Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38		Total O & M Expense	$ -	$ -	$ -	$ 740,391	$ -	$ -	$ -	$ -	$ -	$ 11,548,891	$ 59,581,369	$ 7,450,206	$ -	$ -	$ 34,551,775

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
DATA ENTRY AND CLASSIFICATION OF COSTS

Line No.	Acct No.	Description	Production Specific	Production Demand	Production Customer	Production Commodity	Transmission Specific	Transmission Demand	Transmission Customer	Transmission Commodity	Distribution Specific	Distribution Demand	Distribution Customer	Distribution Commodity	Customer Accounting Specific	Customer Accounting Demand	Customer Accounting Customer
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
1		Administrative & General Expense	$ -	$ -	$ -	$ 341,229	$ -	$ -	$ -	$ -	$ -	$ 5,322,610	$ 27,459,640	$ 3,433,623	$ -	$ -	$ 15,924,093
2		Interest on Customer Deposits	-	-	-	-	-	-	-	-	-	-	-	-	-	-	717,364
3		Taxes other than Income	-	-	-	-	-	-	-	-	-	7,418,884	25,074,709	961,530	-	-	-
4		Interest Expense	-	-	-	-	-	-	-	-	-	8,985,904	30,371,001	1,164,625	-	-	-
5		South Georgia - State	-	-	-	-	-	-	-	-	-	17,080	57,727	2,214	-	-	-
6		Investment Tas Credit (I T C)	-	-	-	-	-	-	-	-	-	(117,165)	(396,001)	(15,185)	-	-	-
7		South Georgia - Federal	-	-	-	-	-	-	-	-	-	63,917	216,031	8,284	-	-	-
8		Regulatory Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9		SIT Rate															
10		FIT Rate															
		Rate Base															
11		Direct Net Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 225,604,214	$ 796,528,928	$ 29,239,606	$ -	$ -	$ -
12		Systems Allocable Net Plant	-	-	-	-	-	-	-	-	-	8,709,697	30,750,869	1,128,827	-	-	-
13		Cash Working Capital	-	-	-	-	-	-	-	-	-	(2,378,016)	(8,395,936)	(308,205)	-	-	-
14		Materials & Supplies	-	-	-	-	-	-	-	-	-	1,978,967	6,987,036	256,486	-	-	-
15		Prepayments	-	-	-	-	-	-	-	-	-	588,126	2,076,465	76,224	-	-	-
16		Gas Plant Acquisition Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17		Customer Deposits	-	-	-	-	-	-	-	-	-	-	(23,912,141)	-	-	-	-
18		Customer Advances	-	-	-	-	-	-	-	-	-	-	(7,027,372)	-	-	-	-
19		Deferred Taxes	-	-	-	-	-	-	-	-	-	(29,331,310)	(103,558,512)	(3,801,507)	-	-	-
20		Deferred Gain Hdqtrs Bldg	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21		Total Rate Base	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 205,171,678	$ 693,449,337	$ 26,591,432	$ -	$ -	$ -
22		Net Operating Margin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 67,651,339	$ 228,651,324	$ 8,768,003	$ -	$ -	$ -
23		Special Contract & Optional	-	-	-	-	-	-	-	-	-	1,687,882	5,704,788	218,759	-	-	-
24		Late Charges	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,386,957
25		Service Establishment Charges	-	-	-	-	-	-	-	-	-	-	-	-	-	-	6,950,610
26		Reconnect / Reread Charges	-	-	-	-	-	-	-	-	-	-	-	-	-	-	547,658
27		Other Revenue - Labor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,705
28		Other Revenue - Parts & Material	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,764
29		Other Revenue - Field Collection Fee	-	-	-	-	-	-	-	-	-	-	-	-	-	-	388,540
30		Other Revenue - Returned Item Fee	-	-	-	-	-	-	-	-	-	-	-	-	-	-	135,450
31		Other Revenue - Rental Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	767,198
32		Total Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 69,339,221	$ 234,356,112	$ 8,986,763	$ -	$ -	$ 10,183,882
		Operating Deductions															
33		O & M	$ -	$ -	$ -	$(740,391)	$ -	$ -	$ -	$ -	$ -	$(11,548,891)	$(59,581,369)	$(7,450,206)	$ -	$ -	$(34,551,775)
34		A & G	-	-	-	(341,229)	-	-	-	-	-	(5,322,610)	(27,459,640)	(3,433,623)	-	-	(15,924,093)
35		Depreciation Expense	-	-	-	-	-	-	-	-	-	(14,944,188)	(58,520,627)	(1,639,024)	-	-	-
36		Interest on Customer Deposits	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(717,364)
37		Taxes other than Income	-	-	-	-	-	-	-	-	-	(7,418,884)	(25,074,709)	(961,530)	-	-	-

SOUTHWEST GAS CORPORATION
EMBEDDED CLASS COST OF SERVICE MODEL
DATA ENTRY AND CLASSIFICATION OF COSTS

Line No.	Acct No.	Description	Production Specific	Production Demand	Production Customer	Production Commodity	Transmission Specific	Transmission Demand	Transmission Customer	Transmission Commodity	Distribution Specific	Distribution Demand	Distribution Customer	Distribution Commodity	Customer Accounting Specific	Customer Accounting Demand	Customer Accounting Customer
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
		State Income Tax															
1		Taxable Income before Interest Exp.	$ -	$ -	$ -	$(1,081,620)	$ -	$ -	$ -	$ -	$ -	$ 30,104,648	$ 63,719,766	$(4,497,620)	$ -	$ -	$(41,009,350)
2		Interest Expense	-	-	-	-	-	-	-	-	-	(8,985,904)	(30,371,001)	(1,164,625)	-	-	-
3		State Taxable Income	$ -	$ -	$ -	$(1,081,620)	$ -	$ -	$ -	$ -	$ -	$ 21,118,744	$ 33,348,766	$(5,662,245)	$ -	$ -	$(41,009,350)
4		State Income Tax @ 6.9680%	$ -	$ -	$ -	$(75,367)	$ -	$ -	$ -	$ -	$ -	$ 1,471,554	$ 2,323,742	$(394,545)	$ -	$ -	$(2,857,531)
5		South Georgia	-	-	-	-	-	-	-	-	-	17,080	57,727	2,214	-	-	-
6		State Income Tax	$ -	$ -	$ -	$(75,367)	$ -	$ -	$ -	$ -	$ -	$ 1,488,634	$ 2,381,469	$(392,332)	$ -	$ -	$(2,857,531)
		Federal Income Tax															
7		Taxable Income before Interest Exp.	$ -	$ -	$ -	$(1,081,620)	$ -	$ -	$ -	$ -	$ -	$ 30,104,648	$ 63,719,766	$(4,497,620)	$ -	$ -	$(41,009,350)
8		Interest Expense	-	-	-	-	-	-	-	-	-	(8,985,904)	(30,371,001)	(1,164,625)	-	-	-
9		Federal Taxable Income	$ -	$ -	$ -	$(1,081,620)	$ -	$ -	$ -	$ -	$ -	$ 21,118,744	$ 33,348,766	$(5,662,245)	$ -	$ -	$(41,009,350)
10		Federal Income Tax @ 32.5612%	$ -	$ -	$ -	$(352,188)	$ -	$ -	$ -	$ -	$ -	$ 6,876,516	$ 10,858,758	$(1,843,695)	$ -	$ -	$(13,353,136)
11		I T C	-	-	-	-	-	-	-	-	-	117,165	396,001	15,185	-	-	-
12		South Georgia	-	-	-	-	-	-	-	-	-	63,917	216,031	8,284	-	-	-
13		Total Federal Income Tax	$ -	$ -	$ -	$(352,188)	$ -	$ -	$ -	$ -	$ -	$ 7,057,599	$ 11,470,791	$(1,820,226)	$ -	$ -	$(13,353,136)
14		Regulatory Amortization	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15		Net Income	$ -	$ -	$ -	$(654,064)	$ -	$ -	$ -	$ -	$ -	$ 21,558,415	$ 49,867,507	$(2,285,063)	$ -	$ -	$(24,798,682)

SOUTHWEST GAS CORPORATION
ARIZONA
DEVELOPMENT OF ALLOCATION FACTORS
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Line No.	Description	Allocation Factor No.	Total	Residential Gas Service Demand	Residential Gas Service Customer	Residential Gas Service Commodity	Multi-Family Residential Demand	Multi-Family Residential Customer	Multi-Family Residential Commodity	MMMHP Gas Service Demand	MMMHP Gas Service Customer	MMMHP Gas Service Commodity	Small General Gas Service Demand	Small General Gas Service Customer	Small General Gas Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	CP Demand		1,384,417	766,063			38,053			6,409			11,300		
		1	100.0000%	55.334712%	0.000000%	0.000000%	2.748697%	0.000000%	0.000000%	0.462936%	0.000000%	0.000000%	0.816223%	0.000000%	0.000000%
2	NCP Demand		1,534,800	766,063			38,053			6,409			11,300		
		2	100.0000%	49.912903%	0.000000%	0.000000%	2.479374%	0.000000%	0.000000%	0.417576%	0.000000%	0.000000%	0.736247%	0.000000%	0.000000%
3	Throughput		605,776,598	0		269,525,564	0		15,860,260			2,452,509			3,787,060
		3	100.0000%	0.000000%	0.000000%	44.492568%	0.000000%	0.000000%	2.618170%	0.000000%	0.000000%	0.404854%	0.000000%	0.000000%	0.625158%
4	Customers		863,424		760,637			61,743			189			16,504	
		4	100.0000%	0.000000%	88.095460%	0.000000%	0.000000%	7.150928%	0.000000%	0.000000%	0.021890%	0.000000%	0.000000%	1.911488%	0.000000%
5	Customers With Mains		863,424	0	760,637	0	0	61,743	0	0	189	0	0	16,504	0
		5	100.0000%	0.000000%	88.095460%	0.000000%	0.000000%	7.150928%	0.000000%	0.000000%	0.021890%	0.000000%	0.000000%	1.911488%	0.000000%
6	Meters for Customers		1,125,795		760,637			65,501			3,529			62,327	
		6	100.0000%	0.000000%	67.564442%	0.000000%	0.000000%	5.818203%	0.000000%	0.000000%	0.313490%	0.000000%	0.000000%	5.536253%	0.000000%
7	Service Lines for Customers		974,582		760,637			17,397			980			74,048	
		7	100.0000%	0.000000%	78.047523%	0.000000%	0.000000%	1.785071%	0.000000%	0.000000%	0.100508%	0.000000%	0.000000%	7.597968%	0.000000%
8	Res., MMMHP & Small, Medium GS		855,373	0	760,637	0	0	61,743	0	0	189	0	0	16,504	0
		8	100.0000%	0.000000%	88.924673%	0.000000%	0.000000%	7.218237%	0.000000%	0.000000%	0.022096%	0.000000%	0.000000%	1.929480%	0.000000%
9	Extra		0	0	0	0	0	0	0	0	0	0	0	0	0
		9	0.0000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
10	Extra		0	0	0	0	0	0	0	0	0	0	0	0	0
		10	0.0000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0	0	0	0	0	0	0	0	0	0
		11	0.0000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		7,163	0	0	0	0	0	0	0	0	0	0	0	0
		12	100.0000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		953,272	0	760,637	0	0	61,743	0	0	1,401	0	0	41,590	0
		13	100.0000%	0.000000%	79.792269%	0.000000%	0.000000%	6.476958%	0.000000%	0.000000%	0.146949%	0.000000%	0.000000%	4.362879%	0.000000%
14	Extra		0	0	0	0	0	0	0	0	0	0	0	0	0
		14	0.0000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0	0	0	0	0	0	0	0	0	0
		15	0.0000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors														
	Net Production, Transmission, & Distribution Plant		975,240,756	115,797,715	594,392,729	12,067,411	5,752,136	34,780,573	710,108	968,775	768,600	109,806	1,708,091	36,039,757	169,557
16		1.1	100.0000%	11.873757%	60.948307%	1.237378%	0.589817%	3.566358%	0.072814%	0.099337%	0.078811%	0.011259%	0.175146%	3.695473%	0.017386%
	Distribution Mains		516,273,776	115,351,773	271,168,317	0	5,729,984	22,011,408	0	965,044	67,379	0	1,701,513	5,883,789	0
17		2.2	100.0000%	22.343140%	52.524132%	0.000000%	1.109873%	4.263515%	0.000000%	0.186925%	0.013051%	0.000000%	0.329576%	1.139664%	0.000000%
	Distribution Services		305,210,571	0	238,209,289	0	0	5,448,226	0	0	306,762	0	0	23,189,801	0
18		3.3	100.0000%	0.000000%	78.047523%	0.000000%	0.000000%	1.785071%	0.000000%	0.000000%	0.100508%	0.000000%	0.000000%	7.597968%	0.000000%
	Distribution Mains & Services		821,484,347	115,351,774	509,377,607	0	5,729,984	27,459,634	0	965,044	374,141	0	1,701,513	29,073,589	0
19		4.4	100.0000%	14.041871%	62.006977%	0.000000%	0.697516%	3.342685%	0.000000%	0.117476%	0.045545%	0.000000%	0.207127%	3.539153%	0.000000%
	Allocable Distribution Operating Expenses		29,109,484	1,564,528	16,749,753	1,513,742	77,716	1,219,881	89,076	13,089	50,736	13,774	23,078	1,200,704	21,269
20		5.5	100.0000%	5.374633%	57.540534%	5.200169%	0.266980%	4.190664%	0.306004%	0.044965%	0.174292%	0.047318%	0.079279%	4.124786%	0.073067%
	Allocable Distribution Maintenance Expenses		25,652,348	3,047,664	14,807,080	866,728	151,390	834,027	51,003	25,497	16,085	7,887	44,955	885,689	12,178
21		6.6	100.0000%	11.880645%	57.722122%	3.378746%	0.590159%	3.251271%	0.198823%	0.099395%	0.062704%	0.030744%	0.175247%	3.452662%	0.047474%
	Transmission Operating Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
22		7.7	0.0000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Transmission Mains		0	0	0	0	0	0	0	0	0	0	0	0	0
23		8.8	0.0000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Transmission Maintenance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
24		9.9	0.0000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Customer Accounting Expense		29,816,420	0	23,915,593	0	0	1,941,294	0	0	41,941	0	0	1,264,129	0
25		10.1	100.0000%	0.000000%	80.209470%	0.000000%	0.000000%	6.510822%	0.000000%	0.000000%	0.140665%	0.000000%	0.000000%	4.239706%	0.000000%
	Total O & M Expense		113,872,632	6,076,068	72,978,836	3,897,066	301,823	5,274,960	229,323	50,833	153,821	35,461	89,626	4,515,451	54,757
		11.2	100.0000%	5.335846%	64.088126%	3.422303%	0.265053%	4.632333%	0.201386%	0.044640%	0.135081%	0.031141%	0.078707%	3.965352%	0.048086%

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Line No.	Description	Allocation Factor No.	Medium General Gas Service Demand	Medium General Gas Service Customer	Medium General Gas Service Commodity	Large General Gas Service Demand	Large General Gas Service Customer	Large General Gas Service Commodity	Transportation Eligible Service Demand	Transportation Eligible Service Customer	Transportation Eligible Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	CP Demand		90,019			320,849			119,971		
		1	6.502274%	0.000000%	0.000000%	23.175763%	0.000000%	0.000000%	8.665801%	0.000000%	0.000000%
2	NCP Demand		90,019			320,849			119,971		
		2	5.865167%	0.000000%	0.000000%	20.904954%	0.000000%	0.000000%	7.816708%	0.000000%	0.000000%
3	Throughput				43,029,696			141,998,559			85,801,495
		3	0.000000%	0.000000%	7.103229%	0.000000%	0.000000%	23.440747%	0.000000%	0.000000%	14.163884%
4	Customers			16,299			6,992			171	
		4	0.000000%	1.887746%	0.000000%	0.000000%	0.809789%	0.000000%	0.000000%	0.019805%	0.000000%
5	Customers With Mains		0	16,299	0	0	6,992	0	0	171	0
		5	0.000000%	1.887746%	0.000000%	0.000000%	0.809789%	0.000000%	0.000000%	0.019805%	0.000000%
6	Meters for Customers			66,064			110,413			20,273	
		6	0.000000%	5.868198%	0.000000%	0.000000%	9.807511%	0.000000%	0.000000%	1.800803%	0.000000%
7	Service Lines for Customers			73,533			36,249			2,988	
		7	0.000000%	7.545126%	0.000000%	0.000000%	3.719439%	0.000000%	0.000000%	0.306562%	0.000000%
8	Res., MMMHP & Small, Medium GS		0	16,299							
		8	0.000000%	1.905514%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
9	Extra		0	0	0	0	0	0	0	0	0
		9	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
10	Extra		0	0	0	0	0	0	0	0	0
		10	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0	0	0	0	0	0
		11	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		0	0	0	0	6,992	0	0	171	0
		12	0.000000%	0.000000%	0.000000%	0.000000%	97.612704%	0.000000%	0.000000%	2.387296%	0.000000%
13	Weighted Customers for Meter Reading		0	51,342	0	0	29,366	0	0	718	0
		13	0.000000%	5.385858%	0.000000%	0.000000%	3.080591%	0.000000%	0.000000%	0.075341%	0.000000%
14	Extra		0	0	0	0	0	0	0	0	0
		14	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0	0	0	0	0	0
		15	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors										
	Net Production, Transmission, & Distribution Plant		13,607,163	36,223,075	1,926,560	48,499,401	26,185,365	6,357,672	18,134,728	3,262,541	3,841,572
16		1.1	1.395262%	3.714270%	0.197547%	4.973070%	2.685015%	0.651908%	1.859513%	0.334537%	0.393910%
	Distribution Mains		13,554,761	5,810,706	0	48,312,628	2,492,628	0	18,064,891	60,962	0
17		2.2	2.625499%	1.125509%	0.000000%	9.357947%	0.482811%	0.000000%	3.499091%	0.011808%	0.000000%
	Distribution Services		0	23,028,521	0	0	11,352,122	0	0	935,661	0
18		3.3	0.000000%	7.545126%	0.000000%	0.000000%	3.719439%	0.000000%	0.000000%	0.306562%	0.000000%
	Distribution Mains & Services		13,554,761	28,839,227	0	48,312,628	13,844,750	0	18,064,891	996,623	0
19		4.4	1.650033%	3.510624%	0.000000%	5.881138%	1.685333%	0.000000%	2.199055%	0.121320%	0.000000%
	Allocable Distribution Operating Expenses		183,845	1,245,874	241,669	655,269	1,616,278	797,510	245,016	275,811	481,889
20		5.5	0.631563%	4.279960%	0.830206%	2.251050%	5.552411%	2.739690%	0.841705%	0.947495%	1.655436%
	Allocable Distribution Maintenance Expenses		358,125	885,847	138,373	1,276,449	560,576	456,632	477,285	61,606	275,916
21		6.6	1.396071%	3.453278%	0.539416%	4.975955%	2.185283%	1.780080%	1.860592%	0.240157%	1.075599%
	Transmission Operating Expense		0	0	0	0	0	0	0	0	0
22		7.7	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Transmission Mains		0	0	0	0	0	0	0	0	0
23		8.8	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Transmission Maintenance Expense		0	0	0	0	0	0	0	0	0
24		9.9	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Customer Accounting Expense		0	1,553,463	0	0	884,502	0	0	21,632	0
25		10.1	0.000000%	5.210092%	0.000000%	0.000000%	2.966493%	0.000000%	0.000000%	0.072550%	0.000000%
	Total O & M Expense		713,987	4,928,949	622,166	2,544,832	4,429,886	2,053,155	951,555	568,207	1,240,603
		11.2	0.627005%	4.328476%	0.546370%	2.234805%	3.890212%	1.803028%	0.835631%	0.498984%	1.089465%

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Line No.	Description	Allocation Factor No.	Air-Conditioning Gas Service			CNG - Small			CNG - Large			CNG - Residential		
			Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity	Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	CP Demand		840			181			1,684			83		
		1	0.060691%	0.000000%	0.000000%	0.013093%	0.000000%	0.000000%	0.121615%	0.000000%	0.000000%	0.005981%	0.000000%	0.000000%
2	NCP Demand		5,469			614			14,805			265		
		2	0.356347%	0.000000%	0.000000%	0.040034%	0.000000%	0.000000%	0.964630%	0.000000%	0.000000%	0.017238%	0.000000%	0.000000%
3	Throughput				1,836,544			182,313			1,898,808			79,719
		3	0.000000%	0.000000%	0.303172%	0.000000%	0.000000%	0.030096%	0.000000%	0.000000%	0.313450%	0.000000%	0.000000%	0.013160%
4	Customers			37			22			27			110	
		4	0.000000%	0.004334%	0.000000%	0.000000%	0.002548%	0.000000%	0.000000%	0.003127%	0.000000%	0.000000%	0.012740%	0.000000%
5	Customers With Mains		0	37	0	0	22	0	0	27	0	0	110	0
		5	0.000000%	0.004334%	0.000000%	0.000000%	0.002548%	0.000000%	0.000000%	0.003127%	0.000000%	0.000000%	0.012740%	0.000000%
6	Meters for Customers			74			21			2,360			100	
		6	0.000000%	0.006599%	0.000000%	0.000000%	0.001889%	0.000000%	0.000000%	0.209672%	0.000000%	0.000000%	0.008921%	0.000000%
7	Service Lines for Customers			533			23			558			52	
		7	0.000000%	0.054644%	0.000000%	0.000000%	0.002383%	0.000000%	0.000000%	0.057248%	0.000000%	0.000000%	0.005308%	0.000000%
8	Res., MMMHP & Small, Medium GS													
		8	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
9	Extra		0	0	0	0	0	0	0	0	0	0	0	0
		9	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
10	Extra		0	0	0	0	0	0	0	0	0	0	0	0
		10	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0	0	0	0	0	0	0	0	0
		11	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		0	0	0	0	0	0	0	0	0	0	0	0
		12	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		0	239	0	0	69	0	0	113	0	0	110	0
		13	0.000000%	0.025114%	0.000000%	0.000000%	0.007270%	0.000000%	0.000000%	0.011896%	0.000000%	0.000000%	0.011539%	0.000000%
14	Extra		0	0	0	0	0	0	0	0	0	0	0	0
		14	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0	0	0	0	0	0	0	0	0
		15	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors													
	Net Production, Transmission, & Distribution Plant		127,007	188,422	82,227	27,400	17,493	8,163	254,502	448,179	85,015	12,516	66,642	3,569
16		1.1	0.013023%	0.019321%	0.008431%	0.002810%	0.001794%	0.000837%	0.026096%	0.045956%	0.008717%	0.001283%	0.006833%	0.000366%
	Distribution Mains		126,518	13,339	0	27,295	7,843	0	253,522	9,626	0	12,468	39,215	0
17		2.2	0.024506%	0.002584%	0.000000%	0.005287%	0.001519%	0.000000%	0.049106%	0.001864%	0.000000%	0.002415%	0.007596%	0.000000%
	Distribution Services		0	166,779	0	0	7,273	0	0	174,727	0	0	16,202	0
18		3.3	0.000000%	0.054644%	0.000000%	0.000000%	0.002383%	0.000000%	0.000000%	0.057248%	0.000000%	0.000000%	0.005308%	0.000000%
	Distribution Mains & Services		126,518	180,118	0	27,295	15,116	0	253,522	184,353	0	12,468	55,417	0
19		4.4	0.015401%	0.021926%	0.000000%	0.003323%	0.001840%	0.000000%	0.030861%	0.022441%	0.000000%	0.001518%	0.006746%	0.000000%
	Allocable Distribution Operating Expenses		1,716	3,404	10,315	370	480	1,024	3,439	33,040	10,664	169	2,051	448
20		5.5	0.005895%	0.011694%	0.035434%	0.001272%	0.001649%	0.003518%	0.011812%	0.113502%	0.036635%	0.000581%	0.007046%	0.001538%
	Allocable Distribution Maintenance Expenses		3,343	4,971	5,906	721	437	586	6,698	9,012	6,106	329	1,633	256
21		6.6	0.013031%	0.019380%	0.023023%	0.002811%	0.001705%	0.002285%	0.026111%	0.035132%	0.023803%	0.001284%	0.006366%	0.000999%
	Transmission Operating Expense		0	0	0	0	0	0	0	0	0	0	0	0
22		7.7	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Transmission Mains		0	0	0	0	0	0	0	0	0	0	0	0
23		8.8	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Transmission Maintenance Expense		0	0	0	0	0	0	0	0	0	0	0	0
24		9.9	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Customer Accounting Expense		0	7,177	0	0	2,097	0	0	3,416	0	0	3,459	0
25		10.1	0.000000%	0.024069%	0.000000%	0.000000%	0.007032%	0.000000%	0.000000%	0.011455%	0.000000%	0.000000%	0.011600%	0.000000%
	Total O & M Expense		6,664	19,700	26,555	1,438	3,743	2,636	13,354	70,834	27,455	657	9,351	1,153
		11.2	0.005852%	0.017300%	0.023320%	0.001263%	0.003287%	0.002315%	0.011727%	0.062205%	0.024110%	0.000577%	0.008211%	0.001012%

SOUTHWEST GAS CORPORATION
ARIZONA
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDING
AUGUST 31, 2004

Line No.	Description	Allocation Factor No.	Electric Generation Gas Service Demand	Electric Generation Gas Service Customer	Electric Generation Gas Service Commodity	Small Essential Agr. User Gas Service Demand	Small Essential Agr. User Gas Service Customer	Small Essential Agr. User Gas Service Commodity	Natural Gas Engine Gas Service Demand	Natural Gas Engine Gas Service Customer	Natural Gas Engine Gas Service Commodity	Street Lighting Gas Service Demand	Street Lighting Gas Service Customer	Street Lighting Gas Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
1	CP Demand		14,805			9,130			4,917			113		
		1	1.069413%	0.000000%	0.000000%	0.659489%	0.000000%	0.000000%	0.355179%	0.000000%	0.000000%	0.008133%	0.000000%	0.000000%
2	NCP Demand		45,747			9,130			105,993			113		
		2	2.980643%	0.000000%	0.000000%	0.594871%	0.000000%	0.000000%	6.905971%	0.000000%	0.000000%	0.007336%	0.000000%	0.000000%
3	Throughput				15,007,742			2,945,076			21,271,370			99,883
		3	0.000000%	0.000000%	2.477438%	0.000000%	0.000000%	0.486165%	0.000000%	0.000000%	3.511422%	0.000000%	0.000000%	0.016488%
4	Customers			23			36			604			29	
		4	0.000000%	0.002664%	0.000000%	0.000000%	0.004198%	0.000000%	0.000000%	0.069925%	0.000000%	0.000000%	0.003359%	0.000000%
5	Customers With Mains		0	23	0	0	36	0	0	604	0	0	29	0
		5	0.000000%	0.002664%	0.000000%	0.000000%	0.004198%	0.000000%	0.000000%	0.069925%	0.000000%	0.000000%	0.003359%	0.000000%
6	Meters for Customers			546			714			33,234			0	
		6	0.000000%	0.048537%	0.000000%	0.000000%	0.063399%	0.000000%	0.000000%	2.952084%	0.000000%	0.000000%	0.000000%	0.000000%
7	Service Lines for Customers			398			377			6,776			34	
		7	0.000000%	0.040822%	0.000000%	0.000000%	0.038650%	0.000000%	0.000000%	0.695282%	0.000000%	0.000000%	0.003465%	0.000000%
8	Res., MMMHP & Small, Medium GS													
		8	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
9	Extra		0	0	0	0	0	0	0	0	0	0	0	0
		9	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
10	Extra		0	0	0	0	0	0	0	0	0	0	0	0
		10	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0	0	0	0	0	0	0	0	0
		11	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		0	0	0	0	0	0	0	0	0	0	0	0
		12	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		0	97	0	0	567	0	0	4,757	0	0	522	0
		13	0.000000%	0.010134%	0.000000%	0.000000%	0.059479%	0.000000%	0.000000%	0.498966%	0.000000%	0.000000%	0.054759%	0.000000%
14	Extra		0	0	0	0	0	0	0	0	0	0	0	0
		14	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0	0	0	0	0	0	0	0	0
		15	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors													
	Net Production, Transmission, & Distribution Plant		2,237,937	193,867	671,938	1,380,098	210,662	131,859	743,275	6,051,866	952,379	17,020	20,914	4,472
16		1.1	0.229475%	0.019879%	0.068900%	0.141514%	0.021601%	0.013521%	0.076214%	0.620551%	0.097656%	0.001745%	0.002144%	0.000459%
	Distribution Mains		2,229,318	8,200	0	1,374,784	12,923	0	740,412	215,238	0	16,954	10,339	0
17		2.2	0.431809%	0.001588%	0.000000%	0.266290%	0.002503%	0.000000%	0.143415%	0.041691%	0.000000%	0.003284%	0.002003%	0.000000%
	Distribution Services		0	124,593	0	0	117,964	0	0	2,122,074	0	0	10,575	0
18		3.3	0.000000%	0.040822%	0.000000%	0.000000%	0.038650%	0.000000%	0.000000%	0.695282%	0.000000%	0.000000%	0.003465%	0.000000%
	Distribution Mains & Services		2,229,318	132,793	0	1,374,784	130,888	0	740,412	2,337,312	0	16,954	20,914	0
19		4.4	0.271377%	0.016165%	0.000000%	0.167354%	0.015933%	0.000000%	0.090131%	0.284523%	0.000000%	0.002064%	0.002546%	0.000000%
	Allocable Distribution Operating Expenses		30,236	8,871	84,288	18,646	11,010	16,540	10,042	461,683	119,467	230	284	561
20		5.5	0.103872%	0.030474%	0.289556%	0.064056%	0.037821%	0.056822%	0.034498%	1.586023%	0.410405%	0.000790%	0.000974%	0.001927%
	Allocable Distribution Maintenance Expenses		58,900	4,510	48,261	36,323	4,742	9,471	19,562	119,858	68,403	448	555	321
21		6.6	0.229608%	0.017583%	0.188136%	0.141596%	0.018486%	0.036919%	0.076259%	0.467241%	0.266656%	0.001746%	0.002164%	0.001252%
	Transmission Operating Expense		0	0	0	0	0	0	0	0	0	0	0	0
22		7.7	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Transmission Mains		0	0	0	0	0	0	0	0	0	0	0	0
23		8.8	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Transmission Maintenance Expense		0	0	0	0	0	0	0	0	0	0	0	0
24		9.9	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%	0.000000%
	Customer Accounting Expense		0	2,910	0	0	16,906	0	0	142,346	0	0	15,557	0
25		10.1	0.000000%	0.009758%	0.000000%	0.000000%	0.056702%	0.000000%	0.000000%	0.477408%	0.000000%	0.000000%	0.052176%	0.000000%
	Total O & M Expense		117,428	23,649	216,997	72,416	43,821	42,583	39,001	1,092,790	307,562	893	19,146	1,444
		11.2	0.103122%	0.020768%	0.190561%	0.063594%	0.038482%	0.037395%	0.034249%	0.959660%	0.270093%	0.000784%	0.016814%	0.001268%

H

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF REVENUES AT PRESENT AND PROPOSED RATES
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description	Proposed Schedule Number	Revenues: Present Rates [1]	Revenues: Proposed Rates [2]	Increase/(Decrease): Dollars	Increase/(Decrease): Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Sales Service						
1	Residential Gas Service	G-5	$ 329,052,995	$ 379,916,565	$ 50,863,570	15.46%	1
2	Low Income Residential Gas Service [3]	G-5	10,131,213	10,569,327	438,114	4.32%	2
3	Multi-Family Residential Gas Service	G-6	20,344,346	23,404,391	3,060,045	15.04%	3
4	Low Income Multi-Family Residential [3]	G-6	1,381,224	1,426,811	45,587	3.30%	4
	Master Metered Mobile Home Park						
5	Gas Service	G-20	2,194,379	2,328,772	134,393	6.12%	5
	General Gas Service	G-25					
6	Small		7,438,688	9,590,877	2,152,189	28.93%	6
7	Medium		43,343,592	47,089,208	3,745,616	8.64%	7
8	Large		122,121,737	127,369,985	5,248,248	4.30%	8
9	Transporation Eligible		61,704,477	63,282,108	1,577,631	2.56%	9
10	Optional Gas Service	G-30	61,408,388	61,475,128	66,740	0.11%	10
11	Air Conditioning Gas Service	G-40	1,148,592	1,178,575	29,983	2.61%	11
12	Street Lighting Gas Service	G-45	100,965	107,953	6,988	6.92%	12
	Gas Service for Compression on						
	Customer's Premises	G-55					
13	Small		126,958	128,941	1,983	1.56%	13
14	Large		1,322,363	1,387,595	65,232	4.93%	14
15	Residential		63,766	69,336	5,570	8.74%	15
16	Electric Generation Gas Service	G-60	7,970,039	8,185,176	215,137	2.70%	16
17	Small Essential Agriculture User Gas Service	G-75	2,179,703	2,292,375	112,672	5.17%	17
18	Natural Gas Engine Gas Service	G-80	13,037,945	13,037,860	(85)	(0.00%)	18
19	Total Gas Sales		$ 685,071,369	$ 752,840,982	$ 67,769,613	9.89%	19
20	Special Contract Service	B-1	2,134,837	2,134,837	0	0.00%	20
21	Other Operating Revenue		10,183,883	11,434,480	1,250,597	12.28%	21
22	Total Arizona Revenue		$ 697,390,089	$ 766,410,299	$ 69,020,210	9.90%	22
23	Less Estimated Gas Cost for Transportation customers		$(18,346,462)	$(18,346,462)			23
24	Plus Low Income Benefit		$ 1,593,570	$ 3,381,592	1,788,022	112.20%	24
25	Total Excluding Estimated Gas Cost for Transporation customers		$ 680,637,198	$ 751,445,430	$ 70,808,232	10.40%	25
26	Total Requirement			$ 751,446,319			26
27	Over/(Under) Requirement			$ 889			27

[1] Schedule H-2, Sheets 4-8, including estimated gas cost for transporation customers.
[2] Schedule H-6, Sheets 9-11, including estimated gas cost for transportation customers.
[3] Low Income Benefit at Present Rates excluding reduction to rate Schedule No. G-10 Basic Service Charge.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF MARGIN AT PRESENT AND PROPOSED RATES
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description	Proposed Schedule Number	Margin: Present Rates [1]	Margin: Proposed Rates [2]	Increase/(Decrease) Dollars	Increase/(Decrease) Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Sales Service						
1	Residential Gas Service	G-5	$ 190,026,871	$ 240,890,441	$ 50,863,570	26.77%	1
2	Low Income Residential Gas Service [3]	G-5	5,133,656	5,387,435	253,779	4.94%	2
3	Multi-Family Residential Gas Service	G-6	12,503,879	15,563,924	3,060,045	24.47%	3
4	Low Income Multi-Family Residential [3]	G-6	746,603	768,782	22,179	2.97%	4
	Master Metered Mobile Home Park						
5	Gas Service	G-20	883,856	1,018,249	134,393	15.21%	5
	General Gas Service	G-25					
6	Small		5,415,035	7,567,224	2,152,189	39.74%	6
7	Medium		20,350,243	24,095,859	3,745,616	18.41%	7
8	Large		46,243,388	51,491,636	5,248,248	11.35%	8
9	Transporation Eligible		15,855,591	17,433,222	1,577,631	9.95%	9
10	Optional Gas Service	G-30	5,476,592	5,543,332	66,740	1.22%	10
11	Air Conditioning Gas Service	G-40	167,216	197,199	29,983	17.93%	11
12	Street Lighting Gas Service	G-45	47,592	54,580	6,988	14.68%	12
	Gas Service for Compression on						
	Customer's Premises	G-55					
13	Small		29,537	31,520	1,983	6.71%	13
14	Large		307,716	372,948	65,232	21.20%	14
15	Residential		21,167	26,737	5,570	26.31%	15
16	Electric Generation Gas Service	G-60	1,405,352	1,620,489	215,137	15.31%	16
17	Small Essential Agriculture User Gas Service	G-75	605,972	718,644	112,672	18.59%	17
18	Natural Gas Engine Gas Service	G-80	3,733,422	3,733,337	(85)	(0.00%)	18
19	Total Sales and Full Margin Transportation		$ 308,953,688	$ 376,515,558	$ 67,561,870	21.87%	19
20	Special Contract Service	B-1	2,134,837	2,134,837	0	0.00%	20
21	Other Operating Revenue		10,183,883	11,434,480	1,250,597	12.28%	21
22	Plus Low Income Benefit		$ 1,593,570	$ 3,381,592	1,788,022	112.20%	22
23	Total Arizona Revenue		$ 322,865,978	$ 393,466,467	$ 70,600,489	21.87%	23
24	Total Requirement			$ 393,675,099			24
25	Over/(Under) Requirement			$ 208,632			25

[1] Schedule H-2, Sheets 4-8.
[2] Schedule H-6, Sheets 9-11.
[3] Low Income Benefit at Present Rates excluding reduction to rate Schedule No. G-10 Basic Service Charge.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF REVENUES AT PRESENT RATES BY PRESENT RATE SCHEDULES
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

			Billing Determinants		Present Margin Rates [1]		Margin at Present Rates			Revenue at Present Rates		
Line No.	Description	Proposed Schedule Number	Number of Bills	Sales (Therms)	Basic Service Charge	Commodity Charge	Basic Service Charge	Commodity Charge	Total Margin	Gas Cost [2]	Total Revenue	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
	Residential Gas Service	G-5										
1	Basic Service Charge per Month		9,496,924		$ 8.00		$ 75,975,392		$ 75,975,392		$ 75,975,392	1
	Commodity Charge per Therm											
	Summer (May - October)											
2	First 20 Therms			49,593,360		$ 0.48762		$ 24,182,714	24,182,714	$ 26,500,708	50,683,422	2
3	Over 20 Therms			9,691,283		0.40344		3,909,851	3,909,851	5,178,634	9,088,485	3
	Winter (November - April)											
4	First 40 Therms			136,597,796		$ 0.48762		66,607,817	66,607,817	72,992,398	139,600,215	4
5	Over 40 Therms			78,738,764		0.40344		31,766,367	31,766,367	42,074,846	73,841,213	5
6	Total Residential Gas Service		9,496,924	274,621,203			$ 75,975,392	$ 126,466,749	$ 202,442,141	$ 146,746,586	$ 349,188,727	6
	Low Income Residential Gas Service	G-10										
7	Basic Service Charge		369,755		$ 7.00		$ 2,588,285		$ 2,588,285		$ 2,588,285	7
	Commodity Charge per Therm											
	Summer (May - October)											
8	First 20 Therms			1,996,133		$ 0.48762		$ 973,354	973,354	$ 1,066,654	2,040,008	8
9	Over 20 Therms			238,288		0.40344		96,135	96,135	127,332	223,467	9
	Winter (November - April)											
10	First 40 Therms			5,526,657		0.48762		2,694,908	2,694,908	2,953,224	5,648,132	10
11	Next 110 Therms			2,703,999		0.40344		1,090,901	1,090,901	1,444,909	2,535,810	11
12	Over 150 Therms			74,968		0.40344		30,245	30,245	40,060	70,305	12
13	Total Low Income Residential Gas Service		369,755	10,540,045			$ 2,588,285	$ 4,885,543	$ 7,473,828	$ 5,632,179	$ 13,106,007	13
	Special Residential Gas Service for Air Conditioning	G-15										
14	Basic Service Charge per Month		1,884		$ 8.00		$ 15,072		$ 15,072		$ 15,072	14
	Commodity Charge per Therm											
	Summer (May - October)											
15	First 20 Therms			14,784		$ 0.48762		$ 7,210	7,210	$ 7,900	15,110	15
16	Over 20 Therms			99,140		0.19125		18,961	18,961	52,976	71,937	16
	Winter (November - April)											
17	First 40 Therms			32,391		0.48762		15,794	15,794	17,308	33,102	17
18	Over 40 Therms			78,261		0.40344		31,574	31,574	41,820	73,394	18
19	Total Special Residential Gas Service		1,884	224,576			$ 15,072	$ 73,539	$ 88,611	$ 120,004	$ 208,615	19
	Special Residential Gas Service for Electric Generation	G-16										
20	Basic Service Charge per Month		0		$ 8.00		$ 0		$ 0		$ 0	20
	Commodity Charge per Therm											
	Summer (May - October)											
21	First 20 Therms			0		$ 0.48762		$ 0	0	$ 0	0	21
22	Over 20 Therms			0		0.19125		0	0	0	0	22
	Winter (November - April)											
23	First 40 Therms			0		0.48762		0	0	0	0	23
24	Over 40 Therms			0		0.40344		0	0	0	0	24
25	Total Special Residential Gas Service		0	0			$ 0	$ 0	$ 0	$ 0	$ 0	25
26	Total Residential Gas Service		9,868,563	285,385,824			$ 78,578,749	$ 131,425,831	$ 210,004,580	$ 152,498,769	$ 362,503,349	26
	Master Metered Mobile Home Park Gas Service	G-20										
27	Basic Service Charge per Month		2,268		$ 50.00		$ 113,400		$ 113,400		$ 113,400	27
	Commodity Charge per Therm											
28	All Usage			2,452,509		$ 0.31415		$ 770,456	770,456	1,310,523	2,080,979	28
29	Total MMMHP Gas Service		2,268	2,452,509			$ 113,400	$ 770,456	$ 883,856	$ 1,310,523	$ 2,194,379	29

[1] Margin rates effective November 1, 2001 per Decision No. 64172.
[2] Gas cost effective August 27, 2004 without surcharges.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF REVENUES AT PRESENT RATES BY PRESENT RATE SCHEDULES
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description	Proposed Schedule Number	Billing Determinants: Number of Bills	Billing Determinants: Sales (Therms)	Present Margin Rates [1]: Basic Service Charge	Present Margin Rates [1]: Commodity Charge	Margin at Present Rates: Basic Service Charge	Margin at Present Rates: Commodity Charge	Margin at Present Rates: Total Margin	Revenue at Present Rates: Gas Cost [2]	Revenue at Present Rates: Total Revenue	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
	General Gas Service - Small	G-25(S)										
1	Basic Service Charge		393,517		$ 20.00		$ 7,870,340		$ 7,870,340		$ 7,870,340	1
	Commodity Charge per Therm											
2	Transportation Customers			183,935		$ 0.38024		$ 69,939	69,939	$ 0	69,939	2
3	Sales Customers			47,676,684		0.38024		18,128,582	18,128,582	25,476,513	43,605,095	3
4	Total Small General Gas Service		393,517	47,860,619			$ 7,870,340	$ 18,198,521	$ 26,068,861	$ 25,476,513	$ 51,545,374	4
	General Gas Service - Medium	G-25(M)										
5	Basic Service Charge		83,248		$ 90.00		$ 7,492,320		$ 7,492,320		$ 7,492,320	5
	Commodity Charge per Therm											
6	Transportation Customers			2,781,916		$ 0.27211		$ 756,987	756,987	$ 0	756,987	6
7	Sales Customers			137,503,584		0.27211		37,416,100	37,416,100	73,476,415	110,892,515	7
8	Total Medium General Gas Service		83,248	140,285,500			$ 7,492,320	$ 38,173,087	45,665,407	$ 73,476,415	$ 119,141,822	8
	General Gas Service - Large	G-25(L)										
9	Basic Service Charge		1,812		$ 500.00		$ 906,000		$ 906,000		$ 906,000	9
10	Demand Charge per Month			7,272,517	0.072695			$ 6,344,107	6,344,107		6,344,107	10
	Commodity Charge per Therm:											
11	Transportation Customers			26,148,523		$ 0.08548		$ 2,235,176	2,235,176	$ 0	2,235,176	11
12	Sales Customers			47,519,293		0.08548		4,061,949	4,061,949	25,392,409	29,454,358	12
13	Total Large General Gas Service		1,812	73,667,816			$ 906,000	$ 12,641,232	$ 13,547,232	$ 25,392,409	$ 38,939,641	13
14	Total General Gas Service		478,577	261,813,935			$ 16,268,660	$ 69,012,840	$ 85,281,500	$ 124,345,337	$ 209,626,837	14
	Gas Service to Armed Forces	G-35										
15	Basic Service Charge		108		$ 350.00		$ 37,800		$ 37,800		$ 37,800	15
	Commodity Charge per Therm											
16	Transportation Customers			0		$ 0.18966		$ 0	0	$ 0	0	16
17	Sales Customers			3,168,716		0.18966		600,979	600,979	1,693,235	2,294,214	17
18	Total Armed Forces Gas Service		108	3,168,716			$ 37,800	$ 600,979	$ 638,779	$ 1,693,235	$ 2,332,014	18
	Air Conditioning Gas Service	G-40										
	Basic Service Charge											
19	General Service - Small		317		$ 20.00		$ 6,340		$ 6,340		$ 6,340	19
20	General Service - Medium		24		90.00		2,160		2,160		2,160	20
21	General Service - Large		36		500.00		18,000		18,000		18,000	21
22	Essential Agricultural		12		75.00		900		900		900	22
23	w/ other service (zero BSC)		60		0.00		0		0		0	23
	Commodity Charge per Therm											
24	Transportation Customers			628,909		$ 0.07613		$ 47,879	47,879	$ 0	47,879	24
25	Sales Customers			1,207,635		0.07613		91,937	91,937	645,312	737,249	25
26	Total Air Conditioning Gas Service		449	1,836,544			$ 27,400	$ 139,816	$ 167,216	$ 645,312	$ 812,528	26
	Street Lighting Gas Service	G-45										
	Commodity Charge per Therm											
	of Rated Capacity											
27	All Usage		348	99,883		$ 0.47648		$ 47,592	47,592	53,373	100,965	27
28	Total Street Lighting Gas Service		348	99,883			$ 0	$ 47,592	$ 47,592	$ 53,373	$ 100,965	28

[1] Margin rates effective November 1, 2001 per Decision No. 64172.
[2] Gas cost effective August 27, 2004 without surcharges.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF REVENUES AT PRESENT RATES BY PRESENT RATE SCHEDULES
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Proposed Schedule Number (b)	Billing Determinants: Number of Bills (c)	Billing Determinants: Sales (Therms) (d)	Present Margin Rates [1]: Basic Service Charge (e)	Present Margin Rates [1]: Commodity Charge (f)	Margin at Present Rates: Basic Service Charge (g)	Margin at Present Rates: Commodity Charge (h)	Margin at Present Rates: Total Margin (i)	Revenue at Present Rates: Gas Cost [2] (j)	Revenue at Present Rates: Total Revenue (k)	Line No.
	Gas Service for Compression on Customer's Premises	G-55										
	Basic Service Charge											
1	Small		264		$ 20.00		$ 5,280		$ 5,280		$ 5,280	1
2	Large		324		170.00		55,080		55,080		55,080	2
3	Residential		1,320		8.00		10,560		10,560		10,560	3
	Commodity Charge per Therm											
4	Transportation Customers			0		$ 0.13305		$ 0	0	$ 0	0	4
	Sales Customers											
5	Small			182,313		0.13305		24,257	24,257	97,421	121,678	5
6	Large			1,898,808		0.13305		252,636	252,636	1,014,647	1,267,283	6
7	Residential			79,719		0.13305		10,607	10,607	42,599	53,206	7
8	Total Air Conditioning Gas Service		1,908	2,160,840			$ 70,920	287,500	358,420	1,154,667	1,513,087	8
	Cogeneration Gas Service	G-60										
	Basic Service Charge											
9	General Service - Small		60		$ 20.00		$ 1,200		$ 1,200		$ 1,200	9
10	General Service - Medium		84		$ 90.00		$ 7,560		$ 7,560		$ 7,560	10
11	General Service - Large		108		500.00		54,000		54,000		54,000	11
12	Essential Agricultural		24		75.00		1,800		1,800		1,800	12
	Commodity Charge per Therm											
13	Transportation Customers			0		$ 0.08934		$ 0	0	$ 0	0	13
14	Sales Customers			15,007,742		0.08934		1,340,792	1,340,792	6,564,687	7,905,479	14
15	Total Cogeneration Gas Service		276	15,007,742			$ 64,560	$ 1,340,792	$ 1,405,352 #	$ 6,564,687	$ 7,970,039	15
	Small Essential Agriculture User Gas Service	G-75										
16	Basic Service Charge		1,347		$ 75.00		$ 101,025		$ 101,025		$ 101,025	16
	Commodity Charge per Therm											
17	Transportation Customers			4,590,241		$ 0.19468		$ 893,628	893,628	$ 0	893,628	17
18	Sales Customers			7,988,994		0.19468		1,555,297	1,555,297	4,268,999	5,824,296	18
19	Total Essential Agricultural Gas Service		1,347	12,579,235			$ 101,025	$ 2,448,925	$ 2,549,950	$ 4,268,999	$ 6,818,949	19
	Natural Gas Engine Gas Service	G-80										
	Basic Service Charge											
20	Off-Peak Season (Oct. - March)		3,623		$ 0.00		$ 0		$ 0		$ 0	20
21	Peak Season (April - September)		3,623		80.00		289,800		289,800		289,800	21
	Commodity Charge per Therm											
22	Transportation Customers			0		$ 0.16189		$ 0	0	$ 0	0	22
23	Sales Customers			21,271,370		0.16189		3,443,622	3,443,622	9,304,523	12,748,145	23
24	Total Natural Gas Engine Gas Service		7,245	21,271,370			$ 289,800	$ 3,443,622	$ 3,733,422	$ 9,304,523	$ 13,037,945	24
25	Total Tariff Sales		10,361,089	605,776,598			95,552,314	209,518,353	305,070,667	301,839,425	606,910,092	25
26	Optional Gas Service	G-30	324	101,647,104			$ 479,840	$ 4,996,752	$ 5,476,592	$ 55,931,796	$ 61,408,388	26
27	Special Contract Service	B-1	271	30,410,785			$ 184,703	$ 1,950,134	$ 2,134,837		$ 2,134,837	27
28	Other Operating Revenues						$ 10,183,883		$ 10,183,883		$ 10,183,883	28
29	Total Revenue		10,361,684	737,834,487			$ 106,400,740	$ 216,465,239	$ 322,865,979	$ 357,771,221	$ 680,637,200	29
30	Total Revenue Requirement								393,675,106	357,771,221	751,446,327	30
31	Over/(Under)								($70,809,127)	$ 0	($70,809,127)	31

[1] Margin rates effective November 1, 2001 per Decision No. 64172.
[2] Gas cost effective August 27, 2004 without surcharges.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF REVENUES AT PRESENT RATES BY PROPOSED RATE SCHEDULES
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description	Proposed Schedule Number	Billing Determinants: Number of Bills	Billing Determinants: Sales (Therms)	Present Margin Rates [1]: Basic Service Charge	Present Margin Rates [1]: Commodity Charge	Margin at Present Rates: Basic Service Charge	Margin at Present Rates: Commodity Charge	Margin at Present Rates: Total Margin	Revenue at Present Rates: Gas Cost [2]	Revenue at Present Rates: Total Revenue	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
	Single-Family Residential Gas Service	G-5										
	Summer (April - November)											
1	Basic Service Charge per Month		5,834,248		$ 8.00		$ 46,673,984		$ 46,673,984		$ 46,673,984	1
	Commodity Charge per Therm											
2	First 8 Therms			40,157,005		$ 0.48762		$ 19,581,359	19,581,359	$ 21,458,297	41,039,656	2
3	Next 12 / 32 Therms [3]			35,488,283		0.48762		17,304,796	17,304,796	18,963,519	36,268,315	3
4	Over 20 / 40 Therms [3]			15,159,885		0.40344		6,116,104	6,116,104	8,100,836	14,216,940	4
5	Over 20 Therms (prior G-15 Summer)			99,140		0.19125		18,961	18,961	52,976	71,937	5
	Winter (December - March)											
6	Basic Service Charge per Month		2,974,733		$ 8.00		$ 23,797,864		$ 23,797,864		$ 23,797,864	6
	Commodity Charge per Therm											
7	First 30 Therms			78,149,816		$ 0.48762		38,107,413	38,107,413	41,760,136	79,867,549	7
8	Next 10 Therms			19,783,002		0.48762		9,646,587	9,646,587	10,571,245	20,217,832	8
9	Over 40 Therms			71,336,019		0.40344		28,779,803	28,779,803	38,119,115	66,898,918	9
10	Total Single-Family Residential Gas Service		8,808,981	260,173,149			$ 70,471,848	$ 119,555,023	$ 190,026,871	$ 139,026,124	$ 329,052,995	10
	Low Income Residential Gas Service	G-5										
	Summer (April - November)											
11	Basic Service Charge		211,472		$ 7.00		$ 1,480,304		$ 1,480,304		$ 1,480,304	11
	Commodity Charge per Therm											
	Summer (May - October)											
12	First 8 Therms			1,491,739		$ 0.48762		$ 727,402	727,402	$ 797,125	1,524,527	12
13	Next 12 / 32 Therms [3]			1,419,741		0.48762		692,294	692,294	758,653	1,450,947	13
14	Over 20 / 40 Therms [3]			328,699		0.40344		132,610	132,610	175,644	308,254	14
	Winter (December - March)											
15	Basic Service Charge per Month		107,196		$ 7.00		$ 750,372		$ 750,372		$ 750,372	15
	Commodity Charge per Therm											
16	First 30 Therms			2,567,923		0.48762		1,252,170	1,252,170	1,372,195	2,624,365	16
17	Next 10 Therms			1,049,387		0.48762		511,702	511,702	560,750	1,072,452	17
18	Next 110 Therms			2,424,450		0.40344		978,120	978,120	1,295,529	2,273,649	18
19	Over 150 Therms			70,477		0.40344		28,433	28,433	37,660	66,093	19
20	Total Low Income Residential Gas Service		318,668	9,352,415			$ 2,230,676	$ 4,322,731	$ 6,553,407	$ 4,997,556	$ 11,550,963	20
	Multi-Family Residential Gas Service	G-6										
	Summer (April - November)											
21	Basic Service Charge per Month		456,582		$ 8.00		$ 3,652,656		$ 3,652,656		$ 3,652,656	21
	Commodity Charge per Therm											
22	First 7 Therms			2,901,893		$ 0.48762		$ 1,415,021	1,415,021	$ 1,550,656	2,965,677	22
23	Next 13 / 33 Therms [3]			2,697,544		$ 0.48762		1,315,377	1,315,377	1,441,460	2,756,837	23
24	Over 20 / 40 Therms [3]			479,657		$ 0.40344		193,513	193,513	256,309	449,822	24
	Winter (December - March)											
25	Basic Service Charge per Month		233,245		$ 8.00		$ 1,865,960		$ 1,865,960		$ 1,865,960	25
	Commodity Charge per Therm											
26	First 18 Therms			4,364,020		0.48762		2,127,983	2,127,983	2,331,958	4,459,941	26
27	Next 22 Therms			2,696,749		0.48762		1,314,989	1,314,989	1,441,035	2,756,024	27
28	Over 40 Therms			1,532,767		0.40344		618,380	618,380	819,049	1,437,429	28
29	Total Multi-Family Residential Gas Service		689,827	14,672,630			$ 5,518,616	$ 6,985,263	$ 12,503,879	$ 7,840,467	$ 20,344,346	29

[1] Margin rates effective November 1, 2001 per Decision No. 64172.
[2] Gas cost effective August 27, 2004 without surcharges.
[3] Proposed change in summer and winter season.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF REVENUES AT PRESENT RATES BY PROPOSED RATE SCHEDULES
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Proposed Schedule Number (b)	Billing Determinants: Number of Bills (c)	Billing Determinants: Sales (Therms) (d)	Present Margin Rates [1]: Basic Service Charge (e)	Present Margin Rates [1]: Commodity Charge (f)	Margin at Present Rates: Basic Service Charge (g)	Margin at Present Rates: Commodity Charge (h)	Margin at Present Rates: Total Margin (i)	Revenue at Present Rates: Gas Cost [2] (j)	Revenue at Present Rates: Total Revenue (k)	Line No.
	Multi-Family Low Income Residential Gas Service	G-6										
	Summer (April - November)											
1	Basic Service Charge per Month		33,599		$ 7.00		$ 235,193		$ 235,193		$ 235,193	1
	Commodity Charge per Therm											
2	First 7 Therms			208,053		$ 0.48762		$ 101,451	101,451	$ 111,175	212,626	2
3	Next 13 / 33 Therms [3]			216,713		0.48762		105,674	105,674	115,803	221,477	3
4	Over 20 / 40 Therms [3]			38,126		0.40344		15,382	15,382	20,373	35,755	4
	Winter (December - March)											
5	Basic Service Charge per Month		17,488		$ 7.00		$ 122,416		$ 122,416		$ 122,416	5
	Commodity Charge per Therm											
6	First 18 Therms			327,920		0.48762		159,900	159,900	175,227	335,127	6
7	Next 22 Therms			241,315		0.48762		117,670	117,670	128,949	246,619	7
8	Next 110 Therms			153,349		0.40344		61,867	61,867	81,944	143,811	8
9	Over 150 Therms			2,154		0.40344		869	869	1,151	2,020	9
10	Total Multi-Family Low Income Residential Gas Service		51,087	1,187,630			$ 357,609	$ 562,813	$ 920,422	$ 634,822	$ 1,555,044	10
11	Total Residential Gas Service		9,868,563	285,385,824			78,578,749	131,425,830	210,004,579	152,498,769	362,503,348	11
	Master Metered Mobile Home Park Gas Service	G-20										
12	Basic Service Charge per Month		2,268		$ 50.00		$ 113,400		$ 113,400		$ 113,400	12
	Commodity Charge per Therm All Usage											
13	All Usage			2,452,509		$ 0.31415		$ 770,456	770,456	1,310,523	2,080,979	13
14	Total MMMHP Gas Service		2,268	2,452,509			$ 113,400	$ 770,456	$ 883,856	$ 1,310,523	$ 2,194,379	14
	General Gas Service - Small	G-25(S)										
	Basic Service Charge											
15	Former Small GS Customers		197,811		$ 20.00		$ 3,956,220		$ 3,956,220		$ 3,956,220	15
16	Former Medium GS Customers		96		$ 90.00		$ 8,640		$ 8,640		$ 8,640	16
17	Former Essential Agriculture Customers		144		$ 75.00		$ 10,800		$ 10,800		$ 10,800	17
	Commodity Charge per Therm All Usage											
18	Transportation Customers			629		$ 0.38024		$ 239	239	$ 0	239	18
	Sales Customers											
19	Former Small GS Customers			3,782,407		0.38024		$ 1,438,222	1,438,222	$ 2,021,167	3,459,389	19
20	Former Medium GS Customers			1,687		0.27211		$ 459	459	$ 901	1,360	20
21	Former Essential Agriculture Customers			2,337		0.19468		$ 455	455	$ 1,249	1,704	21
22	Total Small General Gas Service		198,051	3,787,060			3,975,660	1,439,375	5,415,035	2,023,317	7,438,352	22
	General Gas Service - Medium	G-25(M)										
	Basic Service Charge											
23	Former Small GS Customers		191,331		$ 20.00		$ 3,826,620		$ 3,826,620		$ 3,826,620	23
24	Former Medium GS Customers		3,708		90.00		333,720		333,720		333,720	24
25	Former Large GS Customers		12		500.00		6,000		6,000		6,000	25
25	Former Armed Forces Customers		24		350.00		8,400		8,400		8,400	25
26	Former Essential Agriculture Customers		516		75.00		38,700		38,700		38,700	26
	Transportation Customers											
27	Former Small GS Customers			101,424		$ 0.38024		$ 38,565	38,565	0	38,565	27
28	Former Medium GS Customers			85,250		0.27211		23,197	23,197	0	23,197	28
	Sales Customers											
29	Former Small GS Customers			40,955,338		0.38024		15,572,858	15,572,858	21,884,894	37,457,752	29
30	Former Medium GS Customers			1,745,235		0.27211		474,896	474,896	932,584	1,407,480	30
31	Former Armed Forces Customers			5,050		0.18966		958	958	2,699	3,657	31
31	Former Large GS Customers			3,847		0.08548		329	329	2,056	2,385	31
32	Former Essential Agriculture Customers			133,552		0.19468		26,000	26,000	71,365	97,365	32
33	Total Medium General Gas Service		195,591	43,029,696			$ 4,213,440	$ 16,136,803	$ 20,350,243	$ 22,893,598	$ 43,243,841	33

[1] Margin rates effective November 1, 2001 per Decision No. 64172.
[2] Gas cost effective August 27, 2004 without surcharges.
[3] Proposed change in summer and winter season.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF REVENUES AT PRESENT RATES BY PROPOSED RATE SCHEDULES
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

			Billing Determinants		Present Margin Rates [1]		Margin at Present Rates			Revenue at Present Rates		
Line No.	Description	Proposed Schedule Number	Number of Bills	Sales (Therms)	Basic Service Charge	Commodity Charge	Basic Service Charge	Commodity Charge	Total Margin	Gas Cost [2]	Total Revenue	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
	General Gas Service - Large	G-25(L)										
	Basic Service Charge											
1	Former Small GS Customers		4,375		$ 20.00		$ 87,500		$ 87,500		$ 87,500	1
2	Former Medium GS Customers		79,384		90.00		7,144,560		7,144,560		7,144,560	2
3	Former Large GS Customers		120		500.00		60,000		60,000		60,000	3
3	Former Armed Forces Customers		24		350.00		8,400		8,400		8,400	3
	Demand Charge per Month											
4	Former Large GS Customers			283,133	0.072695			$ 246,988	246,988		246,988	4
	Commodity Charge per Therm All Usage											
	Transportation Customers											
5	Former Small GS Customers			81,882		$ 0.38024		$ 31,135	31,135	$ 0	31,135	5
6	Former Medium GS Customers			2,696,666		0.27211		733,790	733,790	0	733,790	6
7	Former Large GS Customers			316,390		0.08548		27,045	27,045	0	27,045	7
	Sales Customers											
8	Former Small GS Customers			2,938,939		0.38024		1,117,502	1,117,502	1,570,451	2,687,953	8
9	Former Medium GS Customers			134,740,525		0.27211		36,664,244	36,664,244	71,999,947	108,664,191	9
10	Former Large GS Customers			1,055,381		0.08548		90,214	90,214	563,953	654,167	10
10	Former Armed Forces Customers			168,776		0.18966		32,010	32,010	90,187	122,197	10
11	Total Large General Gas Service		83,903	141,998,559			$ 7,300,460	$ 38,942,928	46,243,388	$ 74,224,538	$ 120,467,926	11
	General Gas Service - Transportation Eligible	G-25(TE)										
	Basic Service Charge											
12	Former Medium GS Customers		60		$ 90.00		$ 5,400		5,400		$ 5,400	12
13	Former Essential Agricultural Service Customers		252		$ 75.00		$ 18,900		18,900		$ 18,900	13
14	Former Large GS Customers		1,680		500.00		840,000		840,000		840,000	14
14	Former Armed Forces Customers		60		350.00		21,000		21,000		21,000	14
	Demand Charge per Month											
15	Former Medium GS Customers			0	0.000000			$ 0	0		0	15
16	Former Essential Agricultural Service Customers			0	0.000000			$ 0	0		0	16
17	Former Large GS Customers			6,989,384	0.072695			6,097,119	6,097,119		6,097,119	17
	Commodity Charge per Therm All Usage											
	Transportation Customers											
18	Former Medium GS Customers			0		$ 0.27211		$ 0	0	0	0	18
19	Former Essential Agricultural Service Customers			4,434,348		$ 0.19468		$ 863,279	863,279	0	863,279	19
20	Former Large GS Customers			25,832,133		0.08548		2,208,131	2,208,131	0	2,208,131	20
	Sales Customers											
21	Former Medium GS Customers			1,016,137		0.27211		276,501	276,501	542,983	819,484	21
22	Former Essential Agricultural Service Customers			5,063,922		0.19468		985,844	985,844	2,705,957	3,691,801	22
23	Former Large GS Customers			46,460,065		0.08548		3,971,406	3,971,406	24,826,400	28,797,806	23
23	Former Armed Forces Customers			2,994,890		0.18966		568,011	568,011	1,600,349	2,168,360	23
24	Total Transportation Eligible General Gas Service		2,052	85,801,495			$ 885,300	$ 14,970,291	$ 15,855,591	$ 29,675,689	$ 45,531,280	24
25	Total General Gas Service		479,597	274,616,810			$ 16,374,860	$ 71,489,397	$ 87,864,257	$ 128,817,142	$ 216,681,399	25
	Gas Service to Armed Forces	G-35										
26	Basic Service Charge		0		$ 350.00		$ 0		$ 0		$ 0	26
	Commodity Charge per Therm All Usage											
27	Transportation Customers			0		$ 0.18966		$ 0	0	$ 0	0	27
28	Sales Customers			0		0.18966		0	0	0	0	28
29	Total Armed Forces Gas Service		0	0			$ 0	$ 0	$ 0	$ 0	$ 0	29

[1] Margin rates effective November 1, 2001 per Decision No. 64172.
[2] Gas cost effective August 27, 2004 without surcharges.

Schedule H-2
Sheet 7 of 16

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF REVENUES AT PRESENT RATES BY PROPOSED RATE SCHEDULES
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description	Proposed Schedule Number	Billing Determinants: Number of Bills	Billing Determinants: Sales (Therms)	Present Margin Rates [1]: Basic Service Charge	Present Margin Rates [1]: Commodity Charge	Margin at Present Rates: Basic Service Charge	Margin at Present Rates: Commodity Charge	Margin at Present Rates: Total Margin	Revenue at Present Rates: Gas Cost [2]	Revenue at Present Rates: Total Revenue	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
	Air Conditioning Gas Service	G-40										
	Basic Service Charge											
1	With Other Service - No BSC		60		$ 0.00		$ 0		$ 0		$ 0	1
2	General Service - Small		317		$ 20.00		$ 6,340		$ 6,340		$ 6,340	2
3	General Service - Medium		24		90.00		2,160		2,160		2,160	3
4	General Service - Large		36		500.00		18,000		18,000		18,000	4
5	Essential Agricultural		12		75.00		900		900		900	5
	Commodity Charge per Therm All Usage											
6	Transportation Customers			628,909		$ 0.07613		$ 47,879	47,879	$ 0	47,879	6
7	Sales Customers			1,207,635		0.07613		91,937	91,937	645,312	737,249	7
8	Total Air Conditioning Gas Service		449	1,836,544			$ 27,400	$ 139,816	$ 167,216	$ 645,312	$ 812,528	8
	Street Lighting Gas Service	G-45										
	Commodity Charge per Therm											
	of Rated Capacity											
9	All Usage		348	99,883		$ 0.47648		$ 47,592	47,592	53,373	100,965	9
10	Total Street Lighting Gas Service		348	99,883			$ 0	$ 47,592	$ 47,592	$ 53,373	$ 100,965	10
	Gas Service for Compression on Customer's Premises	G-55										
	Basic Service Charge											
11	Small		264		$ 20.00		$ 5,280		$ 5,280		$ 5,280	11
12	Large		324		170.00		55,080		55,080		55,080	12
13	Residential		1,320		8.00		10,560		10,560		10,560	13
	Commodity Charge per Therm All Usage											
14	Transportation Customers			0		$ 0.13305		$ 0	0	$ 0	0	14
	Sales Customers											
15	Small			182,313		0.13305		24,257	24,257	97,421	121,678	15
16	Large			1,898,808		0.13305		252,636	252,636	1,014,647	1,267,283	16
17	Residential			79,719		0.13305		10,607	10,607	42,599	53,206	17
18	Total CNG Gas Service		1,908	2,160,840			$ 70,920	$ 287,500	$ 358,420	$ 1,154,667	$ 1,513,087	18
	Electric Generation Gas Service	G-60										
	Basic Service Charge											
19	General Service - Small		60		$ 20.00		$ 1,200		$ 1,200		$ 1,200	19
20	General Service - Medium		84		$ 90.00		$ 7,560		$ 7,560		$ 7,560	20
21	General Service - Large		0		500.00		0		0		0	21
22	General Service - Transportation Eligible		108		500.00		54,000		54,000		54,000	22
23	Essential Agricultural		24		75.00		1,800		1,800		1,800	23
	Commodity Charge per Therm All Usage											
24	Transportation Customers			0		$ 0.08934		$ 0	0	$ 0	0	24
25	Sales Customers			15,007,742		0.08934		1,340,792	1,340,792	6,564,687	7,905,479	25
26	Total Electric Generation Gas Service		$ 276	15,007,742			$ 64,560	$ 1,340,792	$ 1,405,352	$ 6,564,687	$ 7,970,039	26
	Essential Agriculture User Gas Service	G-75										
27	Basic Service Charge		435		$ 75.00		$ 32,625		$ 32,625		$ 32,625	27
	Commodity Charge per Therm All Usage											
28	Transportation Customers			155,893		$ 0.19468		$ 30,349	30,349	$ 0	30,349	28
29	Sales Customers			2,789,183		0.19468		542,998	542,998	1,490,428	2,033,426	29
30	Total Essential Agricultural Gas Service		435	2,945,076			$ 32,625	$ 573,347	$ 605,972	$ 1,490,428	$ 2,096,400	30

[1] Margin rates effective November 1, 2001 per Decision No. 64172.
[2] Gas cost effective August 27, 2004 without surcharges.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF REVENUES AT PRESENT RATES BY PROPOSED RATE SCHEDULES
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description	Proposed Schedule Number	Billing Determinants: Number of Bills	Billing Determinants: Sales (Therms)	Present Margin Rates [1]: Basic Service Charge	Present Margin Rates [1]: Commodity Charge	Margin at Present Rates: Basic Service Charge	Margin at Present Rates: Commodity Charge	Margin at Present Rates: Total Margin	Revenue at Present Rates: Gas Cost [2]	Revenue at Present Rates: Total Revenue	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
	Natural Gas Engine Gas Service	G-80										
	Basic Service Charge											
1	Off-Peak Season (Oct. - March)		3,623		$ 0.00		$ 0		$ 0		$ 0	1
2	Peak Season (April - September)		3,623		80.00		289,800		289,800		289,800	2
	Commodity Charge per Therm All Usage											
3	Transportation Customers			0		$ 0.16189		$ 0	0	$ 0	0	3
4	Sales Customers			21,271,370		0.16189		3,443,622	3,443,622	9,304,523	12,748,145	4
5	Total Natural Gas Engine Gas Service		7,245	21,271,370			$ 289,800	$ 3,443,622	$ 3,733,422	$ 9,304,523	$ 13,037,945	5
6	Total Tariff Sales		10,361,089	605,776,598			95,552,314	209,518,352	305,070,666	301,839,424	606,910,090	6
7	Optional Gas Service	G-30	324	101,647,104			$ 479,840	$ 4,996,752	$ 5,476,592	$ 55,931,796	$ 61,408,388	7
8	Special Contract Service	B-1	271	30,410,785			$ 184,703	$ 1,950,134	$ 2,134,837		$ 2,134,837	8
9	Other Operating Revenues						$ 10,183,883		$ 10,183,883		$ 10,183,883	9
10	Total		10,361,684	737,834,487			$ 106,400,740	$ 216,465,238	$ 322,865,978	$ 357,771,220	$ 680,637,198	10
11	Total Revenue Requirement								393,675,099	357,771,220	751,446,319	11
12	Over/(Under)								$ (70,809,121)	$ -	$ (70,809,121)	12

[1] Margin rates effective November 1, 2001 per Decision No. 64172.
[2] Gas cost effective August 27, 2004 without surcharges.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF PRESENT AND PROPOSED REVENUES BY RATE COMPONENT
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Reference (b)	Proposed Schedule Number (b)	Billing Determinants: Number of Bills (c)	Billing Determinants: Sales (Therms) (d)	Basic Service Charge (e)	Commodity Charge (f)	Revenue at Proposed Rates [1]: Basic Service Charge (g)	Revenue at Proposed Rates [1]: Commodity Charge (h)	Total Margin (i)	Gas Cost (j)	Total Revenue (k)	Revenue at Present Rates [2] (l)	Increase / Decrease: Dollars (m)	Increase / Decrease: Percent (n)	Line No.
	Single-Family Residential Gas Service		G-5													
	Summer (April - November)															
1	Basic Service Charge per Month			5,834,248		$ 12.00		$ 70,010,976		$ 70,010,976		$ 70,010,976	46,673,984	23,336,992		1
	Commodity Charge per Therm															
2	First 8 Therms				40,157,005		$ 0.84286		$ 33,846,733	33,846,733	$ 21,458,297	55,305,030	41,039,656	14,265,374		2
3	Over 8 Therms				50,747,308		0.25000		12,686,827	12,686,827	27,117,331	39,804,158	50,557,192	-10,753,034		3
	Winter (December - March)															
4	Basic Service Charge per Month			2,974,733		$ 12.00		$ 35,696,796		$ 35,696,796		$ 35,696,796	23,797,864	11,898,932		4
	Commodity Charge per Therm															
5	First 30 Therms				78,149,816		0.84286		65,869,354	65,869,354	41,760,136	107,629,490	79,867,549	27,761,941		5
6	Over 30 Therms				91,119,021		0.25000		22,779,755	22,779,755	48,690,360	71,470,115	87,116,750	-15,646,635		6
7	Total Single-Family Residential Gas Service			8,808,981	260,173,149			$ 105,707,772	$ 135,182,869	$ 240,890,441	$ 139,026,124	$ 379,916,565	329,052,995	50,863,570	15.46%	7
	Low Income Residential Gas Service		G-5													
	Summer (April - November)															
8	Basic Service Charge			211,472		$ 12.00		$ 2,537,664		$ 2,537,664		$ 2,537,664	1,480,304	1,057,360		8
	Commodity Charge per Therm															
	Summer (May - October)															
9	First 8 Therms				1,491,739		$ 0.84286		$ 1,257,327	1,257,327	$ 797,125	2,054,452	1,524,527	529,925		9
10	Over 8 Therms				1,748,440		0.25000		437,110	437,110	934,297	1,371,407	1,759,201	-387,794		10
	Winter (December - March)															
11	Basic Service Charge per Month			107,196		$ 12.00		$ 1,286,352		$ 1,286,352		$ 1,286,352	750,372	535,980		11
	Commodity Charge per Therm															
12	First 30 Therms				2,567,923		0.84286		2,164,399	2,164,399	1,372,195	3,536,594	2,624,365	912,229		12
13	Over 30 Therms				3,544,314		0.25000		886,078	886,078	1,893,939	2,780,017	3,412,194	-632,177		13
14	Total Low Income Residential Gas Service			318,668	9,352,415			$ 3,824,016	$ 4,744,914	$ 8,568,930	$ 4,997,556	$ 13,566,486	11,550,963	2,015,523	17.45%	14
	Multi-Family Residential Gas Service		G-6													
	Summer (April - November)															
15	Basic Service Charge per Month			456,582		$ 11.00		$ 5,022,402		$ 5,022,402		$ 5,022,402	3,652,656	1,369,746		15
	Commodity Charge per Therm															
16	First 7 Therms				2,901,893		$ 0.84286		$ 2,445,890	2,445,890	$ 1,550,656	3,996,546	2,965,677	1,030,869		16
17	Over 7 Therms				3,177,201		0.25000		794,300	794,300	1,697,769	2,492,069	3,206,659	-714,590		17
	Winter (December - March)															
18	Basic Service Charge per Month			233,245		$ 11.00		$ 2,565,695		$ 2,565,695		$ 2,565,695	1,865,960	699,735		18
	Commodity Charge per Therm															
19	First 18 Therms				4,364,020		0.84286		3,678,258	3,678,258	2,331,958	6,010,216	4,459,941	1,550,275		19
20	Over 18 Therms				4,229,516		0.25000		1,057,379	1,057,379	2,260,084	3,317,463	4,193,453	-875,990		20
21	Total Multi-Family Residential Gas Service			689,827	14,672,630			$ 7,588,097	$ 7,975,827	$ 15,563,924	$ 7,840,467	$ 23,404,391	20,344,346	3,060,045	15.04%	21
	Multi-Family Low Income Residential Gas Service		G-6													
	Summer (April - November)															
22	Basic Service Charge per Month			33,599		$ 11.00		$ 369,589		$ 369,589		$ 369,589	235,193	134,396		22
	Commodity Charge per Therm															
23	First 7 Therms				208,053		$ 0.84286		$ 175,360	175,360	$ 111,175	286,535	212,626	73,909		23
24	Over 7 Therms				254,839		0.25000		63,710	63,710	136,176	199,886	257,232	-57,346		24
	Winter (December - March)															
25	Basic Service Charge per Month			17,488		$ 11.00		$ 192,368		$ 192,368		$ 192,368	122,416	69,952		25
	Commodity Charge per Therm															
26	First 18 Therms				327,920		0.84286		276,390	276,390	175,227	451,617	335,127	116,490		26
27	Over 18 Therms				396,818		0.25000		99,205	99,205	212,044	311,249	392,450	-81,201		27
28	Total Low Income Multi-Family Residential Gas Service			51,087	1,187,630			$ 561,957	$ 614,665	$ 1,176,622	$ 634,622	$ 1,811,244	1,555,044	256,200	16.48%	28
29	Total Residential Gas Service			9,868,563	285,385,824			$117,681,842	$ 148,518,075	$ 266,199,917	$ 152,498,769	$ 418,698,686	$ 362,503,348	$ 56,195,338	15.50%	29
	Master Metered Mobile Home Park Gas Service		G-20													
30	Basic Service Charge per Month			2,268		$ 100.00		$ 226,800		$ 226,800		$ 226,800	113,400	113,400		30
	Commodity Charge per Therm All Usage															
31	All Usage				2,452,509		$ 0.32271		$ 791,449	791,449	1,310,523	2,101,972	2,080,979	20,993		31
32	Total MMMHP Gas Service			2,268	2,452,509			$ 226,800	$ 791,449	$ 1,018,249	$ 1,310,523	$ 2,328,772	2,194,379	134,393	6.12%	32

[1] Schedule H-6, Sheets 3-5.
[2] Schedule H-2, Sheets 4-8.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF PRESENT AND PROPOSED REVENUES BY RATE COMPONENT
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

				Billing Determinants		Revenue at Proposed Rates [1]								Increase / Decrease		
Line No.	Description	Reference	Proposed Schedule Number	Number of Bills	Sales (Therms)	Basic Service Charge	Commodity Charge	Basic Service Charge	Commodity Charge	Total Margin	Gas Cost	Total Revenue	Revenue at Present Rates [2]	Dollars	Percent	Line No.
	(a)	(b)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
	General Gas Service - Small		G-25(S)													
	Basic Service Charge															
1	Former Small GS Customers			197,811		$ 25.00		$ 4,945,275		$ 4,945,275		$ 4,945,275	3,956,220	989,055		1
2	Former Medium GS Customers			96		$ 25.00		$ 2,400		$ 2,400		$ 2,400	8,640	-6,240		2
3	Former Essential Agiculture Customers			144		$ 25.00		$ 3,600		$ 3,600		$ 3,600	10,800	-7,200		3
	Commodity Charge per Therm All Usage															
4	Transportation Customers				629		$ 0.69076		$ 434	434	$ 0	434	239	195		4
5	Sales Customers				3,786,431		0.69076		2,615,515	$ 2,615,515	2,023,317	4,638,832	3,462,453	1,176,379		5
6	Total Small General Gas Service			198,051	3,787,060			$ 4,951,275	$ 2,615,949	$ 7,567,224	$ 2,023,317	$ 9,590,541	7,438,352	2,152,189	28.93%	6
	General Gas Service - Medium		G-25(M)													
	Basic Service Charge															
7	Former Small GS Customers			191,331		$ 35.00		$ 6,696,585		$ 6,696,585		$ 6,696,585	3,826,620	2,869,965		7
8	Former Medium GS Customers			3,708		35.00		129,780		129,780		129,780	333,720	-203,940		8
9	Former Large GS Customers			12		35.00		420		420		420	6,000	-5,580		9
10	Former Armed Forces Customers			24		35.00		840		840		840	8,400	-7,560		10
11	Former Essential Agriculture Customers			516		35.00		18,060		18,060		18,060	38,700	-20,640		11
	Commodity Charge per Therm All Usage															
	Transportation Customers															
12	Former Small GS Customers				101,424		$ 0.40089		$ 40,660	40,660	$ 0	40,660	38,565	2,095		12
13	Former Medium GS Customers				85,250		0.40089		34,176	34,176	0	34,176	23,197	10,979		13
	Sales Customers															
14	Former Small GS Customers				40,955,338		0.40089		16,418,585	16,418,585	21,884,894	38,303,479	37,457,752	845,727		14
15	Former Medium GS Customers				1,745,235		0.40089		699,647	699,647	932,584	1,632,231	1,407,480	224,751		15
16	Former Large GS Customers				5,050		0.40089		2,024	2,024	2,699	4,723	3,657	1,066		16
17	Former Armed Forces Customers				3,847		0.40089		1,542	1,542	2,056	3,598	2,385	1,213		17
18	Former Essential Agriculture Customers				133,552		0.40089		53,540	53,540	71,365	124,905	97,365	27,540		18
19	Total Medium General Gas Service			195,591	43,029,696			6,845,685	17,250,174	24,095,859	22,893,598	46,989,457	43,243,841	3,745,616	8.66%	19
	General Gas Service - Large		G-25(L)													
	Basic Service Charge															
20	Former Small GS Customers			4,375		$ 150.00		$ 656,250		$ 656,250		$ 656,250	87,500	568,750		20
21	Former Medium GS Customers			79,384		150.00		11,907,600		11,907,600		11,907,600	7,144,560	4,763,040		21
22	Former Large GS Customers			120		150.00		18,000		18,000		18,000	306,988	-288,988		22
23	Former Armed Forces Customers			24		150.00		3,600		3,600		3,600	8,400	-4,800		23
	Commodity Charge per Therm All Usage															
	Transportation Customers															
24	Former Small GS Customers				81,882		$ 0.27399		$ 22,435	22,435	$ 0	22,435	31,135	-8,700		24
25	Former Medium GS Customers				2,696,666		0.27399		738,860	738,860	$ 0	738,860	733,790	5,070		25
26	Former Large GS Customers				316,390		0.27399		86,688	86,688	$ 0	86,688	27,045	59,643		26
	Sales Customers															
27	Former Small GS Customers				2,938,939		0.27399		805,240	805,240	$ 1,570,451	2,375,691	2,687,953	-312,262		27
28	Former Medium GS Customers				134,740,525		0.27399		36,917,556	36,917,556	$ 71,999,947	108,917,503	108,664,191	253,312		28
29	Former Large GS Customers				1,055,381		0.27399		289,164	289,164	$ 563,953	853,117	654,167	198,950		29
30	Former Armed Forces Customers				168,776		0.27399		46,243	46,243	$ 90,187	136,430	122,197	14,233		30
31	Total Large General Gas Service			83,903	141,998,559			12,585,450	38,906,186	51,491,636	74,224,538	125,716,174	120,467,926	5,248,248	4.36%	31
	General Gas Service - Transportation Eligible		G-25(TE)													
	Basic Service Charge															
32	Former Medium GS Customers			60		$ 750.00		$ 45,000		$ 45,000		$ 45,000	5,400	39,600		32
33	Former Essential Agricultural Service Customers			252		$ 750.00		$ 189,000		$ 189,000		$ 189,000	18,900	170,100		33
34	Former Large GS Customers			1,680		$ 750.00		$ 1,260,000		$ 1,260,000		$ 1,260,000	840,000	420,000		34
35	Former Armed Forces Customers			60		750.00		45,000		45,000		45,000	21,000	24,000		35
36	Demand Charge per Month				10,571,934	0.062645			7,947,288	7,947,288		7,947,288	6,097,119	1,850,169		36
	Commodity Charge per Therm All Usage															
	Transportation Customers															
37	Former Medium GS Customers				0		$ 0.09262		$ 0	0	$ 0	0	0	0		37
38	Former Essential Agricultural Services Customers				4,434,348		$ 0.09262		$ 410,709	410,709	$ 0	410,709	863,279	-452,570		38
39	Former Large GS Customers				25,832,133		0.09262		2,392,572	2,392,572	$ 0	2,392,572	2,208,131	184,441		39
	Sales Customers															
40	Former Medium GS Customers				1,016,137		0.09262		94,115	94,115	$ 542,983	637,098	819,484	-182,386		40
41	Former Essential Agricultural Services Customers				5,063,922		0.09262		469,020	469,020	$ 2,705,957	3,174,977	3,691,801	-516,824		41
42	Former Large GS Customers				46,460,065		0.09262		4,303,131	4,303,131	$ 24,826,400	29,129,531	28,797,806	331,725		42
43	Former Armed Forces Customers				2,994,890		0.09262		277,387	277,387	$ 1,600,349	1,877,736	2,168,360	-290,624		43
44	Total Transportation Eligible General Gas Service			2,052	85,801,495			$ 1,539,000	$ 15,894,222	$ 17,433,222	$ 29,675,689	$ 47,108,911	45,531,280	1,577,631	3.46%	44
45	Total General Gas Service			479,597	274,616,810			$ 25,921,410	$ 74,666,531	$ 100,587,941	$ 128,817,142	$ 229,405,063	216,681,399	12,723,684	5.87%	45

[1] Schedule H-6, Sheets 3-5.
[2] Schedule H-2, Sheets 4-8.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF PRESENT AND PROPOSED REVENUES BY RATE COMPONENT
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Proposed Schedule Number (b)	Billing Determinants: Number of Bills (c)	Billing Determinants: Sales (Therms) (d)	Basic Service Charge (e)	Commodity Charge (f)	Revenue at Proposed Rates [1]: Basic Service Charge (g)	Revenue at Proposed Rates [1]: Commodity Charge (h)	Revenue at Proposed Rates [1]: Total Margin (i)	Revenue at Proposed Rates [1]: Gas Cost (j)	Revenue at Proposed Rates [1]: Total Revenue (k)	Revenue at Present Rates [2] (l)	Increase / Decrease: Dollars (m)	Increase / Decrease: Percent (n)	Line No.
	Air Conditioning Gas Service	G-40													
	Basic Service Charge														
1	W/ Other Service (No BSC)		60		0.00		0		0		0	0	0		1
2	Basic Service Charge		389		$ 25.00		$ 9,725		$ 9,725		$ 9,725	27,400	-17,675		2
	Commodity Charge per Therm All Usage														
3	Transportation Customers			628,909		$ 0.10208		$ 64,199	64,199	$ 0	64,199	47,879	16,320		3
4	Sales Customers			1,207,635		0.10208		123,275	123,275	645,312	768,587	737,249	31,338		4
5	Total Air Conditioning Gas Service		449	1,836,544			$ 9,725	$ 187,474	$ 197,199	$ 645,312	$ 842,511	812,528	29,963	3.69%	5
	Street Lighting Gas Service	G-45													
	Commodity Charge per Therm of Rated Capacity														
6	All Usage		348	99,883		$ 0.54644		$ 54,580	54,580	53,373	107,953	100,965	6,988		6
7	Total Street Lighting Gas Service		348	99,883			$ 0	$ 54,580	$ 54,580	$ 53,373	$ 107,953	100,965	6,988	6.92%	7
	Gas Service for Compression on Customer's Premises	G-55													
	Basic Service Charge														
8	Small		264		$ 25.00		$ 6,600		$ 6,600		$ 6,600	5,280	1,320		8
9	Large		324		350.00		113,400		113,400		113,400	55,080	58,320		9
10	Residential		1,320		12.00		15,840		15,840		15,840	10,560	5,280		10
	Commodity Charge per Therm All Usage														
11	Transportation Customers			0		$ 0.13669		$ 0	0	$ 0	0	0	0		11
	Sales Customers														
12	Small			182,313		0.13669		$ 24,920	24,920	$ 97,421	122,341	121,678	663		12
13	Large			1,898,808		0.13669		$ 259,548	259,548	$ 1,014,647	1,274,195	1,267,283	6,912		13
14	Residential			79,719		0.13669		$ 10,897	10,897	$ 42,599	53,496	53,206	290		14
15	Total CNG Gas Service		1,908	2,160,840			$ 135,840	$ 295,365	$ 431,205	$ 1,154,667	$ 1,585,872	1,513,087	72,785	4.81%	15
	Electric Generation Gas Service	G-60													
	Basic Service Charge														
16	General Service - Small		60		$ 25.00		$ 1,500		$ 1,500		$ 1,500	1,200	300		16
17	General Service - Medium		0		$ 35.00		$ 0		$ 0		$ 0	7,560	-7,560		17
18	General Service - Large		96		150.00		14,400		14,400		14,400	0	14,400		18
19	General Service - Transportation Eligible		96		750.00		72,000		72,000		72,000	54,000	18,000		19
20	Essential Agricultural		24		150.00		3,600		3,600		3,600	1,800	1,800		20
	Commodity Charge per Therm All Usage														
21	Transportation Customers			0		$ 0.10188		$ 0	0	$ 0	0	0	0		21
22	Sales Customers			15,007,742		0.10188		1,528,989	1,528,989	6,564,687	8,093,676	7,905,479	188,197		22
23	Total Electric Generation Gas Service		276	15,007,742			$ 91,500	$ 1,528,989	$ 1,620,489	$ 6,564,687	$ 8,185,176	7,970,039	215,137	2.70%	23
	Small Essential Agriculture User Gas Service	G-75													
24	Basic Service Charge		435		$ 150.00		$ 65,250		$ 65,250		$ 65,250	32,625	32,625		24
	Commodity Charge per Therm All Usage														
25	Transportation Customers			155,893		$ 0.22186		$ 34,586	34,586	$ 0	34,586	30,349	4,237		25
26	Sales Customers			2,789,183		0.22186		618,808	618,808	1,490,428	2,109,236	2,033,426	75,810		26
27	Total Essential Agricultural Gas Service		435	2,945,076			$ 65,250	$ 653,394	$ 718,644	$ 1,490,428	$ 2,209,072	2,096,400	112,672	5.37%	27
	Natural Gas Engine Gas Service	G-80													
	Basic Service Charge														
28	Off-Peak Season (Oct. - March)		3,623		$ 0.00		$ 0		$ 0		$ 0	0	0		28
29	Peak Season (April - September)		3,623		100.00		362,250		362,250		362,250	289,800	72,450		29
	Commodity Charge per Therm All Usage														
30	Transportation Customers			0		$ 0.15848		$ 0	0	$ 0	0	0	0		30
31	Sales Customers			21,271,370		0.15848		3,371,087	3,371,087	9,304,523	12,675,610	12,748,145	-72,535		31
32	Total Natural Gas Engine Gas Service		7,245	21,271,370			$ 362,250	$ 3,371,087	$ 3,733,337	$ 9,304,523	$ 13,037,860	13,037,945	-85	0.00%	32
33	Total Tariff Sales		10,361,089	605,776,598			144,494,617	230,066,944	374,561,561	301,839,424	676,400,985	606,910,090	69,490,895	11.45%	33
34	Optional Gas Service	G-30	324	101,647,104			$ 510,740	$ 5,032,592	5,543,332	$ 55,931,796	$ 61,475,128	61,408,388	66,740	0.11%	34
35	Special Contract Service	B-1	271	30,410,785			$ 184,703	$ 1,950,134	$ 2,134,837		$ 2,134,837	2,134,837	0	0.00%	35
36	Other Operating Revenues						$ 11,434,480		$ 11,434,480		$ 11,434,480	10,183,883	1,250,597	12.28%	36
37	Total Revenue		10,361,684	737,834,487			$ 156,624,540	$ 237,049,670	$ 393,674,210	$ 357,771,220	$ 751,445,430	680,637,198	70,808,232	10.40%	37
38	Total Revenue Requirement								393,675,099	357,771,220	751,446,319				38
39	Over/(Under)								($889)	$ 0	($889)				39

[1] Schedule H-6, Sheets 3-5.
[2] Schedule H-2, Sheets 4-8.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF ADJUSTMENTS OF SALES AND ANNUAL NUMBER OF BILLS BY PROPOSED RATE SCHEDULE
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

				Annual Number of Bills			Annual Sales Volumes (Therms)			Annual Revenues At Present Rates			
Line No.	Description	Present Schedule Number	Proposed Schedule Number	Test Period Adjusted At 8-31-04 [1]	Adjustment [2]	Test Period Adjusted At 8-31-04	Test Period Adjusted At 8-31-04 [1]	Adjustment [2]	Test Period Adjusted At 8-31-04	Test Period Adjusted At 8-31-04 [1]	Adjustment [2]	Test Period Adjusted At 8-31-04	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
1	Single-Family Residential Gas Service	G-5	G-5	9,496,924	(687,943)	8,808,981	274,621,203	(14,448,054)	260,173,149	$ 349,188,727	(20,135,732)	$ 329,052,995	1
2	Low Income Residential Gas Service	G-10	G-5	369,755	(51,087)	318,668	10,540,045	(1,187,630)	9,352,415	13,106,007	(1,555,044)	11,550,963	2
3	Special Residential Gas Service for Air Conditioning	G-15	G-15	1,884	(1,884)	0	224,576	(224,576)	0	208,615	(208,615)	0	3
4	Multi-Family Residential Gas Service	G-5	G-6	0	689,827	689,827	0	14,672,630	14,672,630	0	20,344,346	20,344,346	4
5	Low Income Multi-Family Res Service	G-10	G-6	0	51,087	51,087	0	1,187,630	1,187,630	0	1,555,044	1,555,044	5
6	Master Metered Mobile Home Park Gas Service	G-20	G-20	2,268	0	2,268	2,452,509	0	2,452,509	2,194,379	0	2,194,379	6
	General Gas Service	G-25	G-25										
7	Small			393,517	(195,466)	198,051	47,860,619	(44,073,559)	3,787,060	51,545,374	(44,107,022)	7,438,352	7
8	Medium			83,248	112,343	195,591	140,285,500	(97,255,804)	43,029,696	119,141,822	(75,897,981)	43,243,841	8
9	Large			1,812	82,091	83,903	73,667,816	68,330,743	141,998,559	38,939,641	81,528,285	120,467,926	9
10	Transportation Eligible			0	2,052	2,052	0	85,801,495	85,801,495	0	45,531,280	45,531,280	10
11	Optional Gas Service	G-30	G-30	324	0	324	101,647,104	0	101,647,104	61,408,388	0	61,408,388	11
12	Gas Service to Armed Forces	G-35	G-25	108	(108)	0	3,168,716	(3,168,716)	0	2,332,014	(2,332,014)	0	12
13	Air Conditioning Gas Service	G-40	G-40	449	0	449	1,836,544	0	1,836,544	812,528	0	812,528	13
14	Street Lighting Gas Service	G-45	G-45	348	0	348	99,883	0	99,883	100,965	0	100,965	14
	Gas Service for Compression on Customer's Premises	G-55	G-55										
15	Small			264	0	264	182,313	0	182,313	126,958	0	126,958	15
16	Large			324	0	324	1,898,808	0	1,898,808	1,322,363	0	1,322,363	16
17	Residential			1,320	0	1,320	79,719	0	79,719	63,766	0	63,766	17
18	Electric Generation Gas Service	G-60	G-60	276	0	276	15,007,742	0	15,007,742	7,970,039	0	7,970,039	18
19	Small Essential Agriculture User Gas Service	G-75	G-75	1,347	(912)	435	12,579,235	(9,634,159)	2,945,076	6,818,949	(4,722,549)	2,096,400	19
20	Natural Gas Engine Gas Service	G-80	G-80	7,245	0	7,245	21,271,370	0	21,271,370	13,037,945	0	13,037,945	20
21	Total Gas Sales			10,361,413	0	10,361,413	707,423,702	0	707,423,702	$ 668,318,480	(2)	$ 668,318,478	21
22	Transportation Service	T-1	T-1	0	0	0	0	0	0	0	0	0	22
23	Special Contract Service	B-1	B-1	271	0	271	30,410,785	0	30,410,785	2,134,837	0	2,134,837	23
24	Other Operating Revenue									10,183,883	0	10,183,883	24
25	Total Arizona			10,361,684	0	10,361,684	737,834,487	0	737,834,487	$ 680,637,200	(2)	$ 680,637,198	25

[1] Schedule H-2, Sheet 13, Columns (e), (h) and (k).
[2] Adjustment to move bills, volumes and revenues to proposed rate schedules.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF ADJUSTMENTS OF SALES AND ANNUAL NUMBER OF BILLS BY PRESENT RATE SCHEDULE
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

				Annual Number of Bills			Annual Sales Volumes (Therms)			Annual Revenues At Present Rates			
Line No.	Description	Present Schedule Number	Schedule Number	Recorded 12 Months Ended 08-31-04[1]	Adjustment [2]	Test Period As Adjusted At 08-31-04	Recorded 12 Months Ended 08-31-04[1]	Adjustment [2]	Test Period As Adjusted At 08-31-04	Recorded 12 Months Ended 08-31-04[1]	Adjustment	Test Year As Adjusted At 08-31-04 [3]	Line No.
	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
1	Residential Gas Service	G-5	G-5	9,253,061	243,863	9,496,924	267,837,474	6,783,729	274,621,203	$ 330,193,899	$ 18,994,828	$ 349,188,727	1
2	Low Income Residential Gas Service	G-10	G-10	371,675	(1,920)	369,755	10,695,648	(155,603)	10,540,045	11,186,780	1,919,227	13,106,007	2
3	Special Residential Gas Service for Air Conditioning	G-15	G-15	1,883	1	1,884	228,821	(4,245)	224,576	201,618	6,997	208,615	3
4	Special Residential Gas Service for Electric Generation	G-16	G-16	0	0	0	0	0	0	0	0	0	4
5	Master Metered Mobile Home Park Gas Service	G-20	G-20	2,293	(25)	2,268	2,519,499	(66,990)	2,452,509	2,126,052	68,327	2,194,379	5
	General Gas Service	G-25	G-25										
6	Small			391,164	2,353	393,517	47,557,432	303,187	47,860,619	49,120,076	2,425,298	51,545,374	6
7	Medium			81,423	1,825	83,248	136,866,745	3,418,755	140,285,500	110,818,391	8,323,431	119,141,822	7
8	Large			1,254	558	1,812	44,280,034	29,387,782	73,667,816	29,805,775	9,133,866	38,939,641	8
9	Optional Gas Service	G-30	G-30	395	(71)	324	103,995,837	(2,348,733)	101,647,104	64,228,107	(2,819,720)	61,408,388	9
10	Gas Service to Armed Forces	G-35	G-35	99	9	108	3,308,091	(139,375)	3,168,716	1,738,241	593,773	2,332,014	10
11	Air Conditioning Gas Service	G-40	G-40	465	(16)	449	1,067,788	768,756	1,836,544	628,151	184,377	812,528	11
12	Street Lighting Gas Service	G-45	G-45	338	10	348	100,215	(332)	99,883	600,963	(499,998)	100,965	12
	Gas Service for Compression on Customer's Premises	G-55	G-55										
13	Small			309	(45)	264	196,184	(13,871)	182,313	139,636	(12,678)	126,958	13
14	Large			323	1	324	1,873,025	25,783	1,898,808	1,208,203	114,160	1,322,363	14
15	Residential			1,348	(28)	1,320	80,334	(615)	79,719	60,298	3,468	63,766	15
16	Electric Generation Gas Service	G-60	G-60	269	7	276	14,998,373	9,369	15,007,742	8,293,990	(323,951)	7,970,039	16
17	Small Essential Agriculture User Gas Service	G-75	G-75	1,169	178	1,347	7,932,305	4,646,930	12,579,235	5,507,594	1,311,355	6,818,949	17
18	Natural Gas Engine Gas Service	G-80	G-80	7,372	(127)	7,245	20,198,094	1,073,276	21,271,370	12,442,282	595,663	13,037,945	18
19	Resale Gas Service	G-95	G-95	3	(3)	0	(14,502)	14,502	0	(7,296)	7,296	0	19
20	Total Gas Sales			10,114,843	246,570	10,361,413	663,721,397	43,702,305	707,423,702	$ 628,292,760	$ 40,025,719	$ 668,318,480	20
21	Transportation Service	T-1	T-1	2,770	(2,770)	0	65,680,156	(65,680,156)	0	9,099,186	(9,099,186)	0	21
22	Special Contract Service	B-1	B-1	0	271	271	0	30,410,785	30,410,785	0	2,134,837	2,134,837	22
23	Other Operating Revenue									9,885,120	298,763	10,183,883	23
24	Total Arizona			10,117,613	244,071	10,361,684	729,401,553	8,432,934	737,834,487	$ 647,277,066	$ 33,360,133	$ 680,637,200	24

[1] Schedule H-2, Sheet 16.
[2] Schedule H-2, Sheet 14, Columns (g) and (h).
[3] Schedule H-2, Sheets 1 - 3.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF ADJUSTMENTS OF SALES AND ANNUAL NUMBER OF BILLS BY PRESENT RATE SCHEDULE
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

			Weather Adjustment [1]		Customer Annualization and Reclassify Full-Margin Transportation Customers [2]		Total Adjustments		
Line No.	Description	Schedule Number	Annual Bills	Sales (Therms)	Annual Bills	Sales (Therms)	Annual Bills	Sales (Therms)	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	
1	Residential Gas Service	G-5	0	(856,714)	243,838	7,638,184	243,863	6,783,729	1
2	Low Income Residential Gas Service	G-10	0	(95,864)	(1,920)	(59,739)	(1,920)	(155,603)	2
3	Special Residential Gas Service	G-15	0	(3,081)	0	0	1	(4,245)	3
	Master Metered Mobile Home Park								
4	Gas Service	G-20	0	(14,619)	0	0	(25)	(66,990)	4
	General Gas Service	G-25							
5	Small		0	(27,001)	2,307	406,978	2,353	303,187	5
6	Medium		0	516,636	1,833	3,800,920	1,825	3,418,755	6
7	Large		0	(50,231)	504	26,148,523	558	29,387,782	7
8	Optional Gas Service	G-30	0	0	0	0	(71)	(2,348,733)	8
9	Gas Service to Armed Forces	G-35	0	(45,020)	0	0	9	(139,375)	9
10	Air Conditioning Gas Service	G-40	0	0	24	628,909	(16)	768,756	10
11	Street Lighting Gas Service	G-45	0	0	0	0	10	(332)	11
	Gas Service for Compression on Customer's Premises	G-55							
12	Small		0	0	0	0	(45)	(13,871)	12
13	Large		0	0	0	0	1	25,783	13
14	Residential		0	0	0	0	(28)	(615)	14
15	Electric Generation Gas Service	G-60	0	0	0	0	7	9,369	15
	Small Essential Agriculture User								
16	Gas Service	G-75	0	0	144	4,590,241	178	4,646,930	16
17	Natural Gas Engine Gas Service	G-80	0	0	0	0	(127)	1,073,276	17
18	Resale Gas Service	G-95	0	0	0	0	(3)	14,502	18
19	Total Gas Sales		0	(575,894)	246,730	43,154,016	246,570	43,702,305	19
20	Transportation Service	T-1	0	9,553	(2,436)	(34,334,784)	(2,770)	(65,680,156)	20
21	Special Contract Service	B-1	0	0	0	0	271	30,410,785	21
22	Total Arizona		0	(566,341)	244,294	8,819,232	244,071	8,432,934	22

[1] Adjustment to reflect normal weather within the test year. (Workpapers H-2, Sheets 18 - 24).
[2] Adjustment to reflect customer annualization (Workpapers H-2, Sheet 17) and to reflect full-margin transportation customers' bills and volumes on their otherwise.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF ADJUSTMENTS OF SALES AND ANNUAL NUMBER OF BILLS BY PRESENT RATE SCHEDULE
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description	Schedule Number	Billing Adjustments [1] Annual Bills	Billing Adjustments [1] Sales (Therms)	Volume Annualization [2] Annual Bills	Volume Annualization [2] Sales (Therms)	Reclassification [3] Annual Bills	Reclassification [3] Sales (Therms)	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	
1	Residential Gas Service	G-5	0	(828)	0	0	25	3,087	1
2	Low Income Residential Gas Service	G-10	0	0	0	0	0	0	2
3	Special Residential Gas Service	G-15	7	(129)	31	1,379	(37)	(2,414)	3
	Master Metered Mobile Home Park								
4	Gas Service	G-20	0	1,855	(31)	(60,255)	6	6,029	4
	General Gas Service	G-25							
5	Small		44	43,708	(31)	(5,813)	33	(114,685)	5
6	Medium		17	(52,637)	6	(4,494)	(31)	(841,670)	6
7	Large		(2)	(17,807)	0	(28,417)	56	3,335,714	7
8	Optional Gas Service	G-30	108	(89)	0	0	(179)	(2,348,644)	8
9	Gas Service to Armed Forces	G-35	9	(1,150)	0	0	0	(93,205)	9
10	Air Conditioning Gas Service	G-40	4	5,613	(47)	(1,917)	3	136,151	10
11	Street Lighting Gas Service	G-45	5	0	5	(332)	0	0	11
	Gas Service for Compression on Customer's Premises	G-55							
12	Residential		4	(182)	(43)	(1,155)	11	722	12
13	Small		(1)	(59)	(28)	134	(16)	(13,946)	13
14	Large		0	0	(4)	12,559	5	13,224	14
15	Electric Generation Gas Service	G-60	5	3,004	2	6,365	0	0	15
	Small Essential Agriculture User								
16	Gas Service	G-75	29	43,318	0	1,057	5	12,314	16
17	Natural Gas Engine Gas Service	G-80	20	3,854	(301)	200,811	154	868,611	17
18	Resale Gas Service	G-95	0	0	(3)	14,502	0	0	18
19	Total Gas Sales		249	28,471	(444)	134,424	35	961,288	19
20	Transportation Service	T-1	(5)	65,169	(23)	(48,021)	(306)	(31,372,073)	20
21	Special Contract Service		0	0	0	0	271	30,410,785	21
22	Total Arizona		244	93,640	(467)	86,403	0	0	22

[1] Adjustments to recorded amounts to correct billing errors and to reflect the number of Basic Service Charges billed. (Workpapers H-2, Sheets 28 - 40).
[2] Adjustments to annualize partial test year volumes to reflect loss or addition of load within the test year (Workpapers H-2, Sheets 28 - 40).
[3] Adjustment to reclassify bills and volumes to other schedule in compliance with Southwest's Arizona Gas Tariff (Workpapers H-2, Sheets 28 - 40).

SOUTHWEST GAS CORPORTATION
ARIZONA DIVISION
SALES AND REVENUE BY RATE SCHEDULE AS RECORDED
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Schedule No. (b)	Recorded Test Year Data: Number Of Bills [1] (c)	Sales (Therms) [1] (d)	Revenues (e)	Line No.
1	Residential Gas Service	G-5	9,253,061	267,837,474	$ 330,193,899	1
2	Low Income Residential Gas Service	G-10	371,675	10,695,648	11,186,780	2
3	Special Residential Gas Service for A/C	G-15	1,883	228,821	201,618	3
4	Special Residential Gas Service for Electric Generation	G-16	0	0	0	4
	Master Metered Mobile Home Park					
5	Gas Service	G-20	2,293	2,519,499	2,126,052	5
	General Gas Service	G-25				
6	Small		391,164	47,557,432	49,120,076	6
7	Medium		81,423	136,866,745	110,818,391	7
8	Large		1,254	44,280,034	29,805,775	8
9	Optional Gas Service	G-30	395	103,995,837	64,228,107	9
10	Gas Service to Armed Forces	G-35	99	3,308,091	1,738,241	10
11	Air Conditioning Gas Service	G-40	465	1,067,788	628,151	11
12	Street Lighting Gas Service	G-45	338	100,215	600,963	12
	Gas Service for Compression on					
	Customer's Premises	G-55				
13	Small		309	196,184	139,636	13
14	Large		323	1,873,025	1,208,203	14
15	Residential		1,348	80,334	60,298	15
16	Cogeneration Gas Service	G-60	269	14,998,373	8,293,990	16
	Small Essential Agriculture User					
17	Gas Service	G-75	1,169	7,932,305	5,507,594	17
18	Natural Gas Engine Gas Service	G-80	7,372	20,198,094	12,442,282	18
19	Resale Gas Service	G-95	3	(14,502)	(7,296)	19
20	Total Gas Sales		10,114,843	663,721,397	$ 628,292,760	20
	Transportation Service Including					
21	Special Contract	T-1/B-1	2,770	65,680,156	9,099,186	21
22	Other Operating Revenue				9,885,120	22
23	Total Arizona		10,117,613	729,401,553	$ 647,277,066	23

[1] See Workpapers H-2, Sheets 41 - 43.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF PRESENT AND PROPOSED RATES
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

			Present Rates [1]							Proposed Rates [2]					
			Base Tariff Rate			Monthly	Currently			Base Tariff Rate			Monthly	Currently	
Line No.	Description	Schedule	Margin	Gas Cost	Rate Adjustment	Gas Cost Adjustment	Effective Tariff Rate	Description	Schedule	Margin	Gas Cost	Rate Adjustment	Gas Cost Adjustment	Effective Tariff Rate	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(d)	(k)	(l)	(m)	
	Residential Gas Service	G-5						Single-Family Residential Gas Service	G-5						
	Summer (May - October)							Summer (April - November)							
1	Basic Service Charge per Month		$ 8.00				$ 8.00	Basic Service Charge per Month		$ 12.00				$ 12.00	1
	Commodity Charge per Therm							Commodity Charge per Therm							
2	First 20 Therms		$ 0.48762	$ 0.37034	$ 0.01073	$ 0.16402	$ 1.03271	First 8 therms		$ 0.84286	$ 0.53436	$ 0.01971	-	$ 1.39693	2
3	Over 20 Therms		0.40344	0.37034	0.01073	0.16402	0.94853	Over 8 Therms		0.25000	0.53436	0.01971	-	0.80407	3
	Winter (November - April)							Winter (December - March)							
4	Basic Service Charge per Month		$ 8.00				$ 8.00	Basic Service Charge per Month		$ 12.00				$ 12.00	4
	Commodity Charge per Therm							Commodity Charge per Therm							
5	First 40 Therms		$ 0.48762	$ 0.37034	$ 0.01073	$ 0.16402	$ 1.03271	First 30 Therms		$ 0.84286	$ 0.53436	$ 0.01971	-	$ 1.39693	5
6	Over 40 Therms		0.40344	0.37034	0.01073	0.16402	0.94853	Over30 Therms		0.25000	0.53436	0.01971	-	0.80407	6
								Multi-Family Residential Gas Service	G-6						
								Summer (April - November)							
7								Basic Service Charge per Month		$ 11.00				$ 11.00	7
								Commodity Charge per Therm							
8								First 7 Therms		$ 0.84286	$ 0.53436	$ 0.01971	-	$ 1.39693	8
9								Over 7 Therms		0.25000	0.53436	0.01971	-	0.80407	9
								Winter (December - March)							
10								Basic Service Charge per Month		$ 11.00				$ 11.00	10
11								Commodity Charge per Therm							11
12								First 18 Therms		$ 0.84286	$ 0.53436	$ 0.01971	-	$ 1.39693	12
13								Over 18 Therms		0.25000	0.53436	0.01971	-	0.80407	13
								Illustrative Low Income Residential Rates							
	Low Income Residential Gas Service	G-10						Single-Family Residential Gas Service							
	Summer (May - October)							Summer (April - November)							
14	Basic Service Charge per Month		$ 7.00				$ 7.00	Basic Service Charge per Month		$ 7.00				$ 7.00	14
	Commodity Charge per Therm							Commodity Charge per Therm							
15	First 20 Therms		$ 0.48762	$ 0.37034	$ 0.00486	$ 0.16402	$ 1.02684	First 8 therms		$ 0.63519	$ 0.53436	$ 0.00724	-	$ 1.17679	15
16	Over 20 Therms		0.40344	0.37034	0.00486	0.16402	0.94266	Over 8 Therms		0.13126	0.53436	0.00724	-	0.67286	16
	Winter (November - April)							Winter (December - March)							
17	Basic Service Charge per Month		$ 7.00				$ 7.00	Basic Service Charge per Month		$ 7.00				$ 7.00	17
	Commodity Charge per Therm							Commodity Charge per Therm							
18	First 40 Therms		$ 0.28225	$ 0.37034	$ 0.00486	$ 0.16402	$ 0.82147	First 30 Therms		$ 0.63519	$ 0.53436	$ 0.00724	-	$ 1.17679	18
19	Next 110 Therms		0.21491	0.37034	0.00486	0.16402	0.75413	Over30 Therms		0.13126	0.53436	0.00724	-	0.67286	19
20	Over 150 Therms		0.40344	0.37034	0.00486	0.16402	0.94266								20
								Multi-Family Residential Gas Service	G-6						
								Summer (April - November)							
21								Basic Service Charge per Month		$ 7.00				$ 7.00	21
								Commodity Charge per Therm							
22								First 7 Therms		$ 0.63519	$ 0.53436	$ 0.00724	-	$ 1.17679	22
23								Over 7 Therms		0.13126	0.53436	0.00724	-	0.67286	23
								Winter (December - March)							
24								Basic Service Charge per Month		$ 7.00				$ 7.00	24
25								Commodity Charge per Therm							25
26								First 18 Therms		$ 0.63519	$ 0.53436	$ 0.00724	-	$ 1.17679	26
27								Over 18 Therms		0.13126	0.53436	0.00724	-	0.67286	27

[1] Margin rates effective November 1, 2001, per Decision No. 64172. Gas cost and rate adjustment effective August 31, 2004.
[2] Proposed margin rates per Schedule H-6, sheets 3-5.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF PRESENT AND PROPOSED RATES
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

			Present Rates [1]							Proposed Rates [2]					
			Base Tariff Rate							Base Tariff Rate					
Line No.	Description	Schedule	Margin	Gas Cost	Rate Adjustment	Monthly Gas Cost Adjustment	Currently Effective Tariff Rate	Description	Schedule	Margin	Gas Cost	Rate Adjustment	Monthly Gas Cost Adjustment	Currently Effective Tariff Rate	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(d)	(k)	(l)	(m)	
	Special Residential Gas Service for Air Conditioning	G-15													
1	Basic Service Charge per Month		$ 8.00				$ 8.00								1
	Commodity Charge per Therm														
	Summer (May - October)														
2	First 20 Therms		$ 0.48762	$ 0.37034	$ 0.00486	$ 0.16402	$ 1.02684								2
3	Over 20 Therms		0.19125	0.37034	0.00486	0.16402	0.73047								3
	Winter (November - April)														
4	First 40 Therms		$ 0.48762	$ 0.37034	$ 0.00486	$ 0.16402	$ 1.02684								4
5	Over 40 Therms		0.40344	0.37034	0.00486	0.16402	0.94266								5
	Special Residential Gas Service for Electric Generation	G-16													
6	Basic Service Charge per Month		$ 8.00				$ 8.00								6
	Commodity Charge per Therm														
	Summer (May - October)														
7	First 20 Therms		$ 0.48762	$ 0.37034	$ 0.00486	$ 0.16402	$ 1.02684								7
8	Over 20 Therms		0.19125	0.37034	0.00486	0.16402	0.73047								8
	Winter (November - April)														
9	First 40 Therms		$ 0.48762	$ 0.37034	$ 0.00486	$ 0.16402	$ 1.02684								9
10	Over 40 Therms		0.40344	0.37034	0.00486	0.16402	0.94266								10
	Master Metered Mobile Home Park Gas Service	G-20						Master Metered Mobile Home Park Gas Service	G-20						
11	Basic Service Charge per Month		$ 50.00				$ 50.00	Basic Service Charge per Month		$ 100.00				$ 100.00	11
	Commodity Charge per Therm							Commodity Charge per Therm							
12	All Usage		$ 0.31415	$ 0.37034	$ 0.01073	$ 0.16402	$ 0.85924	All Usage		$ 0.32271	$ 0.53436	$ 0.01971	-	$ 0.87678	12
	General Gas Service	G-25						General Gas Service	G-25						
	Basic Service Charge per Month							Basic Service Charge per Month							
13	Small		$ 20.00				$ 20.00	Small		$ 25.00				$ 25.00	13
14	Medium		90.00				90.00	Medium		35.00				35.00	14
15	Large		500.00				500.00	Large		150.00				150.00	15
16								Transportation Eligible		750.00				750.00	16
	Commodity Charge per Therm							Commodity Charge per Therm							
17	Small, All Usage		$ 0.38024	$ 0.37034	$ 0.00000	$ 0.16402	$ 0.91460	Small, All Usage		$ 0.69076	$ 0.53436	$ 0.00000	-	$ 1.22512	17
18	Medium, All Usge		0.27211	0.37034	0.00000	0.16402	0.80647	Medium, All Usge		0.40089	0.53436	0.00000	-	0.93525	18
19	Large, All Usage		0.08548	0.37034	0.00000	0.16402	0.61984	Large, All Usage		0.27399	0.53436	0.00000	-	0.80835	19
20								Transportation Eligible, All Usage		0.09262	0.53436	0.00000	-	0.62698	20
	Demand Charge per Month							Demand Charge per Month							
	Large General Service Peak Winter Month Usage							Transportation Eligible Peak Month Usage							
21	Times Demand Rate per Therm		$0.072695				$0.072695	Times Demand Rate per Therm		$ 0.062645				$0.062645	21
	Optional Gas Service	G-30						Optional Gas Service	G-30						
22	Basic Service Charge per Month		As Specified on A.C.C. Sheet No. 27.					Basic Service Charge per Month		As Specified on A.C.C. Sheet No. 27.					22
	Commodity Charge per Therm							Commodity Charge per Therm							
23	All Usage		As Specified on A.C.C. Sheet No. 28.					All Usage		As Specified on A.C.C. Sheet No. 28.					23
	Gas Service to Armed Forces	G-35													
24	Basic Service Charge per Month		$ 350.00				$ 350.00								24
	Commodity Charge per Therm														
25	All Usage		$ 0.18966	$ 0.37034	$ 0.00000	$ 0.16402	$ 0.72402								25
	Air-Conditioning Gas Service	G-40						Air-Conditioning Gas Service	G-40						
26	Basic Service Charge per Month		As Specified on A.C.C. Sheet No. 32.					Basic Service Charge per Month		$ 25.00				$ 25.00	26
	Commodity Charge per Therm							Commodity Charge per Therm							
27	All Usage		$ 0.07613	$ 0.37034	$ 0.00000	$ 0.16402	$ 0.61049	All Usage		$ 0.10208	$ 0.53436	$ 0.00000	-	$ 0.63644	27

[1] Margin rates effective November 1, 2001, per Decision No. 64172. Gas cost and rate adjustment effective August 31, 2004.
[2] Proposed margin rates per Schedule H-6, sheets 3-5.

Schedule H-3
Sheet 3 of 3

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF PRESENT AND PROPOSED RATES
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Present Rates [1]

Line No.	Description (a)	Schedule (b)	Base Tariff Rate: Margin (c)	Base Tariff Rate: Gas Cost (d)	Rate Adjustment (e)	Monthly Gas Cost Adjustment (f)	Currently Effective Tariff Rate (g)
	Street Lighting Gas Service	G-45					
	Commodity Charge per Therm						
	of Rated Capacity						
1	All Usage		$ 0.47648	$ 0.37034	$ 0.00000	$ 0.16402	$ 1.01084
	Gas Service for Compression on Customer's Premises	G-55					
	Basic Service Charge per Month						
2	Small		$ 20.00				$ 20.00
3	Large		170.00				170.00
4	Residential		8.00				8.00
	Commodity Charge per Therm						
5	Small, All Usage		$ 0.13305	$ 0.37034	$ 0.00000	$ 0.16402	$ 0.66741
6	Large, All Usage		0.13305	0.37034	0.00000	0.16402	0.66741
	Cogeneration Gas Service	G-60					
7	Basic Service Charge per Month		As Specified on A.C.C. Sheet No. 40.				
	Commodity Charge per Therm						
8	All Usage		$ 0.08934	$ 0.43742			$ 0.52676
	Small Essential Agriculture User Gas Service	G-75					
9	Basic Service Charge per Month		$ 75.00				$ 75.00
	Commodity Charge per Therm						
10	All Usage		$ 0.19468	$ 0.37034	$ 0.00000	$ 0.16402	$ 0.72904
	Natural Gas Engine Gas Service	G-80					
	Basic Service Charge per Month						
11	Off-Peak Season (October - March)		$ 0.00				$ 0.00
12	Peak Season (April - September)		80.00				80.00
	Commodity Charge per Therm						
13	All Usage		$ 0.16189	$ 0.43742			$ 0.59931

Proposed Rates [2]

Description (h)	Schedule (i)	Base Tariff Rate: Margin (j)	Base Tariff Rate: Gas Cost (d)	Rate Adjustment (k)	Monthly Gas Cost Adjustment (l)	Currently Effective Tariff Rate (m)	Line No.
Street Lighting Gas Service	G-45						
Commodity Charge per Therm							
of Rated Capacity							
All Usage		$ 0.54644	$ 0.53436	$ 0.00000	-	$ 1.08080	1
Gas Service for Compression on Customer's Premises	G-55						
Basic Service Charge per Month							
Small		$ 25.00				$ 25.00	2
Large		350.00				350.00	3
Residential		12.00				12.00	4
Commodity Charge per Therm							
All Usage		$ 0.13669	$ 0.53436	$ 0.00000	-	$ 0.67105	5
							6
Electric Generation Gas Service	G-60						
Basic Service Charge per Month		Otherwise applicable schedule					7
Commodity Charge per Therm							
All Usage		$ 0.10188	$ 0.43742		-	$ 0.53930	8
Small Essential Agriculture User Gas Service	G-75						
Basic Service Charge per Month		$ 150.00				$ 150.00	9
Commodity Charge per Therm							
All Usage		$ 0.22186	$ 0.53436	$ 0.00000	-	$ 0.75622	10
Natural Gas Engine Gas Service	G-80						
Basic Service Charge per Month							
Off-Peak Season (October - March)		$ 0.00				$ 0.00	11
Peak Season (April - September)		100.00				100.00	12
Commodity Charge per Therm							
All Usage		$ 0.15848	$ 0.43742			$ 0.59590	13

[1] Margin rates effective November 1, 2001, per Decision No. 64172. Gas cost and rate adjustment effective August 31, 2004.
[2] Proposed margin rates per Schedule H-6, sheets 3-5.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PROPOSED vs. CURRENTLY EFFECTIVE RATES
SINGLE-FAMILY RESIDENTIAL GAS SERVICE

Line No.	Description (a)	Monthly Consumption (Therms) (b)	Monthly Bill At Currently Effective Rates (c)		Monthly Bill At Proposed Tariff Rates (d)		Increase/(Decrease) Dollars (e)	Increase/(Decrease) Percent (f)	Line No.
	Summer Season Bills								
1	75 Percent Average Use	12	20.39	$	26.39	$	6.00	29.43%	1
2	Average Summer Use [1]	16	24.52	$	29.61		5.09	20.76%	2
3	125 Percent Average Use	20	28.65	$	32.82		4.17	14.55%	3
	Winter Season Bills								
4	75 Percent Average Use	42	51.21	$	63.56	$	12.35	24.12%	4
5	Average Winter Use [1]	56	64.48	$	74.81		10.33	16.02%	5
6	125 Percent Average Use	70	77.76	$	86.07		8.31	10.69%	6

Effective Tariff Rates [2]		Amount
Basic Service Charge per Month	$	8.00
Commodity Charge Summer		
First 20 Therms	$	1.03271
Over 20 Therms		0.94853
Commodity Charge Winter		
First 40 Therms	$	1.03271
Over 40 Therms		0.94853

Proposed Tariff Rates [3]		
Basic Service Charge per Month	$	12.00
Commodity Charge Summer		
First 8 Therms	$	1.39693
Over 8 Therms	$	0.80407
Commodity Charge Winter		
First 30 Therms	$	1.39693
Over 30 Therms	$	0.80407

[1] Seasonal average use per Schedule H-6, Sheets 3 - 5.
[2] Rates effective August 31, 2004 including all adjustments.
[3] Schedule H-3, Sheets 1 - 3.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PROPOSED vs. CURRENTLY EFFECTIVE RATES
MULTI-FAMILY RESIDENTIAL GAS SERVICE

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill At Currently Effective Rates	Monthly Bill At Proposed Tariff Rates	Increase/(Decrease) Dollars	Increase/(Decrease) Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	9	17.29	$ 22.39	$ 5.10	29.50%	1
2	Average Summer Use [1]	12	20.39	$ 24.80	4.41	21.63%	2
3	125 Percent Average Use	15	23.49	$ 27.21	3.72	15.84%	3
	Winter Season Bills						
4	75 Percent Average Use	23	31.75	$ 40.17	$ 8.42	26.52%	4
5	Average Winter Use [1]	30	38.98	$ 45.79	6.81	17.47%	5
6	125 Percent Average Use	38	47.24	$ 52.23	4.99	10.56%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge per Month	$ 8.00
Commodity Charge Summer	
First 20 Therms	$ 1.03271
Over 20 Therms	0.94853
Commodity Charge Winter	
First 40 Therms	$ 1.03271
Over 40 Therms	0.94853

Proposed Tariff Rates [3]	
Basic Service Charge per Month	$ 11.00
Commodity Charge Summer	
First 7 Therms	$ 1.39693
Over 7 Therms	$ 0.80407
Commodity Charge Winter	
First 18 Therms	$ 1.39693
Over 18 Therms	$ 0.80407

[1] Seasonal average use per Schedule H-6, Sheets 3 - 5.
[2] Rates effective August 31, 2004 including all adjustments.
[3] Schedule H-3, Sheets 1 - 3.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PROPOSED vs. CURRENTLY EFFECTIVE RATES
MASTER METERED MOBILE HOME PARK GAS SERVICE

Line No.	Description (a)	Monthly Consumption (Therms) (b)	Monthly Bill: At Currently Effective Rates (c)	Monthly Bill: At Proposed Tariff Rates (d)	Increase/(Decrease): Dollars (e)	Increase/(Decrease): Percent (f)	Line No.
	Summer Season Bills						
1	75 Percent Average Use	447	434.08	491.92	$ 57.84	13.32%	1
2	Average Summer Use [1]	596	562.11	622.56	60.45	10.75%	2
3	125 Percent Average Use	745	690.13	753.20	63.07	9.14%	3
	Winter Season Bills						
4	75 Percent Average Use	1,539	1,372.37	1,449.36	76.99	5.61%	4
5	Average Winter Use [1]	2,052	1,813.16	1,899.15	85.99	4.74%	5
6	125 Percent Average Use	2,565	2,253.95	2,348.94	94.99	4.21%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 50.00
Commodity Charge	
All Usage	$ 0.85924
Proposed Tariff Rates [3]	
Basic Service Charge	$ 100.00
Commodity Charge	
All Usage	$ 0.87678

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective August 31, 2004 including all adjustments.
[3] *Schedule H-3, Sheets 1 - 3.*

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PROPOSED vs. CURRENTLY EFFECTIVE RATES
GENERAL GAS SERVICE - SMALL

Line No.	Description (a)	Monthly Consumption (Therms) (b)	Monthly Bill At Currently Effective Rates (c)	Monthly Bill At Proposed Tariff Rates (d)	Increase/(Decrease) Dollars (e)	Increase/(Decrease) Percent (f)	Line No.
	Summer Season Bills						
1	75 Percent Average Use	7	$ 26.40	$ 33.58	$ 7.17	27.17%	1
2	Average Summer Use [1]	9	$ 28.23	$ 36.03	7.79	27.61%	2
3	125 Percent Average Use	11	$ 30.06	$ 38.48	8.42	28.00%	3
	Winter Season Bills						
4	75 Percent Average Use	29	$ 46.52	$ 60.53	14.01	30.10%	4
5	Average Winter Use [1]	38	$ 54.75	$ 71.55	16.80	30.68%	5
6	125 Percent Average Use	48	$ 63.90	$ 83.81	19.90	31.15%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 20.00
Commodity Charge	
All Usage	$ 0.91460
Proposed Tariff Rates [3]	
Basic Service Charge	$ 25.00
Commodity Charge	
All Usage	$ 1.22512

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective August 31, 2004 including all adjustments.
[3] Schedule H-3, Sheets 1 - 3.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PROPOSED vs. CURRENTLY EFFECTIVE RATES
GENERAL GAS SERVICE - MEDIUM

Line No.	Description (a)	Monthly Consumption (Therms) (b)	Monthly Bill At Currently Effective Rates (c)	Monthly Bill At Proposed Tariff Rates (d)	Increase/(Decrease) Dollars (e)	Increase/(Decrease) Percent (f)	Line No.
	Summer Season Bills						
1	75 Percent Average Use	121	$ 130.67	$ 148.17	$ 17.50	13.39%	1
2	Average Summer Use [1]	161	$ 167.25	$ 185.58	18.32	10.96%	2
3	125 Percent Average Use	201	$ 203.83	$ 222.99	19.15	9.40%	3
	Winter Season Bills						
4	75 Percent Average Use	251	$ 249.56	$ 269.75	20.18	8.09%	4
5	Average Winter Use [1]	335	$ 326.39	$ 348.31	21.92	6.72%	5
6	125 Percent Average Use	419	$ 403.22	$ 426.87	23.65	5.87%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 20.00
Commodity Charge	
All Usage	$ 0.91460

Proposed Tariff Rates [3]	Amount
Basic Service Charge	$ 35.00
Commodity Charge	
All Usage	$ 0.93525

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective August 31, 2004 including all adjustments.
[3] Schedule H-3, Sheets 1 - 3.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PROPOSED vs. CURRENTLY EFFECTIVE RATES
GENERAL GAS SERVICE - LARGE

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill At Currently Effective Rates	Monthly Bill At Proposed Tariff Rates	Increase/(Decrease) Dollars	Increase/(Decrease) Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	992	$ 890.02	$ 951.88	$ 61.86	6.95%	1
2	Average Summer Use [1]	1,322	$ 1,156.15	$ 1,218.64	62.49	5.40%	2
3	125 Percent Average Use	1,653	$ 1,423.09	$ 1,486.20	63.11	4.43%	3
	Winter Season Bills						
4	75 Percent Average Use	1,786	$ 1,530.36	$ 1,593.71	63.36	4.14%	4
5	Average Winter Use [1]	2,381	$ 2,010.21	$ 2,074.68	64.48	3.21%	5
6	125 Percent Average Use	2,976	$ 2,490.05	$ 2,555.65	65.59	2.63%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 90.00
Commodity Charge	
All Usage	$ 0.80647
Proposed Tariff Rates [3]	
Basic Service Charge	$ 150.00
Commodity Charge	
All Usage	$ 0.80835

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective August 31, 2004 including all adjustments.
[3] Schedule H-3, Sheets 1 - 3.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PROPOSED vs. CURRENTLY EFFECTIVE RATES
GAS SERVICE FOR COMPRESSION ON CUSTOMER PREMISES - SMALL

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill At Currently Effective Rates	Monthly Bill At Proposed Tariff Rates	Increase/(Decrease) Dollars	Increase/(Decrease) Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	536	$ 377.73	$ 384.68	$ 6.95	1.84%	1
2	Average Summer Use [1]	714	$ 496.53	$ 504.13	7.60	1.53%	2
3	125 Percent Average Use	893	$ 616.00	$ 624.25	8.25	1.34%	3
	Winter Season Bills						
4	75 Percent Average Use	483	$ 342.36	$ 349.12	6.76	1.97%	4
5	Average Winter Use [1]	644	$ 449.81	$ 457.16	7.34	1.63%	5
6	125 Percent Average Use	805	$ 557.27	$ 565.20	7.93	1.42%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 20.00
Commodity Charge	
All Usage	$ 0.66741
Proposed Tariff Rates [3]	
Basic Service Charge	$ 25.00
Commodity Charge	
All Usage	$ 0.67105

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective August 31, 2004 including all adjustments.
[3] Schedule H-3, Sheets 1 - 3.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PROPOSED vs. CURRENTLY EFFECTIVE RATES
GAS SERVICE FOR COMPRESSION ON CUSTOMER PREMISES - LARGE

			Monthly Bill				
Line No.	Description	Monthly Consumption (Therms)	At Currently Effective Rates	At Proposed Tariff Rates	Increase/(Decrease) Dollars	Increase/(Decrease) Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	4,484	$ 3,162.67	$ 3,358.99	$ 196.32	6.21%	1
2	Average Summer Use [1]	5,978	$ 4,159.78	$ 4,361.54	201.76	4.85%	2
3	125 Percent Average Use	7,473	$ 5,157.55	$ 5,364.76	207.20	4.02%	3
	Winter Season Bills						
4	75 Percent Average Use	4,219	$ 2,985.80	$ 3,181.16	195.36	6.54%	4
5	Average Winter Use [1]	5,625	$ 3,924.18	$ 4,124.66	200.47	5.11%	5
6	125 Percent Average Use	7,031	$ 4,862.56	$ 5,068.15	205.59	4.23%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 170.00
Commodity Charge	
All Usage	$ 0.66741
Proposed Tariff Rates [3]	
Basic Service Charge	$ 350.00
Commodity Charge	
All Usage	$ 0.67105

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective August 31, 2004 including all adjustments.
[3] Schedule H-3, Sheets 1 - 3.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PROPOSED vs. CURRENTLY EFFECTIVE RATES
GAS SERVICE FOR COMPRESSION ON CUSTOMER PREMISES - RESIDENTIAL

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill: At Currently Effective Rates	Monthly Bill: At Proposed Tariff Rates	Increase/(Decrease): Dollars	Increase/(Decrease): Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	46	$ 38.70	$ 42.87	$ 4.17	10.77%	1
2	Average Summer Use [1]	61	$ 48.71	$ 52.93	4.22	8.67%	2
3	125 Percent Average Use	76	$ 58.72	$ 63.00	4.28	7.28%	3
	Winter Season Bills						
4	75 Percent Average Use	44	$ 37.37	$ 41.53	4.16	11.13%	4
5	Average Winter Use [1]	59	$ 47.38	$ 51.59	4.21	8.90%	5
6	125 Percent Average Use	74	$ 57.39	$ 61.66	4.27	7.44%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 8.00
Commodity Charge	
All Usage	$ 0.66741

Proposed Tariff Rates [3]	
Basic Service Charge	$ 12.00
Commodity Charge	
All Usage	$ 0.67105

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective August 31, 2004 including all adjustments.
[3] Schedule H-3, Sheets 1 - 3.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PROPOSED vs. CURRENTLY EFFECTIVE RATES
ESSENTIAL AGRICULTURAL USER GAS SERVICE

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill At Currently Effective Rates	Monthly Bill At Proposed Tariff Rates	Increase/(Decrease) Dollars	Increase/(Decrease) Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	4,905	$ 3,650.94	$ 3,859.26	$ 208.32	5.71%	1
2	Average Summer Use [1]	6,540	$ 4,842.92	$ 5,095.68	252.76	5.22%	2
3	125 Percent Average Use	8,175	$ 6,034.90	$ 6,332.10	297.20	4.92%	3
	Winter Season Bills						
4	75 Percent Average Use	5,321	$ 3,954.22	$ 4,173.85	219.62	5.55%	4
5	Average Winter Use [1]	7,094	$ 5,246.81	$ 5,514.62	267.81	5.10%	5
6	125 Percent Average Use	8,868	$ 6,540.13	$ 6,856.16	316.03	4.83%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 75.00
Commodity Charge	
All Usage	$ 0.72904
Proposed Tariff Rates [3]	
Basic Service Charge	$ 150.00
Commodity Charge	
All Usage	$ 0.75622

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective August 31, 2004 including all adjustments.
[3] Schedule H-3, Sheets 1 - 3.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
RESIDENTIAL BILL FREQUENCY ANALYSES (BFA) AT PRESENT RATE SCHEDULES AND RATE BLOCKS
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description	September	October	November	December	January	February	March	April	May	June	July	August	Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
	Schedule G-5														
	Summer (May-Oct)														
1	Monthly Total	8,087,866	9,143,627							14,571,538	10,697,080	8,927,658	7,856,874	59,284,643	1
2	1st 20	7,305,105	7,965,554							10,725,772	8,753,296	7,768,320	7,075,313	49,593,360	2
3	Over 20	782,761	1,178,073							3,845,766	1,943,784	1,159,338	781,561	9,691,283	3
	Winter (Nov-April)														
4	Monthly Total			14,945,074	40,352,489	57,594,051	43,894,135	35,936,315	22,614,496					215,336,560	4
5	1st 40			13,257,576	25,371,301	28,333,971	26,764,164	24,500,687	18,370,097					136,597,796	5
6	Over 40			1,687,498	14,981,188	29,260,080	17,129,971	11,435,628	4,244,399					78,738,764	6
	Schedule G-10														
	Summer (May-Oct)														
7	Monthly Total	324,357	353,826							530,134	382,770	333,123	310,211	2,234,421	7
8	1st 20	302,964	325,964							428,242	342,434	306,211	290,318	1,996,133	8
9	Over 20	21,393	27,862							101,892	40,336	26,912	19,893	238,288	9
	Winter (Nov-April)														
10	Monthly Total			618,785	1,629,254	2,191,625	1,645,221	1,370,874	849,865					8,305,624	10
11	1st 40			581,266	1,034,328	1,123,216	1,054,112	974,888	758,847					5,526,657	11
12	Next 110			36,758	582,613	1,021,816	583,600	389,770	89,442					2,703,999	12
13	Over 150			761	12,313	46,593	7,509	6,216	1,576					74,968	13
	Schedule G-15														
	Summer (May-Oct)														
14	Monthly Total	23,863	16,321							13,260	16,514	20,230	23,736	113,924	14
15	1st 20	2,472	2,491							2,591	2,487	2,334	2,409	14,784	15
16	Over 20	21,391	13,830							10,669	14,027	17,896	21,327	99,140	16
	Winter (Nov-April)														
17	Monthly Total			11,737	21,031	26,264	19,738	18,349	13,533					110,652	17
18	1st 40			4,364	5,838	6,032	5,927	5,666	4,564					32,391	18
19	Over 40			7,373	15,193	20,232	13,811	12,683	8,969					78,261	19

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
RESIDENTIAL BILL FREQUENCY ANALYSES (BFA) PRESENT RATE SCHEDULES AT PROPOSED RATE BLOCKS
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	September (b)	October (c)	November (d)	December (e)	January (f)	February (g)	March (h)	April (i)	May (j)	June (k)	July (l)	August (m)	Total (n)	Line No.
	Single-Family Residential														
	Summer (April-Nov)														
1	Monthly Total	7,804,915	8,836,327	14,528,069					22,083,573	14,170,850	10,352,044	8,625,043	7,584,196	93,985,017	1
2	1st 8 therms	4,819,326	5,036,598	5,547,927					5,884,368	5,610,149	5,234,391	4,965,214	4,745,358	41,843,331	2
3	Next 12/32	2,224,079	2,644,268	7,304,737					11,981,157	4,771,505	3,213,238	2,528,399	2,078,353	36,745,736	3
4	Over 20/40	761,510	1,155,461	1,675,405					4,218,048	3,789,196	1,904,415	1,131,430	760,485	15,395,950	4
	Winter (Dec-March)														
5	Monthly Total				39,508,150	56,497,723	43,040,069	35,199,692						174,245,634	5
6	1st 30				20,009,096	21,399,993	20,647,984	19,699,548						81,756,621	6
7	Next 10				4,655,052	6,112,950	5,395,088	4,148,242						20,311,332	7
8	Over 40				14,844,002	28,984,780	16,996,997	11,351,902						72,177,681	8
	Single-Family Residential Transportation Volumes														
	Summer (April-Nov)														
9	Monthly Total	31	33	42					119	51	33	36	35	380	9
10	1st 8 therms	8	8	8					8	8	8	8	8	64	10
11	Next 12/32	12	12	22					22	12	12	12	12	116	11
12	Over 20/40	11	13	12					89	31	13	16	15	200	12
	Winter (Dec-March)														
13	Monthly Total				146	282	196	256						880	13
14	1st 30				30	30	30	30						120	14
15	Next 10				10	10	10	10						40	15
16	Over 40				106	242	156	216						720	16
	Special Residential (Schedule G-15)														
	Summer (April-Nov)														
17	Monthly Total	23,863	16,321	11,737					13,533	13,260	16,514	20,230	23,736	139,194	17
18	1st 8 therms	1,164	1,176	1,213					1,231	1,204	1,174	1,132	1,144	9,438	18
19	Next 12/32	1,308	1,315	3,151					3,333	1,387	1,313	1,202	1,265	14,274	19
20	Over 20/40	21,391	13,830	7,373					8,969	10,669	14,027	17,896	21,327	115,482	20
	Winter (Dec-March)														
21	Monthly Total				21,031	26,264	19,738	18,349						85,382	21
22	1st 30				4,504	4,573	4,543	4,428						18,048	22
23	Next 10				1,334	1,459	1,384	1,238						5,415	23
24	Over 40				15,193	20,232	13,811	12,683						61,919	24
	Total Single-Family Residential														
	Summer (April-Nov)														
25	Monthly Total	7,828,809	8,852,681	14,539,848					22,097,225	14,184,161	10,368,591	8,645,309	7,607,967	94,124,591	25
26	1st 8 therms	4,820,498	5,037,782	5,549,148					5,885,607	5,611,361	5,235,573	4,966,354	4,746,510	41,852,833	26
27	Next 12/32	2,225,399	2,645,595	7,307,910					11,984,512	4,772,904	3,214,563	2,529,613	2,079,630	36,760,126	27
28	Over 20/40	782,912	1,169,304	1,682,790					4,227,106	3,799,896	1,918,455	1,149,342	781,827	15,511,632	28
	Winter (Dec-March)														
29	Monthly Total				39,529,327	56,524,269	43,060,003	35,218,297						174,331,896	29
30	1st 30				20,013,630	21,404,596	20,652,557	19,704,006						81,774,789	30
31	Next 10				4,656,396	6,114,419	5,396,482	4,149,490						20,316,787	31
32	Over 40				14,859,301	29,005,254	17,010,964	11,364,801						72,240,320	32

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
RESIDENTIAL BILL FREQUENCY ANALYSES (BFA) PRESENT RATE SCHEDULES AT PROPOSED RATE BLOCKS
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	September (b)	October (c)	November (d)	December (e)	January (f)	February (g)	March (h)	April (i)	May (j)	June (k)	July (l)	August (m)	Total (n)	Line No.
	Low-Income Single-Family Residential														
	Summer (April-Nov)														
1	Monthly Total	301,897	329,584	584,488					804,903	497,525	356,068	310,002	287,785	3,472,252	1
2	1st 8	190,482	196,868	216,794					224,055	213,106	196,437	185,375	184,276	1,607,393	2
3	Next 12/32	91,412	106,765	330,869					492,202	187,671	122,657	100,149	85,544	1,517,269	3
4	Over 20/40	20,003	25,951	36,825					88,646	96,748	36,974	24,478	17,965	347,590	4
	Winter (Dec-March)														
5	Monthly Total				1,555,947	2,092,790	1,569,460	1,303,631						6,521,828	5
6	1st 30				480,139	818,058	786,587	755,897						2,840,681	6
7	Next 10				494,081	236,099	205,363	162,666						1,098,209	7
8	Next 110 therms				569,552	992,776	570,017	378,894						2,511,239	8
9	Over 150				12,175	45,857	7,493	6,174						71,699	9
	Multi-Family Residential														
	Summer (April-Nov)														
10	Monthly Total	282,920	307,267	416,963					530,804	400,637	345,003	302,579	272,643	2,858,816	10
11	1st 7	162,757	168,210	178,287					187,311	179,295	172,779	165,677	159,900	1,374,216	11
12	Next 13/33	98,923	116,458	226,585					317,221	164,803	132,868	109,010	91,682	1,257,550	12
13	Over	21,240	22,599	12,091					26,272	56,539	39,356	27,892	21,061	227,050	13
	Winter (Dec-March)														
14	Monthly Total				844,193	1,096,046	853,870	736,367						3,530,476	14
15	1st 18				441,286	467,923	447,743	437,640						1,794,592	15
16	Next 22				265,827	353,065	273,309	215,217						1,107,418	16
17	Over 40				137,080	275,058	132,818	83,510						628,466	17
	Low-Income Multi-Family Residential														
	Summer (April-Nov)														
18	Monthly Total	22,460	24,242	34,297					44,962	32,609	26,702	23,121	22,426	230,819	18
19	1st 7	12,744	12,933	13,880					14,374	13,567	12,596	11,883	12,217	104,194	19
20	Next 13/33	8,326	9,398	19,723					28,216	13,898	10,744	8,804	8,281	107,390	20
21	Over	1,390	1,911	694					2,372	5,144	3,362	2,434	1,928	19,235	21
	Winter (Dec-March)														
22	Monthly Total				73,307	98,835	75,761	67,243						315,146	22
23	1st 18				35,131	36,900	36,026	34,706						142,763	23
24	Next 22				24,977	32,159	26,136	21,619						104,891	24
25	Next 110				13,061	29,040	13,583	10,876						66,560	25
26	Over 150				138	736	16	42						932	26

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
RESIDENTIAL BILL FREQUENCY ANALYSES (BFA) AT PROPOSED RATE SCHEDULES INCLUDING MULTI-FAMILY RATE SCHEDULE RATEMAKING ADJUSTMENT
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description	September	October	November	December	January	February	March	April	May	June	July	August	Total	Line
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
	Total Multi-Family Adjustment Volumes and Customers [1]														
1	Recorded	301,486	338,441	466,809	1,166,135	1,511,820	1,482,622	1,088,614	573,484	440,124	357,169	310,523	277,837	8,315,064	1
2	Weather Normal Adjustment	1.00	1.00	1.02	1.02	1.05	0.85	0.94	1.20	1.07	1.00	1.00	1.00		2
3	Weather Normalized Volumes	301,486	338,441	477,579	1,190,465	1,588,354	1,265,706	1,018,535	686,594	470,648	357,169	310,523	277,837	8,283,338	3
4	Customers	29,598	29,187	25,040	28,841	28,769	28,775	28,820	28,760	28,623	28,611	28,571	28,495	342,090	4
	Volume Adjustment Out of Single-Family Rate Schedule at Proposed Single-Family Blocks														
	Multi-Family BFA Before Ratemaking Adjustment														
	Summer (April-Nov)														
5	Monthly Total	282,920	307,267	416,963					530,804	400,637	345,003	302,579	272,643	2,858,816	5
6	First 8 Therms	178,727	185,827	199,224					211,315	200,525	191,527	182,339	174,865	1,524,349	6
7	Next 12 / 32 Therms	82,953	98,841	205,648					293,217	143,573	114,120	92,348	76,717	1,107,417	7
8	Over 20 / 40 Therms	21,240	22,599	12,091					26,272	56,539	39,356	27,892	21,061	227,050	8
	Winter (Dec-March)														
9	Monthly Total				844,193	1,096,046	853,870	736,367						3,530,476	9
10	First 30 Therms				620,829	690,211	630,014	589,493						2,530,547	10
11	Next 10 Therms				86,284	130,777	91,038	63,364						371,463	11
12	Over 40 Therms				137,080	275,058	132,818	83,510						628,466	12
	Single-Family Adjustment [2]														
	Summer (April-Nov)														
13	Monthly Total	301,486	338,441	477,579					686,594	470,648	357,169	310,523	277,837	3,220,278	13
14	First 8 Therms	190,456	204,680	228,186					273,336	235,567	198,281	187,126	178,196	1,695,828	14
15	Next 12 / 32 Therms	88,397	108,869	235,544					379,276	168,662	118,144	94,773	78,179	1,271,843	15
16	Over 20 / 40 Therms	22,634	24,892	13,849					33,983	66,419	40,744	28,624	21,462	252,607	16
	Winter (Dec-March)														
17	Monthly Total				1,190,465	1,588,354	1,265,706	1,018,535						5,063,060	17
18	First 30 Therms				875,481	1,000,231	933,880	815,381						3,624,973	18
19	Next 10 Therms				121,676	189,518	134,947	87,644						533,785	19
20	Over 40 Therms				193,308	398,605	196,878	115,510						904,301	20
	Total Single-Family Residential														
	Summer (April-Nov)														
21	Monthly Total	7,828,809	8,852,681	14,539,848					22,097,225	14,184,161	10,368,591	8,645,309	7,607,967	94,124,591	21
22	1st 8 therms	4,820,498	5,037,782	5,549,148					5,885,607	5,611,361	5,235,573	4,966,354	4,746,510	41,852,833	22
23	Next 12/32	2,225,399	2,645,595	7,307,910					11,984,512	4,772,904	3,214,563	2,529,613	2,079,630	36,760,126	23
24	Over 20/40	782,912	1,169,304	1,682,790					4,227,106	3,799,896	1,918,455	1,149,342	781,827	15,511,632	24
	Winter (Dec-March)														
25	Monthly Total				39,529,327	56,524,269	43,060,003	35,218,297						174,331,896	25
26	1st 30				20,013,630	21,404,596	20,652,557	19,704,006						81,774,789	26
27	Next 10				4,656,396	6,114,419	5,396,482	4,149,490						20,316,787	27
28	Over 40				14,859,301	29,005,254	17,010,964	11,364,801						72,240,320	28
	Adjusted Single-Family Volumes [3]														
	Summer (April-Nov)														
29	Monthly Total	7,527,323	8,514,240	14,062,269					21,410,631	13,713,513	10,011,422	8,334,786	7,330,130	90,904,313	29
30	First 8 Therms	4,630,042	4,833,102	5,320,962					5,612,271	5,375,794	5,037,292	4,779,228	4,568,314	40,157,005	30
31	Next 12 / 32 Therms	2,137,002	2,536,726	7,072,366					11,605,236	4,604,242	3,096,419	2,434,840	2,001,451	35,488,283	31
32	Over 20 / 40 Therms	760,278	1,144,412	1,668,941					4,193,123	3,733,477	1,877,711	1,120,718	760,365	15,259,025	32
	Winter (Dec-March)														
33	Monthly Total				38,338,862	54,935,915	41,794,297	34,199,762						169,268,836	33
34	First 30 Therms				19,138,149	20,404,365	19,718,677	18,888,625						78,149,816	34
35	Next 10 Therms				4,534,720	5,924,901	5,261,535	4,061,846						19,783,002	35
36	Over 40 Therms				14,665,993	28,606,649	16,814,086	11,249,291						71,336,019	36

[1] Multi-family customers identified subsequent to preparation of BFAs.
[2] Total multi-family adjustment volumes prorated to blocks per multi-family BFA.
[3] Multi-family/Single-family BFA volumes including prorated adjustment volumes.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
RESIDENTIAL BILL FREQUENCY ANALYSES (BFA) AT PROPOSED RATE SCHEDULES INCLUDING MULTI-FAMILY RATE SCHEDULE RATEMAKING ADJUSTMENT
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	September (b)	October (c)	November (d)	December (e)	January (f)	February (g)	March (h)	April (i)	May (j)	June (k)	July (l)	August (m)	Total (n)	Line
	Total Low-Income Multi-Family Adjustment Volumes and Customers [1]														
1	Recorded	22,601	24,365	36,044	94,500	123,782	118,777	87,292	40,946	30,130	24,436	21,834	20,720	645,427	1
2	Weather Normal Adjustment [1]	1.00	1.00	1.02	1.02	1.05	0.85	0.94	1.20	1.07	1.00	1.00	1.00		2
3	Weather Normalized Volumes	22,601	24,365	36,876	96,472	130,048	101,399	81,673	49,022	32,220	24,436	21,834	20,720	641,665	3
4	Customers	2,201	2,186	1,874	2,162	2,174	2,161	2,147	2,110	2,081	2,045	1,999	2,065	25,205	4
	Volume Adjustment Out of Low-Income Single-Family Rate Schedule at Proposed Single-Family Blocks														
	Low-Income Multi-Family BFA Before Ratemaking Adjustment														
	Summer (April-Nov)														
5	Monthly Total	22,460	24,242	34,297					44,962	32,609	26,702	23,121	22,426	230,819	5
6	First 8 Therms	14,059	14,311	15,556					16,259	15,227	14,012	13,123	13,432	115,979	6
7	Next 12 / 32 Therms	7,011	8,020	18,047					26,331	12,238	9,328	7,564	7,066	95,605	7
8	Over 20 / 40 Therms	1,390	1,911	694					2,372	5,144	3,362	2,434	1,928	19,235	8
	Winter (Dec-March)														
9	Monthly Total				73,307	98,835	75,761	67,243						315,146	9
10	First 30 Therms				51,538	56,602	52,856	49,164						210,160	10
11	Next 10 Therms				8,570	12,457	9,306	7,161						37,494	11
12	Next 110 Therms				13,061	29,040	13,583	10,876						66,560	12
13	Over 150 Therms				138	736	16	42						932	13
	Low-Income Single-Family Adjustment [2]														
	Summer (April-Nov)														
14	Monthly Total	22,601	24,365	36,876					49,022	32,220	24,436	21,834	20,720	232,073	14
15	First 8 Therms	14,147	14,384	16,726					17,727	15,045	12,823	12,393	12,410	115,654	15
16	Next 12 / 32 Therms	7,055	8,061	19,404					28,709	12,092	8,536	7,143	6,528	97,528	16
17	Over 20 / 40 Therms	1,399	1,921	746					2,586	5,083	3,077	2,299	1,781	18,891	17
	Winter (Dec-March)														
18	Monthly Total				96,472	130,048	101,399	81,673						409,592	18
19	First 30 Therms				67,824	74,478	70,743	59,714						272,758	19
20	Next 10 Therms				11,278	16,391	12,455	8,698						48,822	20
21	Next 110 Therms				17,188	38,211	18,180	13,210						86,789	21
22	Over 150 Therms				182	968	21	51						1,222	22
	Low-Income Single-Family Residential														
	Summer (April-Nov)														
23	Monthly Total	301,897	329,584	584,488					804,903	497,525	356,068	310,002	287,785	3,472,252	23
24	1st 8	190,482	196,868	216,794					224,055	213,106	196,437	185,375	184,276	1,607,393	24
25	Next 12/32	91,412	106,765	330,869					492,202	187,671	122,657	100,149	85,544	1,517,269	25
26	Over 20/40	20,003	25,951	36,825					88,646	96,748	36,974	24,478	17,965	347,590	26
	Winter (Dec-March)														
27	Monthly Total				1,555,947	2,092,790	1,569,460	1,303,631						6,521,828	27
28	1st 30				480,139	818,058	786,587	755,897						2,840,681	28
29	Next 10				494,081	236,099	205,363	162,666						1,098,209	29
30	Next 110 therms				569,552	992,776	570,017	378,894						2,511,239	30
31	Over 150				12,175	45,857	7,493	6,174						71,699	31
	Adjusted Low-Income Single-Family Volumes [3]														
	Summer (April-Nov)														
32	Monthly Total	279,296	305,219	547,612					755,881	465,305	331,632	288,168	267,065	3,240,179	32
33	First 8 Therms	176,335	182,484	200,068					206,328	198,061	183,614	172,982	171,866	1,491,739	33
34	Next 12 / 32 Therms	84,357	98,704	311,465					463,493	175,579	114,121	93,006	79,016	1,419,741	34
35	Over 20 / 40 Therms	18,604	24,030	36,079					86,060	91,665	33,897	22,179	16,184	328,699	35
	Winter (Dec-March)														
36	Monthly Total				1,459,475	1,962,742	1,468,061	1,221,958						6,112,236	36
37	First 30 Therms				412,315	743,580	715,844	696,183						2,567,923	37
38	Next 10 Therms				482,803	219,708	192,908	153,968						1,049,387	38
39	Next 110 Therms				552,364	954,565	551,837	365,684						2,424,450	39
40	Over 150 Therms				11,993	44,889	7,472	6,123						70,477	40

[1] Multi-family customers identified subsequent to preparation of BFAs.
[2] Total multi-family adjustment volumes prorated to blocks per multi-family BFA.
[3] Multi-family/Single-family BFA volumes including prorated adjustment volumes.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
RESIDENTIAL BILL FREQUENCY ANALYSES (BFA) AT PROPOSED RATE SCHEDULES INCLUDING MULTI-FAMILY RATE SCHEDULE RATEMAKING ADJUSTMENT
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description	September	October	November	December	January	February	March	April	May	June	July	August	Total	Line
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
	Total Multi-Family Adjustment Volumes and Customers [1]														
1	Recorded	301,486	338,441	466,809	1,166,135	1,511,820	1,482,622	1,088,614	573,484	440,124	357,169	310,523	277,837	8,315,064	1
2	Weather Normal Adjustment	1.00	1.00	1.02	1.02	1.05	0.85	0.94	1.20	1.07	1.00	1.00	1.00		2
3	Weather Normalized Volumes	301,486	338,441	477,579	1,190,465	1,588,354	1,265,706	1,018,535	686,594	470,648	357,169	310,523	277,837	8,283,338	3
4	Customers	29,598	29,187	25,040	28,841	28,769	28,775	28,820	28,760	28,623	28,611	28,571	28,495	342,090	4
	Volume Adjustment to Multi-Family at Proposed Multi-Family Blocks														
	Multi-Family BFA Before Ratemaking Adjustment														
	Summer (April-Nov)														
5	Monthly Total	282,920	307,267	416,963					530,804	400,637	345,003	302,579	272,643	2,858,816	5
6	First 7 Therms	162,757	168,210	178,287					187,311	179,295	172,779	165,677	159,900	1,374,216	6
7	Next 13 / 33 Therms	98,923	116,458	226,585					317,221	164,803	132,868	109,010	91,682	1,257,550	7
8	Over 20 / 40 Therms	21,240	22,599	12,091					26,272	56,539	39,356	27,892	21,061	227,050	8
	Winter (Dec-March)														
9	Monthly Total				844,193	1,096,046	853,870	736,367						3,530,476	9
10	First 18 Therms				441,286	467,923	447,743	437,640						1,794,592	10
11	Next 22 Therms				265,827	353,065	273,309	215,217						1,107,418	11
12	Over 40 Therms				137,080	275,058	132,818	83,510						628,466	12
	Multi-Family Adjustment [2]														
	Summer (April-Nov)														
13	Monthly Total	301,486	338,441	477,579					686,594	470,648	357,169	310,523	277,837	3,220,278	13
14	First 7 Therms	173,438	185,276	204,206					242,287	210,627	178,872	170,027	162,946	1,527,677	14
15	Next 13 / 33 Therms	105,415	128,273	259,525					410,325	193,602	137,553	111,872	93,429	1,439,994	15
16	Over 20 / 40 Therms	22,634	24,892	13,849					33,983	66,419	40,744	28,624	21,462	252,607	16
	Winter (Dec-March)														
17	Monthly Total				1,190,465	1,588,354	1,265,706	1,018,535						5,063,060	17
18	First 18 Therms				622,293	678,099	663,697	605,339						2,569,428	18
19	Next 22 Therms				374,864	511,650	405,130	297,686						1,589,331	19
20	Over 40 Therms				193,308	398,605	196,878	115,510						904,301	20
	Adjusted Multi-Family Volumes [3]														
	Summer (April-Nov)														
21	Monthly Total	584,406	645,708	894,542					1,217,398	871,285	702,172	613,102	550,480	6,079,094	21
22	First 7 Therms	336,195	353,486	382,493					429,598	389,922	351,651	335,704	322,846	2,901,893	22
23	Next 13 / 33 Therms	204,338	244,731	486,110					727,546	358,405	270,421	220,882	185,111	2,697,544	23
24	Over 20 / 40 Therms	43,874	47,491	25,940					60,255	122,958	80,100	56,516	42,523	479,657	24
	Winter (Dec-March)														
25	Monthly Total				2,034,658	2,684,400	2,119,576	1,754,902						8,593,536	25
26	First 18 Therms				1,063,579	1,146,022	1,111,440	1,042,979						4,364,020	26
27	Next 22 Therms				640,691	864,715	678,439	512,903						2,696,749	27
28	Over 40 Therms				330,388	673,663	329,696	199,020						1,532,767	28

[1] Multi-family customers identified subsequent to preparation of BFAs.
[2] Total multi-family adjustment volumes prorated to blocks per multi-family BFA.
[3] Multi-family/Single-family BFA volumes including prorated adjustment volumes.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
RESIDENTIAL BILL FREQUENCY ANALYSES (BFA) AT PROPOSED RATE SCHEDULES INCLUDING MULTI-FAMILY RATE SCHEDULE RATEMAKING ADJUSTMENT
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	September (b)	October (c)	November (d)	December (e)	January (f)	February (g)	March (h)	April (i)	May (j)	June (k)	July (l)	August (m)	Total (n)	Line
	Total Low-Income Multi-Family Adjustment Volumes and Customers [1]														
1	Recorded	22,601	24,365	36,044	94,500	123,782	118,777	87,292	40,946	30,130	24,436	21,834	20,720	645,427	1
2	Weather Normal Adjustment [1]	1.00	1.00	1.02	1.02	1.05	0.85	0.94	1.20	1.07	1.00	1.00	1.00		2
3	Weather Normalized Volumes	22,601	24,365	36,876	96,472	130,048	101,399	81,673	49,022	32,220	24,436	21,834	20,720	641,665	3
4	Customers	2,201	2,186	1,874	2,162	2,174	2,161	2,147	2,110	2,081	2,045	1,999	2,065	25,205	4
	Volume Adjustment to Low-Income Multi-Family at Proposed Multi-Family Blocks														
	Low-Income Multi-Family BFA Before Ratemaking Adjustment														
	Summer (April-Nov)														
5	Monthly Total	22,460	24,242	34,297					44,962	32,609	26,702	23,121	22,426	230,819	5
6	First 7 Therms	12,744	12,933	13,880					14,374	13,567	12,596	11,883	12,217	104,194	6
7	Next 13 / 33 Therms	8,326	9,398	19,723					28,216	13,898	10,744	8,804	8,281	107,390	7
8	Over 20 / 40 Therms	1,390	1,911	694					2,372	5,144	3,362	2,434	1,928	19,235	8
	Winter (Dec-March)														
9	Monthly Total				73,307	98,835	75,761	67,243						315,146	9
10	First 18 Therms				35,131	36,900	36,026	34,706						142,763	10
11	Next 22 Therms				24,977	32,159	26,136	21,619						104,891	11
12	Next 110 Therms				13,061	29,040	13,583	10,876						66,560	12
13	Over 150 Therms				138	736	16	42						932	13
	Low-Income Multi-Family Adjustment [2]														
14	Monthly Total	22,601	24,365	36,876					49,022	32,220	24,436	21,834	20,720	148,232	14
15	First 7 Therms	12,824	12,999	14,924					15,672	13,405	11,527	11,222	11,288	103,859	15
16	Next 13 / 33 Therms	8,378	9,446	21,206					30,764	13,732	9,832	8,314	7,651	109,323	16
17	Over 20 / 40 Therms	1,399	1,921	746					2,586	5,083	3,077	2,299	1,781	18,891	17
18	Monthly Total				96,472	130,048	101,399	81,673						409,592	18
19	First 18 Therms				46,232	48,553	48,218	42,154						185,157	19
20	Next 22 Therms				32,870	42,315	34,981	26,258						136,424	20
21	Next 110 Therms				17,188	38,211	18,180	13,210						86,789	21
22	Over 150 Therms				182	968	21	51						1,222	22
	Adjusted Low-Income Multi-Family Volumes [3]														
	Summer (April-Nov)														
23	Monthly Total	45,061	48,607	71,173					93,984	64,829	51,138	44,955	43,146	462,892	23
24	First 7 Therms	25,568	25,932	28,804					30,046	26,972	24,123	23,105	23,505	208,053	24
25	Next 13 / 33 Therms	16,704	18,844	40,929					58,980	27,630	20,576	17,118	15,932	216,713	25
26	Over 20 / 40 Therms	2,789	3,832	1,440					4,958	10,227	6,439	4,733	3,709	38,126	26
	Winter (Dec-March)														
27	Monthly Total				169,779	228,883	177,160	148,916						724,738	27
28	First 18 Therms				81,363	85,453	84,244	76,860						327,920	28
29	Next 22 Therms				57,847	74,474	61,117	47,877						241,315	29
30	Next 110 Therms				30,249	67,251	31,763	24,086						153,349	30
31	Over 150 Therms				320	1,704	37	93						2,154	31

[1] Multi-family customers identified subsequent to preparation of BFAs.
[2] Total multi-family adjustment volumes prorated to blocks per multi-family BFA.
[3] Multi-family/Single-family BFA volumes including prorated adjustment volumes.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
LOW INCOME BILL FREQUENCY ANALYSES (BFA) AT PRESENT RATE SCHEDULES INCLUDING MULTI-FAMILY RATE SCHEDULE RATEMAKING ADJUSTMENT
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	September (b)	October (c)	November (d)	December (e)	January (f)	February (g)	March (h)	April (i)	May (j)	June (k)	July (l)	August (m)	Total (n)	Line No.
	Total Low-Income Multi-Family Adjustment Volumes and Customers [1]														
1	Recorded	22,601	24,365	36,044	94,500	123,782	118,777	87,292	40,946	30,130	24,436	21,834	20,720	645,427	1
2	Weather Normal Adjustment [1]	1.00	1.00	1.02	1.02	1.05	0.85	0.94	1.20	1.07	1.00	1.00	1.00		2
3	Weather Normalized Volumes	22,601	24,365	36,876	96,472	130,048	101,399	81,673	49,022	32,220	24,436	21,834	20,720	641,665	3
4	Customers	2,201	2,186	1,874	2,162	2,174	2,161	2,147	2,110	2,081	2,045	1,999	2,065	25,205	4
	Volume Adjustment to Low-Income Multi-Family at Proposed Multi-Family Blocks														
	Low-Income Multi-Family BFA Before Ratemaking Adjustment														
	Summer (May-Oct)														
5	Monthly Total	22,460	24,242							32,609	26,702	23,121	22,426	151,560	5
6	1st 7	12,744	12,933							13,567	12,596	11,883	12,217	75,940	6
7	Next 13	8,326	9,398							13,898	10,744	8,804	8,281	59,451	7
8	Over	1,390	1,911							5,144	3,362	2,434	1,928	16,169	8
	Winter (Nov-April)														
9	Monthly Total			34,297	73,307	98,835	75,761	67,243	44,962					394,405	9
10	1st 18			27,482	35,131	36,900	36,026	34,706	31,201					201,446	10
11	Next 22			6,121	24,977	32,159	26,136	21,619	11,389					122,401	11
12	Next 110			694	13,061	29,040	13,583	10,876	2,285					69,539	12
13	Over 150			0	138	736	16	42	87					1,019	13
	Low-Income Multi-Family/Single-family Adjustment [2]														
	Summer (May-Oct)														
14	Monthly Total	22,601	24,365							32,220	24,436	21,834	20,720	146,176	14
15	1st 7	12,824	12,999							13,405	11,527	11,222	11,288	73,264	15
16	Next 13	8,378	9,446							13,732	9,832	8,314	7,651	57,353	16
17	Over	1,399	1,921							5,083	3,077	2,299	1,781	15,559	17
														0	
	Winter (Nov-April)														
18	Monthly Total			36,876	96,472	130,048	101,399	81,673	49,022					495,489	18
19	1st 18			29,548	46,232	48,553	48,218	42,154	34,018					248,723	19
20	Next 22			6,581	32,870	42,315	34,981	26,258	12,417					155,422	20
21	Next 110			746	17,188	38,211	18,180	13,210	2,491					90,026	21
22	Over 150			-	182	968	21	51	95					1,317	22
	Adjusted Low-Income Multi-Family Volumes [3]														
	Summer (May-Oct)														
23	Monthly Total	45,061	48,607							64,829	51,138	44,955	43,146	297,736	23
24	1st 7	25,568	25,932							26,972	24,123	23,105	23,505	149,204	24
25	Next 13	16,704	18,844							27,630	20,576	17,118	15,932	116,804	25
26	Over	2,789	3,832							10,227	6,439	4,733	3,709	31,728	26
	Winter (Nov-April)														
27	Monthly Total			71,173	169,779	228,883	177,160	148,916	93,984					889,894	27
28	1st 18			57,030	81,363	85,453	84,244	76,860	65,219					450,169	28
29	Next 22			12,702	57,847	74,474	61,117	47,877	23,806					277,823	29
30	Next 110			1,440	30,249	67,251	31,763	24,086	4,776					159,565	30
31	Over 150			-	320	1,704	37	93	182					2,336	31
	Low-Income Single-Family BFA Before Ratemaking Adjustment														
	Summer (May-Oct)														
32	Monthly Total	301,897	329,584							497,525	356,068	310,002	287,785	2,082,861	32
33	1st 8	190,482	196,868							213,106	196,437	185,375	184,276	1,166,544	33
34	Next 12	91,412	106,765							187,671	122,657	100,149	85,544	694,198	34
35	Over 20	20,003	25,951							96,748	36,974	24,478	17,965	222,119	35
	Winter (Nov-April)														
36	Monthly Total			584,488	1,555,947	2,092,790	1,569,460	1,303,631	804,903					7,911,219	36
37	1st 30			510,931	480,139	818,058	786,587	755,897	638,634					3,990,246	37
38	Next 10			36,732	494,081	236,099	205,363	162,666	77,623					1,212,564	38
39	Next 110 therms			36,064	569,552	992,776	570,017	378,894	87,157					2,634,460	39
40	Over 150			761	12,175	45,857	7,493	6,174	1,489					73,949	40
	Adjusted Low-Income Single-Family Volumes [3]														
	Summer (May-Oct)														
41	Monthly Total	279,296	305,219							465,305	331,632	288,168	267,065	1,936,685	41
42	1st 8	177,658	183,869							199,701	184,910	174,153	172,988	1,093,280	42
43	Next 12	83,034	97,319							173,939	112,825	91,835	77,893	636,845	43
44	Over 20	18,604	24,030							91,665	33,897	22,179	16,184	206,560	44
	Winter (Nov-April)														
45	Monthly Total			547,612	1,459,475	1,962,742	1,468,061	1,221,958	755,881					7,415,730	45
46	1st 30			481,383	433,907	769,505	738,369	713,743	604,616					3,741,523	46
47	Next 10			30,151	461,211	193,784	170,382	136,408	65,206					1,057,142	47
48	Next 110 therms			35,318	552,364	954,565	551,837	365,684	84,666					2,544,434	48
49	Over 150			761	11,993	44,889	7,472	6,123	1,394					72,632	49

[1] Multi-family customers identified subsequent to preparation of BFAs.
[2] Total multi-family adjustment prorated to blocks per multi-family BFA.
[3] Multi-family/Single-family BFA volumes including prorated adjustment volumes.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
ALLOCATION OF PROPOSED MARGIN TO CUSTOMER CLASSES
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Total (b)	Single Family Residential (c)	Multi-Family Residential (d)	MMMHP (e)	General Gas Service: Small (f)	General Gas Service: Medium (g)	General Gas Service: Large (h)	General Gas Service: Trans. Eligible (i)	Air-Conditioning (j)	Line No.
1	Margin at Requested System Rate of Return [1]	$ 393,675,106	$ 274,919,190	$ 17,086,091	$ 749,577	$ 14,959,103	$ 20,315,993	$ 30,851,744	$ 9,537,703	$ 163,241	1
2	Margin at Present Rates [2]	$ 322,865,978	$ 196,580,278	$ 13,424,301	$ 883,856	$ 5,415,035	$ 20,350,243	$ 46,243,388	$ 15,855,591	$ 167,216	2
3	Difference (Line 1 minus Line 2)	$ 70,809,128									3
4	System Average Percentage Increase (Line 3 / Line 2)	21.93143%									4
5	Ratio of Margin at System Return to Margin at Present Rates (Line 1 / Line 2)		1.39851	1.27277	0.84808	2.76251	0.99832	0.66716	0.60154	0.97623	5
6	Adjusted Percentage Increase (Line 4 X Line 5)		30.67129%	27.91374%	18.59952%	43.86286%	21.89452%	14.63178%	13.19254%	21.41012%	6
7	Adjusted Percentage Increase $ (Line 2 X Line 6)	$ 81,848,019	$ 60,293,712	$ 3,747,224	$ 164,393	$ 2,375,189	$ 4,455,588	$ 6,766,229	$ 2,091,755	$ 35,801	7
8	Adjusted Margin Requirement (Line 2 + Line 7)	$ 404,713,997	$ 256,873,990	$ 17,171,525	$ 1,048,249	$ 7,790,224	$ 24,805,831	$ 53,009,617	$ 17,947,346	$ 203,017	8
9	Margin at One-Half System Rate of Return	$ 309,657,887	$ 222,024,509	$ 14,105,860	$ 609,324	$ 0	$ 16,419,821	$ 24,688,892	$ 7,618,860	$ 132,928	9
10	Greater of Percentage Increase or One-Half System Rate of Return	$ 404,713,997	$ 256,873,990	$ 17,171,525	$ 1,048,249	$ 7,790,224	$ 24,805,831	$ 53,009,617	$ 17,947,346	$ 203,017	10
11	(Over) / Under Collection [3]	(11,038,891)	(7,353,719)	(491,582)	(30,009)	(223,016)	(710,135)	(1,517,545)	(513,792)	(5,812)	11
12	Margin Requirement (Greater of Line 9 or Line 10 plus Line 11)	$ 393,675,127	$ 249,520,271	$ 16,679,943	$ 1,018,240	$ 7,567,208	$ 24,095,696	$ 51,492,072	$ 17,433,554	$ 197,205	12
13	Proposed Class Margin Requirement	$ 393,675,106	$ 249,520,251	$ 16,679,943	$ 1,018,240	$ 7,567,208	$ 24,095,696	$ 51,492,072	$ 17,433,554	$ 197,205	13
14	Proposed Dollar Increase in Margin	$ 70,809,128	$ 52,939,973	$ 3,255,642	$ 134,384	$ 2,152,173	$ 3,745,453	$ 5,248,684	$ 1,577,963	$ 29,989	14
15	Proposed Percentage Increase in Margin	21.93%	26.93%	24.25%	15.20%	39.74%	18.40%	11.35%	9.95%	17.93%	15
16	Rate of Return at Present Rates	4.78%	2.22%	3.46%	14.36%	-7.1%	9.63%	21.97%	25.91%	10.25%	16
17	Present Rate of Return Indices	1.00	0.46	0.72	3.00	(1.49)	2.01	4.60	5.42	2.14	17
18	Rate of Return at Proposed Rates	9.40%	7.00%	8.80%	18.95%	-3.5%	14.23%	26.03%	29.83%	14.99%	18
19	Proposed Rate of Return Indices	1.00	0.74	0.94	2.02	(0.37)	1.51	2.77	3.17	1.60	19

[1] Class margin required to earn proposed overall system rate of return on rate base.
[2] Schedule H-2, Sheets 4-8.
[3] Difference between total magin required and Line 10, Column (b) prorated to classes as a percentage of margin on Line 10.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
ALLOCATION OF PROPOSED MARGIN TO CUSTOMER CLASSES
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Total (b)	Street Lighting (c)	Small CNG (d)	Large CNG (e)	Residential CNG (f)	Electric Generation (g)	Essential Agricultural (h)	Gas Engines (i)	Optional and Special Contract (j)	Other Revenue (k)	Line No.
1	Margin at Requested System Rate of Return [1]	$ 393,675,106	$ 39,197	$ 22,820	$ 332,735	$ 34,168	$ 1,198,508	$ 610,281	$ 3,742,106	$ 7,678,169	$ 11,434,480	1
2	Margin at Present Rates [2]	$ 322,865,978	$ 47,592	$ 29,537	$ 307,716	$ 21,167	$ 1,405,352	$ 605,972	$ 3,733,422	$ 7,611,429	$ 10,183,883	2
3	Difference (Line 1 minus Line 2)	$ 70,809,128										3
4	System Average Percentage Increase (Line 3 / Line 2)	21.93143%										4
5	Ratio of Margin at System Return to Margin at Present Rates (Line 1 / Line 2)		0.82360	0.77260	1.08131	1.61421	0.85282	1.00711	1.00233	n/a	n/a	5
6	Adjusted Percentage Increase (Line 4 X Line 5)		18.06279%	16.94422%	23.71460%	35.40197%	18.70349%	22.08740%	2.94715%	n/a	n/a	6
7	Adjusted Percentage Increase $ (Line 2 X Line 6)	$ 81,848,019	$ 8,596	$ 5,005	$ 72,974	$ 7,494	$ 262,850	$ 133,843	$ 110,030	$ 66,740	$ 1,250,597	7
8	Adjusted Margin Requirement (Line 2 + Line 7)	$ 404,713,997	$ 56,188	$ 34,542	$ 380,690	$ 28,661	$ 1,668,202	$ 739,815	$ 3,843,452	$ 7,678,169	$ 11,434,480	8
9	Margin at One-Half System Rate of Return	$ 309,657,887	$ 35,829	$ 18,769	$ 272,630	$ 27,860	$ 962,379	$ 479,569	$ 3,148,009	$ 7,678,169	$ 11,434,480	9
10	Greater of Percentage Increase or One-Half System Rate of Return	$ 404,713,997	$ 56,188	$ 34,542	$ 380,690	$ 28,661	$ 1,668,202	$ 739,815	$ 3,843,452	$ 7,678,169	$ 11,434,480	10
11	(Over) / Under Collection [3]	(11,038,891)	(1,609)	(989)	(10,898)	(820)	(47,757)	(21,179)	(110,029)	0	0	11
12	Margin Requirement (Greater of Line 9 or Line 10 plus Line 11)	$ 393,675,127	$ 54,580	$ 33,553	$ 369,791	$ 27,860	$ 1,620,445	$ 718,636	$ 3,733,422	$ 7,678,169	$ 11,434,480	12
13	Proposed Class Margin Requirement	$ 393,675,106	$ 54,580	$ 33,553	$ 369,791	$ 27,860	$ 1,620,445	$ 718,636	$ 3,733,422	$ 7,678,169	$ 11,434,480	13
14	Proposed Dollar Increase in Margin	$ 70,809,128	$ 6,988	$ 4,016	$ 62,075	$ 6,693	$ 215,093	$ 112,664	$ 0	$ 66,740	$ 1,250,597	14
15	Proposed Percentage Increase in Margin	21.93%	14.68%	13.60%	20.17%	31.62%	15.31%	18.59%	0.00%	0.88%	12.28%	15
16	Rate of Return at Present Rates	4.78%	23.29%	17.89%	7.52%	-0.7%	13.93%	9.41%	9.55%	n/a	n/a	16
17	Present Rate of Return Indices	1.00	4.87	3.74	1.57	(0.14)	2.91	1.97	2.00	n/a	n/a	17
18	Rate of Return at Proposed Rates	9.40%	34.04%	20.24%	12.74%	3.54%	18.28%	13.50%	9.54%	n/a	n/a	18
19	Proposed Rate of Return Indices	1.00	3.62	2.15	1.36	0.38	1.95	1.44	1.02	n/a	n/a	19

[1] Class margin required to earn proposed overall system rate of return on rate base.
[2] Schedule H-2, Sheets 4-8.
[3] Difference between total magin required and Line 10, Column (b) prorated to classes as a percentage of margin on Line 10.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF REVENUES AT PROPOSED RATES BY PROPOSED RATE SCHEDULES
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Reference (b)	Proposed Schedule Number (b)	Billing Determinants: Number of Bills (c)	Billing Determinants: Sales (Therms) (d)	Basic Service Charge (e)	Commodity Charge (f)	Revenue at Proposed Rates: Basic Service Charge (g)	Revenue at Proposed Rates: Commodity Charge (h)	Total Margin (i)	Gas Cost [1] (j)	Total Revenue (k)	Line No.
	Single-Family Residential Gas Service		G-5										
	Summer (April - November)												
1	Basic Service Charge per Month			5,834,248		$ 12.00		$ 70,010,976		$ 70,010,976		$ 70,010,976	1
	Commodity Charge per Therm												
2	First 8 Therms				40,157,005		$ 0.84286		$ 33,846,733	33,846,733	$ 21,458,297	55,305,030	2
3	Over 8 Therms				50,747,308		0.25000		12,686,827	12,686,827	27,117,331	39,804,158	3
	Winter (December - March)												
4	Basic Service Charge per Month			2,974,733		$ 12.00		$ 35,696,796		$ 35,696,796		$ 35,696,796	4
	Commodity Charge per Therm												
5	First 30 Therms				78,149,816		0.84286		65,869,354	65,869,354	41,760,136	107,629,490	5
6	Over 30 Therms				91,119,021		0.25000		22,779,755	22,779,755	48,690,360	71,470,115	6
7	Total Single-Family Residential Gas Service			8,808,981	260,173,149			$ 105,707,772	$ 135,182,669	$ 240,890,441	$ 139,026,124	$ 379,916,565	7
	Low Income Residential Gas Service		G-5										
	Summer (April - November)												
8	Basic Service Charge			211,472		$ 12.00		$ 2,537,664		$ 2,537,664		$ 2,537,664	8
	Commodity Charge per Therm												
	Summer (May - October)												
9	First 8 Therms				1,491,739		$ 0.84286		$ 1,257,327	1,257,327	$ 797,125	2,054,452	9
10	Over 8 Therms				1,748,440		0.25000		437,110	437,110	934,297	1,371,407	10
	Winter (December - March)												
11	Basic Service Charge per Month			107,196		$ 12.00		$ 1,286,352		$ 1,286,352		$ 1,286,352	11
	Commodity Charge per Therm												
12	First 30 Therms				2,567,923		0.84286		2,164,399	2,164,399	1,372,195	3,536,594	12
13	Over 30 Therms				3,544,314		0.25000		886,078	886,078	1,893,939	2,780,017	13
14	Total Low Income Residential Gas Service			318,668	9,352,415			$ 3,824,016	$ 4,744,914	$ 8,568,930	$ 4,997,556	$ 13,566,486	14
	Multi-Family Residential Gas Service		G-6										
	Summer (April - November)												
15	Basic Service Charge per Month			456,582		$ 11.00		$ 5,022,402		$ 5,022,402		$ 5,022,402	15
	Commodity Charge per Therm												
16	First 7 Therms				2,901,893		$ 0.84286		$ 2,445,890	2,445,890	$ 1,550,656	3,996,546	16
17	Over 7 Therms				3,177,201		0.25000		794,300	794,300	1,697,769	2,492,069	17
	Winter (December - March)												
18	Basic Service Charge per Month			233,245		$ 11.00		$ 2,565,695		$ 2,565,695		$ 2,565,695	18
	Commodity Charge per Therm												
19	First 18 Therms				4,364,020		0.84286		3,678,258	3,678,258	2,331,958	6,010,216	19
20	Over 18 Therms				4,229,516		0.25000		1,057,379	1,057,379	2,260,084	3,317,463	20
21	Total Multi-Family Residential Gas Service			689,827	14,672,630			$ 7,588,097	$ 7,975,827	$ 15,563,924	$ 7,840,467	$ 23,404,391	21
	Multi-Family Low Income Residential Gas Service		G-6										
	Summer (April - November)												
22	Basic Service Charge per Month			33,599		$ 11.00		$ 369,589		$ 369,589		$ 369,589	22
	Commodity Charge per Therm												
23	First 7 Therms				208,053		$ 0.84286		$ 175,360	175,360	$ 111,175	286,535	23
24	Over 7 Therms				254,839		0.25000		63,710	63,710	136,176	199,886	24
	Winter (December - March)												
25	Basic Service Charge per Month			17,488		$ 11.00		$ 192,368		$ 192,368		$ 192,368	25
	Commodity Charge per Therm												
26	First 18 Therms				327,920		0.84286		276,390	276,390	175,227	451,617	26
27	Over 18 Therms				396,818		0.25000		99,205	99,205	212,044	311,249	27
28	Total Low Income Multi-Family Residential Gas Service			51,087	1,187,630			$ 561,957	$ 614,665	$ 1,176,622	$ 634,622	$ 1,811,244	28
29	Total Residential Gas Service			9,868,563	285,385,824			$117,681,842	$148,518,075	$ 266,199,917	$ 152,498,769	$ 418,698,686	29
	Master Metered Mobile Home Park Gas Service		G-20										
30	Basic Service Charge per Month			2,268		$ 100.00		$ 226,800		$ 226,800		$ 226,800	30
	Commodity Charge per Therm All Usage												
31	All Usage				2,452,509		$ 0.32271		$ 791,449	791,449	1,310,523	2,101,972	31
32	Total MMMHP Gas Service			2,268	2,452,509			$ 226,800	$ 791,449	$ 1,018,249	$ 1,310,523	$ 2,328,772	32

[1] Gas cost effective August 27, 2004 without surcharges.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF REVENUES AT PROPOSED RATES BY PROPOSED RATE SCHEDULES
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

				Billing Determinants		Revenue at Proposed Rates							
Line No.	Description	Reference	Proposed Schedule Number	Number of Bills	Sales (Therms)	Basic Service Charge	Commodity Charge	Basic Service Charge	Commodity Charge	Total Margin	Gas Cost [1]	Total Revenue	Line No.
	(a)	(b)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
	General Gas Service - Small		G-25(S)										
	Basic Service Charge												
1	Former Small GS Customers			197,811		$ 25.00		$ 4,945,275		$ 4,945,275		$ 4,945,275	1
2	Former Medium GS Customers			96		$ 25.00		$ 2,400		$ 2,400		$ 2,400	2
3	Former Essential Agiculture Customers			144		$ 25.00		$ 3,600		$ 3,600		$ 3,600	3
	Commodity Charge per Therm All Usage												
4	Transportation Customers				629		$ 0.69076		$ 434	434	$ 0	434	4
5	Sales Customers				3,786,431		0.69076		2,615,515	$ 2,615,515	2,023,317	4,638,832	5
6	Total Small General Gas Service			198,051	3,787,060			$ 4,951,275	$ 2,615,949	$ 7,567,224	$ 2,023,317	$ 9,590,541	6
	General Gas Service - Medium		G-25(M)										
	Basic Service Charge												
7	Former Small GS Customers			191,331		$ 35.00		$ 6,696,585		$ 6,696,585		$ 6,696,585	7
8	Former Medium GS Customers			3,708		35.00		129,780		129,780		129,780	8
9	Former Large GS Customers			12		35.00		420		420		420	9
10	Former Armed Forces Customers			24		35.00		840		840		840	10
11	Former Essential Agriculture Customers			516		35.00		18,060		18,060		18,060	11
	Commodity Charge per Therm All Usage												
	Transportation Customers												
12	Former Small GS Customers				101,424		$ 0.40089		$ 40,660	40,660	$ 0	40,660	12
13	Former Medium GS Customers				85,250		0.40089		34,176	34,176	0	34,176	13
	Sales Customers												
14	Former Small GS Customers				40,955,338		0.40089		16,418,585	16,418,585	21,884,894	38,303,479	14
15	Former Medium GS Customers				1,745,235		0.40089		699,647	699,647	932,584	1,632,231	15
16	Former Large GS Customers				5,050		0.40089		2,024	2,024	2,699	4,723	16
17	Former Armed Forces Customers				3,847		0.40089		1,542	1,542	2,056	3,598	17
18	Former Essential Agriculture Customers				133,552		0.40089		53,540	53,540	71,365	124,905	18
19	Total Medium General Gas Service			195,591	43,029,696			6,845,685	17,250,174	24,095,859	22,893,598	46,989,457	19
	General Gas Service - Large		G-25(L)										
	Basic Service Charge												
20	Former Small GS Customers			4,375		$ 150.00		$ 656,250		$ 656,250		$ 656,250	20
21	Former Medium GS Customers			79,384		150.00		11,907,600		11,907,600		11,907,600	21
22	Former Large GS Customers			120		150.00		18,000		18,000		18,000	22
23	Former Armed Forces Customers			24		150.00		3,600		3,600		3,600	23
	Commodity Charge per Therm All Usage												
	Transportation Customers												
24	Former Small GS Customers				81,882		$ 0.27399		$ 22,435	22,435	$ 0	22,435	24
25	Former Medium GS Customers				2,696,666		0.27399		738,860	738,860	$ 0	738,860	25
26	Former Large GS Customers				316,390		0.27399		86,688	86,688	$ 0	86,688	26
	Sales Customers												
27	Former Small GS Customers				2,938,939		0.27399		805,240	805,240	$ 1,570,451	2,375,691	27
28	Former Medium GS Customers				134,740,525		0.27399		36,917,556	36,917,556	$ 71,999,947	108,917,503	28
29	Former Large GS Customers				1,055,381		0.27399		289,164	289,164	$ 563,953	853,117	29
30	Former Armed Forces Customers				168,776		0.27399		46,243	46,243	$ 90,187	136,430	30
31	Total Large General Gas Service			83,903	141,998,559			12,585,450	38,906,186	51,491,636	74,224,538	125,716,174	31
	General Gas Service - Transportation Eligible		G-25(TE)										
	Basic Service Charge												
32	Former Medium GS Customers			60		$ 750.00		$ 45,000		$ 45,000		$ 45,000	32
33	Former Essential Agricultural Service Customers			252		$ 750.00		$ 189,000		$ 189,000		$ 189,000	33
34	Former Large GS Customers			1,680		$ 750.00		$ 1,260,000		$ 1,260,000		$ 1,260,000	34
35	Former Armed Forces Customers			60		750.00		45,000		45,000		45,000	35
36	Demand Charge per Month				10,571,934	0.062645			7,947,288	7,947,288		7,947,288	36
	Commodity Charge per Therm All Usage												
	Transportation Customers												
37	Former Medium GS Customers				0		$ 0.09262		$ 0	0	$ 0	0	37
38	Former Essential Agricultural Services Customers				4,434,348		$ 0.09262		$ 410,709	410,709	$ 0	410,709	38
39	Former Large GS Customers				25,832,133		0.09262		2,392,572	2,392,572	$ 0	2,392,572	39
	Sales Customers												
40	Former Medium GS Customers				1,016,137		0.09262		94,115	94,115	$ 542,983	637,098	40
41	Former Essential Agricultural Services Customers				5,063,922		0.09262		469,020	469,020	$ 2,705,957	3,174,977	41
42	Former Large GS Customers				46,460,065		0.09262		4,303,131	4,303,131	$ 24,826,400	29,129,531	42
43	Former Armed Forces Customers				2,994,890		0.09262		277,387	277,387	$ 1,600,349	1,877,736	43
44	Total Transportation Eligible General Gas Service			2,052	85,801,495			$ 1,539,000	$ 15,894,222	$ 17,433,222	$ 29,675,689	$ 47,108,911	44
45	Total General Gas Service			479,597	274,616,810			$ 25,921,410	$ 74,666,531	$ 100,587,941	$ 128,817,142	$ 229,405,083	45

[1] Gas cost effective August 27, 2004 without surcharges.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF REVENUES AT PROPOSED RATES BY PROPOSED RATE SCHEDULES
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Reference (b)	Proposed Schedule Number (b)	Billing Determinants: Number of Bills (c)	Billing Determinants: Sales (Therms) (d)	Basic Service Charge (e)	Commodity Charge (f)	Revenue at Proposed Rates: Basic Service Charge (g)	Revenue at Proposed Rates: Commodity Charge (h)	Total Margin (i)	Gas Cost [1] (j)	Total Revenue (k)	Line No.
	Air Conditioning Gas Service		G-40										
	Basic Service Charge												
1	W/ Other Service (No BSC)			60		0.00		0		0		0	1
2	Basic Service Charge			389		$ 25.00		$ 9,725		$ 9,725		$ 9,725	2
	Commodity Charge per Therm All Usage												
3	Transportation Customers				628,909		$ 0.10208		$ 64,199	64,199	$ 0	64,199	3
4	Sales Customers				1,207,635		0.10208		123,276	123,276	645,312	768,587	4
5	Total Air Conditioning Gas Service			449	1,836,544			$ 9,725	$ 187,474	$ 197,199	$ 645,312	$ 842,511	5
	Street Lighting Gas Service		G-45										
	Commodity Charge per Therm of Rated Capacity												
6	All Usage			348	99,883		$ 0.54644		$ 54,580	54,580	53,373	107,953	6
7	Total Street Lighting Gas Service			348	99,883			$ 0	$ 54,580	$ 54,580	$ 53,373	$ 107,953	7
	Gas Service for Compression on Customer's Premises		G-55										
	Basic Service Charge												
8	Small			264		$ 25.00		$ 6,600		$ 6,600		$ 6,600	8
9	Large			324		350.00		113,400		113,400		113,400	9
10	Residential			1,320		12.00		15,840		15,840		15,840	10
	Commodity Charge per Therm All Usage												
11	Transportation Customers				0		$ 0.13669		$ 0	0	$ 0	0	11
	Sales Customers												
12	Small				182,313		0.13669		$ 24,920	24,920	$ 97,421	122,341	12
13	Large				1,898,808		0.13669		$ 259,548	259,548	$ 1,014,647	1,274,195	13
14	Residential				79,719		0.13669		$ 10,897	10,897	$ 42,599	53,496	14
15	Total CNG Gas Service			1,908	2,160,840			$ 135,840	$ 295,365	$ 431,205	$ 1,154,667	$ 1,585,872	15
	Electric Generation Gas Service		G-60										
	Basic Service Charge												
16	General Service - Small			60		$ 25.00		$ 1,500		$ 1,500		$ 1,500	16
17	General Service - Medium			0		$ 35.00		$ 0		$ 0		$ 0	17
18	General Service - Large			96		150.00		14,400		14,400		14,400	18
19	General Service - Transportation Eligible			96		750.00		72,000		72,000		72,000	19
20	Essential Agricultural			24		150.00		3,600		3,600		3,600	20
	Commodity Charge per Therm All Usage												
21	Transportation Customers				0		$ 0.10188		$ 0	0	$ 0	0	21
22	Sales Customers				15,007,742		0.10188		1,528,989	1,528,989	6,564,687	8,093,676	22
23	Total Electric Generation Gas Service			276	15,007,742			$ 91,500	$ 1,528,989	$ 1,620,489	$ 6,564,687	$ 8,185,176	23
	Small Essential Agriculture User Gas Service		G-75										
24	Basic Service Charge			435		$ 150.00		$ 65,250		$ 65,250		$ 65,250	24
	Commodity Charge per Therm All Usage												
25	Transportation Customers				155,893		$ 0.22186		$ 34,586	34,586	$ 0	34,586	25
26	Sales Customers				2,789,183		0.22186		618,808	618,808	1,490,428	2,109,236	26
27	Total Essential Agricultural Gas Service			435	2,945,076			$ 65,250	$ 653,394	$ 718,644	$ 1,490,428	$ 2,209,072	27
	Natural Gas Engine Gas Service		G-80										
	Basic Service Charge												
28	Off-Peak Season (Oct. - March)			3,623		$ 0.00		$ 0		$ 0		$ 0	28
29	Peak Season (April - September)			3,623		100.00		362,250		362,250		362,250	29
	Commodity Charge per Therm All Usage												
30	Transportation Customers				0		$ 0.15848		$ 0	0	$ 0	0	30
31	Sales Customers				21,271,370		0.15848		3,371,087	3,371,087	9,304,523	12,675,610	31
32	Total Natural Gas Engine Gas Service			7,245	21,271,370			$ 362,250	$ 3,371,087	$ 3,733,337	$ 9,304,523	$ 13,037,860	32
33	Total Tariff Sales			10,361,089	605,776,598			144,494,617	230,066,944	374,561,561	301,839,424	676,400,985	33
34	Optional Gas Service		G-30	324	101,647,104			$ 510,740	$ 5,032,592	5,543,332	$ 55,931,796	$ 61,475,128	34
35	Special Contract Service		B-1	271	30,410,785			$ 184,703	$ 1,950,134	$ 2,134,837		$ 2,134,837	35
36	Other Operating Revenues							$ 11,434,480		$ 11,434,480		$ 11,434,480	36
37	Total Revenue			10,361,684	737,834,487			$ 156,624,540	$ 237,049,670	$ 393,674,210	$ 357,771,220	$ 751,445,430	37
38	Total Revenue Requirement									393,675,099	357,771,220	751,446,319	38
39	Over/(Under)									($889)	$ 0	($889)	39

[1] Gas cost effective August 27, 2004 without surcharges.

SOUTHWEST GAS CORPORATION
ARIZONA
CALCULATION OF MONTHLY BASIC SERVICE CHARGE

		Allocated Amount							
Line No.	Description	Residential	Multi-Family Residential	MMMHP	Small General Service	Medium General Service	Large General Service	Transportation Eligible	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	
1	Total Customer-Related Revenue Requirement at Proposed System ROR	$ 239,626,944	$ 15,297,050	$ 398,481	$ 14,827,050	$ 15,455,769	$ 12,234,190	$ 1,549,246	1
2	Total Number of Monthly Bills	9,127,649	740,914	2,268	198,051	195,591	83,903	2,052	2
3	Average Customer-Related Cost per Bill	$ 26.25	$ 20.65	$ 175.70	$ 74.86	$ 79.02	$ 145.81	$ 754.99	3
4	Total Commodity-Related Revenue Requirement at Proposed System ROR	$ 8,517,018	$ 501,185	$ 77,499	$ 119,671	$ 1,359,740	$ 4,487,160	$ 2,711,331	4
5	Total Demand-Related Revenue Requirement at Proposed System ROR	$ 29,221,862	$ 1,370,219	$ 259,984	$ 453,668	$ 3,341,630	$ 12,993,803	$ 4,834,747	5
6	Total Annual Throughput	269,525,564	15,860,260	2,452,509	3,787,060	43,029,696	141,998,559	85,801,495	6
7	Average Commodity Cost per Therm	$ 0.03160	$ 0.03160	$ 0.03160	$ 0.03160	$ 0.03160	$ 0.03160	$ 0.03160	7
8	Average Demand Cost per Therm	$ 0.10842	$ 0.08639	$ 0.10601	$ 0.11979	$ 0.07766	$ 0.09151	$ 0.05635	8
9	Average Annual Cost per Customer	$ 364.65	$ 278.06	$ 3,893.99	$ 933.12	$ 1,236.69	$ 4,249.93	$ 53,189.02	9
10	Per Month	$ 30.39	$ 23.17	$ 324.50	$ 77.76	$ 103.06	$ 354.16	$ 4,432.42	10

SOUTHWEST GAS CORPORATION
ARIZONA
CALCULATION OF MONTHLY BASIC SERVICE CHARGE

Line No.	Description (a)	Air Conditioning (b)	CNG - Small (c)	CNG - Large (d)	CNG - Residential (e)	Electric Generation (f)	Small Essential Agriculture (g)	Gas Engine (h)	Line No.
1	Total Customer-Related Revenue Requirement at Proposed System ROR	$ 71,896	$ 9,283	$ 206,263	$ 28,823	$ 76,739	$ 111,777	$ 3,008,753	1
2	Total Number of Monthly Bills	449	264	324	1,320	276	435	7,245	2
3	Average Customer-Related Cost per Bill	$ 160.12	$ 35.16	$ 636.61	$ 21.84	$ 278.04	$ 256.96	$ 415.29	3
4	Total Commodity-Related Revenue Requirement at Proposed System ROR	$ 58,035	$ 5,761	$ 60,002	$ 2,519	$ 474,245	$ 93,065	$ 672,176	4
5	Total Demand-Related Revenue Requirement at Proposed System ROR	$ 31,820	$ 7,209	$ 65,369	$ 3,321	$ 626,190	$ 400,948	$ 33,077	5
6	Total Annual Throughput	1,836,544	182,313	1,898,808	79,719	15,007,742	2,945,076	21,271,370	6
7	Average Commodity Cost per Therm	$ 0.03160	$ 0.03160	$ 0.03160	$ 0.03160	$ 0.03160	$ 0.03160	$ 0.03160	7
8	Average Demand Cost per Therm	$ 0.01733	$ 0.03954	$ 0.03443	$ 0.04166	$ 0.04172	$ 0.13614	$ 0.00155	8
9	Average Annual Cost per Customer	$ 4,322.98	$ 1,011.50	$ 12,282.75	$ 315.12	$ 51,181.48	$ 16,711.43	$ 6,151.56	9
10	Per Month	$ 360.25	$ 84.29	$ 1,023.56	$ 26.26	$ 4,265.12	$ 1,392.62	$ 512.63	10

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF
ALTERNATE FUEL BTU
EQUIVALENT PRICE COMPARISON
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Value [1] (b)	Line No.
	No. 4 Grade Fuel Oil		
1	Price/Barrel	N/A	1
2	Price/Gallon	N/A	2
3	BTU Content/Gallon	144,503	3
4	Price Per 100,000 BTU	N/A	4
	No. 2 Grade Fuel Oil (Diesel)		
5	Price/Gallon	$ 1.42550	5
6	BTU Content/Gallon	138,750	6
7	Price Per 100,000 BTU	$ 1.02739	7
	Propane		
8	Price/Gallon	$ 1.03500	8
9	BTU Content/Gallon	91,500	9
10	Price Per 100,000 BTU	$ 1.13115	10

Explanation:
No. 4 Fuel Oil - A medium viscosity oil. May require preheating.

No. 2 Fuel Oil - For general industrial purposes. Moderately volatile.

[1] Does not include handling/storage costs.

SOUTHWEST GAS CORPORATION
ARIZONA
CALCULATION OF MONTHLY MARGIN PER CUSTOMER
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	September-03 (b)	October-03 (c)	November-03 (d)	December-03 (e)	January-04 (f)	February-04 (g)	March-04 (h)	April-04 (i)	May-04 (j)	June-04 (k)	July-04 (l)	August-04 (m)	Total (n)	Line No.
	Single-Family Residential														
	Monthly Billing Determinants														
1	Single-Family Customers	752,725	753,914	758,264	770,966	773,785	771,771	772,788	765,775	760,618	758,147	756,240	754,194	9,149,187	1
2	Low-Income Customers	28,939	28,977	28,979	28,866	29,050	28,905	29,019	28,717	28,488	28,081	27,543	28,309	343,873	2
3	Special Res.	157	157	157	157	157	157	157	157	157	157	157	157	1,884	3
4	Less Multi-Family Adjustment	(31,799)	(31,373)	(26,914)	(31,003)	(30,943)	(30,936)	(30,967)	(30,870)	(30,704)	(30,656)	(30,570)	(30,560)	(367,295)	4
5	Customers	750,022	751,675	760,486	768,986	772,049	769,897	770,997	763,779	758,559	755,729	753,370	752,100	9,127,649	5
6	First Block Volumes	4,806,377	5,015,586	5,521,030	19,550,464	21,147,945	20,434,521	19,584,808	5,818,599	5,573,855	5,220,906	4,952,210	4,740,180	122,366,482	6
7	Second Block Volumes	3,000,242	3,803,873	9,088,851	20,247,873	35,750,712	22,827,837	15,836,912	16,347,913	8,604,963	5,122,148	3,670,744	2,857,015	147,159,082	7
8	Total Volume	7,806,619	8,819,459	14,609,881	39,798,337	56,898,657	43,262,358	35,421,720	22,166,512	14,178,818	10,343,054	8,622,954	7,597,195	269,525,564	8
	Proposed Margin Rates														
9	Basic Service Charge	$ 12.00	$ 12.00	$ 12.00	$ 12.00	$ 12.00	$ 12.00	$ 12.00	$ 12.00	$ 12.00	$ 12.00	$ 12.00	$ 12.00		9
10	First Block Margin Rate	$ 0.84286	$ 0.84286	$ 0.84286	$ 0.84286	$ 0.84286	$ 0.84286	$ 0.84286	$ 0.84286	$ 0.84286	$ 0.84286	$ 0.84286	$ 0.84286		10
11	Second Block Margin Rate	0.25000	0.25000	0.25000	0.25000	0.25000	0.25000	0.25000	0.25000	0.25000	0.25000	0.25000	0.25000		11
	Proposed Margin														
12	First Block Margin Revenue	$ 4,051,103	$ 4,227,437	$ 4,653,455	$ 16,478,304	$ 17,824,757	$ 17,223,440	$ 16,507,252	$ 4,904,264	$ 4,697,979	$ 4,400,493	$ 4,174,020	$ 3,995,308	$ 103,137,813	12
13	Second Block Margin Revenue	750,060	950,968	2,272,213	5,061,968	8,937,678	5,706,959	3,959,228	4,086,978	2,151,241	1,280,537	917,686	714,254	36,789,771	13
14	Basic Service Charge Revenue	9,000,264	9,020,100	9,125,832	9,227,832	9,264,588	9,238,764	9,251,964	9,165,348	9,102,708	9,068,748	9,040,440	9,025,200	109,531,788	14
15	Total Margin Revenue	13,801,428	14,198,505	16,051,500	30,768,104	36,027,023	32,169,164	29,718,443	18,156,591	15,951,928	14,749,778	14,132,146	13,734,762	249,459,372	15
16	Margin per Customer	$ 18.40	$ 18.89	$ 21.11	$ 40.01	$ 46.66	$ 41.78	$ 38.55	$ 23.77	$ 21.03	$ 19.52	$ 18.76	$ 18.26	$ 326.74	16
	Multi-Family Residential														
	Monthly Billing Determinants														
17	Customers	28,350	28,569	28,727	29,204	29,573	29,544	29,719	29,314	29,032	28,806	28,583	28,316	347,737	17
18	Low-Income Customers	2,173	2,173	2,189	2,190	2,220	2,229	2,205	2,180	2,136	2,064	2,011	2,112	25,882	18
19	Plus Multi-Family Adjustment	31,799	31,373	26,914	31,003	30,943	30,936	30,967	30,870	30,704	30,656	30,570	30,560	367,295	19
20	Customers	62,322	62,115	57,830	62,397	62,736	62,709	62,891	62,364	61,872	61,526	61,164	60,988	740,914	20
21	First Block Volumes	361,763	379,417	411,296	1,144,942	1,231,475	1,195,683	1,119,839	459,644	416,894	375,774	358,808	346,351	7,801,886	21
22	Second Block Volumes	267,704	314,898	554,419	1,059,494	1,681,808	1,101,052	783,979	851,739	519,220	377,536	299,249	247,275	8,058,374	22
23	Total Volume	629,467	694,315	965,715	2,204,437	2,913,283	2,296,736	1,903,818	1,311,382	936,114	753,310	658,057	593,626	15,860,260	23
	Proposed Margin Rates														
24	Basic Service Charge	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00	$ 11.00		24
25	First Block Margin Rate	$ 0.84286	$ 0.84286	$ 0.84286	$ 0.84286	$ 0.84286	$ 0.84286	$ 0.84286	$ 0.84286	$ 0.84286	$ 0.84286	$ 0.84286	$ 0.84286		25
26	Second Block Margin Rate	0.25000	0.25000	0.25000	0.25000	0.25000	0.25000	0.25000	0.25000	0.25000	0.25000	0.25000	0.25000		26
	Proposed Margin														
27	First Block Margin Revenue	$ 304,915	$ 319,796	$ 346,665	$ 965,026	$ 1,037,961	$ 1,007,794	$ 943,867	$ 387,415	$ 351,383	$ 316,725	$ 302,425	$ 291,925	$ 6,575,898	27
28	Second Block Margin Revenue	66,926	78,724	138,605	264,874	420,452	275,263	195,995	212,935	129,805	94,384	74,812	61,819	2,014,593	28
29	Basic Service Charge Revenue	685,542	683,265	636,130	686,367	690,096	689,799	691,801	686,004	680,592	676,786	672,804	670,868	8,150,054	29
30	Total Margin Revenue	1,057,383	1,081,785	1,121,400	1,916,267	2,148,509	1,972,856	1,831,663	1,286,354	1,161,780	1,087,895	1,050,041	1,024,612	16,740,545	30
31	Margin per Customer	$ 16.97	$ 17.42	$ 19.39	$ 30.71	$ 34.25	$ 31.46	$ 29.12	$ 20.63	$ 18.78	$ 17.68	$ 17.17	$ 16.80	$ 270.37	31
	MMMHP														
	Monthly Billing Determinants														
32	Customers	189	189	189	189	189	189	189	189	189	189	189	189	2,268	32
33	Therms	476,710	382,858	301,624	215,328	135,235	90,420	77,417	66,248	66,671	81,440	168,361	390,197	2,452,509	33
	Proposed Margin Rates														
34	Basic Service Charge Revenue	$ 100.00	$ 100.00	$ 100.00	$ 100.00	$ 100.00	$ 100.00	$ 100.00	$ 100.00	$ 100.00	$ 100.00	$ 100.00	$ 100.00		34
35	Margin Rate All Usage	$ 0.32271	$ 0.32271	$ 0.32271	$ 0.32271	$ 0.32271	$ 0.32271	$ 0.32271	$ 0.32271	$ 0.32271	$ 0.32271	$ 0.32271	$ 0.32271		35
	Proposed Margin														
36	Commodity Margin Revenue	$ 153,839	$ 123,552	$ 97,337	$ 69,488	$ 43,642	$ 29,179	$ 24,983	$ 21,379	$ 21,515	$ 26,282	$ 54,332	$ 125,920		36
37	Basic Service Charge Revenue	18,900	18,900	18,900	18,900	18,900	18,900	18,900	18,900	18,900	18,900	18,900	18,900		37
38	Total Margin Revenue	172,739	142,452	116,237	88,388	62,542	48,079	43,883	40,279	40,415	45,182	73,232	144,820	1,018,249	38
39	Margin per Customer	$ 913.96	$ 753.71	$ 615.01	$ 467.66	$ 330.91	$ 254.39	$ 232.19	$ 213.12	$ 213.84	$ 239.06	$ 387.47	$ 766.25	$ 5,387.56	39

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF LOW INCOME DISCOUNT AT PRESENT AND PROPOSED RATES
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Proposed Schedule Number (b)	Billing Determinants: Number of Bills (c)	Billing Determinants: Sales (Therms) (d)	Total Revenue Before Discount: Basic Service Charge (e)	Total Revenue Before Discount: Commodity Charge (f)	Total Revenue Before Discount: Total Revenue (k)	Total Revenue After Discount: Basic Service Charge (e)	Total Revenue After Discount: Commodity Charge (f)	Total Revenue After Discount: Total Revenue (k)	Low Income Discount: Dollars (m)	Low Income Discount: Percent (n)	Line No.
	Low Income Discount at Present Rates												
	Single-Family Residential Gas Service	G-5											
	Summer (May - October)												
1	Basic Service Charge		157,760		$ 8.00		$ 1,262,080	$ 7.00		$ 1,104,320	$ (157,760)		1
	Commodity Charge per Therm												
2	First 20 Therms			1,730,125		$ 1.02198	1,768,153		$ 1.02684	1,776,561	8,408		2
3	Over 20 Therms			206,560		0.93780	193,712		0.94266	194,716	1,004		3
	Winter (November - April)												
4	Basic Service Charge per Month		160,908		$ 8.00		$ 1,287,264	$ 7.00		$ 1,126,356	(160,908)		4
	Commodity Charge per Therm												
5	First 40 Therms			4,798,664		1.02198	4,904,139		0.82147	3,941,959	(962,180)		5
6	Next 110 Therms			2,544,434		0.93780	2,386,170		0.75413	1,918,834	(467,336)		6
7	Over 150 Therms			72,632		0.93780	68,114		0.94266	68,467	353		7
8	Total Low Income Residential Gas Service		318,668	9,352,415			$ 11,869,632			$ 10,131,213	(1,738,419)	-14.65%	8
	Multi-Family Residential Gas Service	G-6											
	Summer (May - October)												
9	Basic Service Charge per Month		25,246		$ 8.00		$ 201,968	$ 7.00		$ 176,722	$ (25,246)		9
	Commodity Charge per Therm												
10	First 20 Therms			266,008		$ 1.02198	271,855		$ 1.02684	273,148	1,293		10
11	Over 20 Therms			31,728		0.93780	29,754		0.94266	29,908	154		11
	Winter (November - April)												
12	Basic Service Charge per Month		25,841		$ 8.00		$ 206,728	$ 7.00		$ 180,887	(25,841)		12
	Commodity Charge per Therm												
13	First 40 Therms			727,993		1.02198	743,994		0.82147	598,024	(145,970)		13
14	Next 110 Therms			159,565		0.93780	149,640		0.75413	120,333	(29,307)		14
15	Over 150 Therms			2,336		0.93780	2,191		0.94266	2,202	11		15
16	Total Low Income Multi-Family Residential Gas Service		51,087	1,187,630			$ 1,606,130			$ 1,381,224	(224,906)	-14.00%	16
17	Total Low Income Residential Gas Service at Present Rates		369,755	10,540,045			$ 13,475,762			$ 11,512,437	$ (1,963,325)	-14.57%	17
	Low Income Discount at Proposed Rates												
	Single-Family Residential Gas Service	G-5											
	Summer (April - November)												
18	Basic Service Charge		211,472		$ 12.00		$ 2,537,664	$ 7.00		$ 1,480,304	$ (1,057,360)		18
	Commodity Charge per Therm												
19	First 8 Therms			1,491,739		$ 1.39693	2,083,854		$ 1.17679	1,755,463	(328,391)		19
20	Over 8 Therms			1,748,440		0.80407	1,405,868		0.67286	1,176,455	(229,413)		20
	Winter (December - March)												
21	Basic Service Charge per Month		107,196		$ 12.00		$ 1,286,352	$ 7.00		$ 750,372	(535,980)		21
	Commodity Charge per Therm												
22	First 30 Therms			2,567,923		1.39693	3,587,208		1.17679	3,021,906	(565,302)		22
23	Over 30 Therms			3,544,314		0.80407	2,849,876		0.67286	2,384,827	(465,049)		23
24	Total Low Income Residential Gas Service		318,668	9,352,415			13,750,822			10,569,327	(3,181,495)	-23.14%	24
	Multi-Family Residential Gas Service	G-6											
	Summer (April - November)												
25	Basic Service Charge per Month		33,599		$ 11.00		$ 369,589	$ 7.00		$ 235,193	$ (134,396)		25
	Commodity Charge per Therm												
26	First 7 Therms			208,053		$ 1.39693	290,636		$ 1.17679	244,835	(45,801)		26
27	Over 7 Therms			254,839		0.80407	204,908		0.67286	171,471	(33,437)		27
	Winter (December - March)												
28	Basic Service Charge per Month		17,488		$ 11.00		$ 192,368	$ 7.00		$ 122,416	(69,952)		28
	Commodity Charge per Therm												
29	First 18 Therms			327,920		1.39693	458,081		1.17679	385,893	(72,188)		29
30	Over 18 Therms			396,818		0.80407	319,069		0.67286	267,003	(52,066)		30
31	Total Low Incom Multi-Family Residential Gas Service		51,087	1,187,630			1,834,651			1,426,811	(407,840)	-22.23%	31
32	Total Low Income Residential Gas Service at Proposed Rates		369,755	10,540,045			$ 15,585,473			$ 11,996,138	$ (3,589,335)	-23.03%	32
	Total Proposed Increase to Low Income Customers												
33	Dollars									$ 483,701			33
34	Percent									4.20%			34

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PROPOSED vs. CURRENTLY EFFECTIVE RATES INCLUDING DISCOUNT
LOW-INCOME SINGLE-FAMILY RESIDENTIAL GAS SERVICE

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill: At Currently Effective Rates	Monthly Bill: At Proposed Tariff Rates	Increase/(Decrease): Dollars	Increase/(Decrease): Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	11	18.30	$ 18.43	$ 0.13	0.71%	1
2	Average Summer Use [1]	15	22.40	$ 21.12	(1.28)	(5.71%)	2
3	125 Percent Average Use	19	26.51	$ 23.82	(2.69)	(10.15%)	3
	Winter Season Bills						
4	75 Percent Average Use	43	42.12	$ 51.05	$ 8.93	21.20%	4
5	Average Winter Use [1]	57	52.68	$ 60.47	7.79	14.79%	5
6	125 Percent Average Use	71	63.24	$ 69.89	6.65	10.52%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge per Month	$ 7.00
Commodity Charge Summer	
First 20 Therms	$ 1.02684
Over 20 Therms	0.94266
Commodity Charge Winter	
First 40 Therms	$ 0.82147
Next 110 Therms	0.75413
Over 150 Therms	0.94266
Proposed Tariff Rates [3]	
Basic Service Charge per Month	$ 7.00
Commodity Charge Summer	
First 8 Therms	$ 1.17679
Over 8 Therms	0.67286
Commodity Charge Winter	
First 30 Therms	$ 1.17679
Over 30 Therms	0.67286

[1] Seasonal average use per Schedule H-6, Sheets 3 - 5.
[2] Rates effective August 31, 2004 including all adjustments.
[3] Schedule H-3, Sheets 1 - 3.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PROPOSED vs. CURRENTLY EFFECTIVE RATES INCLUDING DISCOUNT
LOW-INCOME MULTI-FAMILY RESIDENTIAL GAS SERVICE

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill: At Currently Effective Rates	Monthly Bill: At Proposed Tariff Rates	Increase/(Decrease): Dollars	Increase/(Decrease): Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	11	18.30	$ 17.93	$(0.37)	(2.02%)	1
2	Average Summer Use [1]	14	21.38	$ 19.95	(1.43)	(6.69%)	2
3	125 Percent Average Use	18	25.48	$ 22.64	(2.84)	(11.15%)	3
	Winter Season Bills						
4	75 Percent Average Use	31	32.47	$ 36.93	$ 4.46	13.74%	4
5	Average Winter Use [1]	41	40.61	$ 43.66	3.05	7.51%	5
6	125 Percent Average Use	51	48.15	$ 50.39	2.24	4.65%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge per Month	$ 7.00
Commodity Charge Summer	
First 20 Therms	$ 1.02684
Over 20 Therms	0.94266
Commodity Charge Winter	
First 40 Therms	$ 0.82147
Next 110 Therms	0.75413
Over 150 Therms	0.94266
Proposed Tariff Rates [3]	
Basic Service Charge per Month	$ 7.00
Commodity Charge Summer	
First 7 Therms	$ 1.17679
Over 7 Therms	0.67286
Commodity Charge Winter	
First 18 Therms	$ 1.17679
Over 18 Therms	0.67286

[1] Seasonal average use per Schedule H-6, Sheets 3 - 5.
[2] Rates effective August 31, 2004 including all adjustments.
[3] Schedule H-3, Sheets 1 - 3.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF REVENUES AT PROPOSED RATES BY PROPOSED RATE SCHEDULES WITHOUT CONSERVATION MARGIN TRACKER
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

			Billing Determinants				Revenue at Proposed Rates [1]					
Line No.	Description (a)	Proposed Schedule Number (b)	Number of Bills (c)	Sales (Therms) (d)	Basic Service Charge (e)	Commodity Charge (f)	Basic Service Charge (g)	Commodity Charge (h)	Total Margin (i)	Gas Cost [2] (j)	Total Revenue (k)	Line No.
	Single-Family Residential Gas Service	G-5										
	Summer (April - November)											
1	Basic Service Charge per Month		5,834,248		$ 16.00		$ 93,347,968		$ 93,347,968		$ 93,347,968	1
	Commodity Charge per Therm											
2	First 8 Therms			40,157,005		$ 0.66454		$ 26,685,936	26,685,936	$ 21,458,297	48,144,233	2
3	Over 8 Therms			50,747,308		0.15000		7,612,096	7,612,096	27,117,331	34,729,427	3
	Winter (December - March)											
4	Basic Service Charge per Month		2,974,733		$ 16.00		$ 47,595,728		$ 47,595,728		$ 47,595,728	4
	Commodity Charge per Therm											
5	First 30 Therms			78,149,816		0.66454		51,933,679	51,933,679	41,760,136	93,693,815	5
6	Over 30 Therms			91,119,021		0.15000		13,667,853	13,667,853	48,690,360	62,358,213	6
7	Total Single-Family Residential Gas Service		8,808,981	260,173,149			$ 140,943,696	$ 99,899,564	$ 240,843,260	$ 139,026,124	$ 379,869,384	7
	Low Income Residential Gas Service	G-5										
	Summer (April - November)											
8	Basic Service Charge		211,472		$ 16.00		$ 3,383,552		$ 3,383,552		$ 3,383,552	8
	Commodity Charge per Therm											
	Summer (May - October)											
9	First 8 Therms			1,491,739		$ 0.66454		$ 991,320	991,320	$ 797,125	1,788,445	9
10	Over 8 Therms			1,748,440		0.15000		262,266	262,266	934,297	1,196,563	10
	Winter (December - March)											
11	Basic Service Charge per Month		107,196		$ 16.00		$ 1,715,136		$ 1,715,136		$ 1,715,136	11
	Commodity Charge per Therm											
12	First 30 Therms			2,567,923		0.66454		1,706,487	1,706,487	1,372,195	3,078,682	12
13	Over 30 Therms			3,544,314		0.15000		531,647	531,647	1,893,939	2,425,586	13
14	Total Low Income Residential Gas Service		318,668	9,352,415			$ 5,098,688	$ 3,491,720	$ 8,590,408	$ 4,997,556	$ 13,587,964	14
	Multi-Family Residential Gas Service	G-6										
	Summer (April - November)											
15	Basic Service Charge per Month		456,582		$ 14.00		$ 6,392,148		$ 6,392,148		$ 6,392,148	15
	Commodity Charge per Therm											
16	First 7 Therms			2,901,893		$ 0.66454		$ 1,928,424	1,928,424	$ 1,550,656	3,479,080	16
17	Over 7 Therms			3,177,201		0.15000		476,580	476,580	1,697,769	2,174,349	17
	Winter (December - March)											
18	Basic Service Charge per Month		233,245		$ 14.00		$ 3,265,430		$ 3,265,430		$ 3,265,430	18
	Commodity Charge per Therm											
19	First 18 Therms			4,364,020		0.66454		2,900,066	2,900,066	2,331,958	5,232,024	19
20	Over 18 Therms			4,229,516		0.15000		634,427	634,427	2,260,084	2,894,511	20
21	Total Multi-Family Residential Gas Service		689,827	14,672,630			$ 9,657,578	$ 5,939,497	$ 15,597,075	$ 7,840,467	$ 23,437,542	21
	Multi-Family Low Income Residential Gas Service	G-6										
	Summer (April - November)											
22	Basic Service Charge per Month		33,599		$ 14.00		$ 470,386		$ 470,386		$ 470,386	22
	Commodity Charge per Therm											
23	First 7 Therms			208,053		$ 0.66454		$ 138,260	138,260	$ 111,175	249,435	23
24	Over 7 Therms			254,839		0.15000		38,226	38,226	136,176	174,402	24
	Winter (December - March)											
25	Basic Service Charge per Month		17,488		$ 14.00		$ 244,832		$ 244,832		$ 244,832	25
	Commodity Charge per Therm											
26	First 18 Therms			327,920		0.66454		217,916	217,916	175,227	393,143	26
27	Over 18 Therms			396,818		0.15000		59,523	59,523	212,044	271,567	27
28	Total Low Incom Multi-Family Residential Gas Service		51,087	1,187,630			$ 715,218	$ 453,925	$ 1,169,143	$ 634,622	$ 1,803,765	28
29	Total Residential Gas Service		9,868,563	285,385,824			$156,415,180	$ 109,784,706	$ 266,199,886	$ 152,498,769	$ 418,698,655	29
	Master Metered Mobile Home Park Gas Service	G-20										
30	Basic Service Charge per Month		2,268		$ 100.00		$ 226,800		$ 226,800		$ 226,800	30
	Commodity Charge per Therm All Usage											
31	All Usage			2,452,509		$ 0.32271		$ 791,449	791,449	1,310,523	2,101,972	31
32	Total MMMHP Gas Service		2,268	2,452,509			$ 226,800	$ 791,449	$ 1,018,249	$ 1,310,523	$ 2,328,772	32

[1] Proposed Residential and CNG rates without the Conservation Margin Tracker.
[2] Gas cost effective August 27, 2004 without surcharges.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF REVENUES AT PROPOSED RATES BY PROPOSED RATE SCHEDULES WITHOUT CONSERVATION MARGIN TRACKER
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description	Proposed Schedule Number	Billing Determinants: Number of Bills	Billing Determinants: Sales (Therms)	Revenue at Proposed Rates [1]: Basic Service Charge	Commodity Charge	Basic Service Charge	Commodity Charge	Total Margin	Gas Cost [2]	Total Revenue	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
	General Gas Service - Small	G-25(S)										
	Basic Service Charge											
1	Former Small GS Customers		197,811		$ 25.00		$ 4,945,275		$ 4,945,275		$ 4,945,275	1
2	Former Medium GS Customers		96		$ 25.00		$ 2,400		$ 2,400		$ 2,400	2
3	Former Essential Agiculture Customers		144		$ 25.00		$ 3,600		$ 3,600		$ 3,600	3
	Commodity Charge per Therm All Usage											
4	Transportation Customers			629		$ 0.69076		$ 434	434	$ 0	434	4
5	Sales Customers			3,786,431		0.69076		2,615,515	$ 2,615,515	2,023,317	4,638,832	5
6	Total Small General Gas Service		198,051	3,787,060			$ 4,951,275	$ 2,615,949	$ 7,567,224	$ 2,023,317	$ 9,590,541	6
	General Gas Service - Medium	G-25(M)										
	Basic Service Charge											
7	Former Small GS Customers		191,331		$ 35.00		$ 6,696,585		$ 6,696,585		$ 6,696,585	7
8	Former Medium GS Customers		3,708		35.00		129,780		129,780		129,780	8
9	Former Large GS Customers		12		35.00		420		420		420	9
10	Former Armed Forces Customers		24		35.00		840		840		840	10
11	Former Essential Agriculture Customers		516		35.00		18,060		18,060		18,060	11
	Commodity Charge per Therm All Usage											
	Transportation Customers											
12	Former Small GS Customers			101,424		$ 0.40089		$ 40,660	40,660	$ 0	40,660	12
13	Former Medium GS Customers			85,250		0.40089		34,176	34,176	0	34,176	13
	Sales Customers											
14	Former Small GS Customers			40,955,338		0.40089		16,418,585	16,418,585	21,884,894	38,303,479	14
15	Former Medium GS Customers			1,745,235		0.40089		699,647	699,647	932,584	1,632,231	15
16	Former Large GS Customers			5,050		0.40089		2,024	2,024	2,699	4,723	16
17	Former Armed Forces Customers			3,847		0.40089		1,542	1,542	2,056	3,598	17
18	Former Essential Agriculture Customers			133,552		0.40089		53,540	53,540	71,365	124,905	18
19	Total Medium General Gas Service		195,591	43,029,696			6,845,685	17,250,174	24,095,859	22,893,598	46,989,457	19
	General Gas Service - Large	G-25(L)										
	Basic Service Charge											
20	Former Small GS Customers		4,375		$ 150.00		$ 656,250		$ 656,250		$ 656,250	20
21	Former Medium GS Customers		79,384		150.00		11,907,600		11,907,600		11,907,600	21
22	Former Large GS Customers		120		150.00		18,000		18,000		18,000	22
23	Former Armed Forces Customers		24		150.00		3,600		3,600		3,600	23
	Commodity Charge per Therm All Usage											
	Transportation Customers											
24	Former Small GS Customers			81,882		$ 0.27399		$ 22,435	22,435	$ 0	22,435	24
25	Former Medium GS Customers			2,696,666		0.27399		738,860	738,860	$ 0	738,860	25
26	Former Large GS Customers			316,390		0.27399		86,688	86,688	$ 0	86,688	26
	Sales Customers											
27	Former Small GS Customers			2,938,939		0.27399		805,240	805,240	$ 1,570,451	2,375,691	27
28	Former Medium GS Customers			134,740,525		0.27399		36,917,556	36,917,556	$ 71,999,947	108,917,503	28
29	Former Large GS Customers			1,055,381		0.27399		289,164	289,164	$ 563,953	853,117	29
30	Former Armed Forces Customers			168,776		0.27399		46,243	46,243	$ 90,187	136,430	30
31	Total Large General Gas Service		83,903	141,998,559			12,585,450	38,906,186	51,491,636	74,224,538	125,716,174	31
	General Gas Service - Transportation Eligible	G-25(TE)										
	Basic Service Charge											
32	Former Medium GS Customers		60		$ 750.00		$ 45,000		$ 45,000		$ 45,000	32
33	Former Essential Agricultural Service Customers		252		$ 750.00		$ 189,000		$ 189,000		$ 189,000	33
34	Former Large GS Customers		1,680		$ 750.00		$ 1,260,000		$ 1,260,000		$ 1,260,000	34
35	Former Armed Forces Customers		60		750.00		45,000		45,000		45,000	35
36	Demand Charge per Month			10,571,934	0.062645			7,947,288	7,947,288		7,947,288	36
	Commodity Charge per Therm All Usage											
	Transportation Customers											
37	Former Medium GS Customers			0		$ 0.09262		$ 0	0	$ 0	0	37
38	Former Essential Agricultural Services Customers			4,434,348		$ 0.09262		$ 410,709	410,709	$ 0	410,709	38
39	Former Large GS Customers			25,832,133		0.09262		2,392,572	2,392,572	$ 0	2,392,572	39
	Sales Customers											
40	Former Medium GS Customers			1,016,137		0.09262		94,115	94,115	$ 542,983	637,098	40
41	Former Essential Agricultural Services Customers			5,063,922		0.09262		469,020	469,020	$ 2,705,957	3,174,977	41
42	Former Large GS Customers			46,460,065		0.09262		4,303,131	4,303,131	$ 24,826,400	29,129,531	42
43	Former Armed Forces Customers			2,994,890		0.09262		277,387	277,387	$ 1,600,349	1,877,736	43
44	Total Transportation Eligible General Gas Service		2,052	85,801,495			$ 1,539,000	$ 15,894,222	$ 17,433,222	$ 29,675,689	$ 47,108,911	44
45	Total General Gas Service		479,597	274,616,810			$ 25,921,410	$ 74,666,531	$ 100,587,941	$ 128,817,142	$ 229,405,083	45

[1] Proposed Residential and CNG rates without the Conservation Margin Tracker.
[2] Gas cost effective August 27, 2004 without surcharges.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF REVENUES AT PROPOSED RATES BY PROPOSED RATE SCHEDULES WITHOUT CONSERVATION MARGIN TRACKER
FOR THE TWELVE MONTHS ENDED AUGUST 31, 2004

Line No.	Description (a)	Proposed Schedule Number (b)	Billing Determinants: Number of Bills (c)	Billing Determinants: Sales (Therms) (d)	Revenue at Proposed Rates [1]: Basic Service Charge (e)	Commodity Charge (f)	Basic Service Charge (g)	Commodity Charge (h)	Total Margin (i)	Gas Cost [2] (j)	Total Revenue (k)	Line No.
	Air Conditioning Gas Service	G-40										
	Basic Service Charge											
1	W/ Other Service (No BSC)		60		0.00		0		0		0	1
2	Basic Service Charge		389		$ 25.00		$ 9,725		$ 9,725		$ 9,725	2
	Commodity Charge per Therm All Usage											
3	Transportation Customers			626,909		$ 0.10208		$ 64,199	64,199	$ 0	64,199	3
4	Sales Customers			1,207,635		0.10208		123,275	123,275	645,312	768,587	4
5	Total Air Conditioning Gas Service		449	1,836,544			$ 9,725	$ 187,474	$ 197,199	$ 645,312	$ 842,511	5
	Street Lighting Gas Service	G-45										
	Commodity Charge per Therm of Rated Capacity											
6	All Usage		348	99,883		$ 0.54644		$ 54,580	54,580	53,373	107,953	6
7	Total Street Lighting Gas Service		348	99,883			$ 0	$ 54,580	$ 54,580	$ 53,373	$ 107,953	7
	Gas Service for Compression on Customer's Premises	G-55										
	Basic Service Charge											
8	Small		264		$ 25.00		$ 6,600		$ 6,600		$ 6,600	8
9	Large		324		350.00		113,400		113,400		113,400	9
10	Residential		1,320		16.00		21,120		21,120		21,120	10
	Commodity Charge per Therm All Usage											
11	Transportation Customers			0		$ 0.13425		$ 0	0	$ 0	0	11
	Sales Customers											
12	Small			182,313		0.13425		$ 24,476	24,476	$ 97,421	121,897	12
13	Large			1,898,808		0.13425		$ 254,915	254,915	$ 1,014,647	1,269,562	13
14	Residential			79,719		0.13425		$ 10,702	10,702	$ 42,599	53,301	14
15	Total CNG Gas Service		1,908	2,160,840			$ 141,120	$ 290,093	$ 431,213	$ 1,154,667	$ 1,585,880	15
	Electric Generation Gas Service	G-60										
	Basic Service Charge											
16	General Service - Small		60		$ 25.00		$ 1,500		$ 1,500		$ 1,500	16
17	General Service - Medium		0		$ 35.00		$ 0		$ 0		$ 0	17
18	General Service - Large		96		150.00		14,400		14,400		14,400	18
19	General Service - Transportation Eligible		96		750.00		72,000		72,000		72,000	19
20	Essential Agricultural		24		150.00		3,600		3,600		3,600	20
	Commodity Charge per Therm All Usage											
21	Transportation Customers			0		$ 0.10188		$ 0	0	$ 0	0	21
22	Sales Customers			15,007,742		0.10188		1,528,989	1,528,989	6,564,687	8,093,676	22
23	Total Electric Generation Gas Service		276	15,007,742			$ 91,500	$ 1,528,989	$ 1,620,489	$ 6,564,687	$ 8,185,176	23
	Small Essential Agriculture User Gas Service	G-75										
24	Basic Service Charge		435		$ 150.00		$ 65,250		$ 65,250		$ 65,250	24
	Commodity Charge per Therm All Usage											
25	Transportation Customers			155,893		$ 0.22186		$ 34,586	34,586	$ 0	34,586	25
26	Sales Customers			2,789,183		0.22186		618,808	618,808	1,490,428	2,109,236	26
27	Total Essential Agricultural Gas Service		435	2,945,076			$ 65,250	$ 653,394	$ 718,644	$ 1,490,428	$ 2,209,072	27
	Natural Gas Engine Gas Service	G-80										
	Basic Service Charge											
28	Off-Peak Season (Oct. - March)		3,623		$ 0.00		$ 0		$ 0		$ 0	28
29	Peak Season (April - September)		3,623		100.00		362,250		362,250		362,250	29
	Commodity Charge per Therm All Usage											
30	Transportation Customers			0		$ 0.15848		$ 0	0	$ 0	0	30
31	Sales Customers			21,271,370		0.15848		3,371,087	3,371,087	9,304,523	12,675,610	31
32	Total Natural Gas Engine Gas Service		7,245	21,271,370			$ 362,250	$ 3,371,087	$ 3,733,337	$ 9,304,523	$ 13,037,860	32
33	Total Tariff Sales		10,361,089	605,776,598			183,233,235	191,328,303	374,561,538	301,839,424	676,400,962	33
34	Optional Gas Service	G-30	324	101,647,104			$ 510,740	$ 5,032,592	5,543,332	$ 55,931,796	$ 61,475,128	34
35	Special Contract Service	B-1	271	30,410,785			$ 184,703	$ 1,950,134	$ 2,134,837		$ 2,134,837	35
36	Other Operating Revenues						$ 11,434,480		$ 11,434,480		$ 11,434,480	36
37	Total Revenue		10,361,684	737,834,487			$ 195,363,158	$ 198,311,029	$ 393,674,187	$ 357,771,220	$ 751,445,407	37
38	Total Revenue Requirement								393,675,099	357,771,220	751,446,319	38
39	Over/(Under)								($912)	$ 0	($912)	39

[1] Proposed Residential and CNG rates without the Conservation Margin Tracker.
[2] Gas cost effective August 27, 2004 without surcharges.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PROPOSED vs. CURRENTLY EFFECTIVE RATES WITHOUT CONSERVATION MARGIN TRACKER
SINGLE-FAMILY RESIDENTIAL GAS SERVICE

Line No.	Description (a)	Monthly Consumption (Therms) (b)	Monthly Bill At Currently Effective Rates (c)	Monthly Bill At Proposed Tariff Rates (d)	Increase/(Decrease) Dollars (e)	Increase/(Decrease) Percent (f)	Line No.
	Summer Season Bills						
1	75 Percent Average Use	12	20.39	$ 28.57	$ 8.18	40.12%	1
2	Average Summer Use [1]	16	24.52	$ 31.38	6.86	27.98%	2
3	125 Percent Average Use	20	28.65	$ 34.20	5.55	19.37%	3
	Winter Season Bills						
4	75 Percent Average Use	42	51.21	$ 61.01	$ 9.80	19.14%	4
5	Average Winter Use [1]	56	64.48	$ 70.86	6.38	9.89%	5
6	125 Percent Average Use	70	77.76	$ 80.72	2.96	3.81%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge per Month	$ 8.00
Commodity Charge Summer	
First 20 Therms	$ 1.03271
Over 20 Therms	0.94853
Commodity Charge Winter	
First 40 Therms	$ 1.03271
Over 40 Therms	0.94853
Proposed Tariff Rates [3]	
Basic Service Charge per Month	$ 16.00
Commodity Charge Summer	
First 8 Therms	$ 1.21861
Over 8 Therms	$ 0.70407
Commodity Charge Winter	
First 30 Therms	$ 1.21861
Over 30 Therms	$ 0.70407

[1] Seasonal average use per Schedule H-6, Sheets 3 - 5.
[2] Rates effective August 31, 2004 including all adjustments.
[3] Schedule H-3, Sheets 1 - 3.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PROPOSED vs. CURRENTLY EFFECTIVE RATES WITHOUT CONSERVATION MARGIN TRACKER
MULTI-FAMILY RESIDENTIAL GAS SERVICE

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill At Currently Effective Rates	Monthly Bill At Proposed Tariff Rates	Increase/(Decrease) Dollars	Increase/(Decrease) Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	9	17.29	$ 23.94	$ 6.65	38.46%	1
2	Average Summer Use [1]	12	20.39	$ 26.05	5.66	27.76%	2
3	125 Percent Average Use	15	23.49	$ 28.16	4.67	19.88%	3
	Winter Season Bills						
4	75 Percent Average Use	23	31.75	$ 39.46	$ 7.71	24.28%	4
5	Average Winter Use [1]	30	38.98	$ 44.38	5.40	13.85%	5
6	125 Percent Average Use	38	47.24	$ 50.02	2.78	5.88%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge per Month	$ 8.00
Commodity Charge Summer	
First 20 Therms	$ 1.03271
Over 20 Therms	0.94853
Commodity Charge Winter	
First 40 Therms	$ 1.03271
Over 40 Therms	0.94853

Proposed Tariff Rates [3]	
Basic Service Charge per Month	$ 14.00
Commodity Charge Summer	
First 7 Therms	$ 1.21861
Over 7 Therms	$ 0.70407
Commodity Charge Winter	
First 18 Therms	$ 1.21861
Over 18 Therms	$ 0.70407

[1] Seasonal average use per Schedule H-6, Sheets 3 - 5.
[2] Rates effective August 31, 2004 including all adjustments.
[3] Schedule H-3, Sheets 1 - 3.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PROPOSED vs. CURRENTLY EFFECTIVE RATES WITHOUT CONSERVATION MARGIN TRACKER
GAS SERVICE FOR COMPRESSION ON CUSTOMER PREMISES - SMALL

			Monthly Bill				
Line No.	Description (a)	Monthly Consumption (Therms) (b)	At Currently Effective Rates (c)	At Proposed Tariff Rates (d)	Increase/(Decrease) Dollars (e)	Increase/(Decrease) Percent (f)	Line No.
	Summer Season Bills						
1	75 Percent Average Use	536	$ 377.73	$ 383.37	$ 5.64	1.49%	1
2	Average Summer Use [1]	714	$ 496.53	$ 502.39	5.86	1.18%	2
3	125 Percent Average Use	893	$ 616.00	$ 622.07	6.07	0.99%	3
	Winter Season Bills						
4	75 Percent Average Use	483	$ 342.36	$ 347.94	5.58	1.63%	4
5	Average Winter Use [1]	644	$ 449.81	$ 455.58	5.77	1.28%	5
6	125 Percent Average Use	805	$ 557.27	$ 563.23	5.97	1.07%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 20.00
Commodity Charge	
All Usage	$ 0.66741
Proposed Tariff Rates [3]	
Basic Service Charge	$ 25.00
Commodity Charge	
All Usage	$ 0.66861

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective August 31, 2004 including all adjustments.
[3] Schedule H-3, Sheets 1 - 3.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PROPOSED vs. CURRENTLY EFFECTIVE RATES WITHOUT CONSERVATION MARGIN TRACKER
GAS SERVICE FOR COMPRESSION ON CUSTOMER PREMISES - LARGE

Line No.	Description	Monthly Consumption (Therms)	Monthly Bill At Currently Effective Rates	Monthly Bill At Proposed Tariff Rates	Increase/(Decrease) Dollars	Increase/(Decrease) Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	75 Percent Average Use	4,484	$ 3,162.67	$ 3,348.05	$ 185.38	5.86%	1
2	Average Summer Use [1]	5,978	$ 4,159.78	$ 4,346.95	187.17	4.50%	2
3	125 Percent Average Use	7,473	$ 5,157.55	$ 5,346.52	188.97	3.66%	3
	Winter Season Bills						
4	75 Percent Average Use	4,219	$ 2,985.80	$ 3,170.87	185.06	6.20%	4
5	Average Winter Use [1]	5,625	$ 3,924.18	$ 4,110.93	186.75	4.76%	5
6	125 Percent Average Use	7,031	$ 4,862.56	$ 5,051.00	188.44	3.88%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 170.00
Commodity Charge	
All Usage	$ 0.66741
Proposed Tariff Rates [3]	
Basic Service Charge	$ 350.00
Commodity Charge	
All Usage	$ 0.66861

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective August 31, 2004 including all adjustments.
[3] Schedule H-3, Sheets 1 - 3.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PROPOSED vs. CURRENTLY EFFECTIVE RATES WITHOUT CONSERVATION MARGIN TRACKER
GAS SERVICE FOR COMPRESSION ON CUSTOMER PREMISES - RESIDENTIAL

Line No.	Description (a)	Monthly Consumption (Therms) (b)	Monthly Bill At Currently Effective Rates (c)	Monthly Bill At Proposed Tariff Rates (d)	Increase/(Decrease) Dollars (e)	Increase/(Decrease) Percent (f)	Line No.
	Summer Season Bills						
1	75 Percent Average Use	46	$ 38.70	$ 46.76	$ 8.06	20.81%	1
2	Average Summer Use [1]	61	$ 48.71	$ 56.79	8.07	16.57%	2
3	125 Percent Average Use	76	$ 58.72	$ 66.81	8.09	13.78%	3
	Winter Season Bills						
4	75 Percent Average Use	44	$ 37.37	$ 45.42	8.05	21.55%	4
5	Average Winter Use [1]	59	$ 47.38	$ 55.45	8.07	17.04%	5
6	125 Percent Average Use	74	$ 57.39	$ 65.48	8.09	14.09%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 8.00
Commodity Charge	
All Usage	$ 0.66741

Proposed Tariff Rates [3]	
Basic Service Charge	$ 16.00
Commodity Charge	
All Usage	$ 0.66861

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective August 31, 2004 including all adjustments.
[3] Schedule H-3, Sheets 1 - 3.

I

SOUTHWEST GAS CORPORATION
System Allocable Plant

Depreciation Study
as of
December 31, 2002

AUS CONSULTANTS
Utility Services
Weber Fick & Wilson Division

Earl M. Robinson, CDP
President & CEO

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August 25, 2003

Mr. Jerry Vineyard
Specialist/Depreciation
SOUTHWEST GAS CORPORATION
Post Office Box 98510
Mail Code LVC-410
Las Vegas, NV 89193-8510

RE: System Allocable Plant

Dear Mr. Vineyard:

In accordance with your authorization, we have prepared a depreciation study related to the utility plant in service of Southwest Gas Corporation - System Allocable Plant as of December 31, 2002. Our findings and recommendations, together with supporting schedules and exhibits, are set forth in the accompanying report.

Summary schedules have been prepared to illustrate the impact of instituting the recommended annual depreciation rates as a basis for the Company's annual depreciation expense as compared to the rates presently utilized. The application of the present rates to the depreciable plant in service as of December 31, 2002 results in an annual depreciation expense of $5,542,648. In comparison, the application of the proposed depreciation rates to the depreciable plant in service at December 31, 2002 results in an annual depreciation expense of $4,072,947, a depreciation expense decrease of $1,469,701. The composite annual depreciation rate under present rates is 13.00 percent, while the proposed composite depreciation rate is 9.55 percent.

Section 1 of the report contains an Executive Summary as well as the response to the Nevada Commission's NAC 703.2765 Statement A, B, and C requirements

Section 2 of our report contains the summary schedules showing the results of our service life and salvage studies and summaries of presently utilized depreciation rates. The subsequent sections of the report present a detailed outline of the methodology and procedures used in the study together with supporting calculations and analyses used in the development of the results. A detailed table of contents follows this letter.

Respectfully submitted,

Earl M Robinson

EARL M. ROBINSON

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TABLE OF CONTENTS

SECTION 1

SOUTHWEST GAS CORPORATION
System Allocable Plant

Executive Summary

Table 1 on page 2-1 is a comparative summary which illustrates the effect of instituting the revised depreciation rates. The schedule includes a comparison of the annual depreciation rates and annual depreciation expense under both present and proposed rates applied using the Straight Line Method for each depreciable property group of the Southwest Gas Corporation - System Allocable's (the "Company") plant in service as of December 31, 2002. Both the present and proposed depreciation rates are based upon the Broad Group (Average Service Life) Procedures and the Average Remaining Life (ARL) Technique.

Table 2 on page 2-2 provides a summary of the detailed life estimates and service life parameters (Iowa Curves) utilized in preparing the Average Remaining Life depreciation rates for each property group. That is, the schedule provides a summary of the detailed data and a narrative of the study results set forth in Sections 4, 5, and 6. The developed depreciation rates (Column L) were determined by studying the Company's historical investment data together with the interpretation of future life expectancies which will have a bearing on the overall service life of the Company's property.

The utilization of the recommended depreciation rates based upon the Straight Line Average Remaining Life Procedure results in the setting of depreciation rates which will continuously true up the Company's level of capital recovery over the life of each asset group. Application of this procedure, which is based upon the current best estimates of service life together with the Company's plant in service and accrued depreciation, produces annual depreciation rates that will result in the Company recovering one-hundred (100) percent of its investment -- no more, no less.

It is recommended that the Company continue to apply depreciation rates and maintain its book depreciation reserve on an account-level basis. This maintenance of the book reserve on an account-level basis requires both the development of annual depreciation expense and distribution of other reserve account charges to an individual level. Continuing to maintain the Company's depreciation records in this detail will aid in completing the various rate studies and, most importantly, clearly identify the Company's level of capital recovery relative to each category of plant investment.

The results of this study produced numerous revisions to the applicable account-level service life parameters. While a number of the resulting depreciation rate modifications were limited in scope resulting in fine tuning of the current recovery rates, other changes were more significant. The most significant changes in depreciation resulting from this study are for Account 391 - Office Furniture and Equipment, and 391.10 - Computer Equipment.

Currently, given that the Company's book depreciation reserve has increased towards a more normal level, the resulting annual depreciation rate is now more reflective of the average service life being achieved by the property group. The depreciation rate for Account 391.0 - Office Furniture and Equipment increased from 3.99 percent to 8.16 percent. Contributing to the depreciation rate increase was a change in the estimated service life of the property group's asset investments from eighteen (18) to fourteen (14) years.

The depreciation rate for Account 391.10 - Computer Equipment decreased from 30.01 percent to 16.15 percent as a result of incorporating the current applicable service life parameters and book depreciation reserve accrued for this property class. Based upon the historical life analysis and current management expectations, the property group will continue to experience rapid obsolescence and continued replacement. Historically, the book depreciation reserve was materially below the level which should have been relative to the age and anticipated life of the property group. These factors previously resulted in the requirement of a significant increase of the depreciation rate over the current level to enable the recovery of the current asset investments by the end of the property life.

It is further noted that within the Company's property group investments one or more of the general plant equipment categories currently have a debit depreciation reserve balance. This negative depreciation reserve amount, which is the accumulation of past depreciation activity and is the resulting net under-recovery to date of the Company's property investment, needs to be recovered (along with the un-depreciated portion of the plant investment) over the remaining life of the existing plant in service. This net under-recovery occurred as a result of one of several reasons, which may include, but are not necessary limited to, a change in the Company's capital policy during January, 2001 from $300 to $1,000 and the subsequent retirement of all assets under $1,000, the identification of possible discarded but unrecorded retirements discovered via physical inventories, and/or the achievement of the account's property life that is shorter than that underlying prior depreciation rates. Accordingly, the currently developed account level depreciation rates incorporate the existing depreciation reserve level and the current estimate of average service life in setting the applicable account level depreciation rates. A variety of other lesser depreciation changes, both increases and decreases, occurred. In summary, the net change in depreciation expense over present rates produces a proposed depreciation expense decrease of $1,469,701 when applied to the Company's plant in service as of December 31, 2002.

In summary, the Company's historical experience, etc. was studied in detail for each depreciable group in the process of preparing this study. Thus, the resultant proposed depreciation rate should be applied on a similar basis. Accordingly, the following composite summary is provided for illustrative purposes only as a means to compare the present and proposed composite depreciation rates.

Present Depreciation Rates

Depreciable Plant In Service at December 31, 2002	$42,632,113
Annual Depreciation Expense	5,542,648
Composite Annual Depreciation Rate	13.00%

Proposed Depreciation Rates

Depreciable Plant In Service at December 31, 2002	$42,632,113
Annual Depreciation Expense	4,072,947
Composite Annual Depreciation Rate	9.55%

In accordance with NAC 703.2765, the following information is provided:

Statement A

Table 2 in Section 2 contains the Company's historical original cost, future net salvage factors, the Company's accrued depreciation reserve, the applicable average service life and Iowa Survivor Curve utilized to calculate the proposed account-level annual depreciation rate relative to the Company's plant in service as of December 31, 2002.

The account-level depreciation rates presently utilized by the Company to depreciate each depreciable plant account, along with the proposed account-level depreciation rates and net change in annual depreciation expense, are set forth in Table 1 of Section 2.

The proposed depreciation rates are 6.68 percent allocable to Northern Nevada and 26.62 percent allocable to Southern Nevada. This allocation is based on the four-factor method as of December 31, 2002. Of the proposed accrual expense, $272,073 is allocable to Northern Nevada and $1,084,218 is allocable to Southern Nevada.

Statement B

The Company's present depreciation rates are based upon the application of the Straight Line/Broad Group/Average Remaining Life method, procedure, and technique. Likewise, the proposed account-level depreciation rates were prepared using the same depreciation approach. The depreciation life analysis was prepared via the utilization of the Retirement Rate Method, along with the Company's historical accounting data, to develop service life benchmarks. The historical benchmarks were utilized, along with an investigation of the Company's asset investments, consideration of inputs provided via Company management concerning current operations and anticipated future events impacting the Company's fixed capital plant in service. Likewise, similar historical analysis and future considerations were completed relative to the applicable net salvage components. The Nevada Public Service Commission on Docket No. 99-10001 approved the existing rates.

Statement C

Sections 4, 5, 6, and 7 of the report contain the analysis of the life of each plant and the value to be gained from salvage for each depreciable plant account. These sections contain schedules, graphs, and other information necessary to support the selections of the parameters utilized for each plant account.

SECTION 2

Southwest Gas Corporation
System Allocable

Summary of Original Cost of Utility Plant in Service as of December 31, 2002
and Related Annual Depreciation Expenses Under Present and Proposed Depreciation Rates

		Original	Present Rates		Proposed Rates		Net Change
Acct. No.	Account Description	Cost 12-31-2002	Rates %	Annual Accrual	Rates %	Annual Accrual	Depreciation Expense
(a)	(b)	(c)	(d)	(e)=(c)x(d)	(f)	(g)=(c)x(f)	(h)=(g)-(e)
	DEPRECIABLE PLANT						
	General Plant						
390.10	Structures - Owned	11,700,876	2.46%	287,842	2.50%	292,522	4,680
391.00	Office Furniture & Equipment	7,757,739	3.99%	309,534	8.16%	633,032	323,498
391.10	Computer Equipment	13,757,912	30.01%	4,128,749	16.15%	2,221,903	-1,906,846
	Total Account 391	21,515,651	20.63%	4,438,283	13.27%	2,854,935	-1,583,348
392.00	Transportation Equipment	2,904,810	6.42%	186,489	7.20%	209,146	22,657
393.00	Stores Equipment	29,429	4.45%	1,310	16.03%	4,717	3,407
394.00	Tools, Shop & Garage Equipment	227,375	4.10%	9,322	11.16%	25,375	16,053
395.00	Laboratory Equipment	229,994	3.05%	7,015	4.77%	10,971	3,956
397.00	Communication Equipment	4,849,540	9.88%	479,135	8.51%	412,696	-66,439
397.20	Telemetry Equipment	454,151	20.38%	92,556	40.23%	182,705	90,149
	Total Account 397	5,303,691	10.78%	571,691	11.23%	595,401	23,710
398.00	Miscellaneous Equipment	720,287	5.65%	40,696	11.09%	79,880	39,184
	TOTAL General Plant	42,632,113	13.00%	5,542,648	9.55%	4,072,947	-1,469,701
	TOTAL Depreciable Plant	42,632,113	13.00%	5,542,648	9.55%	4,072,947	-1,469,701
	NON-DEPRECIABLE PLANT						
	Intangible Plant						
301.00	Organization	61,816					
303.00	Miscellaneous	68,921,029					
	TOTAL Intangible Plant	68,982,845					
	Land & Land Rights						
389.00	General	391,307					
	TOTAL Land & Land Rights	391,307					
390.20	Structures - Leased	3,001,887					
	TOTAL Non-Depreciable Plant	72,376,039					
	TOTAL PLANT IN SERVICE	115,008,152					

Southwest Gas Corporation

System Allocable

Summary of Original Cost of Utility Plant in Service and Calculation of Annual Depreciation Rates and Depreciation Expense Based Upon Utilization of Book Depreciation Reserve and Average Remaining Lives of Utility Plant in Service as of December 31, 2002

Acct. No. (a)	Account Description (b)	Original Cost 12-31-2002 (c)	Estimated Future Net Salvage % (d)	Estimated Future Net Salvage Amount (e)=(c)x(d)	Original Cost Less Salvage (f)=(c)-(e)	Book Depreciation Reserve (g)	Net Original Cost Less Book Reserve (h)=(f)-(g)	A.S.L./ Survivor Curve (i)	Average Remaining Life (j)	Annual Depreciation Accrual (k)=(h)/(j)	Annual Depreciation Rate (l)=((k)/(c))*100
	DEPRECIABLE PLANT										
	General Plant										
390.10	Structures - Owned	11,700,876	5%	585,044	11,115,832	3,081,073	8,034,759	40-R3	27.5	292,173	2.50%
						0					
391.00	Office Furniture & Equipment	7,757,739	0%	0	7,757,739	1,998,004	5,759,735	14-L2	9.1	632,938	8.16%
391.10	Computer Equipment	13,757,912	0%	0	13,757,912	5,981,198	7,776,714	6-L2	3.5	2,221,918	16.15%
	Total Account 391	21,515,651		0	21,515,651	7,979,202	13,536,449			2,854,856	13.27%
392.00	Transportation Equipment	2,904,810	15%	435,722	2,469,088	1,360,077	1,109,011	7-L0	5.3	209,247	7.20%
393.00	Stores Equipment	29,429	0%	0	29,429	-1,707	31,136	14-R1	6.6	4,718	16.03%
394.00	Tools, Shop & Garage Equipment	227,375	0%	0	227,375	-33,988	261,363	14-LO.5	10.3	25,375	11.16%
395.00	Laboratory Equipment	229,994	0%	0	229,994	75,342	154,652	23-R1.5	14.1	10,968	4.77%
397.00	Communication Equipment	4,849,540	0%	0	4,849,540	2,291,614	2,557,926	11-R3	6.2	412,569	8.51%
397.20	Telemetry Equipment	454,151	0%	0	454,151	-276,702	730,853	8-R3	4.0	182,713	40.23%
	Total Account 397	5,303,691		0	5,303,691	2,014,912	3,288,779			595,282	11.22%
398.00	Miscellaneous Equipment	720,287	0%	0	720,287	-142,762	863,049	14-L0.5	10.8	79,912	11.09%
	TOTAL General Plant	42,632,113		1,020,766	41,611,347	14,332,149	27,279,198			4,072,531	9.55%
	TOTAL Depreciable Plant	42,632,113		1,020,766	41,611,347	14,332,149	27,279,198			4,072,531	9.55%
	NON-DEPRECIABLE PLANT										
	Intangible Plant										
301.00	Organization	61,816									
303.00	Miscellaneous	68,921,029				47,715,424					
	TOTAL Intangible Plant	68,982,845				47,715,424					
	Land & Land Rights										
389.00	General	391,307									
	TOTAL Land & Land Rights	391,307				0					
390.20	Structures - Leased	3,001,887				2,851,609					
	TOTAL Non-Depreciable Plant	72,376,039				50,567,033					
	TOTAL PLANT IN SERVICE	115,008,152				64,899,182					

SECTION 3

SOUTHWEST GAS CORPORATION
System Allocable Plant

General

This report sets forth the results of our study of the depreciable property of the Southwest Gas Corporation - System Allocable Plant (the Company) as of December 31, 2002 and contains the basic parameters (recommended average service lives and life characteristics) for the proposed average remaining life depreciation rates until a subsequent service life study is completed. All average service lives set forth in this report are developed based upon plant in service as of December 31, 2002.

The scope of the study included an analysis of Company historical data through December 31, 2002, discussions with Company management staff to identify prior and prospective factors affecting the Company's plant in service, as well as interpretation of past service life data experience and future life expectancies to determine the appropriate average service lives of the Company's surviving plant. The service lives and life characteristics, resulting from the in-depth study, were utilized together with the Company's plant in service and book depreciation reserve to determine the recommended Average Remaining Life (ARL) depreciation rates related to the Company's plant in service as of December 31, 2002.

In preparing the study, the Company's historical investment data were studied using various service life analysis techniques. Further, discussions were held with the Company's management to obtain an overview of the Company's facilities and to discuss the general scope of operations together with other factors which could have a bearing on the service lives of the Company's property. Finally, the study results were tempered by information gathered during plant inspection tours of a representative portion of the Company's property.

The Company maintains a property record containing a summary of its fixed capital investments by property account. This investment data was analyzed and summarized by property group and/or sub group and vintage then utilized as a basis for the various depreciation calculations.

Depreciation Study Overview

There are numerous methods utilized to recover property investment depending upon the goal. For example, accelerated methods such as double declining balance and sum of years digits are methods used in tax accounting to motivate additional investments. Broad Group (BG) and Equal Life Group (ELG) are both Straight Line Grouping Procedures recognized and utilized by various regulatory jurisdictions depending upon the policy of the specific agency.

The Straight Line (Group) Method of depreciation utilized in this study to develop the recommended depreciation rates is the Broad Group Procedure together with the Average Remaining Life Technique. The use of this procedure and technique is based upon recovering the net book cost (original cost less book reserve) of the surviving plant in service over its estimated remaining useful life. Any variance between the book reserve and an implied theoretical calculated reserve is compensated for under this procedure. That is, as the Company's book reserve increases above or declines below the theoretical reserve at a specific point in time, the Company's average remaining life depreciation rate in subsequent years will be increased or decreased to compensate for the variance, thereby, assuring full recovery of the Company's investment by the end of the property's life.

The Company, like any other business, includes as an annual operating expense an amount which reflects a portion of the capital investment which was consumed in providing service during the accounting period. The annual depreciation amount to be utilized is based upon the remaining productive life over which the undepreciated capital investment needs to be recovered. The determination of the productive remaining life for each property group usually includes an in-depth study of past experience in addition to estimates of future expectations.

Annual Depreciation Accrual

Through the utilization of the Average Remaining Life Technique, the Company will recover the undepreciated fixed capital investment in the appropriate amounts as annual depreciation expense in each year throughout the remaining life of the property. The procedure incorporates the future life expectancy of the property, the vintaged surviving plant in service, and estimated net salvage, together with the book depreciation reserve balance to develop the annual depreciation rate for each property account. Accordingly, the ARL technique meets the objective of providing a straight line recovery of the undepreciated fixed capital property investment.

As indicated, the use of the Average Remaining Life Technique results in charging the appropriate annual depreciation amounts over the remaining life of the property to insure full recovery by end of life. That does not mean that once an average remaining life is estimated, it can not be changed at any point throughout the service life, but that the annual expense is calculated on a Straight Line Method rather than by the previously mentioned, "sum of the years digits" or "double declining balance" methods, etc. The "group" refers to the method of calculating annual depreciation on the summation of the investment in any one depreciable group or plant account rather than calculating depreciation for each individual unit.

Under Broad Group depreciation some units may be over depreciated and other units may be under depreciated at the time when they are retired from service, but overall, the account is fully depreciated when average service life is attained. By comparison, Equal Life Group depreciation rates are designed to fully accrue the cost of the asset group by the time of retirement. For both the Broad Group and Equal Life Group Procedures the full cost of the investment is credited to plant in service when the retirement occurs and likewise the depreciation reserve is debited with an equal retirement cost. No gain or loss is recognized at the time of property retirement because of the assumption the retired property was at average service life.

Group Depreciation Procedures

Group depreciation procedures are utilized to depreciate property when more than one item of property is being depreciated. Such a procedure is appropriate because all of the items within a specific group typically do not have identical service lives, but have lives which are dispersed over a range of time. Utilizing a group depreciation procedure allows for a condensed application of depreciation rates to groups of similar property in lieu of extensive depreciation calculations on an item by item basis. The two more common group depreciation procedures are the Broad Group (BG) and Equal Life Group (ELG) approach.

In developing depreciation rates using the Broad Group procedure, the annual depreciation rate is based on the average of the overall group, which is then applied to the group's surviving original cost investment. A characteristic of this procedure is that retirements of individual units occurring prior to average service life will be under depreciated, while individual units retired after average service life will be over depreciated when removed from service, but overall, the group investment will achieve full recovery by the end of the life of the total property group. That is, the under recovery occurring early in the life of the account is balanced by the over recovery occurring subsequent to average service life. In summary, the cost of the investment is complete at the end of the property's life cycle, but the rate of recovery does not match the consumption pattern which was used to provide service to the company's customers.

Under the average service life procedure, the annual depreciation rate is calculated by the following formula:

$$\text{Annual Accrual Rate, Percent} = \frac{100\% - \text{Salvage}}{\text{Average Service Life}} \times 100$$

The application of the broad group procedure to life span groups results in each vintage investment having a different average service life. This circumstance exists because the concurrent retirement of all vintages at the anticipated retirement year results in truncating and, therefore, restricting the life of each successive years vintage investment. An average service life is calculated for each vintage investment in accordance with the above formula. Subsequently, a composite service life and depreciation rate is calculated relative to all vintages within the property group by weighting the life for each vintage by the related surviving vintage investment within the group.

In the Equal Life Group, the property group is subdivided, through the use of plant life tables, into equal life groups. In each equal life group, portions of the overall property group includes that portion which experiences the life of the specific sub-group. The relative size of each sub-group is determined from the overall group life characteristic (property dispersion curve). This procedure both overcomes the disadvantage of voluminous record requirements of unit depreciation, as well as, eliminates the need to base depreciation on overall lives as required under the broad group procedure. The application of this procedure results in each sub-group of the property having a single life. In this procedure, the full cost of short lived units is accrued during their lives leaving no under accruals to be recovered by over accruals on long lived plant. The annual depreciation for the group is the summation of the depreciation accruals based on the service life of each Equal Life Group.

The ELG Procedure is superior to the BG Procedure because it allocates the capital cost of a group property to annual expense in accordance with the consumption of the property group providing service to customers. In this regard, the company's customers are more appropriately charged with the cost of the property consumed in providing them service during the applicable service period. The more timely return of plant cost is accomplished by fully accruing each unit's cost during its service life, thereby, not only reducing the risk of incomplete cost recovery, but also the procedure results in less return on rate base over the life of a depreciable group. The total depreciation expense is the same for all procedures which allocate the full capital cost to expense, but at any specific point in time, the depreciated original cost is less under the ELG procedure than under the

BG procedure. This circumstance exists because under the equal life group procedure, the rate base is not maintained at a level of greater than the future service value of the surviving plant as is the case when using the average service life procedure. Consequently, the total return required from the ratepayers is less under the ELG procedure.

While the equal life group procedure has been known to depreciation experts for many years, widespread interest in applying the procedure developed only after high speed electronic computers became available to perform the large volume of arithmetic computations required in developing ELG based depreciation lives and rates. The table on the following page illustrates the procedure for calculating equal life group depreciation accrual rates and summarizes the results of the underlying calculations. Depreciation rates are determined for each age interval (one year increment) during the life of a group of property which was installed in a given year or vintage group. The age of the vintage group is shown in column (A) of the ELG table. The percent surviving at the beginning of each age interval is determined from the Iowa 10-R3 survivor curve which is set forth in column (B). The percent retired during each age interval, as shown in column (C), is the difference between the percent surviving at successive age intervals. Accordingly, the percentage amount of the vintage group retired defines the size of each equal life group. For example, during the interval 3 1/2 to 4 1/2, 1.93690 percent of the vintage group is retired at an average age of four years. In this case, the 1.93690 percent of the group experiences an equal life of four years. Likewise, 3.00339 percent is retired during the interval 4 1/2 to 5 1/2 and experiences a service life of five years. Further, 4.42969 percent experiences a six-year life; etc. Calculations are made for each age interval from the zero age interval through the end of the life of the vintage group. The average service life for each age interval's equal life group is shown in column (E) of the table.

The amount to be accrued annually for each equal life group is equal to the percentage retired in the equal life group divided by its service life. Inasmuch as additions and retirements are assumed, for calculation purposes, to occur at midyear only one-half of the equal life group's annual accrual is allocated to expense during its first and last years of service life. The accrual amount for the property retired during age interval 0 to 1/2 must be equal to the amount retired to insure full recovery of that component during that period. The accruals for each equal life group during the age intervals of the vintage group's life cycle are shown in column (F). The total accrual for a given year is the summation of the equal life group accruals for that year. For example, the total accrual for the second year, as shown in column (G), is 11.31019 percent and is the sum of all succeeding years remaining equal life group accruals plus one half of the current years life group accrual listed in column (F). For the zero age interval year, the total accrual is equal to one half of the sum of all succeeding years remaining equal life accruals plus the amount for the zero interval equal life group accrual. The one half year accrual for the zero age interval is consistent with the half year convention relative to property during its installation year. The sum of the annual accruals for each age interval contained in column (G) total to 1.000 demonstrating that the developed rates will recover one-hundred (100) percent of plant no more and no less. The annual accrual rate which will result in the accrual amount is the ratio of the accrual amount (11.31019 percent) to the average percent surviving during the interval, column (D), (99.74145 percent), which is a rate of 11.34 percent (column J). Column (J) contains a summary of the accrual rates for each age interval of the property groups life cycle based upon an Iowa 10-R3 survivor curve.

Remaining Life Technique

In the Average Remaining Life depreciation technique, the annual accrual is calculated according to the following formula where, (A) the annual depreciation for each group equals, (D) the depreciable cost of plant, less (U) the accumulated provision for depreciation, less (S) the estimated future net salvage, divided by (R) the composite remaining life of the group:

$$A = \frac{D - U - S}{R}$$

The annual accrual rate (a) is expressed as a percentage of the depreciable plant balance by dividing the equation by (D) the depreciable cost of plant times 100:

$$(a) = \frac{D - U - S}{R} \times \frac{1}{D} \times 100$$

As further indicated by the equation, the accumulated provision for depreciation by vintage is required in order to calculate the remaining life depreciation rate for each property group. In practice, most often such detail is not available; therefore, composite remaining lives are determined for each depreciable group, i.e., property account.

The remaining life for a depreciable group is calculated by first determining the remaining life for each vintage year in which there is surviving investment. This is accomplished by solving the area under the survivor curve selected to represent the average life and life characteristic of the property account. The remaining life for each vintage is composited by dividing (D) the depreciable cost of each vintage, by (L) its average service life, and multiplying this ratio by its average remaining life (E). The composite remaining life of the group (R) equals the sums of products divided by the sum of the quotients:

$$R\ \text{Group} = \frac{\sum D/L \times E}{\sum D/L}$$

The functional level accumulated provision for depreciation, which was the basis for developing the composite average remaining life accrual and annual depreciation rate for each property account as per this report, was obtained from the Company's books and records. The functional level depreciation reserve was further allocated to each property account and sub-account based upon a detailed theoretical depreciation reserve as of December 31, 2002.

Net Salvage

Net salvage is the difference between gross salvage, or what is received when an asset is disposed of, and the cost of removing it from service. Salvage experience is normally included with the depreciation rate so that current accounting periods reflect a proportional share of the ultimate abandonment and removal cost or salvage received at the end of the property service life. Net salvage is said to be positive if gross salvage exceeds the cost of removal, but if cost of removal exceeds gross salvage the result is then negative salvage.

Cost of removal includes such costs as demolishing, dismantling, tearing down, disconnecting or otherwise removing plant, as well as normal environmental clean up costs associated with the property. Salvage includes proceeds received for the sale of plant and materials or the return of equipment to stores for reuse.

Net salvage experience is routinely studied for a period of years to determine the trends which have occurred in the past to be used as a benchmark for estimating future net salvage. These trends are considered together with any changes that are anticipated in the future to determine the future net salvage factor for remaining life depreciation purposes. The net salvage percentage is determined by relating the total net positive or negative salvage to the book cost of the property investment.

As noted, the historical experience is considered together with additional factors to identify and estimate the applicable future net salvage for each asset group. A significant factor which must be considered in estimating future net salvage is the fact that the experienced historical retirements have routinely occurred at average ages which are significant younger than average service life. This occurrence of retirements at less than average service life, along with the fact that net salvage is generally age sensitive, results in historical net salvage analysis indications which typically and significantly overstate future positive net salvage and understate future negative net salvage.

The issue of the age sensitivity of gross salvage and cost of removal is referenced in the "NARUC Public Utility Depreciation Practices" manual in its discussion on net salvage on pages 158-161. Furthermore, a 1989 AGA/EEI treatise entitled "An Introduction to Net Salvage of Public Utility Plant" discusses the subject of age sensitivity of gross salvage and cost of removal. Other depreciation texts likewise discuss the issue in greater detail.

The process used to adjust the historical net salvage analysis data to appropriately consider the true end of life net salvage is approached in the following manner.

First, it is noted that for each property group an average service life has been estimated. That average service life (of say thirty (30) year) indicates that the entire current investment within the property account will, on average, be retired at the average service life age to attain an average service life of thirty (30) years. Secondly, historical retirements have occurred to date. The historical retirements are analyzed to both identify the average retirement age to date (illustratively assume ten (10) years) at which the retirements have occurred, and in addition, what percent of the original costs of retirements was experienced by the Company for Cost of Removal. That is, relative to the cost of removal percent, if a Company had historically booked retirements with an original cost of $1,000 and it incurred $500 of cost of removal to retire the asset it is said that the cost of removal percent is fifty (50) percent ($500/$1,000) (also being fifty (50) percent negative net salvage, if there was no corresponding gross salvage in conjunction with the retirement).

The next step in the process, giving consideration to the above referenced historical retirements that experienced fifty (50) percent cost of removal and occurred at ten (10) years of age, and the average service life of the property of the asset group being thirty (30) years, and further identifying that the long run inflation rate is 2.75 percent, future cost of removal percent at the end of the property's average life can now be determined. That is, it can be readily identified that the average retirement age will need to increase, on average, an additional twenty (20) years (30 Yrs ASL-10 years average retirement age) before the property is retired, on average, at an age of thirty (30) years.

In simple, non-compounded terms a 2.75 percent cost increase per year for twenty (20) additional years is fifty-five (55) percent. For this example, the original historical fifty

(50) percent cost of removal plus the additional fifty-five (55) percent totals to one-hundred five (105) percent cost of removal.

The initially experienced fifty (50) percent cost of removal is attributable to the actual cost of removal incurred through the ten (10) year average age, while the additional fifty-five (55) percent cost of removal is attributable to the increased cost of removal during the subsequent additional twenty (20) year period (required for the property to be retired, on average, at average service life). The resulting total life future net salvage estimate (assuming no gross salvage) for this example is negative one-hundred five (105) percent net salvage.

Service Lives

Several factors contribute to the length of time or average service life which the property achieves. The three (3) major categories under which these factors fall are: (1) physical; (2) functional, and; (3) contingent casualties.

The physical category includes such things as deterioration, wear and tear and the action of the natural elements. The functional category includes inadequacy, obsolescence and requirements of governmental authorities. Obsolescence occurs when it is no longer economically feasible to use the property to provide service to customers or when technological advances have provided a substitute of superior performance. The remaining factor of contingent casualties relates to retirements caused by accidental damage or construction activity of one type or another.

In performing the life analysis for any property being studied, both past experience and future expectations must be considered in order to fully evaluate the circumstances which may have a bearing on the remaining life of the property. This ensures the selection of an average service life which best represents the expected life of each property investment.

Survivor Curves

The preparation of a depreciation study or theoretical depreciation reserve typically incorporates smooth curves to represent the experienced or estimated survival characteristics of the property. The "smoothed" or standard survivor curves generally used are the family of curves developed at Iowa State University which are widely used and accepted throughout the utility industry.

The shape of the curves within the Iowa family are dependent upon whether the maximum rate of retirement occurs before, during or after the average service life. If the maximum retirement rate occurs earlier in life, it is a left (L) mode curve; if occurring at average life, it is a symmetrical (S) mode curve; if it occurs after average life, it is a right (R) mode curve. In addition, there is the origin (O) mode curve for plant which has heavy retirements at the beginning of life.

Many times, actual Company data has not completed its life cycle, therefore, the survivor table generated from the Company data is not extended to zero percent surviving. This situation requires an estimate be made with regard to the remaining segment of the property group's life experience. Further, actual Company experience is often erratic, making its utilization for average service life estimating difficult. Accordingly, the Iowa curves are used to both extend Company experience to zero (0) percent surviving as well as to smooth actual Company data.

Study Procedures

Several study procedures were used to determine the prospective service lives recommended for the Company's plant in service. These include the review and analysis of historical retirements, current and future construction, historical experience and future expectations of salvage and cost of removal as related to plant investment. Service lives are affected by many different factors, some of which can be obtained from studying plant experience, others which may rely heavily on future expectations. When physical aspects are the controlling factor in determining the service life of property, historical experience is a valuable tool in selecting service lives. In the case where changing technology or a less costly alternative develops, then historical experience is of lesser value.

While various methods are available to study historical data, the principal methods utilized to determine average service lives for a Company's property are the Retirement Rate Method, the Simulated Plant Record Method, the Life Span Method, and the Judgement Method.

Retirement Rate Method - The Retirement Rate Method uses actual Company retirement experience to develop a survivor curve (observed life table) which is used to determine the average service life being experienced in the account under study. Computer processing provides the opportunity to review various experience bands throughout the life of the account to observe trends and changes. For each experience band studied, the "observed life table" is constructed based on retirement experience within the band of years. In some cases, the total life of the account has not been achieved and the experienced life table, when plotted, results in a "stub curve." It is this "stub curve" or total life curve, if achieved, which is matched or fitted to a standard Survivor curve. The matching process is performed both by computer analysis, using a least squares technique, and by manually plotting observed life tables to which smooth curves are fitted. The fitted smooth curve provides the basis to determine the average service life of the property group under study.

Simulated Balances Method - In this method of analysis, simulated surviving balances are determined for each balance included in the test band by multiplying each proceeding years original gross additions installed by the Company by the appropriate factor of each Standard Survivor Curve, summing the products, and comparing the results with the related year end plant balance to determine the "best fitting" curve and life within the test period. Various test bands are reviewed to determine trends or changes to indicated service lives in various bands of years. By definition, the curve with the "best fit" is the curve which produces simulated plant balances that most closely matches the actual plant balances as determined by the sum of the "least squares". The sum of the "least squares" is arrived at by starting with the difference between the simulated balances and the actual balance for a given year, squaring the difference, and the curve which produces the smallest sum (of squared difference) is judged to be the "best fit".

Period Retirements Method - The application of the Period Retirements Method is similar to the "Simulated Plant Balances" Method, except the procedure utilizes an Standard Survivor Curve and service life to simulate annual retirements instead of balances in performing the "least squares" fitting process during the test period. This procedure does tend to experience wider fluctuations due to the greater variations in level of experienced retirements versus additions and balances thereby producing greater variation in the study results.

Life Span Method - The Life Span or Forecast Method is a method utilized to study various accounts in which the expected retirement dates of specific property or locations can be reasonably estimated. In the Life Span Method, an estimated probable retirement year is determined for each location of the property group. An example of this would be a structure account, in which the various segments of the account are "life spanned" to a probable retirement date which is determined after considering a number of factors, such as management plans, industry standards, the original construction date, subsequent additions, resultant average age and the current - as well as the overall - expected service life of the property being studied. If in the past the property has experienced interim retirements, these are studied to determine an interim retirement rate. Otherwise, interim retirement rate parameters are estimated for properties which are anticipated to experience such retirements. The selected interim service life parameters (Iowa curve and life) are then used with the vintage investment and probable retirement year of the property to determine the average remaining life as of the study date. No attempt is made to include any anticipated additions to the property subsequent to the study date. The recovery of such additions if made, is reflected when preparing subsequent depreciation studies.

Judgement Method - Standard quantitative methods such as the Retirement Rate Method, Simulated Plant Record Method, etc. are normally utilized to analyze a Company's available historical service life data. The results of the analysis together with information provided by management as well as judgement are utilized in estimating the prospective recommended average service lives. However, there are some circumstances where sufficient retirements have not occurred, or where prospective plans or guidelines are unavailable. In these circumstances, judgement alone is utilized to estimate service lives based upon service lives used by other utilities for this class of plant as well as what is considered to be a reasonable life for this plant giving consideration to the current age and use of the facilities.

SECTION 4

SOUTHWEST GAS CORPORATION
System Allocable

Study Results

Account 390.10 - Structures and Improvements

The Company's investment in this account totals $11,700,876 of which a large portion is related to the Company's Building C of the corporate complex. The surviving investment has achieved a current average age of 13.14 years and is presently being depreciated based upon an annual depreciation rate of 2.46 percent. Retirements totaling $4,734,369 occurred relative to this property account over the life of the investment, of which $3.26 million occurred during 1982 and $500,000 plus was retired during 1993. The average overall age of the total retirements was 10.2 years. The 1982 retirement of $3.26 million was related to the sale and lease back of the headquarters building. Furthermore, a 1993 retirement was related to the retirement of a staff training center located at the old Southern Nevada Operations Center.

An analysis of the historical data, excluding the sale lease back transaction, produces a very short life indication of twenty-five (25) plus years. However, based upon the account content and more typical property lives, an Iowa 40-R3 life and curve is recommended for the property investment. Application of the recommended service life parameters to the Company's current surviving investment produces an average remaining life of 27.5 years. Net salvage relative to retirements totaling $786,265 occurring during the period 1985-2002 aggregated approximately five (5) percent. Net salvage of five (5) percent is estimated for the property class and the resulting annual depreciation rate is 2.50 percent.

Account 391.00 - Office Furniture and Equipment

The Company's current investment in office furniture and fixtures totals $7,757,739, has achieved a current average age of 7.0 years, and is presently being depreciated utilizing an annual depreciation rate of 3.99 percent. Retirements totaling $6,574,530, which occurred at an average age of 11.9 years during the overall retirement band, were analyzed via the Retirement Rate Method. This analysis identified that the property has experienced life characteristics representative of an Iowa 14-L2 life and curve. Application of the estimated service life parameters to the Company's current surviving investment produced an average remaining life of 9.1 years for this property account.

An analysis of the Company's historical salvage data during the years 1985-2002 identifies that varying levels of net salvage have been received relative to retirements of property from this account. The overall average net salvage achieved was approximately zero (0) percent positive salvage. In some years, such as 1985, the Company experienced positive salvage. This salvage was related to the Company's prior policy of placing retired property in an inventory account for possible later use. The accounting practice has been since discontinued and the furniture was disposed. Furthermore, measurable levels of positive net salvage is not typically experienced by this property class.

In conjunction with the retirement of office furniture and fixtures companies typically experience little, if any, net salvage. Based upon the Company's recent experience and future expectancies, future net salvage is estimated at zero (0) percent and when utilized together with the recommended service life parameters and the Company's investment produces an average remaining life depreciation rate of 8.16 percent.

Account 391.10 - Computer Equipment

The Company's investment in this account totals $13,757,912, has attained a current average age of 3.9 years, and is presently being depreciated based upon an annual depreciation rate of 30.01 percent. The property in this account is subject to a high level of obsolescence and related replacement due to rapid development of new technology.

During May 1999, the Company completed a Company-wide review of its assets in this account to determine what assets were no longer used in the Company's operations. The result of this analysis indicated that investments totaling $1,283,526 should have been previously retired. Subsequent to the retirement adjustments, the property group's resulting accrued depreciation reserve is extremely low given the property's age and typical useful life. The remaining useful assets are principally PC's and peripheral equipment plus investments in the Company's mapping and field order system.

Retirements totaling $28,711,644, which occurred at an average age of 6.5 years during the overall experience band, were analyzed via the Retirement Rate Method. An analysis of both the overall, as well as the more recent five (5) year band, indicates a service life of approximately six (6) years. This property class, which is impacted by the technological advances, routinely requires an even greater frequency of upgrades and/or replacements. Accordingly, an Iowa 6-L2 life and curve is estimated for this property. Application of the recommended service life parameters to the Company's current surviving investment produces an average remaining life of 3.5 years.

An analysis of the historical salvage data during the period 1985-2002 totaling $28.7 million indicates that several earlier years experienced amounts of positive salvage, however, overall salvage was approximately one (1) percent. More recent years experience was zero (0) percent. Future retirements of property from this property group are not anticipated to produce measurable amounts of positive net salvage. Accordingly, zero (0) percent future net salvage is estimated for this property group. The resulting annual depreciation rate is 16.15 percent.

Account 392 - Transportation Equipment

The investment in this account totaling $2,904,810 which currently is depreciated utilizing an annual depreciation rate of 6.42 percent, has currently attained an average age of 3.6 years. The Company's current vehicle policy is to utilize automobiles and light trucks for eight (8) years or 80,000 miles, whichever comes first before replacing them with new vehicles. The policy is subject to exceptions of high maintenance costs or other damages which rendered the vehicle uneconomical to repair or operate.

Retirements totaling $3,777,124, which occurred at an average age of 5.4 years were analyzed for the overall experience period, as well as the various other interim bands. This analysis shows that the Company's automobiles are routinely being replaced between ages of less than three (3) to five (5) years. Based upon the retirement rate analysis results, giving consideration to both the overall and recent experience, an Iowa 7-L0 life and curve is estimated for the future life of this property group. Application of the proposed service life parameters to the Company's current surviving investment produces an average remaining life of 5.3 years.

An analysis of the Company's retirements and related salvage during the period 1985-2002 indicates that the Company has continuously received positive salvage relative to disposal of its automobiles. During the overall study period, annual net salvage ranged from less than five (5) percent to more than twenty-five (25) percent and averaged eighteen (18) percent. Based upon the Company's range of overall experience, future net salvage of fifteen (15) percent was incorporated in developing the resulting depreciation rate for this property. Utilizing the estimated average service life and salvage factors together with the Company's current surviving investment produces an average remaining life depreciation rate of 7.20 percent.

Account 393 - Stores Equipment

The Company's investment in this account totals $29,429, has attained a current average age of 11.9 years, and is presently being depreciated utilizing an annual depreciation rate of 4.45 percent. The account investment is quite small and is related to general storeroom equipment located at the Company's headquarters building. Retirements totaling $21,993, which occurred at an average age of 11.1 years, were analyzed via the Retirement Rate Method which produced a service life indication of an Iowa 14-R1 life and curve. Application of the recommended service life parameters to the Company's current surviving investment produces an average remaining life of 6.6 years.

An analysis of the Company's salvage experience was completed for the period 1985-2002 to identify the level of net salvage achieved with past retirements. The result of the analysis indicates that the Company has experienced no salvage. This property group currently has a negative depreciation reserve balance (see Section 1 page 1-3 of this report for a discussion of the reasons for the negative reserve balance and the basis for recovery of the un-recovered investment). Based upon the Company's experience, future net salvage is estimated at zero (0) percent and the resulting annual depreciation rate is 16.03 percent.

Account 394 - Tools, Shop and Garage Equipment

The investment in this account totaling $227,375 is related to tools, garage, and work equipment utilized to train Company employees to provide service to the Company's customers. The current property investment has attained an average age of 6.5 years and is presently being depreciated by an annual depreciation rate of 4.10 percent.

Retirements totaling $146,131, which occurred at an average age of 10.7 years were analyzed via the Retirement Rate Method. The overall analysis of this account identifies that the property group has been achieving an average service life of approximately fourteen (14) years. Based upon the overall life indication, an Iowa 14-L0.5 life and curve is being utilized for this property group and when applied to the current surviving investment produces an average remaining life of 10.3 years. This property group currently has a negative depreciation reserve balance (see Section 1 page 1-3 of this report for a discussion of the reasons for the negative reserve balance and the basis for recovery of the un-recovered investment).

The net salvage experience was analyzed for the period 1985-2002 and identified that the Company has experienced no net salvage in conjunction with retirements during the study period. Based upon recent experience, future net salvage is estimated at zero (0) percent. The resulting recommended annual depreciation rate is 11.16 percent.

Account 395 - Laboratory Equipment

The Company's current investment in this account totals $229,994 and is currently being depreciated utilizing an annual depreciation rate of 3.05 percent. The surviving property investment has attained a current average age of 11.8 years. Retirements during the study period totaling $71,607, which occurred at an average age of 13.6 years, were analyzed via the Retirement Rate Method. The analysis of the limited available data provided a general life indication of twenty-three (23) years. Accordingly, an average service life of an Iowa 23-R1.5 is recommended for this property group giving consideration to general industry lives. Application of the recommended service life parameters to the Company's current surviving investment produces an average remaining life of 14.1 years.

The Company's available historical salvage data was analyzed during the period 1985-2002 and identified that the property retirements have experienced no net salvage. Based upon the experience, future net salvage is estimated at zero (0) percent and when combined with the recommended service life parameters and the current investment produces an average remaining life depreciation rate of 4.77 percent.

Account 397 - Communication Equipment

This investment, which totals $4,849,540, is related to a data network and the Company's telephone system. The Company's investment in this account is currently depreciated utilizing an annual depreciation rate of 9.88 percent and has attained a current average age of 5.4 years.

Historical retirements totaling $1,319,273, which occurred at an average age of 9.7 years over the life of the account, were analyzed via the Retirement Rate Method and produced a general average service life indication of eleven (11) years. Based upon the historical data analysis results, as well as the account content, an Iowa 11-R3 life and curve is recommended for this property and when applied to current surviving investment produces an average remaining life of 6.2 years.

An analysis of the Company's salvage experience for the years 1985-2002 indicates that only limited amounts of salvage were achieved relative to past property retirements.

The overall average was less than one (1) percent. Based upon recent experience, future net salvage is estimated at zero (0) percent and the resulting recommended remaining life depreciation rate is 8.51 percent.

Account 397.20 - Telemetry Equipment

The Company's current surviving investment totals $454,151 which has achieved a current average age of 4.5 years and is presently being depreciated utilizing an annual depreciation rate of 20.38 percent. An analysis of retirements totaling $1,004,079, which occurred at an average age of 5.4 years was completed via the Retirement Rate Method. Based upon these analysis results, along with consideration of the account content and future expectations, a service life of an Iowa 8-R3 life and curve is estimated for this property group. Application of the recommended service life parameters to the Company's surviving investment produces an average remaining life of 4.0 years. This property group currently has a negative depreciation reserve balance (see Section 1 page 1-3 of this report for a discussion of the reasons for the negative reserve balance and the basis for recovery of the un-recovered investment).

Net salvage relative to past retirements of property from this account was studied for the period 1985-2002. Based upon the available historical information, and future expectations, future net salvage is estimated at zero (0) percent and when combined with the service life parameters and current surviving investment produces an average remaining life depreciation rate of 40.23 percent.

Account 398 - Miscellaneous Equipment

The present surviving investment in this account totals $720,287, has attained a current average age of 5.9 years, and is presently being depreciated utilizing an annual depreciation rate of 5.65 percent. Retirements totaling $805,451, which occurred at an average age of 12.5 years, were analyzed via the Retirement Rate Method and provided the basis of the estimated Iowa 14-L0.5 service life parameters. Application of the recommended life and curve to the Company's current surviving investment produces an average remaining life of 10.8 years. The investment in this property account is generally related to audio/visual equipment, as well as safety and training equipment. This property group currently has a negative depreciation reserve balance (see Section 1 page 1-3 of this report for a discussion of the reasons for the negative reserve balance and the basis for recovery of the un-recovered investment).

An analysis of the Company's salvage experience relative to retirements from this account was studied for the period 1985-2002. This analysis identified that net salvage levels have varied, averaging less than one (1) percent overall, while more recent years have been zero (0) percent. Accordingly, future net salvage is estimated at zero (0) percent. The resulting annual depreciation rate is 11.09 percent.

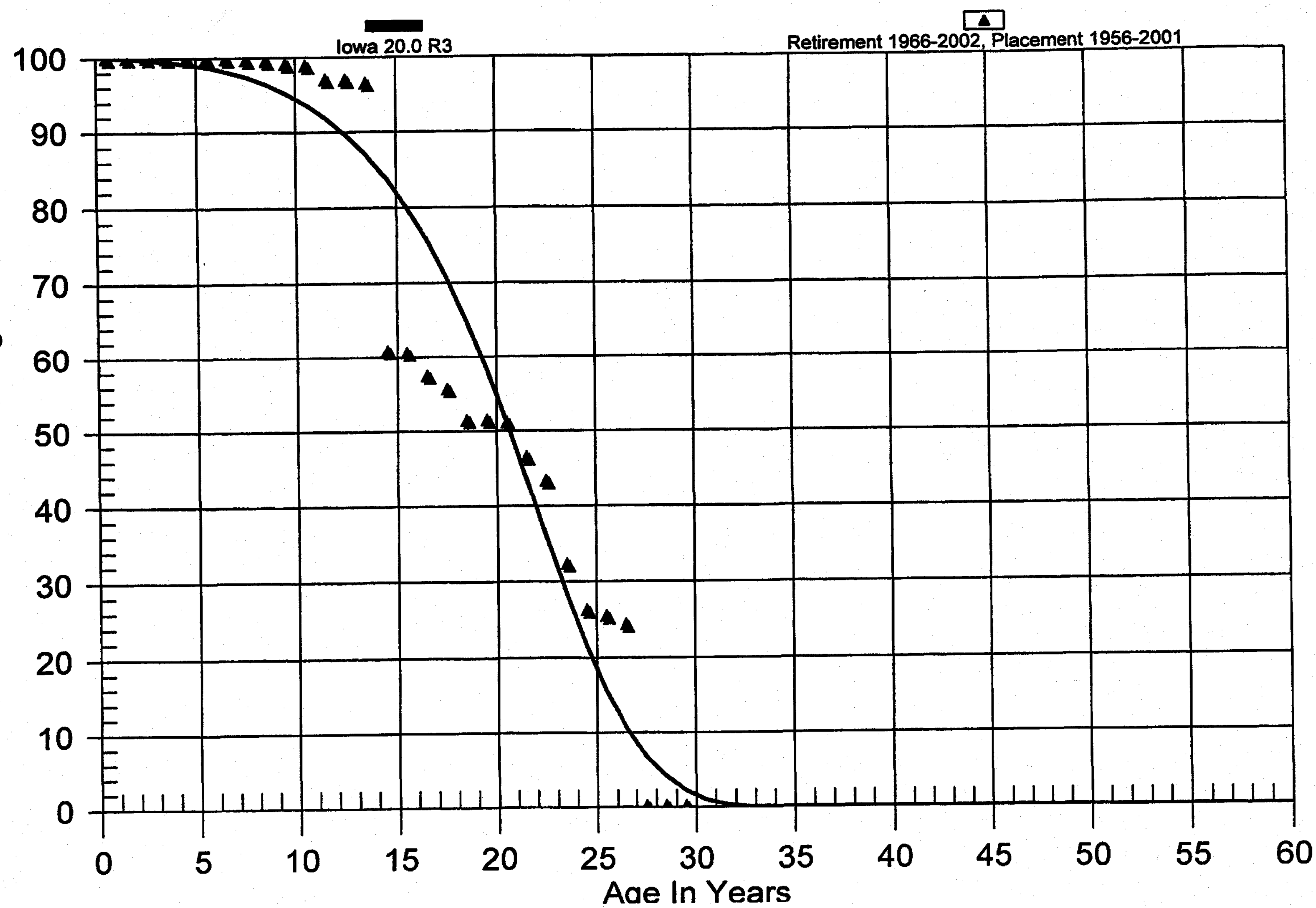
SECTION 5

Southwest Gas Corporation

System Allocable Plant

390.10 STRUCTURES - OWNED

Original And Smooth Survivor Curves



Southwest Gas Corporation
System Allocable Plant
390.10 STRUCTURES - OWNED

Observed Life Table
Retirement Expr. 1966 TO 2002
Placement Years 1956 TO 2001

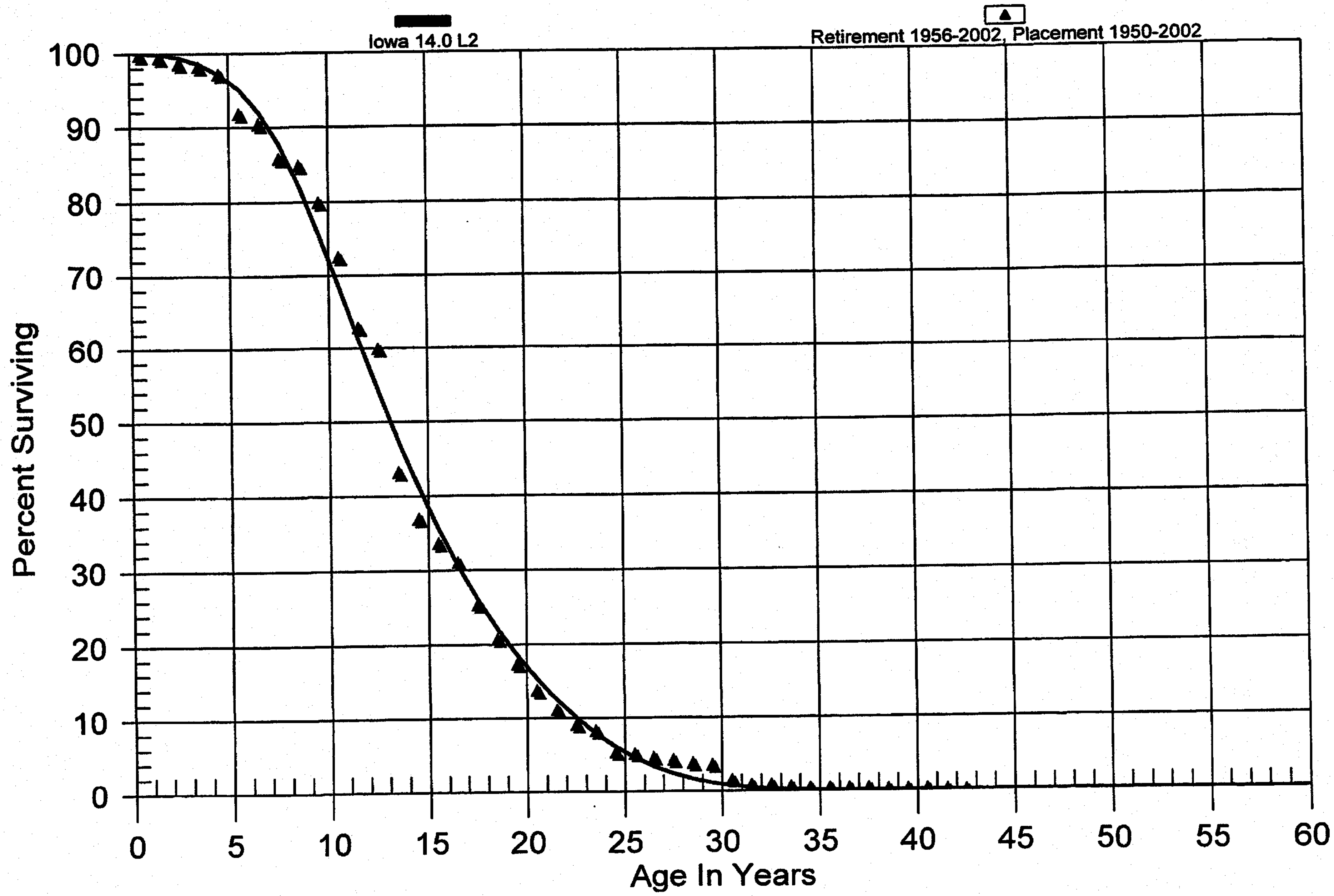
Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
0.0 - 0.5	$15,769,678.00	$0.00	0.00000	100.00
0.5 - 1.5	$15,778,758.00	$0.00	0.00000	100.00
1.5 - 2.5	$15,520,030.00	$3,277.00	0.00021	100.00
2.5 - 3.5	$15,152,100.00	$2,881.00	0.00019	99.98
3.5 - 4.5	$15,051,194.00	$10,757.00	0.00071	99.96
4.5 - 5.5	$15,045,771.00	$4,973.00	0.00033	99.89
5.5 - 6.5	$14,945,520.00	$313.00	0.00002	99.86
6.5 - 7.5	$14,952,282.00	$25,870.00	0.00173	99.85
7.5 - 8.5	$15,139,267.00	$14,997.00	0.00099	99.68
8.5 - 9.5	$12,548,437.00	$53,954.00	0.00430	99.58
9.5 - 10.5	$12,472,260.00	$30,571.00	0.00245	99.15
10.5 - 11.5	$12,396,403.00	$236,612.00	0.01909	98.91
11.5 - 12.5	$12,147,214.00	$3,523.00	0.00029	97.02
12.5 - 13.5	$12,090,319.00	$59,983.00	0.00496	96.99
13.5 - 14.5	$1,502,063.00	$554,310.00	0.36903	96.51
14.5 - 15.5	$945,688.00	$4,389.00	0.00464	60.90
15.5 - 16.5	$463,804.00	$23,663.00	0.05102	60.61
16.5 - 17.5	$440,141.00	$13,838.00	0.03144	57.52
17.5 - 18.5	$426,303.00	$32,298.00	0.07576	55.71
18.5 - 19.5	$394,005.00	$0.00	0.00000	51.49
19.5 - 20.5	$394,005.00	$2,631.00	0.00668	51.49
20.5 - 21.5	$391,374.00	$35,564.00	0.09087	51.15
21.5 - 22.5	$355,810.00	$24,274.00	0.06822	46.50
22.5 - 23.5	$331,536.00	$84,006.00	0.25338	43.33
23.5 - 24.5	$247,530.00	$46,360.00	0.18729	32.35
24.5 - 25.5	$201,170.00	$5,869.00	0.02917	26.29
25.5 - 26.5	$195,301.00	$8,684.00	0.04446	25.52
26.5 - 27.5	$186,617.00	$185,228.00	0.99256	24.39
27.5 - 28.5	$1,389.00	$0.00	0.00000	0.18
28.5 - 29.5	$1,389.00	$0.00	0.00000	0.18

Southwest Gas Corporation

System Allocable Plant

391.00 OFFICE FURITURE & EQUIPMENT

Original And Smooth Survivor Curves



Southwest Gas Corporation
System Allocable Plant
391.00 OFFICE FURITURE & EQUIPMENT

Observed Life Table
Retirement Expr. 1956 TO 2002
Placement Years 1950 TO 2002

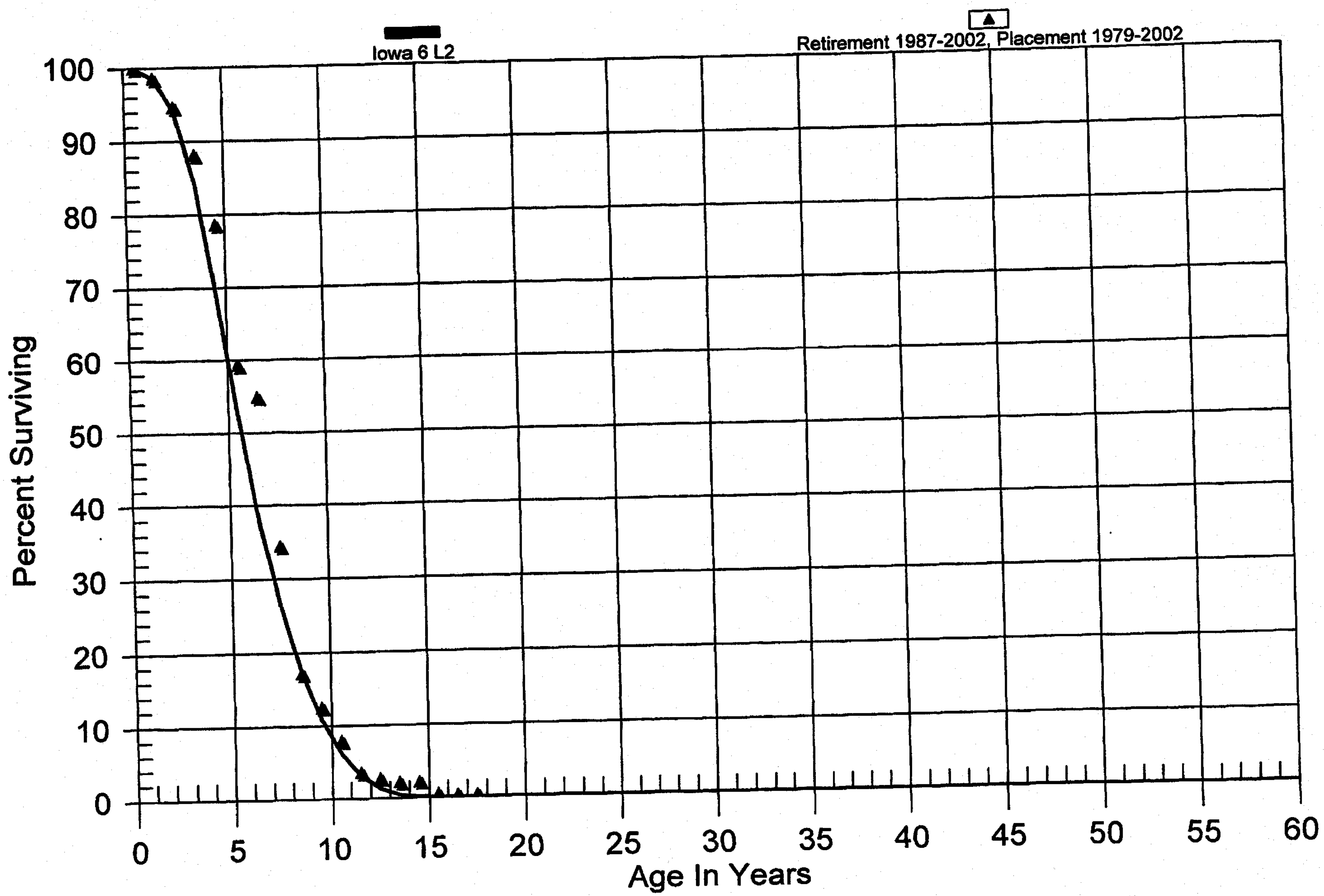
Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
0.0 - 0.5	$14,328,224.00	$32,357.00	0.00226	100.00
0.5 - 1.5	$13,480,014.00	$50,373.00	0.00374	99.77
1.5 - 2.5	$12,164,021.00	$105,289.00	0.00866	99.40
2.5 - 3.5	$11,833,022.00	$41,602.00	0.00352	98.54
3.5 - 4.5	$10,815,148.00	$111,634.00	0.01032	98.19
4.5 - 5.5	$10,149,098.00	$560,253.00	0.05520	97.18
5.5 - 6.5	$9,238,808.00	$137,138.00	0.01484	91.82
6.5 - 7.5	$8,779,993.00	$445,332.00	0.05072	90.45
7.5 - 8.5	$8,032,421.00	$97,992.00	0.01220	85.87
8.5 - 9.5	$7,700,873.00	$444,032.00	0.05766	84.82
9.5 - 10.5	$6,188,259.00	$575,936.00	0.09307	79.93
10.5 - 11.5	$5,544,299.00	$733,647.00	0.13232	72.49
11.5 - 12.5	$4,690,522.00	$218,893.00	0.04667	62.90
12.5 - 13.5	$4,413,218.00	$1,231,692.00	0.27909	59.96
13.5 - 14.5	$3,029,928.00	$439,895.00	0.14518	43.23
14.5 - 15.5	$2,442,231.00	$220,246.00	0.09018	36.95
15.5 - 16.5	$2,061,915.00	$155,681.00	0.07550	33.62
16.5 - 17.5	$1,790,462.00	$329,246.00	0.18389	31.08
17.5 - 18.5	$1,212,482.00	$220,033.00	0.18147	25.36
18.5 - 19.5	$728,704.00	$119,647.00	0.16419	20.76
19.5 - 20.5	$597,512.00	$123,422.00	0.20656	17.35
20.5 - 21.5	$360,770.00	$68,465.00	0.18977	13.77
21.5 - 22.5	$237,539.00	$42,949.00	0.18081	11.16
22.5 - 23.5	$189,520.00	$17,241.00	0.09097	9.14
23.5 - 24.5	$55,732.00	$19,584.00	0.35140	8.31
24.5 - 25.5	$36,148.00	$1,282.00	0.03547	5.39
25.5 - 26.5	$33,757.00	$3,350.00	0.09924	5.20
26.5 - 27.5	$30,407.00	$2,468.00	0.08117	4.68
27.5 - 28.5	$26,829.00	$2,656.00	0.09900	4.30
28.5 - 29.5	$24,173.00	$1,357.00	0.05614	3.88
29.5 - 30.5	$22,816.00	$12,778.00	0.56005	3.66
30.5 - 31.5	$10,038.00	$4,401.00	0.43843	1.61
31.5 - 32.5	$5,637.00	$0.00	0.00000	0.90
32.5 - 33.5	$3,659.00	$1,027.00	0.28068	0.90
33.5 - 34.5	$2,632.00	$931.00	0.35372	0.65
34.5 - 35.5	$1,701.00	$0.00	0.00000	0.42
35.5 - 36.5	$1,701.00	$0.00	0.00000	0.42

Southwest Gas Corporation

System Allocable Plant

391.10 COMPUTER EQUIPMENT

Original And Smooth Survivor Curves



Southwest Gas Corporation
System Allocable Plant
391.10 COMPUTER EQUIPMENT

Observed Life Table
Retirement Expr. 1987 TO 2002
Placement Years 1979 TO 2002

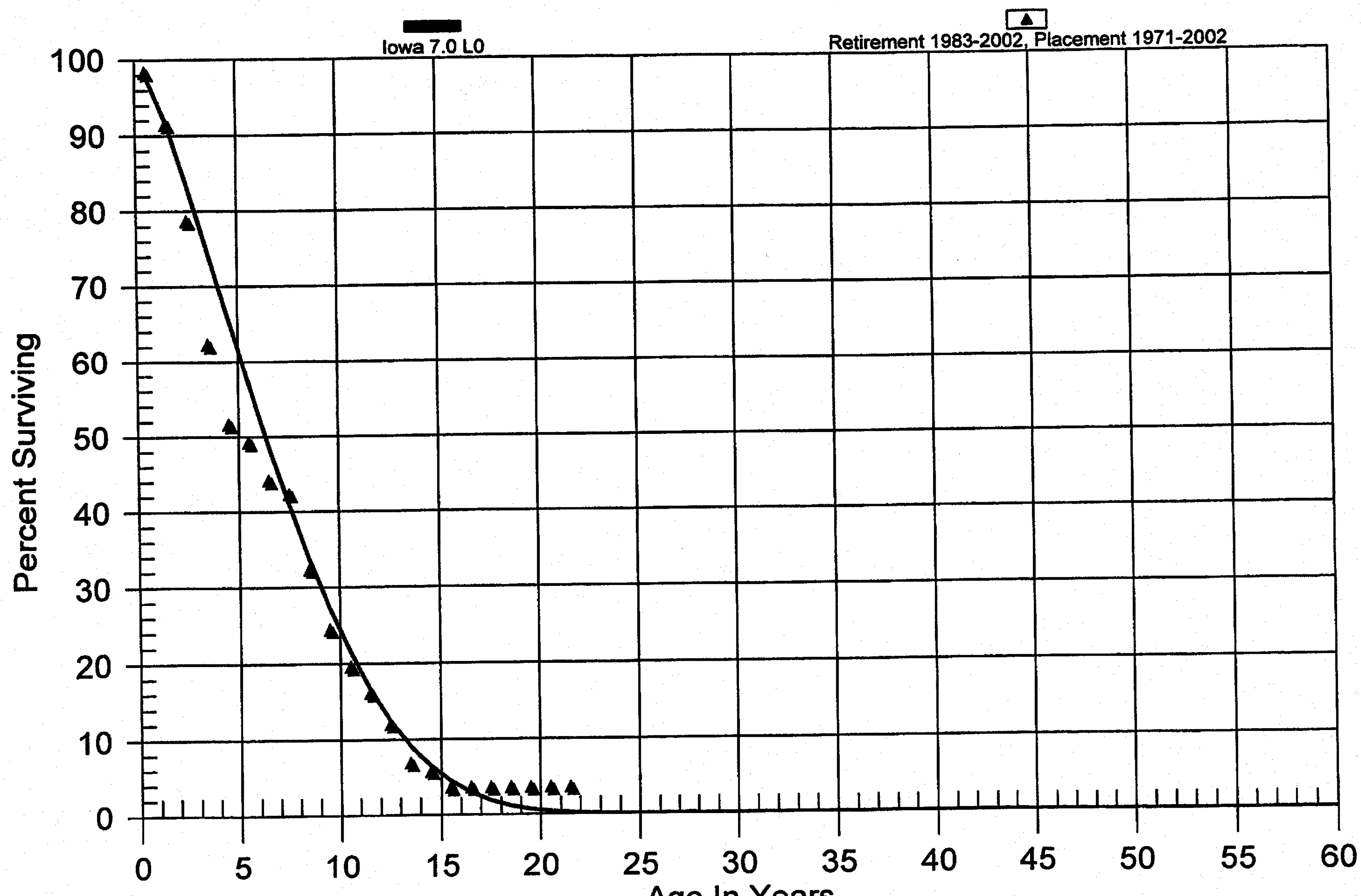
Age Interval	*$ Surviving At Beginning of Age Interval*	*$ Retired During The Age Interval*	*Retirement Ratio*	*% Surviving At Beginning of Age Interval*
0.0 - 0.5	$36,447,984.00	$7,732.00	0.00021	100.00
0.5 - 1.5	$39,214,152.00	$540,745.00	0.01379	99.98
1.5 - 2.5	$36,305,626.00	$1,437,789.00	0.03960	98.60
2.5 - 3.5	$33,691,578.00	$2,312,334.00	0.06863	94.70
3.5 - 4.5	$29,515,373.00	$3,182,239.00	0.10782	88.20
4.5 - 5.5	$25,946,519.00	$6,414,264.00	0.24721	78.69
5.5 - 6.5	$18,309,066.00	$1,349,096.00	0.07368	59.23
6.5 - 7.5	$15,986,089.00	$5,942,296.00	0.37172	54.87
7.5 - 8.5	$8,463,682.00	$4,238,645.00	0.50080	34.47
8.5 - 9.5	$3,667,955.00	$997,703.00	0.27201	17.21
9.5 - 10.5	$2,494,145.00	$900,004.00	0.36085	12.53
10.5 - 11.5	$1,581,255.00	$877,735.00	0.55509	8.01
11.5 - 12.5	$683,718.00	$167,100.00	0.24440	3.56
12.5 - 13.5	$503,329.00	$90,051.00	0.17891	2.69
13.5 - 14.5	$408,874.00	$1,056.00	0.00258	2.21
14.5 - 15.5	$309,818.00	$237,237.00	0.76573	2.20
15.5 - 16.5	$57,072.00	$12,628.00	0.22126	0.52
16.5 - 17.5	$2,990.00	$368.00	0.12308	0.40

Southwest Gas Corporation

System Allocable Plant

392.00 TRANSPORTATION EQUIPMENT

Original And Smooth Survivor Curves



Southwest Gas Corporation
System Allocable Plant
392.00 TRANSPORTATION EQUIPMENT

Observed Life Table
Retirement Expr. 1983 TO 2002
Placement Years 1971 TO 2002

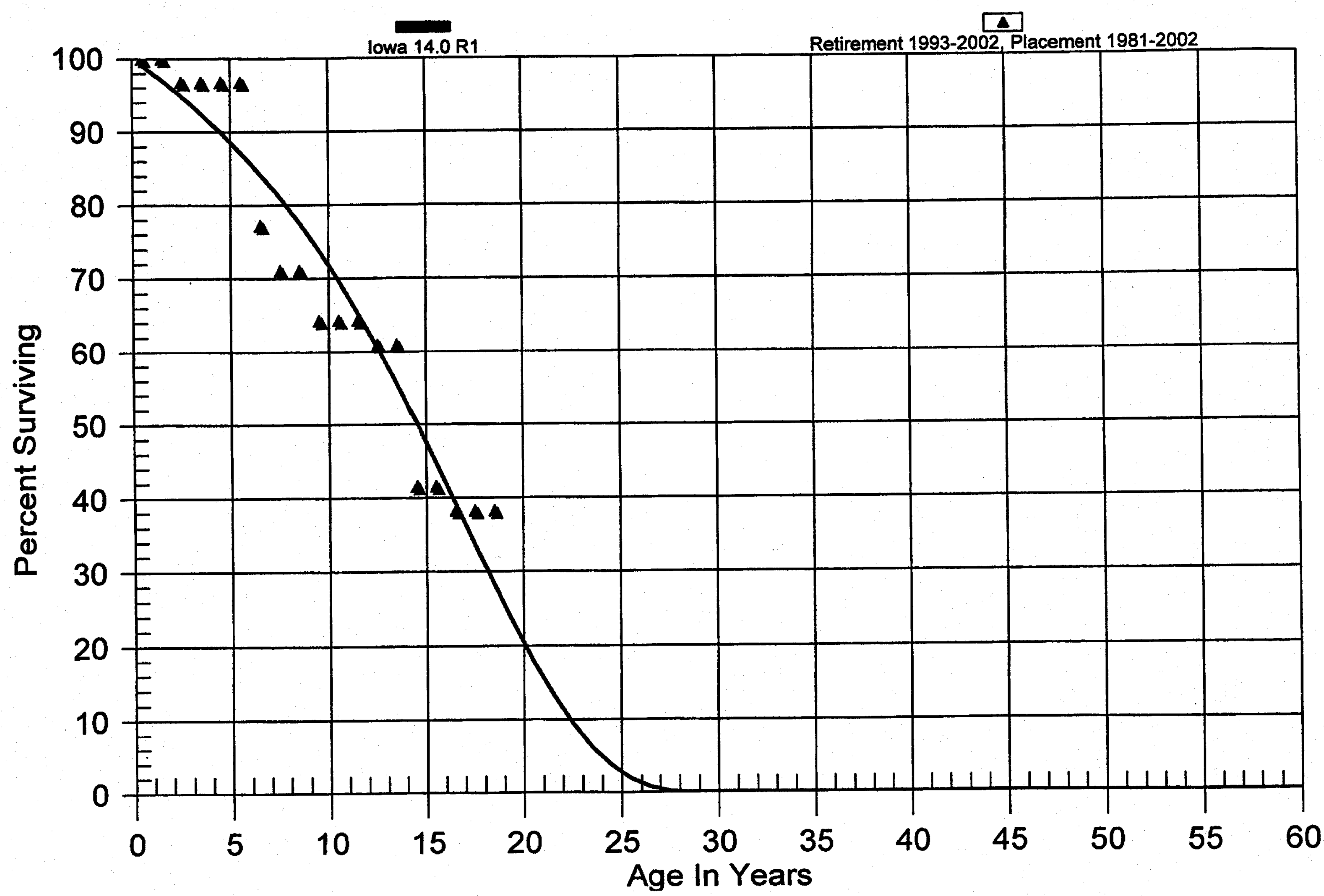
Age Interval	*$ Surviving At Beginning of Age Interval*	*$ Retired During The Age Interval*	*Retirement Ratio*	*% Surviving At Beginning of Age Interval*
0.0 - 0.5	$6,353,064.00	$105,608.00	0.01662	100.00
0.5 - 1.5	$5,935,576.00	$412,128.00	0.06943	98.34
1.5 - 2.5	$4,646,346.00	$650,233.00	0.13995	91.51
2.5 - 3.5	$3,794,007.00	$790,590.00	0.20838	78.70
3.5 - 4.5	$2,867,116.00	$490,900.00	0.17122	62.30
4.5 - 5.5	$2,052,468.00	$94,892.00	0.04623	51.64
5.5 - 6.5	$1,748,582.00	$179,956.00	0.10292	49.25
6.5 - 7.5	$1,466,949.00	$60,619.00	0.04132	44.18
7.5 - 8.5	$1,140,735.00	$269,019.00	0.23583	42.35
8.5 - 9.5	$836,626.00	$205,209.00	0.24528	32.37
9.5 - 10.5	$616,107.00	$122,332.00	0.19856	24.43
10.5 - 11.5	$471,395.00	$82,033.00	0.17402	19.58
11.5 - 12.5	$418,042.00	$106,745.00	0.25535	16.17
12.5 - 13.5	$286,258.00	$121,707.00	0.42517	12.04
13.5 - 14.5	$162,886.00	$26,996.00	0.16574	6.92
14.5 - 15.5	$79,082.00	$29,477.00	0.37274	5.77
15.5 - 16.5	$28,680.00	$0.00	0.00000	3.62
16.5 - 17.5	$28,680.00	$0.00	0.00000	3.62
17.5 - 18.5	$28,680.00	$0.00	0.00000	3.62
18.5 - 19.5	$28,680.00	$334.00	0.01165	3.62
19.5 - 20.5	$28,346.00	$0.00	0.00000	3.58
20.5 - 21.5	$28,346.00	$0.00	0.00000	3.58

Southwest Gas Corporation

System Allocable Plant

393.00 STORES EQUIPMENT

Original And Smooth Survivor Curves



Southwest Gas Corporation

System Allocable Plant

393.00 STORES EQUIPMENT

Observed Life Table

Retirement Expr. 1993 TO 2002
Placement Years 1981 TO 2002

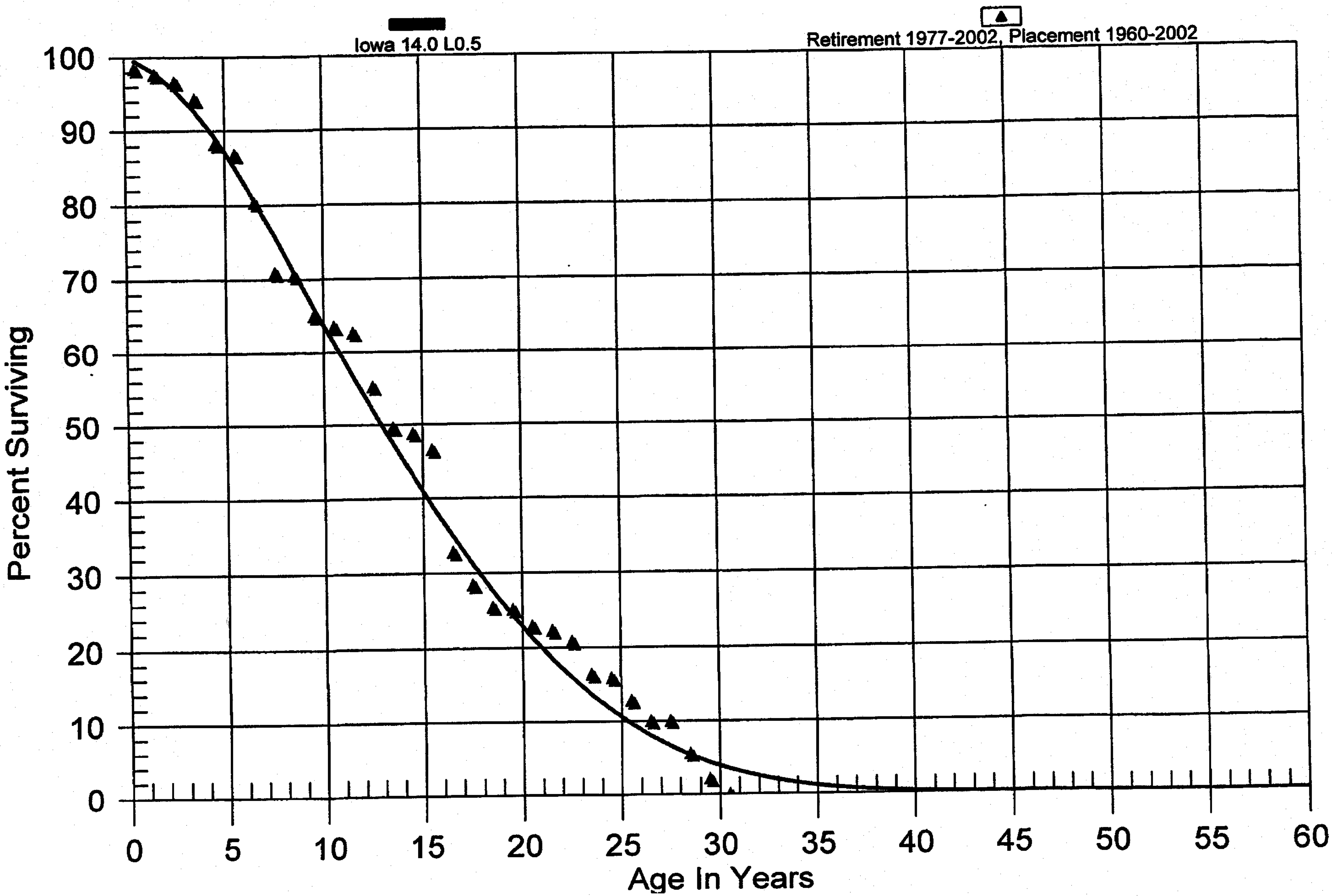
Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
0.0 - 0.5	$18,860.00	$0.00	0.00000	100.00
0.5 - 1.5	$14,862.00	$0.00	0.00000	100.00
1.5 - 2.5	$16,352.00	$530.00	0.03241	100.00
2.5 - 3.5	$15,822.00	$0.00	0.00000	96.76
3.5 - 4.5	$17,200.00	$0.00	0.00000	96.76
4.5 - 5.5	$22,965.00	$0.00	0.00000	96.76
5.5 - 6.5	$22,965.00	$4,638.00	0.20196	96.76
6.5 - 7.5	$28,114.00	$2,245.00	0.07985	77.22
7.5 - 8.5	$35,841.00	$0.00	0.00000	71.05
8.5 - 9.5	$36,485.00	$3,471.00	0.09513	71.05
9.5 - 10.5	$26,145.00	$0.00	0.00000	64.29
10.5 - 11.5	$26,145.00	$0.00	0.00000	64.29
11.5 - 12.5	$26,846.00	$1,378.00	0.05133	64.29
12.5 - 13.5	$25,468.00	$0.00	0.00000	60.99
13.5 - 14.5	$25,468.00	$8,099.00	0.31801	60.99
14.5 - 15.5	$11,604.00	$0.00	0.00000	41.60
15.5 - 16.5	$11,604.00	$931.00	0.08023	41.60
16.5 - 17.5	$10,673.00	$0.00	0.00000	38.26
17.5 - 18.5	$701.00	$0.00	0.00000	38.26

Southwest Gas Corporation

System Allocable Plant

394.00 TOOLS, SHOP & GARAGE EQ.

Original And Smooth Survivor Curves



Southwest Gas Corporation
System Allocable Plant
394.00 TOOLS, SHOP & GARAGE EQ.

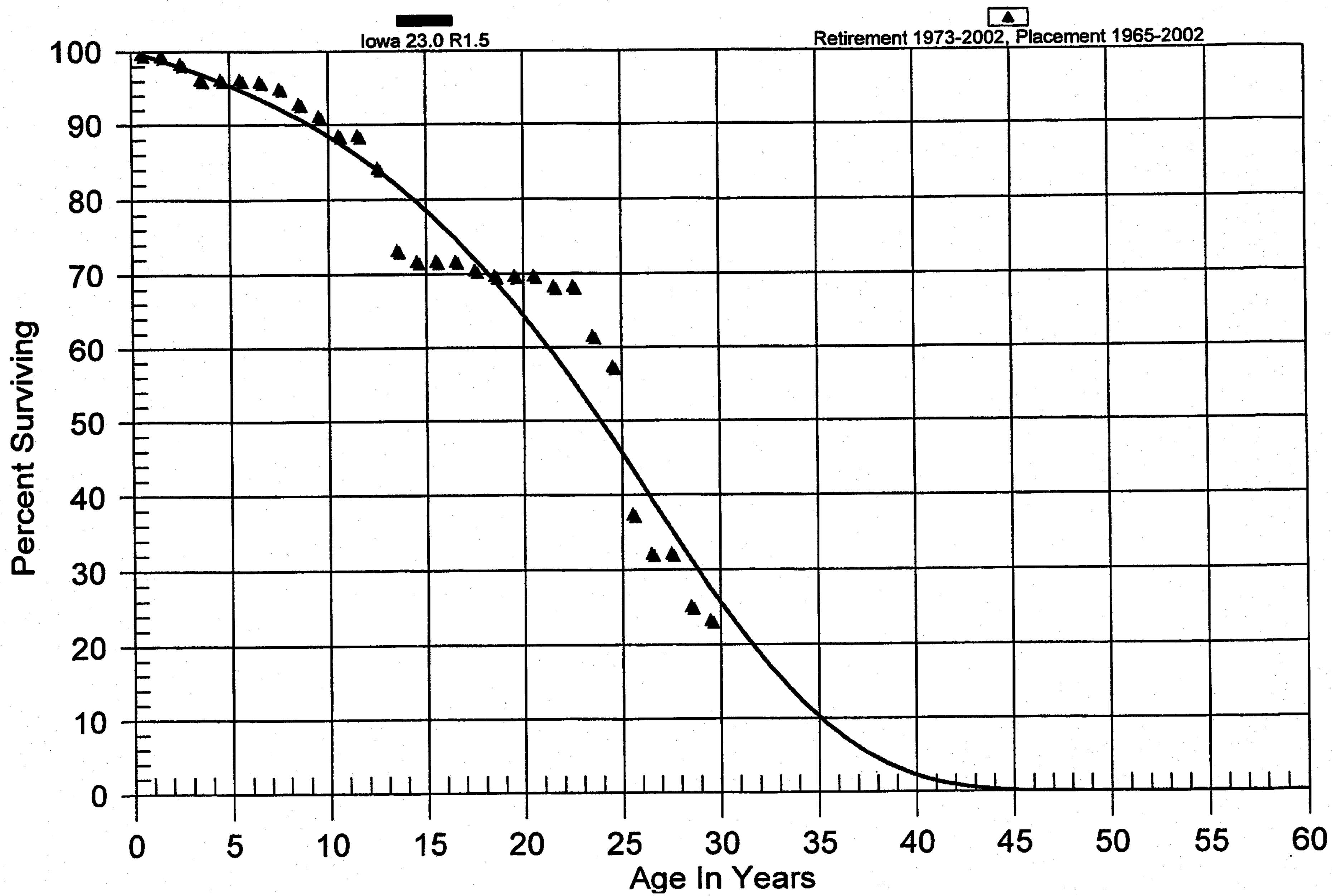
Observed Life Table

Retirement Expr. 1977 TO 2002
Placement Years 1960 TO 2002

Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
0.0 - 0.5	$359,731.00	$5,466.00	0.01519	100.00
0.5 - 1.5	$356,757.00	$2,905.00	0.00814	98.48
1.5 - 2.5	$316,905.00	$3,357.00	0.01059	97.68
2.5 - 3.5	$290,612.00	$6,985.00	0.02404	96.64
3.5 - 4.5	$252,636.00	$16,239.00	0.06428	94.32
4.5 - 5.5	$223,238.00	$3,741.00	0.01676	88.26
5.5 - 6.5	$215,618.00	$15,958.00	0.07401	86.78
6.5 - 7.5	$189,461.00	$22,279.00	0.11759	80.36
7.5 - 8.5	$152,679.00	$829.00	0.00543	70.91
8.5 - 9.5	$125,511.00	$9,737.00	0.07758	70.52
9.5 - 10.5	$103,799.00	$2,453.00	0.02363	65.05
10.5 - 11.5	$70,415.00	$927.00	0.01316	63.51
11.5 - 12.5	$68,826.00	$8,208.00	0.11926	62.68
12.5 - 13.5	$60,618.00	$6,168.00	0.10175	55.20
13.5 - 14.5	$49,667.00	$785.00	0.01581	49.59
14.5 - 15.5	$48,152.00	$2,193.00	0.04554	48.80
15.5 - 16.5	$43,827.00	$12,975.00	0.29605	46.58
16.5 - 17.5	$30,867.00	$4,067.00	0.13176	32.79
17.5 - 18.5	$26,800.00	$2,838.00	0.10590	28.47
18.5 - 19.5	$23,962.00	$306.00	0.01277	25.45
19.5 - 20.5	$23,656.00	$2,084.00	0.08810	25.13
20.5 - 21.5	$21,572.00	$587.00	0.02721	22.92
21.5 - 22.5	$20,985.00	$1,370.00	0.06528	22.29
22.5 - 23.5	$19,615.00	$4,196.00	0.21392	20.84
23.5 - 24.5	$15,419.00	$448.00	0.02906	16.38
24.5 - 25.5	$14,971.00	$2,915.00	0.19471	15.90
25.5 - 26.5	$6,115.00	$1,314.00	0.21488	12.81
26.5 - 27.5	$4,801.00	$0.00	0.00000	10.06
27.5 - 28.5	$4,801.00	$2,127.00	0.44303	10.06
28.5 - 29.5	$2,674.00	$1,664.00	0.62229	5.60
29.5 - 30.5	$1,010.00	$995.00	0.98515	2.12

Southwest Gas Corporation

System Allocable Plant
395.00 LABORATORY EQUIP.
Original And Smooth Survivor Curves

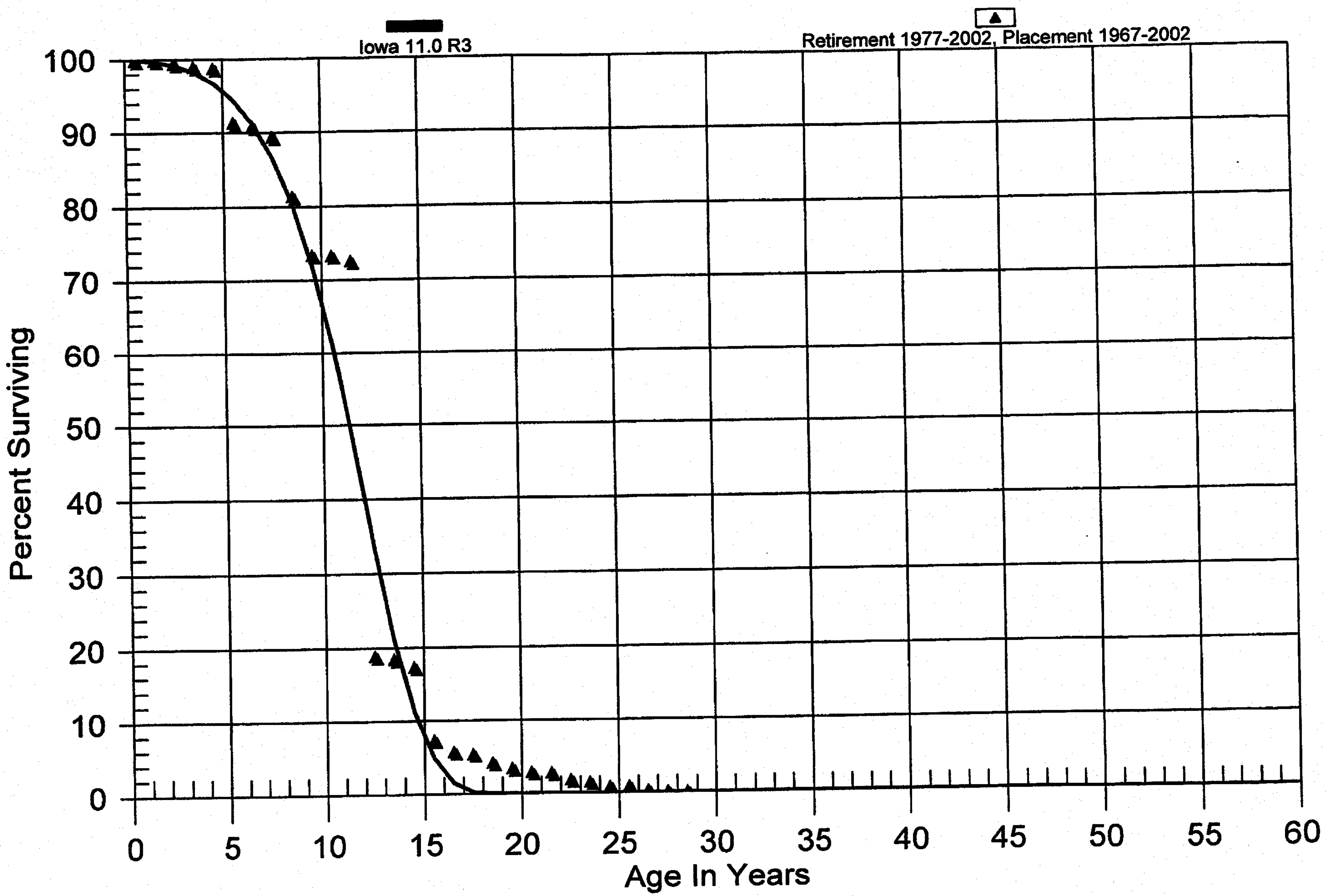


Southwest Gas Corporation
System Allocable Plant
395.00 LABORATORY EQUIP.

Observed Life Table
Retirement Expr. 1973 TO 2002
Placement Years 1965 TO 2002

Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
0.0 - 0.5	$292,919.00	$912.00	0.00311	100.00
0.5 - 1.5	$275,330.00	$843.00	0.00306	99.69
1.5 - 2.5	$274,487.00	$2,865.00	0.01044	99.38
2.5 - 3.5	$273,930.00	$5,942.00	0.02169	98.35
3.5 - 4.5	$273,162.00	$0.00	0.00000	96.21
4.5 - 5.5	$273,162.00	$0.00	0.00000	96.21
5.5 - 6.5	$273,162.00	$814.00	0.00298	96.21
6.5 - 7.5	$269,625.00	$2,705.00	0.01003	95.93
7.5 - 8.5	$259,599.00	$5,660.00	0.02180	94.96
8.5 - 9.5	$251,552.00	$4,574.00	0.01818	92.89
9.5 - 10.5	$230,724.00	$6,568.00	0.02847	91.20
10.5 - 11.5	$222,792.00	$0.00	0.00000	88.61
11.5 - 12.5	$168,973.00	$8,297.00	0.04910	88.61
12.5 - 13.5	$116,750.00	$15,239.00	0.13053	84.26
13.5 - 14.5	$47,960.00	$985.00	0.02054	73.26
14.5 - 15.5	$45,385.00	$0.00	0.00000	71.75
15.5 - 16.5	$36,425.00	$0.00	0.00000	71.75
16.5 - 17.5	$32,159.00	$551.00	0.01713	71.75
17.5 - 18.5	$31,608.00	$331.00	0.01047	70.53
18.5 - 19.5	$31,277.00	$0.00	0.00000	69.79
19.5 - 20.5	$15,321.00	$0.00	0.00000	69.79
20.5 - 21.5	$15,321.00	$316.00	0.02063	69.79
21.5 - 22.5	$15,005.00	$0.00	0.00000	68.35
22.5 - 23.5	$15,005.00	$1,485.00	0.09897	68.35
23.5 - 24.5	$13,520.00	$926.00	0.06849	61.58
24.5 - 25.5	$12,594.00	$4,362.00	0.34636	57.37
25.5 - 26.5	$8,232.00	$1,159.00	0.14079	37.50
26.5 - 27.5	$7,073.00	$0.00	0.00000	32.22
27.5 - 28.5	$7,073.00	$1,538.00	0.21745	32.22
28.5 - 29.5	$5,535.00	$419.00	0.07570	25.21

Southwest Gas Corporation
System Allocable Plant
397.00 COMMUNICATION EQUIPMENT
Original And Smooth Survivor Curves



Southwest Gas Corporation

System Allocable Plant

397.00 COMMUNICATION EQUIPMENT

Observed Life Table

Retirement Expr. 1977 TO 2002
Placement Years 1967 TO 2002

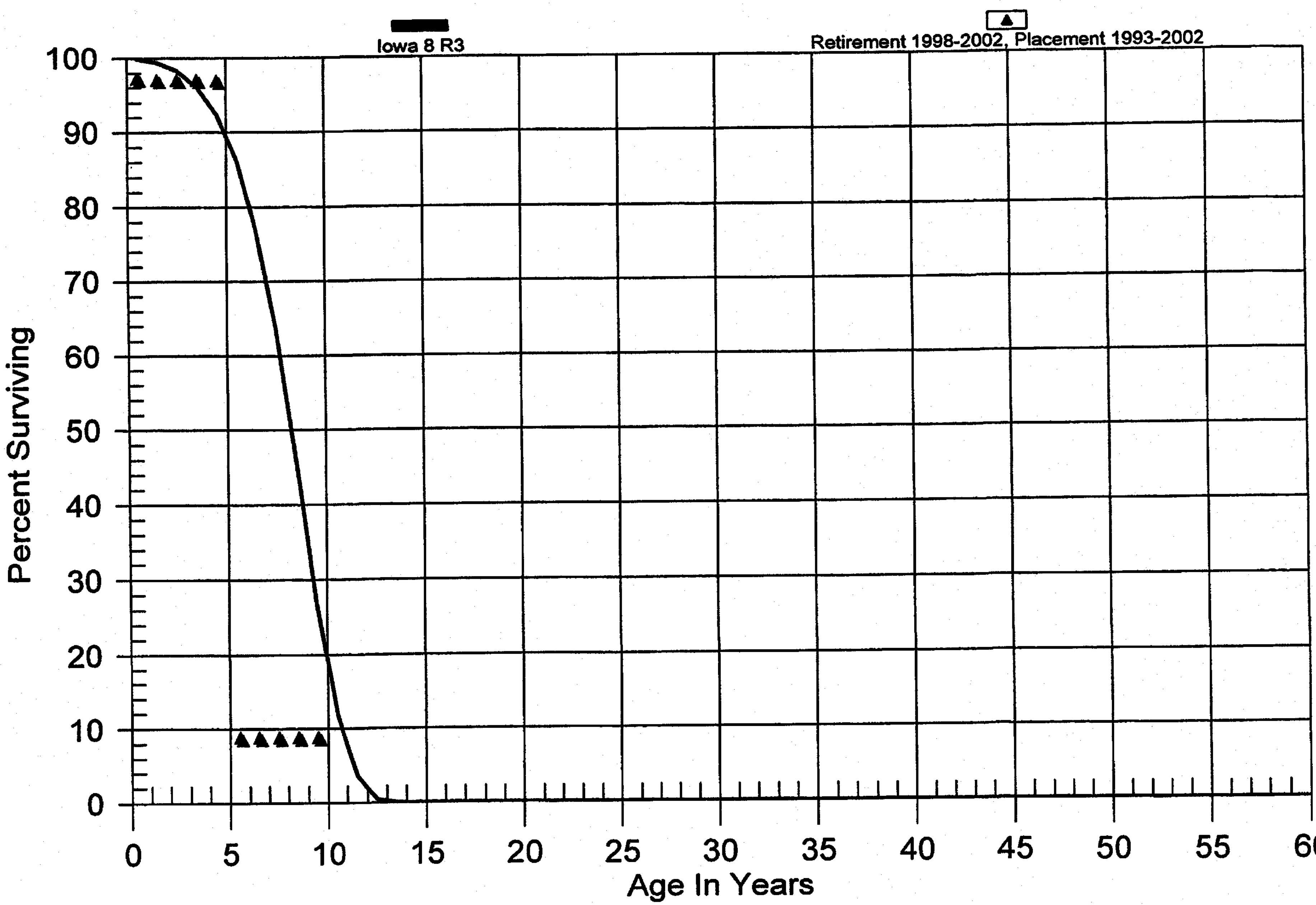
Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
0.0 - 0.5	$6,164,640.00	$8,329.00	0.00135	100.00
0.5 - 1.5	$5,570,872.00	$1,398.00	0.00025	99.86
1.5 - 2.5	$5,440,065.00	$24,007.00	0.00441	99.84
2.5 - 3.5	$4,966,051.00	$24,325.00	0.00490	99.40
3.5 - 4.5	$4,882,448.00	$8,484.00	0.00174	98.91
4.5 - 5.5	$4,396,101.00	$328,781.00	0.07479	98.74
5.5 - 6.5	$3,655,666.00	$20,823.00	0.00570	91.36
6.5 - 7.5	$1,661,567.00	$25,421.00	0.01530	90.84
7.5 - 8.5	$1,520,023.00	$136,665.00	0.08991	89.45
8.5 - 9.5	$874,817.00	$85,876.00	0.09816	81.40
9.5 - 10.5	$767,903.00	$886.00	0.00115	73.41
10.5 - 11.5	$767,017.00	$7,796.00	0.01016	73.33
11.5 - 12.5	$759,221.00	$561,506.00	0.73958	72.58
12.5 - 13.5	$197,715.00	$4,814.00	0.02435	18.90
13.5 - 14.5	$192,901.00	$11,440.00	0.05931	18.44
14.5 - 15.5	$70,758.00	$40,683.00	0.57496	17.35
15.5 - 16.5	$30,075.00	$6,562.00	0.21819	7.37
16.5 - 17.5	$23,513.00	$1,523.00	0.06477	5.76
17.5 - 18.5	$19,954.00	$4,290.00	0.21499	5.39
18.5 - 19.5	$15,664.00	$3,041.00	0.19414	4.23
19.5 - 20.5	$12,623.00	$1,925.00	0.15250	3.41
20.5 - 21.5	$10,698.00	$354.00	0.03309	2.89
21.5 - 22.5	$10,344.00	$3,715.00	0.35915	2.79
22.5 - 23.5	$6,629.00	$1,097.00	0.16548	1.79
23.5 - 24.5	$5,532.00	$2,245.00	0.40582	1.49
24.5 - 25.5	$3,287.00	$0.00	0.00000	0.89
25.5 - 26.5	$3,287.00	$2,140.00	0.65105	0.89
26.5 - 27.5	$1,147.00	$629.00	0.54839	0.31
27.5 - 28.5	$518.00	$0.00	0.00000	0.14

Southwest Gas Corporation

System Allocable Plant

397.20 TELEMETRY EQUIPMENT

Original And Smooth Survivor Curves



Southwest Gas Corporation
System Allocable Plant
397.20 TELEMETRY EQUIPMENT

Observed Life Table
Retirement Expr. 1998 TO 2002
Placement Years 1993 TO 2002

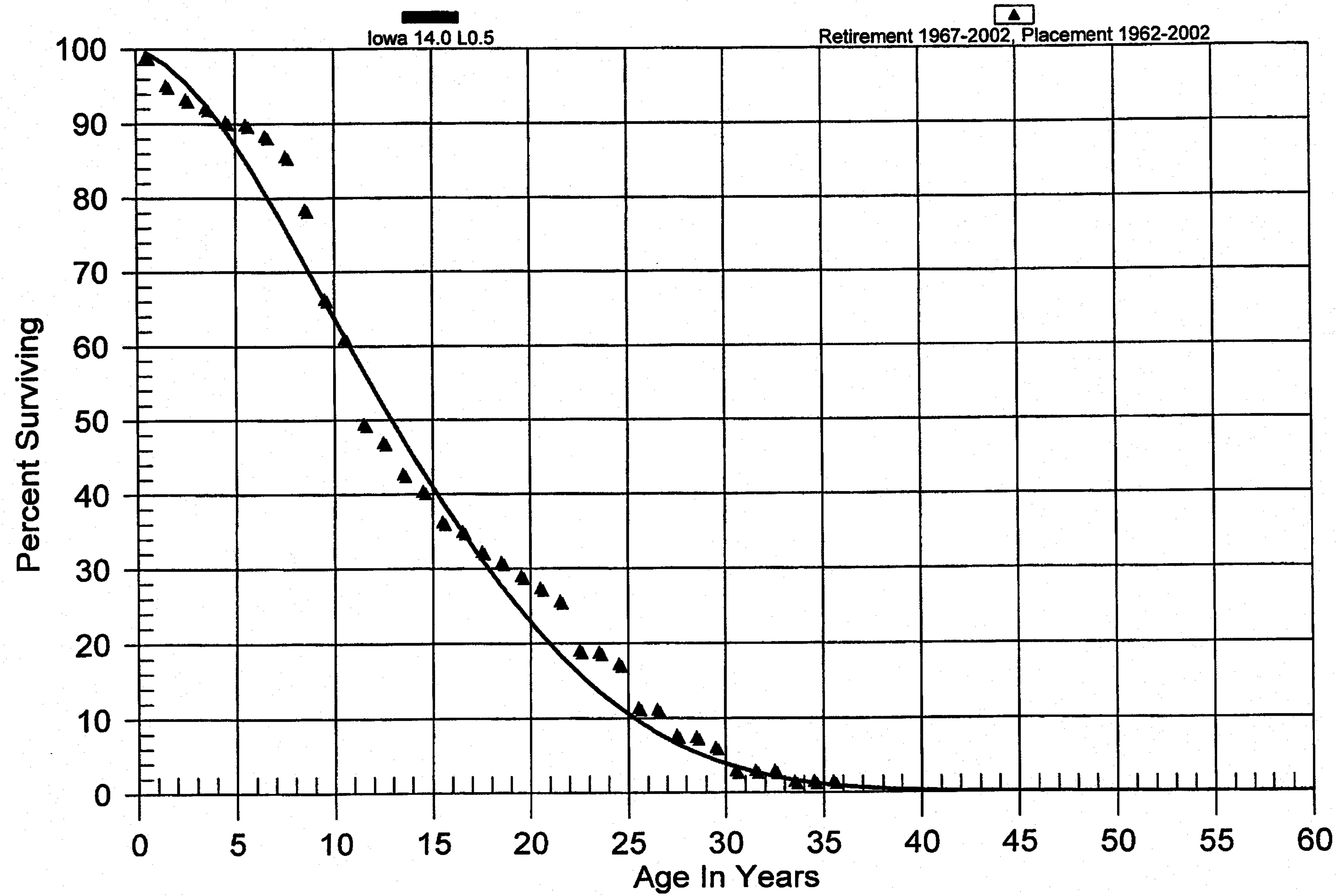
Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
0.0 - 0.5	$365,509.00	$9,940.00	0.02719	100.00
0.5 - 1.5	$383,578.00	$925.00	0.00241	97.28
1.5 - 2.5	$428,871.00	$0.00	0.00000	97.05
2.5 - 3.5	$383,462.00	$0.00	0.00000	97.05
3.5 - 4.5	$381,082.00	$430.00	0.00113	97.05
4.5 - 5.5	$1,092,290.00	$992,784.00	0.90890	96.94
5.5 - 6.5	$62,676.00	$0.00	0.00000	8.83
6.5 - 7.5	$1,460.00	$0.00	0.00000	8.83
7.5 - 8.5	$0.00	$0.00	0.00000	8.83
8.5 - 9.5	$0.00	$0.00	0.00000	8.83

Southwest Gas Corporation

System Allocable Plant

398.00 MISCELLANEOUS EQUIPMENT

Original And Smooth Survivor Curves



Southwest Gas Corporation
System Allocable Plant
398.00 MISCELLANEOUS EQUIPMENT

Observed Life Table
Retirement Expr. 1967 TO 2002
Placement Years 1962 TO 2002

Age Interval	$ Surviving At Beginning of Age Interval	$ Retired During The Age Interval	Retirement Ratio	% Surviving At Beginning of Age Interval
0.0 - 0.5	$1,517,962.00	$14,693.00	0.00968	100.00
0.5 - 1.5	$1,354,549.00	$52,878.00	0.03904	99.03
1.5 - 2.5	$1,233,056.00	$24,221.00	0.01964	95.17
2.5 - 3.5	$1,161,872.00	$13,655.00	0.01175	93.30
3.5 - 4.5	$982,063.00	$19,848.00	0.02021	92.20
4.5 - 5.5	$919,743.00	$3,862.00	0.00420	90.34
5.5 - 6.5	$906,435.00	$15,617.00	0.01723	89.96
6.5 - 7.5	$856,677.00	$26,605.00	0.03106	88.41
7.5 - 8.5	$792,501.00	$66,407.00	0.08379	85.66
8.5 - 9.5	$715,595.00	$110,603.00	0.15456	78.48
9.5 - 10.5	$599,116.00	$47,738.00	0.07968	66.35
10.5 - 11.5	$550,313.00	$104,252.00	0.18944	61.07
11.5 - 12.5	$444,581.00	$22,069.00	0.04964	49.50
12.5 - 13.5	$415,196.00	$37,862.00	0.09119	47.04
13.5 - 14.5	$370,100.00	$20,134.00	0.05440	42.75
14.5 - 15.5	$330,182.00	$33,755.00	0.10223	40.43
15.5 - 16.5	$263,719.00	$9,290.00	0.03523	36.29
16.5 - 17.5	$249,661.00	$19,432.00	0.07783	35.01
17.5 - 18.5	$217,062.00	$9,686.00	0.04462	32.29
18.5 - 19.5	$207,376.00	$12,327.00	0.05944	30.85
19.5 - 20.5	$166,508.00	$9,198.00	0.05524	29.01
20.5 - 21.5	$149,278.00	$9,549.00	0.06397	27.41
21.5 - 22.5	$139,729.00	$35,906.00	0.25697	25.66
22.5 - 23.5	$89,496.00	$983.00	0.01098	19.06
23.5 - 24.5	$86,419.00	$7,099.00	0.08215	18.86
24.5 - 25.5	$79,320.00	$26,824.00	0.33817	17.31
25.5 - 26.5	$50,958.00	$1,094.00	0.02147	11.45
26.5 - 27.5	$49,864.00	$15,269.00	0.30621	11.21
27.5 - 28.5	$34,595.00	$877.00	0.02535	7.78
28.5 - 29.5	$33,718.00	$6,152.00	0.18245	7.58
29.5 - 30.5	$27,566.00	$14,212.00	0.51556	6.20
30.5 - 31.5	$13,354.00	$0.00	0.00000	3.00
31.5 - 32.5	$13,354.00	$0.00	0.00000	3.00
32.5 - 33.5	$13,354.00	$6,355.00	0.47589	3.00
33.5 - 34.5	$6,999.00	$0.00	0.00000	1.57
34.5 - 35.5	$6,999.00	$0.00	0.00000	1.57

SECTION 6

Southwest Gas Corporation
System Allocable Plant
390.10 STRUCTURES - OWNED

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2002
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 40 *Survivor Curve:* R3

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1987	477,495.00	40.00	11,937.37	25.37	302,853.23
1988	2,065.00	40.00	51.62	26.26	1,355.54
1989	10,528,273.00	40.00	263,206.65	27.15	7,147,105.77
1990	53,372.00	40.00	1,334.30	28.06	37,441.98
1991	12,577.00	40.00	314.42	28.98	9,110.97
1992	45,286.00	40.00	1,132.15	29.90	33,853.18
1993	32,261.00	40.00	806.52	30.83	24,868.46
1995	215,301.00	40.00	5,382.52	32.72	176,127.54
1996	2,600.00	40.00	65.00	33.68	2,188.97
1997	50,000.00	40.00	1,250.00	34.64	43,295.28
1998	4,191.00	40.00	104.77	35.60	3,730.19
1999	40,000.00	40.00	1,000.00	36.57	36,572.08
2000	212,862.00	40.00	5,321.55	37.55	199,808.48
2001	24,593.00	40.00	614.82	38.53	23,686.47
Total	11,700,876.00	40.00	292,521.70	27.49	8,041,998.15

Composite Average Remaining Life ... 27.49 *Years*

Southwest Gas Corporation

System Allocable Plant

391.00 OFFICE FURITURE & EQUIPMENT

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2002

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 14 *Survivor Curve: L2*

Year (1)	*Original Cost* (2)	*Avg. Service Life* (3)	*Avg. Annual Accrual* (4)	*Avg. Remaining Life* (5)	*Future Annual Accruals* (6)
1970	1,978.00	14.00	141.29	1.36	192.64
1975	1,110.00	14.00	79.29	2.30	182.21
1977	1,109.00	14.00	79.21	2.71	214.73
1979	116,547.00	14.00	8,324.76	3.15	26,214.02
1980	5,070.00	14.00	362.14	3.38	1,223.56
1981	54,766.00	14.00	3,911.85	3.62	14,143.51
1982	113,320.00	14.00	8,094.27	3.86	31,227.83
1983	11,545.00	14.00	824.64	4.11	3,386.35
1984	263,745.00	14.00	18,838.88	4.36	82,092.30
1985	248,734.00	14.00	17,766.67	4.61	81,880.05
1986	115,772.00	14.00	8,269.41	4.86	40,163.32
1987	160,070.00	14.00	11,433.54	5.10	58,318.31
1988	147,802.00	14.00	10,557.26	5.34	56,381.05
1989	151,598.00	14.00	10,828.40	5.58	60,417.28
1990	58,411.00	14.00	4,172.20	5.83	24,310.12
1991	120,130.00	14.00	8,580.69	6.09	52,280.33
1992	68,024.00	14.00	4,858.84	6.39	31,061.71
1993	1,068,582.00	14.00	76,327.09	6.74	514,791.79
1994	233,556.00	14.00	16,682.53	7.17	119,568.61
1995	302,240.00	14.00	21,588.52	7.68	165,793.77
1996	321,677.00	14.00	22,976.87	8.30	190,630.40
1997	350,161.00	14.00	25,011.44	9.02	225,499.65
1998	554,416.00	14.00	39,601.04	9.82	388,760.90
1999	976,272.00	14.00	69,733.54	10.67	744,064.76
2000	225,710.00	14.00	16,122.10	11.57	186,544.92
2001	1,266,283.00	14.00	90,448.56	12.52	1,132,178.69
2002	819,111.00	14.00	58,507.78	13.50	789,893.13

Southwest Gas Corporation

System Allocable Plant

391.00 OFFICE FURITURE & EQUIPMENT

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2002

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 14 *Survivor Curve:* L2

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
Total	7,757,739.00	14.00	554,122.82	9.06	5,021,415.94

Composite Average Remaining Life ... 9.06 *Years*

Southwest Gas Corporation
System Allocable Plant
391.10 COMPUTER EQUIPMENT

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2002
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 6 *Survivor Curve:* L2

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1986	41,454.00	6.00	6,908.68	0.50	3,454.34
1987	15,509.00	6.00	2,584.71	0.51	1,323.81
1988	98,000.00	6.00	16,332.58	0.61	9,892.67
1989	4,404.00	6.00	733.97	0.75	547.05
1990	13,289.00	6.00	2,214.73	0.91	2,017.55
1991	19,802.00	6.00	3,300.18	1.10	3,615.44
1992	12,886.00	6.00	2,147.57	1.30	2,784.51
1993	176,107.00	6.00	29,349.81	1.52	44,506.90
1994	557,082.00	6.00	92,842.70	1.75	162,863.79
1995	1,582,733.00	6.00	263,776.61	2.00	527,803.38
1996	974,249.00	6.00	162,367.31	2.24	364,271.33
1997	1,235,817.00	6.00	205,959.96	2.48	511,237.74
1998	390,903.00	6.00	65,147.48	2.76	179,591.18
1999	1,953,300.00	6.00	325,534.92	3.15	1,025,913.16
2000	1,976,495.00	6.00	329,400.57	3.76	1,238,868.23
2001	2,722,952.00	6.00	453,804.31	4.57	2,076,067.39
2002	1,982,930.00	6.00	330,473.02	5.50	1,818,934.69
Total	13,757,912.00	6.00	2,292,879.11	3.48	7,973,693.15

Composite Average Remaining Life ... 3.48 Years

Southwest Gas Corporation

System Allocable Plant

392.11 TRANSPORTATION EQUIP-LIGHT

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2002

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 7 *Survivor Curve:* L0

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1987	20,925.00	7.00	2,987.90	2.11	6,292.72
1988	56,808.00	7.00	8,111.65	2.29	18,543.75
1989	1,665.00	7.00	237.75	2.48	588.70
1990	25,039.00	7.00	3,575.34	2.68	9,572.34
1992	22,380.00	7.00	3,195.66	3.12	9,960.05
1993	15,310.00	7.00	2,186.13	3.36	7,340.90
1994	43,932.00	7.00	6,273.08	3.62	22,677.48
1995	265,595.00	7.00	37,924.49	3.89	147,527.82
1996	101,677.00	7.00	14,518.53	4.18	60,753.30
1997	208,994.00	7.00	29,842.40	4.50	134,304.50
1998	329,607.00	7.00	47,064.81	4.84	227,787.05
1999	197,032.00	7.00	28,134.34	5.21	146,442.37
2000	259,481.00	7.00	37,051.47	5.60	207,592.17
2001	922,136.00	7.00	131,672.44	6.06	798,018.12
2002	434,229.00	7.00	62,003.86	6.63	410,967.31
Total	2,904,810.00	7.00	414,779.83	5.32	2,208,368.58

Composite Average Remaining Life ... 5.32 *Years*

Southwest Gas Corporation
System Allocable Plant
393.00 STORES EQUIPMENT

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2002
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 14 *Survivor Curve:* R1

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1985	9,972.00	14.00	712.19	3.59	2,560.30
1988	5,765.00	14.00	411.73	4.91	2,021.63
1993	6,869.00	14.00	490.58	7.58	3,720.05
1994	2,825.00	14.00	201.76	8.19	1,652.47
2002	3,998.00	14.00	285.53	13.63	3,892.39
Total	29,429.00	14.00	2,101.80	6.59	13,846.84

Composite Average Remaining Life ... *6.59* *Years*

Southwest Gas Corporation

System Allocable Plant

394.00 TOOLS, SHOP & GARAGE EQ.

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2002

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 14 *Survivor Curve:* L0.5

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1977	5,941.00	14.00	424.32	4.55	1,931.40
1987	3,127.00	14.00	223.34	6.86	1,533.03
1988	2,394.00	14.00	170.99	7.15	1,222.82
1989	5,352.00	14.00	382.26	7.45	2,847.91
1991	2,392.00	14.00	170.84	8.08	1,381.26
1992	30,931.00	14.00	2,209.18	8.42	18,604.98
1993	11,975.00	14.00	855.29	8.77	7,502.70
1994	26,339.00	14.00	1,881.21	9.14	17,188.44
1995	14,503.00	14.00	1,035.85	9.52	9,859.76
1996	10,199.00	14.00	728.44	9.93	7,233.05
1997	3,879.00	14.00	277.05	10.38	2,876.52
1998	13,746.00	14.00	981.78	10.89	10,690.61
1999	31,579.00	14.00	2,255.47	11.46	25,837.31
2000	22,936.00	14.00	1,638.16	12.09	19,799.17
2001	38,965.00	14.00	2,783.00	12.79	35,582.58
2002	3,117.00	14.00	222.63	13.56	3,019.89
Total	227,375.00	14.00	16,239.79	10.29	167,111.42

Composite Average Remaining Life ... *10.29 Years*

Southwest Gas Corporation
System Allocable Plant
395.00 LABORATORY EQUIP.

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2002
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 23 *Survivor Curve: R1.5*

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1983	15,956.00	23.00	693.71	9.18	6,368.24
1986	4,266.00	23.00	185.47	10.92	2,025.28
1987	8,960.00	23.00	389.55	11.54	4,495.58
1988	1,590.00	23.00	69.13	12.18	841.94
1989	53,551.00	23.00	2,328.22	12.84	29,885.34
1990	43,926.00	23.00	1,909.76	13.51	25,801.61
1991	53,819.00	23.00	2,339.87	14.20	33,226.11
1992	1,364.00	23.00	59.30	14.90	883.85
1993	16,254.00	23.00	706.67	15.62	11,040.19
1994	2,387.00	23.00	103.78	16.35	1,697.16
1995	7,362.00	23.00	320.08	17.10	5,472.06
1996	2,723.00	23.00	118.39	17.85	2,113.24
2002	17,836.00	23.00	775.45	22.59	17,517.04
Total	229,994.00	23.00	9,999.38	14.14	141,367.66

Composite Average Remaining Life ... 14.14 Years

Southwest Gas Corporation
System Allocable Plant
397.00 COMMUNICATION EQUIPMENT

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2002
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 11 *Survivor Curve:* R3

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1985	2,036.00	11.00	185.09	0.50	92.68
1988	110,703.00	11.00	10,063.96	1.08	10,860.96
1993	21,924.00	11.00	1,993.10	3.03	6,041.13
1994	508,541.00	11.00	46,231.23	3.66	169,238.31
1995	116,123.00	11.00	10,556.69	4.36	46,010.80
1996	1,973,276.00	11.00	179,389.61	5.11	917,351.35
1997	412,801.00	11.00	37,527.55	5.92	222,134.54
1998	480,003.00	11.00	43,636.85	6.77	295,413.77
1999	59,278.00	11.00	5,388.94	7.66	41,281.94
2000	450,007.00	11.00	40,909.93	8.59	351,222.00
2001	129,409.00	11.00	11,764.51	9.54	112,198.91
2002	585,439.00	11.00	53,221.99	10.51	559,294.11
Total	4,849,540.00	11.00	440,869.44	6.19	2,731,140.53

Composite Average Remaining Life ... 6.19 *Years*

Southwest Gas Corporation
System Allocable Plant
397.20 TELEMETRY EQUIPMENT

Original Cost Of Utility Plant In Service
And Development Of Composite Remaining Life as of December 31, 2002
Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 8 *Survivor Curve:* R3

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1995	1,460.00	8.00	182.49	1.88	343.92
1996	61,216.00	8.00	7,651.75	2.46	18,833.45
1997	36,830.00	8.00	4,603.60	3.14	14,456.28
1998	281,146.00	8.00	35,142.11	3.90	137,078.71
1999	2,380.00	8.00	297.49	4.73	1,406.59
2000	46,869.00	8.00	5,858.44	5.61	32,886.45
2001	15,428.00	8.00	1,928.44	6.55	12,621.72
2002	8,821.00	8.00	1,102.59	7.51	8,280.10
Total	454,150.00	8.00	56,766.91	3.98	225,907.23

Composite Average Remaining Life ... 3.98 *Years*

Southwest Gas Corporation

System Allocable Plant

398.00 MISCELLANEOUS EQUIPMENT

Original Cost Of Utility Plant In Service

And Development Of Composite Remaining Life as of December 31, 2002

Based Upon Broad Group/Remaining Life Procedure and Technique

Average Service Life: 14 *Survivor Curve: L0.5*

Year (1)	Original Cost (2)	Avg. Service Life (3)	Avg. Annual Accrual (4)	Avg. Remaining Life (5)	Future Annual Accruals (6)
1977	1,538.00	14.00	109.85	4.55	500.00
1979	2,094.00	14.00	149.56	4.94	738.56
1980	14,327.00	14.00	1,023.28	5.15	5,265.06
1982	8,032.00	14.00	573.67	5.59	3,204.90
1983	28,541.00	14.00	2,038.48	5.82	11,868.00
1985	13,167.00	14.00	940.43	6.32	5,945.65
1986	4,768.00	14.00	340.54	6.59	2,243.46
1987	32,708.00	14.00	2,336.10	6.86	16,035.33
1988	19,784.00	14.00	1,413.03	7.15	10,105.37
1989	7,234.00	14.00	516.67	7.45	3,849.35
1990	7,316.00	14.00	522.53	7.76	4,055.51
1991	1,480.00	14.00	105.71	8.08	854.62
1992	1,065.00	14.00	76.07	8.42	640.60
1993	5,876.00	14.00	419.68	8.77	3,681.49
1994	10,499.00	14.00	749.87	9.14	6,851.49
1995	37,571.00	14.00	2,683.43	9.52	25,542.37
1996	34,141.00	14.00	2,438.45	9.93	24,212.54
1997	9,446.00	14.00	674.66	10.38	7,004.79
1998	42,662.00	14.00	3,047.05	10.89	33,179.31
1999	166,154.00	14.00	11,867.21	11.46	135,943.89
2000	48,045.00	14.00	3,431.52	12.09	41,474.15
2001	74,896.00	14.00	5,349.29	12.79	68,394.54
2002	148,944.00	14.00	10,638.02	13.56	144,303.75
Total	720,288.00	14.00	51,445.09	10.81	555,894.73

Composite Average Remaining Life ... 10.81 Years

SECTION 7

Southwest Gas Corporation

System Allocable

Analysis of Experienced Salvage
1985 through 2002

Account 390.10 - Structures - Owned

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1985	0	0	0.00%	0	0.00%	0	0.00%
1986	0	0	0.00%	0	0.00%	0	0.00%
1987	0	0	0.00%	0	0.00%	0	0.00%
1988	1,389	0	0.00%	0	0.00%	0	0.00%
1989	0	0	0.00%	0	0.00%	0	0.00%
1990	0	0	0.00%	0	0.00%	0	0.00%
1991	0	0	0.00%	0	0.00%	0	0.00%
1992	0	0	0.00%	0	0.00%	0	0.00%
1993	529,082	212,800	40.22%	176,742	33.41%	36,058	6.82%
1994	7,406	0	0.00%	0	0.00%	0	0.00%
1995	0	0	0.00%	0	0.00%	0	0.00%
1996	0	0	0.00%	0	0.00%	0	0.00%
1997	0	0	0.00%	0	0.00%	0	0.00%
1998	9,199	0	0.00%	0	0.00%	0	0.00%
1999	13,329	0	0.00%	0	0.00%	0	0.00%
2000	204,860	0	0.00%	0	0.00%	0	0.00%
2001	21,000	0	0.00%	0	0.00%	0	0.00%
2002	0	0	0.00%	0	0.00%	0	0.00%

Southwest Gas Corporation

System Allocable

Analysis of Experienced Salvage
1985 through 2002

Account 390.10 - Structures - Owned

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE YEAR ROLLING BANDS							
1983-85	0	0	0.00%	0	0.00%	0	0.00%
1984-86	0	0	0.00%	0	0.00%	0	0.00%
1985-87	0	0	0.00%	0	0.00%	0	0.00%
1986-88	1,389	0	0.00%	0	0.00%	0	0.00%
1987-89	1,389	0	0.00%	0	0.00%	0	0.00%
1988-90	1,389	0	0.00%	0	0.00%	0	0.00%
1989-91	0	0	0.00%	0	0.00%	0	0.00%
1990-92	0	0	0.00%	0	0.00%	0	0.00%
1991-93	529,082	212,800	40.22%	176,742	33.41%	36,058	6.82%
1992-94	536,488	212,800	39.67%	176,742	32.94%	36,058	6.72%
1993-95	536,488	212,800	39.67%	176,742	32.94%	36,058	6.72%
1994-96	7,406	0	0.00%	0	0.00%	0	0.00%
1995-97	0	0	0.00%	0	0.00%	0	0.00%
1996-98	9,199	0	0.00%	0	0.00%	0	0.00%
1997-99	22,528	0	0.00%	0	0.00%	0	0.00%
1998-00	227,388	0	0.00%	0	0.00%	0	0.00%
1999-01	239,189	0	0.00%	0	0.00%	0	0.00%
2000-02	225,860	0	0.00%	0	0.00%	0	0.00%
1985-02	786,265	212,800	27.06%	176,742	22.48%	36,058	4.59%

Trend Analysis (End Year) 2002

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	40
Avg Ret Age	10.2
Years to ASL	29.8
Inflation Factor At 2.75% to ASL	2.24

Gross Salv. Trend Analysis*		
1983-2002	**20-Year Trend**	**#VALUE!**
1988-2002	**15-Year Trend**	**4.54%**
1993-2002	**10-Year Trend**	**-15.98%**
1998-2002	**5-Year Trend**	**0.00%**

Adjusted Salvage & C/O/R	**0.00%**	**50.45%**	**-50.45%**

Southwest Gas Corporation

System Allocable

Analysis of Experienced Salvage
1985 through 2002

Account 391 - Office Furniture & Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1985	26,765	11,637	43.48%	0	0.00%	11,637	43.48%
1986	28,913	0	0.00%	0	0.00%	0	0.00%
1987	26,871	0	0.00%	0	0.00%	0	0.00%
1988	19,839	500	2.52%	0	0.00%	500	2.52%
1989	3,220	20	0.62%	0	0.00%	20	0.62%
1990	57,291	600	1.05%	0	0.00%	600	1.05%
1991	12,124	0	0.00%	0	0.00%	0	0.00%
1992	17,130	0	0.00%	0	0.00%	0	0.00%
1993	567,720	8,000	1.41%	0	0.00%	8,000	1.41%
1994	58,100	4,200	7.23%	0	0.00%	4,200	7.23%
1995	59,684	0	0.00%	0	0.00%	0	0.00%
1996	538,107	1,000	0.19%	0	0.00%	1,000	0.19%
1997	193,779	0	0.00%	0	0.00%	0	0.00%
1998	230,177	0	0.00%	0	0.00%	0	0.00%
1999	148,246	0	0.00%	0	0.00%	0	0.00%
2000	1,408,973	0	0.00%	0	0.00%	0	0.00%
2001	2,098,382	0	0.00%	0	0.00%	0	0.00%
2002	704,994	0	0.00%	0	0.00%	0	0.00%

Southwest Gas Corporation

System Allocable

Analysis of Experienced Salvage
1985 through 2002

Account 391 - Office Furniture & Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE YEAR ROLLING BANDS							
1983-85	26,765	11,637	43.48%	0	0.00%	11,637	43.48%
1984-86	55,678	11,637	20.90%	0	0.00%	11,637	20.90%
1985-87	82,549	11,637	14.10%	0	0.00%	11,637	14.10%
1986-88	75,623	500	0.66%	0	0.00%	500	0.66%
1987-89	49,930	520	1.04%	0	0.00%	520	1.04%
1988-90	80,350	1,120	1.39%	0	0.00%	1,120	1.39%
1989-91	72,635	620	0.85%	0	0.00%	620	0.85%
1990-92	86,545	600	0.69%	0	0.00%	600	0.69%
1991-93	596,974	8,000	1.34%	0	0.00%	8,000	1.34%
1992-94	642,950	12,200	1.90%	0	0.00%	12,200	1.90%
1993-95	685,504	12,200	1.78%	0	0.00%	12,200	1.78%
1994-96	655,891	5,200	0.79%	0	0.00%	5,200	0.79%
1995-97	791,570	1,000	0.13%	0	0.00%	1,000	0.13%
1996-98	962,063	1,000	0.10%	0	0.00%	1,000	0.10%
1997-99	572,202	0	0.00%	0	0.00%	0	0.00%
1998-00	1,787,396	0	0.00%	0	0.00%	0	0.00%
1999-01	3,655,600	0	0.00%	0	0.00%	0	0.00%
2000-02	4,212,349	0	0.00%	0	0.00%	0	0.00%
1985-02	6,200,315	25,957	0.42%	0	0.00%	25,957	0.42%

Trend Analysis (End Year) 2002

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	14
Avg Ret Age	11.9
Years to ASL	2.1
Inflation Factor At 2.75% to ASL	1.06

Gross Salv. Trend Analysis*		
1983-2002	20-Year Trend	#VALUE!
1988-2002	15-Year Trend	-0.05%
1993-2002	10-Year Trend	-0.62%
1998-2002	5-Year Trend	-0.04%

Adjusted Salvage & C/O/R	**-0.04%**	**0.00%**	**-0.04%**

Southwest Gas Corporation

System Allocable

Analysis of Experienced Salvage
1985 through 2002

Account 391.10 - Computer Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1985	0	0	0.00%	0	0.00%	0	0.00%
1986	0	0	0.00%	0	0.00%	0	0.00%
1987	1,182	0	0.00%	0	0.00%	0	0.00%
1988	511,339	83,500	16.33%	0	0.00%	83,500	16.33%
1989	14,769	0	0.00%	0	0.00%	0	0.00%
1990	166,520	0	0.00%	0	0.00%	0	0.00%
1991	1,605,116	122,147	7.61%	0	0.00%	122,147	7.61%
1992	569,201	13,195	2.32%	0	0.00%	13,195	2.32%
1993	1,521,380	0	0.00%	0	0.00%	0	0.00%
1994	1,489,228	1,000	0.07%	0	0.00%	1,000	0.07%
1995	2,102,006	400	0.02%	0	0.00%	400	0.02%
1996	7,127,233	0	0.00%	0	0.00%	0	0.00%
1997	5,752,961	1,000	0.02%	0	0.00%	1,000	0.02%
1998	454,126	0	0.00%	0	0.00%	0	0.00%
1999	1,471,590	57,120	3.88%	0	0.00%	57,120	3.88%
2000	72,772	1,800	2.47%	0	0.00%	1,800	2.47%
2001	3,889,138	0	0.00%	0	0.00%	0	0.00%
2002	1,963,093	0	0.00%	0	0.00%	0	0.00%

Southwest Gas Corporation

System Allocable

Analysis of Experienced Salvage
1985 through 2002

Account 391.10 - Computer Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE YEAR ROLLING BANDS							
1983-85	0	0	0.00%	0	0.00%	0	0.00%
1984-86	0	0	0.00%	0	0.00%	0	0.00%
1985-87	1,182	0	0.00%	0	0.00%	0	0.00%
1986-88	512,521	83,500	16.29%	0	0.00%	83,500	16.29%
1987-89	527,290	83,500	15.84%	0	0.00%	83,500	15.84%
1988-90	692,628	83,500	12.06%	0	0.00%	83,500	12.06%
1989-91	1,786,405	122,147	6.84%	0	0.00%	122,147	6.84%
1990-92	2,340,837	135,342	5.78%	0	0.00%	135,342	5.78%
1991-93	3,695,697	135,342	3.66%	0	0.00%	135,342	3.66%
1992-94	3,579,809	14,195	0.40%	0	0.00%	14,195	0.40%
1993-95	5,112,614	1,400	0.03%	0	0.00%	1,400	0.03%
1994-96	10,718,467	1,400	0.01%	0	0.00%	1,400	0.01%
1995-97	14,982,200	1,400	0.01%	0	0.00%	1,400	0.01%
1996-98	13,334,320	1,000	0.01%	0	0.00%	1,000	0.01%
1997-99	7,678,677	58,120	0.76%	0	0.00%	58,120	0.76%
1998-00	1,998,487	58,920	2.95%	0	0.00%	58,920	2.95%
1999-01	5,433,500	58,920	1.08%	0	0.00%	58,920	1.08%
2000-02	5,925,003	1,800	0.03%	0	0.00%	1,800	0.03%
1985-02	28,711,654	280,162	0.98%	0	0.00%	280,162	0.98%

Trend Analysis (End Year) 2002

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	6
Avg Ret Age	6.5
Years to ASL	-0.5
Inflation Factor At 2.75% to ASL	0.99

Gross Salv. Trend Analysis*		
1983-2002	20-Year Trend	#VALUE!
1988-2002	15-Year Trend	-4.11%
1993-2002	10-Year Trend	0.53%
1998-2002	5-Year Trend	1.08%

Adjusted Salvage & C/O/R	**1.08%**	**0.00%**	**1.08%**

Southwest Gas Corporation

System Allocable

Analysis of Experienced Salvage
1985 through 2002

Account 392 - Transportation Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Femoval	%	Net Salvage	%
1985	93,686	2,236	2.39%	0	0.00%	2,236	2.39%
1986	50,853	5,761	11.33%	0	0.00%	5,761	11.33%
1987	69,446	2,706	3.90%	0	0.00%	2,706	3.90%
1988	183,866	6,533	3.55%	0	0.00%	6,533	3.55%
1989	206,022	13,566	6.58%	0	0.00%	13,566	6.58%
1990	240,588	62,066	25.80%	0	0.00%	62,066	25.80%
1991	195,997	6,762	3.45%	0	0.00%	6,762	3.45%
1992	36,775	1,254	3.41%	0	0.00%	1,254	3.41%
1993	327,269	43,851	13.40%	0	0.00%	43,851	13.40%
1994	191,384	53,178	27.79%	0	0.00%	53,178	27.79%
1995	231,961	44,986	19.39%	0	0.00%	44,986	19.39%
1996	126,200	28,854	22.86%	0	0.00%	28,854	22.86%
1997	236,902	29,293	12.37%	0	0.00%	29,293	12.37%
1998	93,707	16,874	18.01%	0	0.00%	16,874	18.01%
1999	364,817	142,417	39.04%	0	0.00%	142,417	39.04%
2000	335,681	10,115	3.01%	0	0.00%	10,115	3.01%
2001	350,341	122,683	35.02%	0	0.00%	122,683	35.02%
2002	398,944	91,061	22.83%	0	0.00%	91,061	22.83%

Southwest Gas Corporation

System Allocable

Analysis of Experienced Salvage
1985 through 2002

Account 392 - Transportation Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE YEAR ROLLING BANDS							
1983-85	93,686	2,236	2.39%	0	0.00%	2,236	2.39%
1984-86	144,539	7,997	5.53%	0	0.00%	7,997	5.53%
1985-87	213,985	10,703	5.00%	0	0.00%	10,703	5.00%
1986-88	304,165	15,000	4.93%	0	0.00%	15,000	4.93%
1987-89	459,334	22,805	4.96%	0	0.00%	22,805	4.96%
1988-90	630,476	82,165	13.03%	0	0.00%	82,165	13.03%
1989-91	642,607	82,394	12.82%	0	0.00%	82,394	12.82%
1990-92	473,360	70,082	14.81%	0	0.00%	70,082	14.81%
1991-93	560,041	51,867	9.26%	0	0.00%	51,867	9.26%
1992-94	555,428	98,283	17.70%	0	0.00%	98,283	17.70%
1993-95	750,614	142,015	18.92%	0	0.00%	142,015	18.92%
1994-96	549,545	127,018	23.11%	0	0.00%	127,018	23.11%
1995-97	595,063	103,133	17.33%	0	0.00%	103,133	17.33%
1996-98	456,809	75,021	16.42%	0	0.00%	75,021	16.42%
1997-99	642,607	82,394	12.82%	0	0.00%	82,394	12.82%
1998-00	473,360	70,082	14.81%	0	0.00%	70,082	14.81%
1999-01	560,041	51,867	9.26%	0	0.00%	51,867	9.26%
2000-02	555,428	98,283	17.70%	0	0.00%	98,283	17.70%
1985-02	3,734,439	684,195	18.32%	0	0.00%	684,195	18.32%

Trend Analysis (End Year)	2002

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	7
Avg Ret Age	5.4
Years to ASL	1.6
Inflation Factor At 2.75% to ASL	1.04

Gross Salv. Trend Analysis*		
1983-2002	20-Year Trend	#VALUE!
1988-2002	15-Year Trend	18.16%
1993-2002	10-Year Trend	14.55%
1998-2002	5-Year Trend	13.90%

	Gross %	Cost of Removal %	Net %
Adjusted Salvage & C/O/R	**13.90%**	**0.00%**	**13.90%**

Southwest Gas Corporation

System Allocable

Analysis of Experienced Salvage
1985 through 2002

Account 393 - Stores Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1985	0	0	0.00%	0	0.00%	0	0.00%
1986	0	0	0.00%	0	0.00%	0	0.00%
1987	0	0	0.00%	0	0.00%	0	0.00%
1988	0	0	0.00%	0	0.00%	0	0.00%
1989	0	0	0.00%	0	0.00%	0	0.00%
1990	0	0	0.00%	0	0.00%	0	0.00%
1991	0	0	0.00%	0	0.00%	0	0.00%
1992	0	0	0.00%	0	0.00%	0	0.00%
1993	4,226	0	0.00%	0	0.00%	0	0.00%
1994	0	0	0.00%	0	0.00%	0	0.00%
1995	0	0	0.00%	0	0.00%	0	0.00%
1996	0	0	0.00%	0	0.00%	0	0.00%
1997	0	0	0.00%	0	0.00%	0	0.00%
1998	557	0	0.00%	0	0.00%	0	0.00%
1999	0	0	0.00%	0	0.00%	0	0.00%
2000	11,195	0	0.00%	0	0.00%	0	0.00%
2001	6,016	0	0.00%	0	0.00%	0	0.00%
2002	0	0	0.00%	0	0.00%	0	0.00%

Southwest Gas Corporation

System Allocable

Analysis of Experienced Salvage
1985 through 2002

Account 393 - Stores Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE YEAR ROLLING BANDS							
1983-85	0	0	0.00%	0	0.00%	0	0.00%
1984-86	0	0	0.00%	0	0.00%	0	0.00%
1985-87	0	0	0.00%	0	0.00%	0	0.00%
1986-88	0	0	0.00%	0	0.00%	0	0.00%
1987-89	0	0	0.00%	0	0.00%	0	0.00%
1988-90	0	0	0.00%	0	0.00%	0	0.00%
1989-91	0	0	0.00%	0	0.00%	0	0.00%
1990-92	0	0	0.00%	0	0.00%	0	0.00%
1991-93	4,226	0	0.00%	0	0.00%	0	0.00%
1992-94	4,226	0	0.00%	0	0.00%	0	0.00%
1993-95	4,226	0	0.00%	0	0.00%	0	0.00%
1994-96	0	0	0.00%	0	0.00%	0	0.00%
1995-97	0	0	0.00%	0	0.00%	0	0.00%
1996-98	557	0	0.00%	0	0.00%	0	0.00%
1997-99	557	0	0.00%	0	0.00%	0	0.00%
1998-00	11,752	0	0.00%	0	0.00%	0	0.00%
1999-01	17,211	0	0.00%	0	0.00%	0	0.00%
2000-02	17,211	0	0.00%	0	0.00%	0	0.00%
1985-02	21,994	0	0.00%	0	0.00%	0	0.00%

Trend Analysis (End Year) 2002

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	14
Avg Ret Age	11.1
Years to ASL	2.9
Inflation Factor At 2.75% to ASL	1.00

Gross Salv. Trend Analysis*		
1983-2002	20-Year Trend	#VALUE!
1988-2002	15-Year Trend	#VALUE!
1993-2002	10-Year Trend	#VALUE!
1998-2002	5-Year Trend	#VALUE!

Adjusted Salvage & C/O/R	**#VALUE!**	**0.00%**	**#VALUE!**

Southwest Gas Corporation

System Allocable

Analysis of Experienced Salvage
1985 through 2002

Account 394 - Tools, Shop and Garage Equipment\

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1985	0	0	0.00%	0	0.00%	0	0.00%
1986	0	0	0.00%	0	0.00%	0	0.00%
1987	0	0	0.00%	0	0.00%	0	0.00%
1988	0	0	0.00%	0	0.00%	0	0.00%
1989	6,288	0	0.00%	0	0.00%	0	0.00%
1990	0	0	0.00%	0	0.00%	0	0.00%
1991	5,448	0	0.00%	0	0.00%	0	0.00%
1992	0	0	0.00%	0	0.00%	0	0.00%
1993	8,916	0	0.00%	0	0.00%	0	0.00%
1994	0	0	0.00%	0	0.00%	0	0.00%
1995	0	0	0.00%	0	0.00%	0	0.00%
1996	0	0	0.00%	0	0.00%	0	0.00%
1997	1,332	0	0.00%	0	0.00%	0	0.00%
1998	424	0	0.00%	0	0.00%	0	0.00%
1999	2,381	0	0.00%	0	0.00%	0	0.00%
2000	64,140	0	0.00%	0	0.00%	0	0.00%
2001	30,673	0	0.00%	0	0.00%	0	0.00%
2002	26,047	0	0.00%	0	0.00%	0	0.00%

Southwest Gas Corporation

System Allocable

Analysis of Experienced Salvage
1985 through 2002

Account 394 - Tools, Shop and Garage Equipment\

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE YEAR ROLLING BANDS							
1983-85	0	0	0.00%	0	0.00%	0	0.00%
1984-86	0	0	0.00%	0	0.00%	0	0.00%
1985-87	0	0	0.00%	0	0.00%	0	0.00%
1986-88	0	0	0.00%	0	0.00%	0	0.00%
1987-89	6,288	0	0.00%	0	0.00%	0	0.00%
1988-90	6,288	0	0.00%	0	0.00%	0	0.00%
1989-91	11,736	0	0.00%	0	0.00%	0	0.00%
1990-92	5,448	0	0.00%	0	0.00%	0	0.00%
1991-93	14,364	0	0.00%	0	0.00%	0	0.00%
1992-94	8,916	0	0.00%	0	0.00%	0	0.00%
1993-95	8,916	0	0.00%	0	0.00%	0	0.00%
1994-96	0	0	0.00%	0	0.00%	0	0.00%
1995-97	1,332	0	0.00%	0	0.00%	0	0.00%
1996-98	1,756	0	0.00%	0	0.00%	0	0.00%
1997-99	4,137	0	0.00%	0	0.00%	0	0.00%
1998-00	66,945	0	0.00%	0	0.00%	0	0.00%
1999-01	97,194	0	0.00%	0	0.00%	0	0.00%
2000-02	120,860	0	0.00%	0	0.00%	0	0.00%
1985-02	145,649	0	0.00%	0	0.00%	0	0.00%

Trend Analysis (End Year) 2002

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	14
Avg Ret Age	10.7
Years to ASL	3.3
Inflation Factor At 2.75% to ASL	1.09

Gross Salv. Trend Analysis*		
1983-2002	**20-Year Trend**	**#VALUE!**
1988-2002	**15-Year Trend**	**0.00%**
1993-2002	**10-Year Trend**	**0.00%**
1998-2002	**5-Year Trend**	**0.00%**

Adjusted Salvage & C/O/R	**0.00%**	**0.00%**	**0.00%**

Southwest Gas Corporation

System Allocable

Analysis of Experienced Salvage
1985 through 2002

Account 395 - Laboratory Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1985	0	0	0.00%	0	0.00%	0	0.00%
1986	0	0	0.00%	0	0.00%	0	0.00%
1987	0	0	0.00%	0	0.00%	0	0.00%
1988	0	0	0.00%	0	0.00%	0	0.00%
1989	0	0	0.00%	0	0.00%	0	0.00%
1990	0	0	0.00%	0	0.00%	0	0.00%
1991	398	0	0.00%	0	0.00%	0	0.00%
1992	0	0	0.00%	0	0.00%	0	0.00%
1993	11,827	0	0.00%	0	0.00%	0	0.00%
1994	0	0	0.00%	0	0.00%	0	0.00%
1995	0	0	0.00%	0	0.00%	0	0.00%
1996	0	0	0.00%	0	0.00%	0	0.00%
1997	0	0	0.00%	0	0.00%	0	0.00%
1998	4,980	0	0.00%	0	0.00%	0	0.00%
1999	15,335	0	0.00%	0	0.00%	0	0.00%
2000	20,266	0	0.00%	0	0.00%	0	0.00%
2001	15,515	0	0.00%	0	0.00%	0	0.00%
2002	2,466	0	0.00%	0	0.00%	0	0.00%

Southwest Gas Corporation

System Allocable

Analysis of Experienced Salvage
1985 through 2002

Account 395 - Laboratory Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE YEAR ROLLING BANDS							
1983-85	0	0	0.00%	0	0.00%	0	0.00%
1984-86	0	0	0.00%	0	0.00%	0	0.00%
1985-87	0	0	0.00%	0	0.00%	0	0.00%
1986-88	0	0	0.00%	0	0.00%	0	0.00%
1987-89	0	0	0.00%	0	0.00%	0	0.00%
1988-90	0	0	0.00%	0	0.00%	0	0.00%
1989-91	398	0	0.00%	0	0.00%	0	0.00%
1990-92	398	0	0.00%	0	0.00%	0	0.00%
1991-93	12,225	0	0.00%	0	0.00%	0	0.00%
1992-94	11,827	0	0.00%	0	0.00%	0	0.00%
1993-95	11,827	0	0.00%	0	0.00%	0	0.00%
1994-96	0	0	0.00%	0	0.00%	0	0.00%
1995-97	0	0	0.00%	0	0.00%	0	0.00%
1996-98	4,980	0	0.00%	0	0.00%	0	0.00%
1997-99	20,315	0	0.00%	0	0.00%	0	0.00%
1998-00	40,581	0	0.00%	0	0.00%	0	0.00%
1999-01	51,116	0	0.00%	0	0.00%	0	0.00%
2000-02	38,246	0	0.00%	0	0.00%	0	0.00%
				0			
1985-02	70,786	0	0.00%	0	0.00%	0	0.00%

Trend Analysis (End Year) 2002

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	23
Avg Ret Age	13.6
Years to ASL	9.4
Inflation Factor At 2.75% to ASL	1.29

Gross Salv. Trend Analysis*		
1983-2002	**20-Year Trend**	**#VALUE!**
1988-2002	**15-Year Trend**	**0.00%**
1993-2002	**10-Year Trend**	**0.00%**
1998-2002	**5-Year Trend**	**0.00%**

	Gross Salvage %	Cost of Removal %	Net Salvage %
Adjusted Salvage & C/O/R	**0.00%**	**0.00%**	**0.00%**

Southwest Gas Corporation

System Allocable

Analysis of Experienced Salvage
1985 through 2002

Account 397 - Communication Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1985	0	0	0.00%	0	0.00%	0	0.00%
1986	0	0	0.00%	0	0.00%	0	0.00%
1987	0	0	0.00%	0	0.00%	0	0.00%
1988	5,400	0	0.00%	320	5.93%	-320	-5.93%
1989	1,072	0	0.00%	0	0.00%	0	0.00%
1990	0	0	0.00%	0	0.00%	0	0.00%
1991	0	0	0.00%	0	0.00%	0	0.00%
1992	0	0	0.00%	0	0.00%	0	0.00%
1993	1,441	0	0.00%	0	0.00%	0	0.00%
1994	869,628	2,557	0.29%	0	0.00%	2,557	0.29%
1995	150,760	0	0.00%	0	0.00%	0	0.00%
1996	0	0	0.00%	0	0.00%	0	0.00%
1997	12,880	400	3.11%	0	0.00%	400	3.11%
1998	6,825	0	0.00%	0	0.00%	0	0.00%
1999	9,915	0	0.00%	0	0.00%	0	0.00%
2000	54,321	0	0.00%	0	0.00%	0	0.00%
2001	166,016	0	0.00%	0	0.00%	0	0.00%
2002	39,820	0	0.00%	0	0.00%	0	0.00%

Southwest Gas Corporation

System Allocable

Analysis of Experienced Salvage
1985 through 2002

Account 397 - Communication Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE YEAR ROLLING BANDS							
1983-85	0	0	0.00%	0	0.00%	0	0.00%
1984-86	0	0	0.00%	0	0.00%	0	0.00%
1985-87	0	0	0.00%	0	0.00%	0	0.00%
1986-88	5,400	0	0.00%	320	5.93%	-320	-5.93%
1987-89	6,472	0	0.00%	320	4.94%	-320	-4.94%
1988-90	6,472	0	0.00%	320	4.94%	-320	-4.94%
1989-91	1,072	0	0.00%	0	0.00%	0	0.00%
1990-92	0	0	0.00%	0	0.00%	0	0.00%
1991-93	1,441	0	0.00%	0	0.00%	0	0.00%
1992-94	871,069	2,557	0.29%	0	0.00%	2,557	0.29%
1993-95	1,021,829	2,557	0.25%	0	0.00%	2,557	0.25%
1994-96	1,020,388	2,557	0.25%	0	0.00%	2,557	0.25%
1995-97	163,640	400	0.24%	0	0.00%	400	0.24%
1996-98	19,705	400	2.03%	0	0.00%	400	2.03%
1997-99	29,620	400	1.35%	0	0.00%	400	1.35%
1998-00	71,061	0	0.00%	0	0.00%	0	0.00%
1999-01	230,252	0	0.00%	0	0.00%	0	0.00%
2000-02	260,157	0	0.00%	0	0.00%	0	0.00%
1985-02	1,318,078	2,957	0.22%	320	0.02%	2,637	0.20%

Trend Analysis (End Year) 2002

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	11
Avg Ret Age	9.7
Years to ASL	1.3
Inflation Factor At 2.75% to ASL	1.04

Gross Salv. Trend Analysis*		
1983-2002	20-Year Trend	#VALUE!
1988-2002	15-Year Trend	0.64%
1993-2002	10-Year Trend	0.50%
1998-2002	5-Year Trend	-0.95%

	Gross Salvage %	Cost of Removal %	Net Salvage %
Adjusted Salvage & C/O/R	**-0.95%**	**0.03%**	**-0.97%**

Southwest Gas Corporation

System Allocable

Analysis of Experienced Salvage
1985 through 2002

Account 397.20 - Telemetry Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1985	0	0	0.00%	0	0.00%	0	0.00%
1986	0	0	0.00%	0	0.00%	0	0.00%
1987	0	0	0.00%	0	0.00%	0	0.00%
1988	0	0	0.00%	0	0.00%	0	0.00%
1989	0	0	0.00%	0	0.00%	0	0.00%
1990	0	0	0.00%	0	0.00%	0	0.00%
1991	0	0	0.00%	0	0.00%	0	0.00%
1992	0	0	0.00%	0	0.00%	0	0.00%
1993	0	0	0.00%	0	0.00%	0	0.00%
1994	0	0	0.00%	0	0.00%	0	0.00%
1995	0	0	0.00%	0	0.00%	0	0.00%
1996	0	0	0.00%	0	0.00%	0	0.00%
1997	0	0	0.00%	0	0.00%	0	0.00%
1998	992,784	0	0.00%	0	0.00%	0	0.00%
1999	0	0	0.00%	0	0.00%	0	0.00%
2000	11,295	0	0.00%	0	0.00%	0	0.00%
2001	0	0	0.00%	0	0.00%	0	0.00%
2002	0	0	0.00%	0	0.00%	0	0.00%

Southwest Gas Corporation

System Allocable

Analysis of Experienced Salvage
1985 through 2002

Account 397.20 - Telemetry Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE YEAR ROLLING BANDS							
1983-85	0	0	0.00%	0	0.00%	0	0.00%
1984-86	0	0	0.00%	0	0.00%	0	0.00%
1985-87	0	0	0.00%	0	0.00%	0	0.00%
1986-88	0	0	0.00%	0	0.00%	0	0.00%
1987-89	0	0	0.00%	0	0.00%	0	0.00%
1988-90	0	0	0.00%	0	0.00%	0	0.00%
1989-91	0	0	0.00%	0	0.00%	0	0.00%
1990-92	0	0	0.00%	0	0.00%	0	0.00%
1991-93	0	0	0.00%	0	0.00%	0	0.00%
1992-94	0	0	0.00%	0	0.00%	0	0.00%
1993-95	0	0	0.00%	0	0.00%	0	0.00%
1994-96	0	0	0.00%	0	0.00%	0	0.00%
1995-97	0	0	0.00%	0	0.00%	0	0.00%
1996-98	992,784	0	0.00%	0	0.00%	0	0.00%
1997-99	0	0	0.00%	0	0.00%	0	0.00%
1998-00	0	0	0.00%	0	0.00%	0	0.00%
1999-01	0	0	0.00%	0	0.00%	0	0.00%
2000-02	0	0	0.00%	0	0.00%	0	0.00%
1985-02	1,004,079	0	0.00%	0	0.00%	0	0.00%

Trend Analysis (End Year) 2002

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	8
Avg Ret Age	5.4
Years to ASL	2.6
Inflation Factor At 2.75% to ASL	1.07

Gross Salv. Trend Analysis*		
1983-2002	20-Year Trend	#VALUE!
1988-2002	15-Year Trend	0.00%
1993-2002	10-Year Trend	0.00%
1998-2002	5-Year Trend	0.00%

Adjusted Salvage & C/O/R **0.00%** **0.00%** **0.00%**

Southwest Gas Corporation

System Allocable

Analysis of Experienced Salvage
1985 through 2002

Account 398 - Miscellaneous Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
1985	2,424	300	12.38%	0	0.00%	300	12.38%
1986	0	0	0.00%	0	0.00%	0	0.00%
1987	0	0	0.00%	0	0.00%	0	0.00%
1988	9,319	4,000	42.92%	0	0.00%	4,000	42.92%
1989	24,476	0	0.00%	0	0.00%	0	0.00%
1990	1	0	0.00%	0	0.00%	0	0.00%
1991	10,106	405	4.01%	0	0.00%	405	4.01%
1992	349	0	0.00%	0	0.00%	0	0.00%
1993	0	0	0.00%	0	0.00%	0	0.00%
1994	0	0	0.00%	0	0.00%	0	0.00%
1995	0	0	0.00%	0	0.00%	0	0.00%
1996	346	0	0.00%	0	0.00%	0	0.00%
1997	279,655	0	0.00%	0	0.00%	0	0.00%
1998	4,113	0	0.00%	0	0.00%	0	0.00%
1999	80,058	0	0.00%	0	0.00%	0	0.00%
2000	138,338	0	0.00%	0	0.00%	0	0.00%
2001	155,842	0	0.00%	0	0.00%	0	0.00%
2002	89,844	0	0.00%	0	0.00%	0	0.00%

Southwest Gas Corporation

System Allocable

Analysis of Experienced Salvage
1985 through 2002

Account 398 - Miscellaneous Equipment

Year	Original Cost of Retirements	Gross Salvage	%	Cost of Removal	%	Net Salvage	%
THREE YEAR ROLLING BANDS							
1983-85	2,424	300	12.38%	0	0.00%	300	12.38%
1984-86	2,424	300	12.38%	0	0.00%	300	12.38%
1985-87	2,424	300	12.38%	0	0.00%	300	12.38%
1986-88	9,319	4,000	42.92%	0	0.00%	4,000	42.92%
1987-89	33,795	4,000	11.84%	0	0.00%	4,000	11.84%
1988-90	33,796	4,000	11.84%	0	0.00%	4,000	11.84%
1989-91	34,583	405	1.17%	0	0.00%	405	1.17%
1990-92	10,456	405	3.87%	0	0.00%	405	3.87%
1991-93	10,455	405	3.87%	0	0.00%	405	3.87%
1992-94	349	0	0.00%	0	0.00%	0	0.00%
1993-95	0	0	0.00%	0	0.00%	0	0.00%
1994-96	346	0	0.00%	0	0.00%	0	0.00%
1995-97	280,001	0	0.00%	0	0.00%	0	0.00%
1996-98	284,114	0	0.00%	0	0.00%	0	0.00%
1997-99	363,826	0	0.00%	0	0.00%	0	0.00%
1998-00	222,509	0	0.00%	0	0.00%	0	0.00%
1999-01	374,238	0	0.00%	0	0.00%	0	0.00%
2000-02	384,024	0	0.00%	0	0.00%	0	0.00%
1985-02	794,871	4,705	0.59%	0	0.00%	4,705	0.59%

Trend Analysis (End Year) 2002

***Based Upon 3-Year Rolling Averages**

Annual Inflation	2.75%
ASL	14
Avg Ret Age	12.5
Years to ASL	1.5
Inflation Factor At 2.75% to ASL	1.04

Gross Salv. Trend Analysis*		
1983-2002	20-Year Trend	#VALUE!
1988-2002	15-Year Trend	-7.96%
1993-2002	10-Year Trend	-0.77%
1998-2002	5-Year Trend	0.00%

Adjusted Salvage & C/O/R	**0.00%**	**0.00%**	**0.00%**

SOUTHWEST GAS CORPORATION

Docket No. G-01551A-04-

2004
ARIZONA
GENERAL RATE CASE

TESTIMONY

Volume III

SOUTHWEST GAS CORPORATION

ARIZONA GENERAL RATE CASE

VOLUME III

<u>LIST OF WITNESSES</u>

Jeffrey W. Shaw

Christina A. Palacios

Robert A. Mashas

Randi L. Aldridge

Theodore K. Wood

Frank J. Hanley

James L. Cattanach

Christy M. Berger

Steven M. Fetter

Edward B. Gieseking

A. Brooks Congdon

Vivian E. Scott

Shaw

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
of
JEFFREY W. SHAW

Q. 1 Please state your name and business address.

A. 1 My name is Jeffrey W. Shaw. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150-0002.

Q. 2 By whom are you employed and in what capacity?

A. 2 I am the Chief Executive Officer of Southwest Gas Corporation (Southwest or the Company).

Q. 3 Please state your educational background and business experience.

A. 3 I graduated from the University of Utah in 1983 with a Bachelor of Science degree in accounting. After graduation, I worked for Arthur Andersen & Co. in its Dallas, Texas and Las Vegas, Nevada offices as a member of the audit division. I am a Certified Public Accountant (CPA) in the State of Nevada. I joined Southwest in May 1988 as the Director of Internal Audit. In July 1991, I was promoted to Controller and Chief Accounting Officer, and in May 1993, was named Vice President. Additionally, in late 1993, I assumed the responsibility for certain treasury functions and was named Treasurer in May 1994.

In July 2000, I was promoted to Senior Vice President/Finance and Treasurer. In addition to financial and treasury functions, I also oversaw the Human Resources department, Corporate Purchasing and the Inventory Management function. In July 2002, I was named Senior Vice President of Gas Resources and Pricing, and was made responsible for the oversight of Gas Procurement and Dispatch, Large Customer Sales, and the Pricing and Tariffs area, including Revenue Requirements and Federal Regulatory Affairs. In July 2003, I was promoted to President and undertook responsibility for the oversight of the Company's business policies, practices and processes. In June 2004, I was promoted to my current position where I am responsible for the overall guidance and strategic direction of the Company. In July 2004, I was elected to Southwest's Board of Directors.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 Yes. I have previously testified before the Arizona Corporation Commission (the Commission), the Public Utilities Commission of Nevada, the California Public Utilities Commission and the Federal Energy Regulatory Commission.

Q. 5 What is the purpose of your prepared direct testimony in this proceeding?

A. 5 I am supporting Southwest's application for necessary and appropriate increases in its general rates in Arizona. In my prepared direct testimony, I provide the overarching reasons that support Southwest's request for necessary rate relief in its Arizona rate jurisdiction. My testimony will focus on Southwest's continued inability to earn its Commission-authorized rate of return. I will provide the Commission with several interrelated policy alternatives that could provide the Company with, at least, a fair and reasonable opportunity to realize the rate of return that will be authorized by this Commission at the conclusion of this proceeding. Specifically, I will address the necessary pricing of the Company's services, the need for a reasonable regulatory capital structure/rate of return, initiatives undertaken by Southwest to control costs and become even more productive, and the impact of rapid growth in combination with regulatory lag.

Q. 6 Other than yourself, please briefly discuss the other Southwest witnesses that will be presenting prepared direct testimony in this proceeding, and the general subject areas that they will be discussing and supporting.

A. 6 In addition to myself, Southwest is presenting eleven (11) other witnesses who provide prepared direct testimony in support of Southwest's request for increases in its general rates. Besides myself, the Southern Arizona Division Senior Vice President, Ms. Christina A. Palacios will discuss in greater detail the local initiatives undertaken to emphasize safety and customer service. She will also discuss the Company's efforts to control and manage costs and to increase the productivity and effectiveness of Southwest's Arizona workforce. Mr. Robert A. Mashas will discuss Southwest's revenue deficiency and quantify the Company's lack of reasonable earnings in Arizona for a number of years. He will also discuss Southwest's Incremental Contribution Method (ICM) model and the expenses associated with the Transmission Integrity Management Program. Ms. Randi L. Aldridge supports the Company's cost of service, including the necessary operations and maintenance (O&M) and administrative and general (A&G) expenses, the methods employed to allocate general corporate costs, depreciation expenses, the various rate base components, and Southwest's tax expenses. Mr. Theodore K. Wood supports the reasonable and necessary overall cost of capital, provides justification for the use of a proposed hypothetical capital structure for Southwest, and provides the determination of the Company's cost of debt and preferred securities. Mr. Frank J. Hanley, President of AUS Consultants - Utility Services, determines and supports a fair and reasonable cost of common equity for Southwest. Mr. James L. Cattanach supports the Company's adjustment to normalize weather and explains and supports the historical decline in residential consumption per customer the Company continues to experience in Arizona. He also provides a price-elasticity study ordered by the Commission in Southwest's last general rate case.

Ms. Christy M. Berger supports the embedded class cost of service studies. Mr. Steven M. Fetter of REGULATION unFETTERED, discusses the recommendations of the Joint Statement of the American Gas Association, the Natural Resources Defense Council, and the American Council for an Energy-Efficient Economy (Joint Statement) that was incorporated in a National Association of Regulatory Commissioners (NARUC) resolution adopted in July 2004, the regulatory policy implications of that Joint Statement, the relationship to a proper rate design, and the positive impact that it could provide Southwest's credit ratings. Mr. A. Brooks Congdon supports adjustments made to Southwest's billing determinants (volumes), the allocation of revenue to customer classes, and various tariff provisions and revisions. Mr. Edward B. Gieseking supports Southwest's rate design proposals and the Company's proposal for a margin decoupling mechanism to track residential margin per customer and to remove Southwest's inherent disincentive to promote customer energy efficiency. Finally, Ms. Vivian E. Scott presents and supports Southwest's package of conservation and energy efficiency programs which, in conjunction with Southwest's recommended rate design and margin decoupling mechanism, will encourage customers to make efficient use of energy.

Q. 7 Why does Southwest require rate relief in its Arizona rate jurisdiction?

A. 7 As is shown in Southwest's Schedule C-1 for its Arizona rate jurisdiction filed in this general rate case, Southwest's unadjusted, earned return is woefully inadequate (5.47 percent on rate base). It does not provide the level of income or cash flow necessary to adequately sustain the natural gas distribution operations of Southwest, nor does it provide adequate support or assurances to investors or creditors from whom the Company must obtain capital to fund its significant infrastructure-related capital expenditures. Southwest has implemented several cost control measures, which have permitted it to achieve one of the best customer-to-employee ratios in the industry – a key indicator of productivity. At the same time, J.D. Power & Associates rated the Company the best utility in the West in terms of customer satisfaction in 2003.

Notwithstanding these positive factors, Southwest faces substantial cost increases related to federal regulation, including but not limited to the Sarbanes-Oxley Act of 2002 and the Pipeline Integrity Management Rule. In addition, Southwest continues to be beset with declining average residential customer usage. These factors have eroded Southwest's Arizona earnings to an extent that general rate relief is the only acceptable alternative available to the Company.

Q. 8 Has Southwest, historically, been able to earn its authorized return in Arizona?

A. 8 No, it has not. As described and quantified in Mr. Mashas' direct prepared testimony, Southwest, in the last 11 years, has realized its authorized rate of return only one time in its Arizona rate jurisdiction, and under circumstances that are not likely to recur.

Q. 9 Have you identified the factors that are the root cause behind Southwest earning below its authorized return?

A. 9 Yes. I believe there are three primary reasons that Southwest has not had a fair and reasonable opportunity to earn its Commission-authorized return, and to a large degree, they are all interrelated. First, the Commission-authorized pricing of the Company's services (rate design) fails to reflect the fact that, absent the actual cost of natural gas itself, the vast majority of the costs of the utility are fixed. Second, declining average natural gas usage by residential customers, resulting in inadequate margins, has strained Southwest's return on equity and capital structure. Third, the use of a historic test year results in nearly constant financial attrition to the Company.

Q. 10 What is the estimated impact to the Company's earnings and equity position from the chronic lower-than-authorized returns over the past 11 years?

A. 10 As noted earlier, Southwest, on an unadjusted basis, in 10 out of 11 years, has not earned its Commission-authorized return. It follows that if the return is lower than authorized, the Company's net income is also lower than what it would have been. Based on Mr. Mashas' calculations, Southwest has foregone more than $145 million in net income in its Arizona service territories. This loss of net income was a result of many factors and was heavily influenced by actual consumption being lower than the consumption volumes used to establish rates. Southwest's analysis shows that increased appliance efficiency, newer and more stringent building codes and standards, and greater energy conservation by customers are the primary causes for the decline in consumption. Although Southwest is a firm supporter of the use of cost-effective conservation measures by its customers, as evidenced by its proposed conservation and energy efficiency programs in this proceeding, and believes energy efficiency is a laudable goal, it is imperative that the Company's margins not be degraded by additional reduced consumption. Mr. Fetter, together with other Company witnesses, discusses several interrelated proposals that hold the Company harmless from a reduction in use of natural gas by its customers, thus encouraging Southwest to continue to aggressively promote energy efficiency.

If Southwest had earned its authorized returns in those years, it would have realized at least $145 million in additional equity (retained earnings) and, concurrently, an approximately equivalent reduction in long-term debt. This, in turn, would significantly have improved Southwest's equity ratio in its capital structure. An improved capital structure would likely lead to better credit ratings which, in turn, would benefit customers through a lower cost of capital.

I want to emphasize that the lower percentage of equity in Southwest's capital structure is substantially all related to continued lack of earnings. In fact, Southwest has issued approximately 40 percent of its total outstanding shares of common stock in the last decade. This is a clear indication of the Company's efforts to strengthen its capital structure and demonstrates that adequate earnings remains the key to actually achieving a reasonably healthy equity ratio.

Q. 11 Can you please explain how Southwest's rate design in Arizona contributed to unrealized margin and the inability to achieve authorized returns?

A. 11 As a natural gas distribution utility, Southwest must make significant investments in infrastructure to meet its explicit service obligation to customers. Customers, once connected, have the assurance of the availability of safe and reliable natural gas service 24 hours a day, seven days a week, regardless of whether they use natural gas or not. The Company's rates must be designed to ensure that the significant fixed costs <u>required</u> to assure that availability, are fully recovered by Southwest.

Q. 12 Could you further explain the dilemma the Company faces because of its commodity-based rate design?

A. 12 Virtually everything Southwest does in the natural gas distribution portion of its business centers on assuring the availability of safe and reliable natural gas service and, accordingly, substantially all of its costs (excluding the cost of gas itself, which is recovered through the Purchased Gas Adjustment mechanism with no profit) are fixed. These fixed costs consist primarily of plant-related costs, such as return on investment, taxes, and depreciation. In addition, many of the operational costs associated with actually providing natural gas service, such as O&M expenses and A&G expenses, are essentially fixed (approximately two-thirds of those expenses are attributable to labor).

Investors provide capital to natural gas utilities (and other businesses, for that matter) with the expectation that they will earn a competitive return commensurate with the risk of the investment. Investors have many investment alternatives to choose from and they will typically provide capital to a business that has an attractive risk-return profile. A rate design, or price to customers, that recovers a large portion of the authorized return or margin through commodity-based rates provides significant additional down-side risk to investors when a utility, like Southwest, suffers from declining average customer usage.

A rate design that recovers fixed costs through commodity-based rates can hurt both the customer and the investor. For example, when the weather is significantly colder than normal, as occurred in 1998, there is generally an over-recovery of fixed costs. Conversely, when the weather is warmer, or when usage declines due to tighter housing envelopes and more efficient appliances, there is an under-recovery of fixed costs, which has been the case for Southwest for ten of the past eleven years. A more equitably balanced solution should be sought.

Approximately 99 percent of Southwest's customers are classified as "weather-sensitive" customers (residential and small commercial). The weather-sensitive customers are responsible for contributing about 75 percent of Southwest's total margin. These customers should, and do save on their natural gas bills when they use lower volumes, irrespective of the reason. However, their "savings" should not prejudice investors from recovery of, and return on, invested capital. Equitable customer savings should only relate to the commodity volumes and the cost of the natural gas in those volumes, not the Company's authorized margin or profit. In other words, customer savings from using fewer volumes should not impair Southwest's ability to provide the availability of safe and reliable natural gas service, since that responsibility remains fixed and inviolate.

Q. 13 Has the Commission recognized this dilemma?

A. 13 Yes, to some degree. In Southwest's last two general rate cases (Docket Nos. U-1551-96-596 and G01551A-00-0309), the Commission recognized the dilemma caused by the Company's commodity-based rate design when it authorized increases in the residential monthly basic service charge (from $5.50 prior to September 1997 to $8.00 today), and authorized a modest declining block rate structure. Southwest is appreciative of the Commission's recognition of the need to increase the monthly fixed charge and implement declining block rates to partially reflect the nature of the Company's cost structure. This enhanced rate design has been noted positively by the various rating agencies that monitor and track the Company. Unfortunately, this gradual transitional process to a more cost-based rate design is not complete, and the Company's dilemma remains. The solution to this problem is to further increase the monthly basic service charge to levels that better reflect the nature of the expenses authorized by the Commission.

Q. 14 What should be done to resolve or at least help mitigate the problem of the variability of Southwest's margin related to the vagaries of customer usage?

A. 14 The fixed costs associated with providing safe and reliable natural gas service are reviewed and scrutinized through the regulatory process in general rate case proceedings, such as this one. Once costs are approved through these proceedings, the authorized rate design should provide a fair and reasonable opportunity for

Southwest to recover those costs. Usage variability should not be a factor in the recovery of Southwest's fixed costs. If the provision of safe and reliable natural gas service is constant, the recovery of the related costs should also be constant.

Invariably, the most important decision this Commission could reach to resolve this dilemma would be to authorize the Conservation Margin Tracker (CMT) that is detailed by Southwest in the prepared direct testimony of Mr. Gieseking. The authorization of this provision would ensure the residential margin level approved in the general rate case would be collected irrespective of any volume variations. Any difference from the authorized level would be deferred and amortized over a specified future period as either a reduction of, or an addition to, customer bills. The Company has proposed a wide array of conservation programs in this proceeding that will serve to benefit customers through lower bills and benefit society through more efficient use of energy resources. However, if the conservation programs are successful, as Southwest believes they will be, the Company will be exposed to further degradation of its margin. The authorization of the CMT by the Commission will alleviate this exposure, and will serve the dual purpose of removing the inherent disincentive to the Company to encourage conservation of the resource (natural gas) and allowing Southwest the reasonable assurance that its costs will be recovered.

In addition to authorizing the CMT, the Commission should also make appropriate and cost-based changes to the Company's current rate design. The margin component of residential rates (residential customers in Arizona comprise approximately 95 percent of the Company's customer base) is composed of two parts: a fixed monthly charge and a commodity charge. The current residential rate design in Arizona recovers only approximately 38 percent of the total margin from that customer class through the fixed charge. The remaining 62 percent of margin is recovered through the commodity charge, and subject to the vagaries associated with declining consumption. Consequently, the Commission should authorize a rate design that fairly balances fixed cost recovery and the interests of the customer in terms of energy efficiency and bill minimization, by increasing the fixed charge component of the residential rate design.

Ideally, fixed costs should be recovered through fixed monthly customer charges. This form of rate design could be done ratably or even in a tiered approach to follow seasonality. Increased monthly customer charges would reduce the volatility of customer bills and provide the utility with a more reasonable opportunity to actually earn its authorized rate of return. This proposal is more fully developed in Mr. Gieseking's prepared direct testimony. Approval of the combination of both the CMT and an enhanced cost-based rate design, as advocated by the Company, would provide Southwest with a fair and reasonable opportunity to recover its fixed costs and actually earn its Commission-authorized return.

Q. 15 Is there a relationship between Southwest's capital structure and its Commission-authorized rate of return?

A. 15 Yes. A leveraged, or highly leveraged (high level of debt compared to equity) capital structure requires a higher overall return (primarily through the return granted on equity) than a capital structure that is less leveraged and more balanced. In essence, the more debt in the capital structure, the higher the risk, and the higher overall return that will be necessary to ensure that the return to the shareholder is commensurate with returns on investments in other businesses having corresponding risks. The Company's witnesses on the necessary hypothetical capital structure and the fair return on common equity, Mr. Wood and Mr. Hanley, respectively, provide additional detailed information concerning the relationships between capital structure and returns.

Q. 16 Are there factors which cause Southwest to have a higher risk profile compared to other local gas distribution companies?

A. 16 Yes, there are several factors that are unique to Southwest. First, most of Southwest's Arizona customers are located in one of the fastest growing regions of the country. Southwest's rate base must, by necessity, grow at a substantial rate, to keep pace with the rapid increase in the number of customers. Since Arizona employs a historic test year, Southwest must file periodic rate cases to allow its rates to "catch up" with the significant capital expenditures the Company has already made.

Second, Southwest's present margin, as noted earlier, is primarily recovered through commodity-based rates. This exposes earnings to the punishing effects of the demonstrated declining average customer usage levels. This phenomenon of declining average customer usage levels is discussed in more detail in Mr. Cattanach's prepared direct testimony. Again, given Arizona's use of historic test year customer usage, Southwest's rates have historically been designed based on customer volumes that the Company is unlikely to realize.

Finally, due to the significant customer growth Southwest has experienced and continues to experience in Arizona, Southwest must continually construct, replace and improve its infrastructure. This requires that the Company must access the capital markets more frequently, resulting in the need to issue more debt and/or equity.

The combination of these three factors generally cause Southwest to have a higher risk profile compared to other local gas distribution companies and underscores the need for the Commission to establish a reasonable return on equity together with a hypothetical capital structure in this proceeding.

Q. 17 Has Southwest taken steps to improve its productivity and control costs?

A. 17 Yes, Southwest most certainly has. I believe it is incumbent upon the Company to take all reasonable and necessary actions to efficiently manage its workforce and to minimize costs. Southwest, for many years, has utilized information technology enhancements to allow its existing workforce to serve more customers, without any degradation in customer service.

For example, several years ago, Southwest implemented a "Start Work from Home" program that increased the number of appointments and tasks that can be completed by service technicians and customer representatives in a given day. That process has been further enhanced with "Maps to the Field", whereby less than optimum paper maps have been replaced with up-to-date and accurate electronic maps that are available to field personnel at the touch of a button. Southwest has also installed a new materials management system that enhances the control of inventory and reduces the holding and handling costs of the many parts and materials needed to satisfactorily serve customers. Southwest has most recently implemented a state-of-the-art work management system that more accurately and efficiently schedules the operational and construction work processes from start to finish.

These technology improvements, among other process improvements, have allowed Southwest to effectively manage its workforce and increase the productivity of its employees. As I noted earlier, a key measure of workforce productivity is the ratio of customers to employees. In Southwest's 1997 Arizona general rate case, with a test year of 1996, the Company had a ratio of 507 customers to each employee. In the 2000 general rate case (test year 1999), Southwest had increased its customer-to-employee ratio to 645:1. In this general rate case, with a test year ended August 31, 2004, Southwest has improved the ratio to 745 customers to each employee. In other words, each Southwest employee is serving nearly 47 percent more customers in 2004 than they did eight years ago. All the while, Southwest has consistently achieved annual customer satisfaction levels of 92 percent or higher in Arizona. This is a phenomenal result, and a clear indication that Southwest has continued to achieve productivity gains and worked to mitigate potential cost increases for customers. In addition, local management in Arizona has undertaken a number of productivity initiatives that have further enhanced the Company's ability to provide excellent customer service at a reasonable cost. Ms. Palacios, the Senior Vice President of the Southern Arizona Division, discusses some of these local initiatives in more detail in her prepared direct testimony.

The Company has also taken advantage of lower interest rates since the last Arizona general rate case to refinance its preferred securities. Southwest refinanced $60 million of Trust Originated Preferred Securities (TOPrS) in 2003 as more fully explained in the testimony of Southwest witness Mr. Wood. That refinancing generated positive net present value savings of approximately $5.8 million and, in turn, reduced Southwest's Arizona revenue requirement in this proceeding by more than $600,000.

Q. 18 What do you believe this Commission can do to ensure that Southwest has a fair and reasonable opportunity to achieve its authorized rate of return?

A. 18 The Commission, in this general rate case, is presented with an opportunity to establish responsive regulatory policy that addresses the concerns enumerated in my testimony and those further elaborated on in the testimony of Mr. Fetter. Ratemaking treatment for Southwest must recognize that declining consumption and significant growth in a historic test year jurisdiction places enormous financial strain on the Company. The Commission's assistance in allowing Southwest a fair and reasonable opportunity to earn its authorized return should, over time, improve the Company's capital structure and provide assurance to the financial markets that this Commission is concerned about the financial health of the utilities it regulates. This is doubly important given the Company's frequent need to access the capital markets to fund the demand in Arizona's infrastructure due to the tremendous growth.

Consequently, the Commission should implement rate designs and other margin-protection mechanisms that minimize the risk that the Company's margin is detrimentally affected by factors outside its control. The ability to actually realize the Commission-authorized margin will lead to improvements in Southwest's capital structure and will directly result in lower financing costs which will be passed through to customers. To this end, the Commission should also adopt a balanced, hypothetical capital structure for Southwest with a fair return on equity. Southwest has offered, in this proceeding, several proposals and recommendations that accomplish these objectives. I strongly implore the Commission to adopt Southwest's proposals.

Q. 19 Does this conclude your prepared direct testimony?

A. 19 Yes, it does.

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Palacios

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
of
CHRISTINA A. PALACIOS

INTRODUCTION/BACKGROUND

Q. 1 Please state your name and business address.

A. 1 My name is Christina A. Palacios. My business address is 3401 East Gas Road, Tucson, Arizona 85714-1994.

Q. 2 By whom are you employed and in what capacity?

A. 2 I am Senior Vice President/Southern Arizona Division for Southwest Gas Corporation (Southwest or the Company).

Q. 3 Please state your educational background and business experience.

A. 3 I earned a bachelor's degree in Marketing and a Masters in Business Administration from the University of Utah in 1975 and 1976, respectively. Prior to beginning my career with Southwest, I held numerous and increasingly responsible positions in human resources for EIMCO, a heavy equipment manufacturer, and Armour Dial, a packaged goods company. In 1984, I joined Southwest as the Human Resources Manager in Phoenix and was subsequently promoted to Manager/Administration in 1989. In 1991, I was promoted to Manager/Customer Relations in the Southern Nevada Division. In 1994, I was promoted to Director/Operations Support at Corporate in Las Vegas. In

1995, I was promoted to Vice President/Southern Nevada Division, and in 1997, I was promoted to Vice President of the Southern Arizona Division. I was promoted to my present position in 2004.

I have been heavily involved in the southern Arizona community. In 1998, I was appointed by Governor Hull to the Arizona School Facilities Board, where I served for one year. In 2002, I received the Good Scout Award from the Catalina Council of the Boy Scouts of America. In 2003, I received the Tucson YWCA's Business Leadership Award and was just recently named Hispanic Business Woman of the Year by the Tucson Hispanic Chamber. I am currently a board member of the Greater Tucson Economic Council, the Southern Arizona Leadership Council, and the United Way of Greater Tucson. I also serve on the Arizona Board of Regents, and I am a member of the Pacific Coast Gas Association, the DM-50 (a support group for Davis-Monthan Air Force Base), and the Tucson Airport Authority.

Q. 4 What is the purpose of your prepared direct testimony in this proceeding?

A. 4 The purpose of my testimony is to provide an overview of Southwest's Arizona operations. I will address the Company's focus on safety and customer service and satisfaction, as well as Southwest's efforts to increase productivity and control costs.

. . . . .

SAFETY

Q. 5 Has the rapid housing growth in Arizona affected Southwest's safety efforts?

A. 5 Yes. During the past four years, the Company has experienced numerous incidents involving third-party damage to Southwest's facilities due in large part to rapid housing growth and the expansion of infrastructure experienced in Pima and Maricopa Counties. Southwest has responded to the increased instances of third-party damage by enhancing the training for Company emergency responders and implementing new safety and operational practices to reduce the time between the receipt of an incident report and controlling the escape of natural gas. As a consequence, Southwest has improved its average response time from 48 minutes to 39 minutes.

Q. 6 Has Southwest taken any proactive steps to reduce the number of incidents due to third-party damage?

A. 6 Yes. Southwest has undertaken substantial outreach efforts with contractors. The Company has also provided training to alert the employees of contractors to the hazards associated with line breaks. The results of these efforts are reflected in a declining number of such incidents and a decrease in the severity of the incidents. For example, in the year 2000, 1,726 line breaks were reported. In the year ended October 31, 2004, even with the record pace of growth, only a total of 1,219 lines breaks were reported.

Q. 7 What other steps has Southwest taken to address safety issues?

A. 7 In addition to internal training, Southwest has forged excellent working relationships with local "first-responders," such as fire and emergency personnel. Southwest has increased its training across-the-board for personnel outside the Company, including utilization of the Emergency Response Facility located at the Company's Tempe Operations Center. Many coordinated training sessions have been undertaken with local fire departments in this real-time, state-of-the-art facility. In an effort to promote its use by first-responders, Southwest has also showcased this facility and demonstrated its effectiveness to many members of local and state government. All of these activities have led to positive results and are evidence of Southwest's strong commitment to safety.

CUSTOMER SERVICE/SATISFACTION

Q. 8 Has Southwest been able to maintain high levels of customer satisfaction in this environment of rapid growth?

A. 8 Yes. Southwest has always prided itself on customer satisfaction. Achieving a high level of customer satisfaction continues to be a major goal for the Company's employees. Southwest has made, and will continue to make, training of its employees a top priority and to provide them with the tools necessary to increase their ability to meet customer needs and expectations.

Q. 9 Can you give any examples that demonstrate how Southwest meets or exceeds its customers' expectations?

A. 9 Yes. Southwest contracts with an independent third-party provider to survey and measure, on a quarterly basis, customer satisfaction with the gas service that Southwest is providing. Southwest has been measuring customer satisfaction since 1994. Both the Southern and Central Arizona Divisions have consistently achieved annual customer satisfaction scores of 92 percent or higher. Most recently (September 30, 2004), the customer satisfaction level in the Southern Arizona Division was 92 percent and 97 percent in the Central Arizona Division. The results of Southwest's surveys were confirmed in 2003 by the nationally-recognized quality-of-service firm, J. D. Power & Associates, which ranked Southwest as the best gas utility in the western region of the United States in terms of customer satisfaction. Although Southwest is pleased with its reputation as an outstanding service provider, Southwest is committed to maintaining and improving its customer satisfaction.

PRODUCTIVITY AND COST CONTROL

Q. 10 How does increased productivity benefit Southwest's Arizona customers?

A. 10 Southwest's customers benefit through increased efficiency and improved levels of customer service. As a result, costs and, consequently, customer bills are kept lower than they otherwise would be. This also allows

Southwest to accomplish more with less.

Q. 11 How has Southwest been able to increase productivity through information technology?

A. 11 It is clear to Southwest's management that increased productivity depends upon the high caliber and performance of its employees coupled with improvements in technology. Examples of this can be seen in the customer service system and work management system. The capability of working directly from home is one of the key benefits of having "Go Books" (portable laptops) in each vehicle in the field. In addition to eliminating the use of paper orders by automating these processes, technicians can electronically access system maps, Company Standard Practices, customer information, and meter reading data in the field. Such data access has not only reduced non-productive time due to the drive time between an employee's residence and the Operations Center, but it also has yielded a substantial benefit to *Clean Air/Trip Reduction* efforts.

Other technologies have also played a part in productivity increases, and they include: expansion of the information services network to boost internal transfer of information; use of tools such as the Global Positioning System; cell phone/direct-connect communications; and key-hole excavation techniques.

Q. 12 Has Southwest increased productivity through means other than information technology improvements?

A. 12 Yes. Logistical planning improvements have also led to the increased productivity of Southwest's employees. The Company has moved to remote storage in Arizona, whereby parts and materials are kept in various locations in the service area which service technicians can more quickly access while in the field. Southwest, in cooperation with the Arizona Blue Stake Center, has instituted Automated Line Location Requests. This greatly reduces the time needed to locate and mark Southwest's facilities and it allows Southwest to utilize its available resources where they are most needed. This has been done by organizing and staffing various distribution areas to enhance the Company's emergency response, meter reading, and scheduled maintenance activities.

Q. 13 What have been the results of Southwest's efforts to increase productivity in Arizona?

A. 13 The results have been extraordinary. On December 31, 1999, the test year ending date in Southwest's last general rate case, Southwest served approximately 748,000 Arizona customers with a staff of 1,159 employees. On August 31, 2004, the last day of the test year in this case, the customer count increased to approximately 872,000, while the employee count remained virtually flat at 1,171 employees. Stated another way, on December 31, 1999, each Southwest Arizona employee served approximately 645 customers; whereas, on August 31, 2004, each Southwest Arizona employee served approximately 745 customers. This equates to a productivity gain of nearly 16 percent, and it was accomplished without negatively affecting customer satisfaction. If the productivity increase were converted to dollars, the enhanced productivity of Southwest's Arizona workforce has benefited customers by nearly $12 million in labor and benefits since December 31, 1999.

Q. 14 Does Arizona's tremendous growth put any strain on Southwest's resources?

A. 14 Yes. In fact, Southwest has had to expand its gas distribution system and related infrastructure dramatically. The magnitude of growth that Arizona has experienced over the past decade has presented a major challenge to the Company. Unfortunately, although the addition of more customers provides Southwest with the opportunity to sell more natural gas and to spread fixed costs across an increasing number of customers, the growth that occurs often "leap-frogs" across under-developed areas and opens up new development far from populated areas. This situation is likely to remain the case as long as the land is cheaper in the rural areas than it is in the core of the cities or existing suburbs. This type of development requires the Company to make large investments in "approach" pipelines and facilities to simply reach the location of new developments. This, in turn, strains Southwest's ability to acquire the capital needed to fund these investments.

Southwest also is faced with a related problem. In rural areas that typically consist of agricultural development, builders are rapidly converting the tracts to high density housing. The gas distribution piping that was installed decades ago to serve farm houses, ranches and other agricultural uses becomes inadequate when replaced with thousands of new homes. This requires Southwest to make investments to reinforce the pressure and capacity of the existing piping systems to ensure that the existing and new customers in these areas have adequate capacity for the delivery of natural gas to their homes and businesses. This creates additional demand on Southwest's financial resources.

Q. 15 What steps has Southwest taken to control costs and address the strain on its financial resources?

A. 15 Southwest has made a concerted effort to reduce the costs of installing facilities in new subdivisions. Accordingly, the Company has employed several approaches to this problem, and I have included the following three examples in my testimony. First, Southwest has sought out and increased the use of joint trenching opportunities with other utilities. Second, the Company has required builders and developers to share in the cost of new infrastructure requirements. Third, Southwest has had builders and developers provide the entire trench for underground gas facilities (as well as other underground facilities), removing one of the largest costs of installing gas pipelines.

Q. 16 Does this conclude your prepared direct testimony?
A. 16 Yes, it does.

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Mashas

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of
ROBERT A. MASHAS

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
of
ROBERT A. MASHAS

Q. 1 Please state your name and business address.

A. 1 My name is Robert A. Mashas. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150-0002.

Q. 2 By whom are you employed and in what capacity?

A. 2 I am employed by Southwest Gas Corporation (Southwest or the Company) as the Director/Revenue Requirements.

Q. 3 Please state your educational background and business experience.

A. 3 I graduated from Wilkes College in Wilkes-Barre, Pennsylvania with a Bachelor of Science degree in Management, with an Economics concentration. I received a Master of Business Administration degree from Shippensburg State College in Shippensburg, Pennsylvania. I am a member of the American Institute of Certified Public Accountants.

After graduation in 1977, I was employed by Marriott Corporation at its headquarters in Bethesda, Maryland. As a staff accountant, I worked in the Foreign Tax Department.

During 1978, I accepted a position with the Federal Energy Regulatory Commission (FERC). At the FERC, I worked in the Office of the Chief Accountant, Division of Audits. My responsibilities included conducting audits of natural gas transmission, electric and oil pipeline companies for compliance with the Uniform System of Accounts, rate orders, and decisions of the FERC.

In July 1983, I joined the Public Service Commission of Nevada (PSCN, now known as the Public Utilities Commission of Nevada or PUCN). As a senior auditor, my duties included the examination of the books and records of gas, electric, water, telephone and cable television utilities, as well as testifying as an expert witness. During my tenure at the PUCN, I participated in the general rate proceedings of water and natural gas companies, deferred energy, and purchased gas adjustment (PGA) filings, general order proceedings, and numerous special projects.

In July 1984, I joined the Rate Department of Southwest as a Cost Analyst. In 1985, I was promoted to Manager/Revenue Requirements. My duties included the review of cost data for the purpose of developing rates and charges, as well as helping to determine the Company's current and future cost of service for each of the Company's rate making areas.

In 1992, I was promoted to Director, Revenue Requirements and Resource Planning, where I undertook additional duties of developing least cost resource plans that integrate supply, facility and demand side resource options into a comprehensive resource plan.

In 1998, the regulatory requirements for resource plan filings were substantially reduced and my responsibilities were changed to focus primarily on revenue requirements.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 Yes. I have previously testified before the Arizona Corporation Commission (Commission), the PUCN, the California Public Utilities Commission and the FERC.

Q. 5 What is the purpose of your prepared direct testimony in this proceeding?

A. 5 My testimony is comprised of six parts. The first part of my testimony provides a broad overview of the test year, adjustments to the test year data and the resulting deficiency. The second part addresses the major reasons and underlying causes for the deficiency. The third part addresses the impact of the Company's inability to earn its authorized rate of return (ROR) in Arizona. The fourth part discusses the proposed adjustments to the test year that I am supporting. The fifth part discusses the Company's line extension policy and the related practices. The discussion of the line extension policy is a compliance item resulting from the Commission's decision in the Company's last general rate case. The sixth part discusses the Company's position on continuing pipe replacement write-offs since the last general rate case, and its proposed changes to the write-off percentages that were set forth in the Settlement Agreement in Docket No. U-1551-93-272.

BROAD OVERVIEW

Q. 6 What is the test year for this rate application?

A. 6 The test year is the 12-month-period ended August 31, 2004. The test year results have been adjusted to normalize and annualize the effects of known and measurable changes that occurred through August 31, 2004. In addition, Southwest has proposed certain adjustments related to events that will take place or be in effect after the end of the test year, but prior to the date new rates will go into effect.

Q. 7 When was Southwest's last general rate case application for its Arizona rate jurisdiction?

A. 7 Southwest's most recent Arizona general rate case was filed on May 5, 2000, approximately 4 1/2 years ago. The test year in that proceeding was based on the 12 months ended December 31, 1999. That rate case was fully litigated resulting in a Commission decision granting an increase in rates of approximately $21.6 million effective November 1, 2001.

Q. 8 What is Southwest's margin deficiency in its Arizona operations?

A. 8 Schedule A-1, Sheet 1, Column (d) reflects that the adjusted margin amount of approximately $322.9 million at present rates yields an overall rate of return (ROR) of

4.78 percent. Southwest is proposing that a rate of return of 9.40 percent be granted by the Commission in this proceeding. A margin increase in the amount of approximately $70.8 million is required in order to achieve the requested ROR.

Q. 9 Your references to the deficiency are characterized as amounts of margin. What is meant by the term margin?

A. 9 The term margin refers to the amount of revenues Southwest receives through rates that are net of the cost of gas. Because there is a separate purchase gas adjustment (PGA) mechanism to ensure that Southwest's customers pay the actual cost incurred by Southwest to purchase natural gas (i.e. Southwest earns no profit on the natural gas itself), revenues associated with the collection of the gas costs are excluded from the general rate case.

Q. 10 Please indicate the Company witnesses that are supporting the proposed adjustments to the recorded test year amounts.

A. 10 There are 21 adjustments to the test year data. They are listed on Schedule C-2, Sheets 1 through 3. Company witness A. Brooks Congdon supports Adjustment Nos. 1 and 2, Company witness Randi L. Aldridge, supports Adjustment Nos. 3 through 9, and 13 through 20. I am supporting Adjustment No. 10 "self insurance", Adjustment No. 11 "pipe replacement, leak survey and repair", Adjustment No. 12 "transmission integrity management program"

(TRIMP), and Adjustment No. 21 "light rail".

Q. 11 You indicated earlier in your testimony that Southwest is proposing certain adjustments related to events that have occurred or will occur after August 31, 2004. Please identify these adjustments.

A. 11 There are six adjustments that fall into this category. They are: 1) wage increase and within-grade movement; 2) completed construction not classified (CCNC); 3) new and expired software amortizations expected to occur by December 31, 2004; 4) audit fees resulting from Sarbanes-Oxley Section 404 compliance (Section 404 Compliance); 5) removal of the service investigation charge (SIP) amortization; 6) and TRIMP expense.

Q. 12 Why has Southwest included these adjustments in this general rate case?

A. 12 Consistent with prior Arizona rate cases filed by Southwest, when events are known or reasonably certain to occur and are measurable prior to hearing, the Commission has allowed adjustments similar to the six adjustments that are proposed herein. With these proposed adjustments the test year more accurately reflects the level of expenses Southwest will be incurring when the rates in this proceeding are in effect.

The adjustments for CCNC, the post-test year wage increase and within-grade movement have been previously accepted by the Commission. An adjustment to remove post-test year software amortizations, expiring shortly after the test year, was accepted by the Commission in the Company's last general rate case. In the Company's 1996 rate case, the Commission authorized the deferral and subsequent amortization of the dig and inspect cost associated with the SIP. This amortization is due to expire prior to the expected effective date of rates in this proceeding. The Company has removed the SIP amortization from its adjusted test year results ended August 31, 2004.

In addition, the Company is proposing post-test year adjustments for Section 404 Compliance and TRIMP. These adjustments include: 1) deferral of amounts through the effective date of rates in this proceeding; 2) an amortization of deferred amounts; and 3) a pro forma adjustment to reflect a level of on going costs related to these two programs.

Ms. Aldridge provides additional detail in her testimony related to the post-test year wage increase and within-grade adjustment, CCNC, post-test year software amortizations, Section 404 Compliance and SIP. I discuss TRIMP in more detail later in my testimony.

MAJOR REASONS AND UNDERLYING CAUSES FOR THE DEFICIENCY

Q. 13 Please identify the major reasons and underlying causes for Southwest's revenue deficiency in Arizona.

A. 13 There are four major reasons and underlying causes for Southwest's present revenue deficiency: 1) decline in average residential usage per customer; 2) increases in operation and maintenance (O&M) expense; 3) the Company's proposal for an increase in the cost of capital above the levels previously authorized by the Commission; and 4) injuries and damages expense.

Q. 14 What is the impact of the decline in average residential usage per customer on the margin deficiency in this rate case?

A. 14 In his prepared direct testimony, Company witness James L. Cattanach discusses the historical decline in average residential usage per customer. As a result of the decline in average residential usage per customer since Southwest's last general rate case, margin at present rates is $15.2 million lower. Accordingly, the decline in average residential usage per customer is $15.2 million of the total deficiency.

Q. 15 What is the impact of the increases in O&M expense since the last general rate case?

A. 15 The O&M expense requested in this general rate case is approximately $24 million higher than authorized in the previous general rate case. The $24 million can be grouped into four categories: 1) base wage increases and within-grade movement(2001 - 2005); 2) benefit expenses related to higher wages; 3) increases in the cost of certain benefits; and 4) increases in expense, other than labor and benefits, due to inflation, federal and local safety guidelines, customer billing expense and uncollectibles.

Q. 16 Please discuss the increase in O&M expense due to increased wages and within-grade movement in more detail.

A. 16 Direct labor is approximately $7.7 million greater than the amount authorized in the last general rate case. The Commission approved the post test-year wage increase that became effective in June 2000. The Company has increased base wages in each year since the last general rate case. The Company has included an adjustment for the 2005 wage increase as part of its annualization of labor. Base wages have increased by 18 percent, or approximately 3.6 percent per year, since 2000. Included in this average is the cost associated with movement within-grade for the Company's hourly workers.

Q. 17 Please discuss the impact of increased cost of benefits on O&M expense?

A. 17 The benefits recorded in O&M expense are approximately $6.9 million higher than the level authorized in the last general rate case. In the last general rate case, the cost of benefits equaled 44.7 percent of direct labor. In this general rate case, the cost of benefits equals 51.5 percent. The increase in the benefits ratio is primarily the result of the increased cost of pension, medical and dental expense. If the 44.7 percent ratio was applied to direct labor in this general rate case, the cost of benefits would have increased by approximately $3.5 million. Therefore, the remaining $3.4 million increase is primarily attributable to the increase in pension, medical and dental expense. Ms. Aldridge supports the Company's labor and benefits adjustment and describes in more detail the components of labor-related loadings including benefits.

Q. 18 Please discuss the increased O&M expense related to costs other than labor and benefits.

A. 18 The increased O&M expense related to costs other than labor and benefits are approximately $9.5 million (34 percent higher than previously authorized). Of the $9.5 million increase, $2.0 million is related to the Blue Stake gas line location portion of the program and another $2.0 million is for the Company's pro forma adjustment for TRIMP. The increase in Blue Stake expense is due to the significant number of requests for the Company to locate its facilities as part of the "Call Before You Dig" program. The significant increase in requests to locate facilities began in 2002. The cost of TRIMP is the result of complying with a nationwide, federally-mandated safety program. I discuss TRIMP in more detail later in my testimony.

Another $1.0 million of the increase is for customer billing expense, which includes postage and envelopes. Approximately $0.8 million was for increased uncollectible accounts expense. The remaining $3.7 million is the result of inflation and other miscellaneous cost increases.

Q. 19 What is the dollar impact on the deficiency related to the Company's request for a higher level of, and a higher return on, common equity?

A. 19 Company witness Theodore K. Wood presents testimony supporting a 42 percent level of common equity for the Company's capital structure, which is two percentage points greater than the 40 percent level authorized by the Commission in the last general rate case. Company witness Frank J. Hanley presents testimony supporting an 11.95 percent return on common equity, which is higher than the 11.00 percent return on equity authorized by the Commission in the Company's last general rate case. The combination of these two changes increase the Company's deficiency by approximately $8.1 million over the level authorized by the Commission in the Company's last general rate case.

Q. 20 What impact has the cost of injuries and damages had on the deficiency?

A. 20 The Company is proposing a level of injuries and damages expense that is approximately $5.9 million higher than the level approved in the Company's last general rate case. The increase is primarily due to a significant increase in liability insurance premiums and the Company's provision for self-insurance. I discuss the increase in injuries and damages expense in more detail later in my testimony.

SOUTHWEST'S INABILITY TO EARN ITS AUTHORIZED RATE OF RETURN

Q. 21 In his prepared direct testimony, Company Witness Jeffrey W. Shaw references your testimony in terms of the

Company's chronic under-earnings. Did you prepare an exhibit that shows this impact?

A. 21 Yes, Exhibit No.___(RAM-1) provides graphic evidence of Southwest's earnings shortfall.

Q. 22 Please describe this exhibit.

A. 22 Exhibit No.___(RAM-1) was prepared to show, in graphic form, a comparison of the actual ROR that Southwest earned versus the ROR that was authorized by the Commission since Southwest's 1992 general rate case.

Q. 23 What does Exhibit NO.___(RAM-1) show?

A. 23 Exhibit No.___(RAM-1) shows that, with the exception of 1998, Southwest has been unable to earn its authorized ROR for the period 1994 to the present. In 1998, Arizona residential average usage was favorably impacted by an unusual weather phenomenon that resulted in the winter weather being 28 percent colder than normal.

Q. 24 Have you quantified the difference and, if so, what is its significance?

A 24 Yes. The schedules that follow the graphs show that over this approximate 11-year period, Southwest's earnings shortfall in Arizona totals approximately $145.6 million. Clearly, if Southwest had been able to earn its authorized ROR over this period of time, its equity ratio would be greatly improved over where it is today.

Q. 25 What does the diagonal pattern bar on Exhibit No.___(RAM-1) Sheet 1, show?

A. 25 As discussed by Company Witness Edward B. Gieseking in his prepared direct testimony, Southwest is proposing that the Conservation Margin Tracker (CMT) be approved by the Commission in this proceeding. The diagonal pattern bar shows what Southwest's earned ROR would have been if the CMT provision had been in effect since 1994. Based on this analysis, Southwest would still not have earned its authorized ROR, however, Southwest's earned ROR would have been measurably improved.

Q. 26 During the period 1992 through the present, what has been the impact of regulatory lag on Southwest?

A. 26 Although the rate relief authorized during this period was much needed and beneficial, the time that elapsed from the end of the respective test years until the effective date of new rates reflected periods when the Company's rates remained deficient, and this had a significant impact on the Company's results of operations and retained earnings. Exhibit No.___(RAM-2) shows that Southwest was granted rate relief five times for a total of approximately $72.8 million from 1992 through 2001. The time between the end of the test periods and the effective date of new rates ranged from 12 to 22 months. This resulted in a pre-tax regulatory lag of approximately $101 million, which Southwest's shareholders absorbed. The after-tax impact on the Company was approximately $60.6 million.

Exhibit No.___(RAM-2) also shows the estimated regulatory lag for this proceeding. Assuming a 17-month lag (the average of the previous five general rate cases) and that the requested amount is approved by the Commission in its entirety, the regulatory lag is projected to be approximately $101.6 million on a pre-tax basis and $60.4 million on an after-tax basis. Even if the regulatory lag was 12 months (shortest of the five previous rate cases) the pre-tax and after-tax regulatory lag would be approximately $71.0 million and $42.6 million, respectively.

Q. 27 Has Southwest made any proposals in this proceeding to address and/or reduce the impact on the Company's operating results as a consequence of regulatory lag and declining average usage?

A. 27 Yes. Company witnesses Mr. Wood and Mr. Hanley address the shareholder cost of regulatory lag and the risk of declining residential usage in their cost of capital proposals. Mr. Gieseking supports the Company's proposal for the CMT which addresses declining average usage. In addition to certain other adjustments sponsored by Ms. Aldridge, two of the adjustments that I am supporting, "self-insurance" and "TRIMP" have the effect of reducing the impact of regulatory lag.

RATE CASE ADJUSTMENTS

Q. 28 Please describe the types of charges included in Account 925, Injuries and Damages.

A. 28 Injuries and damages include four types of charges: 1) insurance premiums; 2) reserve for the self-insured portion of a liability claim; 3) legal and other related expenses necessary to defend and process claims; and 4) worker compensation claims.

Q. 29 Please explain Adjustment No. 10, injuries and damages.

A. 29 Adjustment No. 10 annualizes insurance premiums and normalizes the self-insured components of Account 925.

Q. 30 Please explain the insurance premium annualization component of Adjustment No. 10.

A. 30 The insurance premium component of Adjustment No. 10, adjusts the liability insurance amounts amortized to Account 925 during the test year to the annual premiums paid and in effect at the end of the test year. Insurance premiums are paid annually, recorded on the books as a prepaid asset, and amortized monthly to Account 925. Since policies are renewed at various months throughout the test year, this annualization is necessary to reflect the known and measurable, and on-going expenses for liability insurance.

Q. 31 Please explain the self-insured component of Adjustment No. 10.

A. 31 The self-insured component of Adjustment No. 10, adjusts the recorded self-insured accruals charged to Account 925 during the test year to a normalized level.

Q. 32 Please explain the accounting for the self-insured portion of liability claims.

A. 32 Prior to the renewal of the general liability insurance policies in August 2004, Southwest was self-insured for the first $1 million of each liability claim, with no annual aggregate retention. Costs above the first $1 million were covered by insurance. When an incident is identified where it is likely that payment will be made, the Company records its estimate of payment as a self-insured retention expense. The entry is a debit to Account 925, Injuries and Damages, and a credit to Account 228.2, Accumulated Provision for Injuries and Damages. Once the outcome of the claim becomes final, any claims paid are charged against the accrual in Account 228.2. If the amounts paid are less than the accrual or if Southwest prevails and pays nothing, then the net difference is removed from Account 228.2 and credited back against Account 925. Because of the nature of this process, it is not unusual to have fluctuations in the net charges to Account 925 from period to period. This can lead to an amount in any recorded period in Account 925 being abnormal, and not representative of on-going operations. Because of this, the Company has used a five-year average to normalize this expense for ratemaking purposes. This methodology has been accepted by the Commission in the Company's prior general rate cases.

Q. 33 What changed regarding the renewal terms for the Company's general liability insurance during 2004?

A. 33 The Company's insurance providers no longer offered the type of insurance previously provided ($1 million per occurrence with the insurance provider covering the excess over $1.0 million). In fact, the Company was unable to find any insurance carrier that would provide this level of coverage. Several options were offered by insurance carriers; however, all options included higher premiums than previously experienced and either higher self-insured levels or an aggregate level of self-insurance per claim year.

As such, the option chosen by the Company provides that the Company is self-insured for up to $1.0 million of claims expense for each occurrence. To the extent that a specific claim exceeds $1.0 million, the Company is self-insured for the excess over $1.0 million up to an aggregate of $10 million. Once the $10 million aggregate amount is retained, any amount paid above the $10 million is the responsibility of the insurance carrier. The $10 million aggregate can be the result of payouts from more than one incident. Also, additional insurance policies have been acquired for claims paid above the $10 million level. The move to the $10 million aggregate has the potential of significantly increasing the Company's Account 925 expenses in the future, and magnifying yearly fluctuations in this account.

Q. 34 What was the period of time that the insurance carriers reviewed Southwest's claims history to determine the levels of insurance and corresponding premiums?

A. 34 The insurance carriers reviewed the Company's claims history for the 14 year period 1990 through 2003.

Q. 35 How is the Company proposing to normalize this expense in this rate proceeding?

A. 35 The Company is proposing that a level for the self-insured portion of injuries and damages be based on the same time period (1990 through present) that was reviewed by the insurance carriers when they Company was seeking to renew its insurance coverage. Accordingly, the self-insured expense is based on: 1) the historical average, during that time period, of claims paid that were less than $1 million; 2) claims paid at the previous $1 million maximum; and 3) claims paid that were greater than the previous $1 million maximum but less than the $10 million aggregate that is now a part of the insurance coverage effective August 1, 2004.

Q. 36 Is this historical experience based on only Arizona history or is it based on the history of the entire Company?

A. 36 It is based on total Company history. Given the change in the magnitude of this expense, the Company believes that the total Company experience should be used rather than jurisdictional specific data. The liability insurance premiums have historically been a common expense shared by all rate jurisdictions based on either the Modified Massachusetts Formula (MMF) or the 4-Factor Allocation Methodology (4-Factor). The move to the $10 million aggregate was made to reduce insurance premium increases that would have been allocated to each rate jurisdiction using these allocation methods. Although Arizona benefits from allocation versus direct assignment, the Company believes that it is the fairest way to handle this expense. This is Southwest's first rate case proceeding since this type of coverage was purchased, and the Company intends to present the same methodology in future general rate case filings for each of its other rate jurisdictions.

Q. 37 Please explain the need for Adjustment No. 12, TRIMP.

A. 37 Adjustment No. 12 is needed to allow the Company to recover the costs incurred prior to the effective date of rates in this proceeding and a representative level of on-going expense that will result from the implementation of the Pipeline Safety Improvement Act of 2002 (Act). The Act directed the Office of Pipeline Safety (OPS) and Research and Special Programs Administration (RSPA) divisions of the U.S. Department of Transportation to promulgate regulations prescribing standards for transmission pipeline risk analysis and adopting and implementing a pipeline integrity management program.

Q. 38 Does Southwest have an application pertaining to TRIMP currently pending before the commission?

A. 38 Yes. On September 7, 2004, the Company filed, with the Commission, an application informing the Commission of the Act and TRIMP (see Docket No. G-01551A-04-0647). In the application, the Company requested that the

Commission issue an accounting order acknowledging the appropriateness of recording incremental O&M expense associated with the TRIMP assessment and inspection activities to Account No. 182.3, Other Regulatory Assets. The cost associated with facility repairs and replacements would be recorded to the appropriate expense and plant accounts. The application stated that the amortization of TRIMP assessment and inspection activities would be addressed in the Company's next general rate case filing, at which time the costs associated with on-going TRIMP activities would be included in rates and the Company would discontinue recording TRIMP cost to Account 182.3.

Q. 39 Is Adjustment No. 12 consistent with the proposal set forth in Docket No. G-1551A-04-0647.

A. 39 Yes. Adjustment No. 12 includes a three-year amortization of TRIMP assessment and inspection activities estimated to be deferred through December 31, 2005. The deferral of cost would cease effective the date new rates are placed in effect in this case. In addition, Adjustment No. 12 also includes an on-going annual level of TRIMP assessment, inspection and repair activity expenses. The seven-year average of expense expected to be incurred from 2006 to 2012 was used as the basis for the on-going level of expense. The seven-year average was used to reflect the fact that it is expected that certain costs will be higher in years 2006 and 2007 and lower in years

2008 to 2012. The next rate case cycle is likely to include both the years with higher and lower costs.

Q. 40 Are the costs addressed in Adjustment No. 12 incremental to the Company's current operations?

A. 40 Yes. As stated in the Company's deferred accounting application, the TRIMP assessment and inspection activities are incremental in nature and the work is performed by outside contractors. The repair cost included in the continuing portion of the adjustment are incremental and do not include existing Company labor and related expense.

Q. 41 Please explain Adjustment No. 21, light rail.

A. 41 Adjustment No. 21 removes from rate base the cost (depreciation expense and property tax expense) that the Company has incurred to move its facilities due to the construction of the City of Phoenix (City) Light Rail transportation system (PLR). For various reasons, the construction of the PLR has required that the Company move certain of its existing facilities. The Company and the City have come to an agreement as to the mechanism that will be in place to reimburse the Company for its costs incurred as a result of construction of the PLR. The reimbursements received from the City will be credited to plant in-service, similar to a contribution in-aid-of construction (CIAC). The agreement states that the cost of moving facilities resulting from the construction of the PLR will not be included in the

Company's base rates. Adjustment No. 21 is necessary to comply with the agreement between the City and the Company. Adjustment No. 20, CCNC, does not include any work authorizations related to work performed as a result of the PLR.

LINE EXTENSION POLICY AND PRACTICES

Q. 42 In the Company's last general rate case (Docket No. G-1551A-00-0309), did the Commission direct the Company to specifically address the issue of how it determines the allowance for the hook-up of new residential customers in its next general rate case?

A. 42 Yes.

Q. 43 Please describe the line extension policy set forth in Southwest's Tariff, Rule No. 6, related to residential customer additions.

A. 43 Rule No. 6 B. 1. states: "General Policy - All service and main extensions are made on the basis of economic feasibility except those for master-metered mobile parks (MMP), whose extensions shall be made in accordance with the provisions in Section B.3 hereof. The economic feasibility will be calculated by the Incremental Contribution Method as described in Section B.4 hereof."

Section B.4 states: "Incremental Contribution Method - gas service and main line extension will be made by the Utility at its expense for the allowable investment as calculated by an Incremental Contribution Study (ICS)."

Finally, Section B. states: "Allowable investment shall mean a determination by the Utility that the revenues less the incremental cost to serve the applicant customer provides a rate of return on the Utility's investment no less than the overall rate of return authorized by the Commission in the Utility's most recent general rate case."

Q. 44 What are the main components of the ICS?

A. 44 The main components of the ICS are incremental margin, investment and expenses. The ICS calculates the project's results of operations, much like a mini-rate case. The ICS provides a three year average result, and the incremental result is compared to the most recently authorized ROR. If the three-year average result does not produce the authorized ROR, then either a customer advance or CIAC is applied in order to produce a result at least equal to the authorized ROR.

Q. 45 How is margin calculated in the ICS?

A. 45 Pursuant to Section E. 2. b., the applicant must provide the Company with a list of natural gas equipment to be used. The ICS provides a therm allowance for space heating, water heating, cooking and clothes drying. The estimated therms for each appliance are multiplied by the appropriate residential tariff rate in order to calculate the commodity margin. The basic service charge is added to the commodity in order to determine the incremental margin that will be the result of the addition of new customers. The margin per customer is multiplied by the number of customers to calculate the total project margin. Since not all customers take service at the same time, the ICS provides for a phase-in, by year, of customer additions. The rate of phase-in is determined through conversations with the builder/customer, current market conditions, and previous experience with the applicant or builders of similar projects.

Q. 46 How is the average gas used per appliance determined?

A. 46 Average usage for space heating and water heating vary based on the geographic location throughout the state. Average therm usage for cooking and clothes drying are the same throughout the state. Southwest's Arizona operations are divided into ten districts. The Phoenix and Tucson districts experienced 89 percent of the Company's test year Arizona customer additions, and the average usage in both districts is similar. Several relatively small districts are located in warmer areas and experience lower therm usage, while other relatively small districts are located in colder climates that experience higher therm usage. These differences are taken into consideration in the ICS.

The ICS provides for additional therm usage if a home has additional heating systems, more than 50 gallons of water heating, and if a gas oven is installed. The ICS does not provide additional allowances for gas barbecues, gas fireplaces, pool or spa heaters or any other outdoor amenities. The Company considers use of these appliances to be highly discretionary by the customer, and an estimate of average use would be arbitrary, and not appropriate for determining the allowable cost justification for a fixed long-term investment.

Q. 47 How is the incremental investment to serve a new customer determined?

A. 47 An estimate of the cost of main, service and regulator stations required to serve the individual customer or sub-division is prepared. The cost of the meter set and installation is based on the average cost, depending on the size of the meter.

Q. 48 How are the incremental operating expenses to serve new customers determined?

A. 48 Incremental operating expense consists of customer billing (postage, mailing and processing), meter reading, uncollectibles, customer assistance and Blue Stake line locate. The operating expense is based on total state average cost per customer, except for customer billing, which is based on total Company averages. Operating expense also includes a provision for administrative and general expense.

Q. 49 What other expenses are included in the ICS?

A. 49 The ICS includes the depreciation expense calculated by multiplying incremental investment by the depreciation rates used to establish rates in the Company's last general rate case. Property taxes are calculated using the same method and cost rates used to establish rates in the Company's last general rate case. The income tax calculation uses the weighted average cost of debt and tax-deductible preferred securities, and state and federal income tax rates authorized in the Company's last general rate case.

Q. 50 Do the Company's line extension analyses performed using the ICS model ensure that new customer additions earn, on an incremental basis, at least the authorized ROR as required by Rule No. 6. Section B. a.?

A. 50 Yes. The ICS model accurately reflects incremental revenues, expenses and investment required to serve new customers, and demonstrates that new customers are providing a return at least equal to the authorized ROR.

PIPE REPLACEMENT COSTS

Q. 51 Is the Company proposing that the Commission modify the write-off percentages set forth in the Settlement Agreement (Agreement) in Docket No. U-1551-93-272, which was approved by the Commission approximately 11 years ago?

A. 51 Yes. As I will explain more fully in the testimony that follows, none of the replacements of steel and ABS pipe and essentially, none of the replacements of Aldyl A pipe since 1999 have been related to defective materials and/or installation. Since 1999, only replacements of Aldyl HD pipe have been the result of defective materials and/or installation.

Q. 52 Please describe the Agreement.

A. 52 The Agreement resulting from Docket No. U-1551-93-272 states "In future Southwest rate cases for the Southern Division gas properties, Southwest shall exclude from rate base an additional portion of capitalized expenditures associated with replacements of Aldyl A, Aldyl HD, steel installed in the 1960s, and ABS pipe related to **defective materials and/or installation.** For such capitalized expenditures during the period July 1, 1993 through June 30, 1994, the rate base exclusion shall be based on the following percentages: 36 percent for Aldyl A, 75 percent for Aldyl HD, 19 percent for steel installed in the 1960's, and 24 percent for ABS. During each successive 12-month period following June 30, 1994, the foregoing percentages shall be reduced incrementally by one percent." *[emphasis added]*

Q. 53 Please describe the circumstances that preceded Southwest entering into the Agreement.

A. 53 On April 1, 1979, Southwest purchased the gas distribution properties from Tucson Gas and Electric (TGE), now dba Tucson Electric Power Company (TEP). Prior to 1960, steel was the primary pipe material used to install gas distribution facilities. TGE installed a significant amount of steel pipe up through 1969. By the 1970s steel pipe was used primarily for high pressure distribution main lines, and its use for local distribution facilities was superceded by plastic pipe. The first plastic pipe material used by TGE was ABS, and the distribution facilities installed during the years 1959 through 1969 used this pipe material. From 1967 through 1979, TGE installed 1,333 miles of distribution facilities using Aldyl A pipe.

Within several years after acquiring the TGE gas properties, the Company came to the conclusion that Aldyl A pipe was experiencing a significant number of leaks. The Company concluded that the portions of the gas distribution system where Aldyl A was installed in rock and caliche areas must be replaced. The Company's conclusion was based on the combination of Aldyl A pipe material and TGE's construction practices, which among other things used native soil as backfill. Gas facility installations where the native soil was in rock and caliche zones often resulted in rock and caliche being placed on top of the Aldyl A pipe as backfill. The rock impingement resulting from this construction practice created the potential for catastrophic leaks. The Company began an accelerated program of replacing Aldyl A, and Southwest sued TGE for breach of contract resulting in protracted litigation. The litigation resulted in an out-of-court settlement, where TEP paid Southwest $25 million for reimbursement of capital expenditures required to replace the portion of the Aldyl A system that was defective. The Company credited gas plant in-service with the net proceeds after legal fees. The $22.6 million was approximately 65 percent of the approximately $35 million spent by Southwest as of May 31, 1991 to replace Aldyl A pipe.

Due to the nature of the Aldyl A pipe material, TGE's construction practices, and the significant amount of Aldyl A pipe replaced from 1986 through 1993 after only a useful life of approximately 22 years, Southwest entered into the Agreement to resolve the issues addressed in the Agreement.

Q. 54 What was the Commission's position on the inclusion in rate base of the replacement expenditures net of the TEP proceeds?

A. 54 In Docket No. U-1551-90-322, the Commission removed a portion of Aldyl A pipe replacement cost that remained after crediting the TEP proceeds. It was the Commission's opinion, that a portion of the replacement cost resulted in a better system and the ratepayer should pay for that portion. The remaining portion of the replacement was called remedial, and that portion should not be paid by the ratepayer. However, since the Aldyl A system was installed by TGE and not Southwest, it was decided that the remedial portion should be shared equally by shareholder and customer.

Q. 55 Was southern Arizona rate jurisdiction ABS, Aldyl HD and 1960s steel pipe an issue in Docket No. U-1551-90-322?

A. 55 No. Significant amounts of Aldyl HD and 1960s steel pipe replacement had not taken place, and both pipe types were not an issue. Although most of the ABS pipe originally installed in urban areas of Tucson had already been removed by 1988, ABS pipe replacement was not an issue.

Q. 56 Please describe the circumstances surrounding pipe replacement at the time the Company filed its southern Arizona rate jurisdiction general rate case in Docket No. U-1551-93-272.

A. 56 The Company's general rate case filing in Docket No. U-1551-93-272 removed the portion of Aldyl A replacement expenditures consistent with the Commission's Order in Docket No. U-1551-90-322, and the Company removed all Aldyl HD replacement costs incurred through the end of the test year. At the time of the 1993 general rate case, the Company was just beginning the process of assessing the need to replace a portion of the Aldyl HD system that was installed in Tucson shortly after Southwest acquired the gas distribution system from TGE. Accordingly, the Company chose not to request recovery of any Aldyl HD pipe replacement expenditures until it could more fully assess the extent of the program.

In addition, the Company was in the middle of its 10-year steel cathodic protection program, which was due to be completed by the end of 1998. There was no significant replacement activity involving ABS at that time, and the Agreement addressed the applicable replacement costs associated with ABS.

Q. 57 Why was there a need for a 10-year steel pipe cathodic protection program?

A. 57 In 1970, the federal government ordered all gas utilities to cathodically protect their steel pipe systems by 1975. The steel pipe system acquired in 1979 from TGE was not fully cathodically protected. In 1989, the Company began a program to have the entire steel pipe system cathodically protected by 1998. The Company met the 1998 deadline. As part of that program, some of the pipe could not be cathodically protected and was subsequently replaced. The replacement expenditures incurred on the 1960s vintage steel pipe, as part of the 10-year cathodic protection program, were addressed in the Agreement.

Q. 58 The Agreement has different disallowance percentages for each pipe type, please explain why?

A. 58 Each of the four pipe types were installed at different times; therefore, the remaining pipe still serving the ratepayer at the time of the Agreement, had been on average, serving the ratepayer for different periods of time. A betterment percentage was determined for each pipe type. Pipe types that had served the ratepayer longer were deemed to have a higher betterment percentage and, therefore, a smaller remedial percentage. Embedded in the Agreement was a 50-50 sharing between shareholder and customer. The write-off percentage was calculated by multiplying the remedial percentage by 50 percent. There was one exception to the 50-50 sharing and that was the Aldyl HD pipe installed under Southwest's direction.

The Aldyl HD write-off percentage did not incorporate a 50/50 sharing. The write-off percentage was 100 percent of the remedial portion of the replacement. The Agreement provided for a one percent decrease per year in the write-off percentage. The one percent was presumed to be 50 percent of the two percent annual decline in the remedial percentage. It was presumed that the betterment percentage would increase by two percent per year, and the remedial would decrease by the same amount. Since the write-off percentage delineated in the Agreement was already 50 percent of the remedial percentage, the two percent annual decline in the remedial percentage would result in the write-off percentage declining 50 percent of two percent, or one percent.

Q. 59 Please describe the pipe replacement activity after the Agreement and through the end of the test year in the Company's last general rate case.

A. 59 During the period 1994 through 1999, the 10-year steel pipe cathodic protection program was successfully completed. The Company was replacing Aldyl HD pipe suspected to be in rock and caliche zones, and approximately 17 percent of the Aldyl HD system was replaced by 1999. The Aldyl A pipe replacement activity slowed considerably, and there was little ABS replacement.

Q. 60 Did the Company make the appropriate entries to remove from plant in-service through December 1999 the appropriate amounts of pipe replacement in compliance with the Agreement?

A. 60 Yes.

Q. 61 What relief is Southwest requesting from the Commission with regard to the Agreement.

A. 61 The Company is proposing that the Commission establish a sunset date for writing-off a portion of the replacement cost of any remaining subject pipe. The Company proposes that when the pipe types addressed in the Agreement have reached 40 years of useful service, the continuation of writing-off a portion of the replacement cost, regardless of the reason, is no longer appropriate. For instance, the steel pipe installed in the 1960's and the ABS pipe still in service both have reached an average useful life of 40 years. As such, the replacement cost under Southwest's proposal would no longer be subject to write-off.

The Company is also proposing that a different write-off percentage be used regarding Aldyl A and Aldyl HD pipe, and that the new percentage be based on the premise of 40-years of useful life. Under the Company's proposal, the percent of replacement cost that would be written-off would decrease by 2.5 percent per year and correspondingly an additional 2.5 percent would be afforded rate base treatment. When a pipe type reaches an average useful life of 40-years, 100 percent of the replacement cost would be included in rates (40 years times 2.5 percent per year). If the Commission does not accept this proposal, then the Company requests that the write-off percentage for Aldyl HD decline by two percent per year, rather than the one percent per year included in the Agreement.

Q. 62 Please describe the Aldyl A pipe replacement activity that has taken place from 2000 through the end of the test year (August 31, 2004) as compared to the time period leading up to the Agreement.

A. 62 The Aldyl A pipe replacement activity has been at a normal level considering its average age is approximately 31 years. During the time period of January 2000 through August 31, 2004, the Company replaced approximately 171 thousand feet of Aldyl A main and service lines, or approximately 2.4 percent of the approximately 7.0 million feet of Aldyl A main and service lines originally installed by TGE. On an annual basis, this averages approximately 0.5 percent.

In comparison, from the mid-1980s through 1993, approximately 3.1 million feet of Aldyl A main and service lines were replaced, or approximately 44 percent of the original Aldyl A pipe installed by TGE. Furthermore, on average, the pipe replaced during this period experienced only a 17-year average useful life. As such, the circumstances that preceded Southwest entering in the Agreement have obviously changed.

Q. 63 At test year end, how much Aldyl A pipe is still used and useful?

A. 63 Approximately 3.2 million feet (or 45 percent) of the original Aldyl A pipe installed by TGE is still used and useful.

Q. 64 Is the Company proposing to reduce rate base for pipe replacement cost resulting from Aldyl A pipe?

A. 64 No.

Q. 65 Please explain why the Company has not written-off any of the cost of Aldyl A pipe replacement since December 1999, the end of the test year in the Company's last general rate case?

A. 65 There are several reasons why the Company has not written-off the cost of Aldyl A pipe replacement since year-end 1999. First, the majority of the relatively small amount of Aldyl A pipe that is being replaced **is not due to the criteria set forth in the Agreement.** Aldyl A pipe is being replaced as part of franchise-related projects and other replacement projects involving primarily other pipe types, which happen to have an ancillary amount of Aldyl A pipe. Pipe replacement for these reasons is not subject to the Agreement and do not need to be written off. The Agreement only requires a write-off of replacement costs due to **defective material and/or installation practices.** Second, the Company firmly believes that the circumstances surrounding the Aldyl A pipe have changed significantly and the Aldyl A pipe has now reached an age where a nominal amount of pipe should be expected to be replaced under normal circumstances.

The amount of Aldyl A pipe replacement activity experienced since the last rate case (0.5 percent per year) is normal, and the cost of replacement should be afforded rate base treatment similar to other pipe replacement activities.

Q. 66 Is the Company proposing to reduce rate base for a portion of replacement expenditures related to ABS and 1960s steel pipe that has occurred since the end of the test year used in the Company's last general rate case?

A. 66 No.

Q. 67 Please explain the reasons why the Company has not written-off any of the cost of ABS pipe replacement since the end of the test year in the Company's last rate case?

A. 67 There are several reasons why the Company has not written-off the cost of ABS pipe replacement since the last general rate case. Similar to Aldyl A pipe, the small amount of ABS pipe that has been replaced is **not due to defective material or installation practices and as such, is not subject to the Agreement**. The ABS pipe installed in urban areas was replaced prior to the test year in the last general rate case and the ABS that remains is in rural areas not subject to rock and caliche zones. Accordingly, rock impingement has not been a reason for replacing ABS since the last general rate case.

Furthermore, the ABS pipe is approximately nine years older than the Aldyl A pipe and has now reached an average useful life greater than 40 years. Consequently, the replacement of ABS pipe since 1999 has been for reasons that any pipe of similar age is replaced – it is simply getting old. Therefore, the Company believes that the replacement cost incurred since the last general rate case pertaining to ABS pipe should be afforded rate base treatment.

Q. 68 Please explain why the Company has not written-off any 1960s vintage steel pipe replacement since the Company's last general rate case?

A. 68 The reasons for not writing-off 1960s steel are different than those for Aldyl A and ABS pipe. Steel as a pipe type was never considered a defective material, and the faulty installation practice was that not all steel pipe was cathodically protected. The focus of the 10-year cathodic protection program was to have all steel pipe protected by 1998. In cases where pipe could not be protected, the Company replaced the unprotectable pipe. As such, by the end of 1998, the Company had fully complied with the cathodic protection program and the steel pipe that could not be protected was replaced.

Furthermore, any steel pipe replacement after the end of the 10-year program was **not due to defective material or defective installation (cathodic protection), and as such, not subject to the Agreement.** In addition, the 1960s vintage steel pipe has now been serving the ratepayer for approximately 40 years, and Southwest's replacement of the steel pipe has been modest. Any

40-year old pipe is normal and should be afforded rate base treatment.

Q. 69 Is the Company proposing to reduce rate base for a portion of the Aldyl HD pipe replacement experienced since the Company's last general rate case?

A. 69 Yes. A portion of the expenditures incurred to replace Aldyl HD pipe has been removed from rate base.

Q. 70 Please explain why the Company has not written-off any of the cost resulting from Aldyl HD pipe replacement since the end of the test year in the last general rate case?

A. 70 Although the Company believes that a portion of the Aldyl HD pipe replacement cost was for reasons covered by the Agreement, the Company is requesting that the Commission consider a less onerous pipe write-off with regards to the Aldyl HD pipe. Consistent with the Company's application and the proposals presented herein, the Company has withheld writing-off Aldyl HD pipe from its books until the Commission has ruled on the Company's request in this proceeding.

Q. 71 Does the rate base in this proceeding include all of the cost of replacing Aldyl HD pipe since the last general rate case?

A. 71 No. The cost of replacing Aldyl HD has been reduced by the write-off percentage the Company is proposing in this rate case. Depreciation and property taxes have also been reduced by the appropriate amounts. Adjustment No. 11 reflects the reduction to plant in-service related to the

Company's proposed write-off of Aldyl HD pipe replacement.

Q. 72 Please explain how the write-off percentage pertaining to Aldyl HD that is contained in the Agreement was determined in 1993 and projected into the future?

A. 72 It was determined in 1993 that the betterment and remedial percentages were 25 percent and 75 percent, respectively. Similar to the other pipe types, it was presumed that the betterment percentage would increase two percent per year and the remedial percent would decrease by a like amount. Since the installation of Aldyl HD pipe was under the supervision of Southwest, and not TGE, there was to be no sharing of the remedial cost. The Agreement also provides for the reduction of the Aldyl HD write-off percentage to be one percent per year, similar to the other pipe types that were installed by TGE.

Given this formula, the Company will be writing-off a percentage of Aldyl HD pipe replacement for another 75 years. The average age of Aldyl HD pipe in 1993 was 13 years. Given a strict interpretation of the Agreement, the Company could conceivably be writing-off a portion of pipe replacement cost on Aldyl HD pipe that is 87 years old. As such, the Company is requesting that the Commission reconsider the appropriateness of the Aldyl HD write-off percentage included in the Agreement.

Q. 73 Please explain the change that the Company is proposing to the Aldyl HD write-off calculation?

A. 73 The Company is proposing that a 40-year period be used as a basis for determining the write-off percentage, and the write-off percentage would decrease by 2.5 percent per year (100 percent/40 years). Accordingly, after the remaining pipe has served the customer for 40 years then all write-offs would cease.

Since the average year of installation of Aldyl HD pipe was 1980, a pipe disallowance would be applied up to year 2020 (the year that all remaining Aldyl HD pipe will be 40 years old). Consistent with the Agreement, there would be no sharing, and the proposed change in the write-off percentage would only apply from the end of the test year in the last general rate case.

Q. 74 What is the proposed write-off percentage for the years 2000 through 2004 applied to Aldyl HD pipe replacement cost?

A. 74 Aldyl HD pipe that was replaced during the year 2000 had a useful life of 20 years. Consequently, the year 2000 write-off percentage would be 50 percent (20 years X 2.5 percent per year X 100 percent), and the write-off percentage for years 2001 through 2004 would be 47.5 percent, 45.0 percent, 42.5 percent and 40.0 percent, respectively.

Q. 75 If the 40-year useful life is not accepted by the Commission, what alternative adjustment to the Agreement does Southwest propose regarding the Aldyl HD pipe write-off percentage?

A. 75 At a minimum, the Aldyl HD write-off percentage should be reduced by two percent per year since the remedial percentage calculated in 1993 was not reduced by 50 percent to reflect the ratepayer's share of the remedial portion of the replacement cost. The 75 percent remedial percentage calculated in 1993 should be reduced by two percent per year for 37.5 years, which when added to the 13 year average life in 1993 would establish a 50-year average useful life. Consistent with the Agreement, the write-off percentage established using either the 40- or 50-year average useful life would be applied to the pipe replacement costs resulting from faulty material or installation practices.

Q. 76 Please explain Exhibit No.___(RAM-3)?

A. 76 Exhibit No.___(RAM-3) shows, for each pipe type, the write-off percentage per the Agreement, the Agreement adjusted to reflect a two percent per year reduction in the write-off percentage for Aldyl HD, and the 40-year life write-off calculation proposed by the Company.

Q. 77 Does the Company believe its proposal is fair and equitable to both the customer and shareholder?

A. 77 Yes. The Company believes that establishing a 40-year criteria to cease write-offs of pipe replacement is fair to both shareholders and ratepayers.

If the original pipe addressed in the Agreement served the customer for 40 years, there never would have been an issue. As noted above, preceding the Agreement, a portion of these systems required replacement long before their expected useful life, and the Commission determined that a disallowance of a portion of the replacement cost was appropriate. However, after nearly 11 years of favorable replacement experience since the Agreement was initiated, the Company believes that the issue of pipe replacement write-offs needs to be modified to include a sunset date that is fair and reasonable to both customer and shareholder. The Company believes that the ending of replacement write-offs after the respective pipe has attained an average useful life of 40 years is fair and reasonable.

Q. 78 Has the Company reduced the test year accelerated leak survey costs and the plastic and steel pipe repairs expense that were incurred on the pipe types covered in the Agreement?

A. 78 Yes. Adjustment No. 11, Pipe Replacement, Leak Survey and Repair, reduces test year accelerated leak surveys related to Aldyl A and Aldyl HD by the percent calculated using the 40-year criteria. Steel pipe installed in the 1960s does not require accelerated leak survey, and both ABS and 1960s steel have reached the 40-year average useful life. As such, the accelerated leak survey on ABS was not removed from test year expense.

Adjustment No. 11 also reduces the test year leak repair cost related to the Aldyl A and Aldyl HD using the same percentages derived from the 40-year average life criteria. Repairs on 1960s vintage steel and ABS have not been reduced since both pipe types have reached the

40-year average useful life.

Q. 79 Did the Agreement provide for reductions to test year accelerated leak survey and leak repair maintenance for the four pipe types?

A. 79 Yes. The Agreement provided that to the extent the Company leak surveys the four pipe types on an accelerated basis, a portion of the accelerated leak survey should be removed from test year expenses using the same disallowance percentage used for pipe replacement. However, it should be noted that steel pipe has not required accelerated leak survey, and as such, has not been included in this adjustment.

Q. 80 Should the 40-year criteria and resulting percentages be applied to accelerated leak surveys for ABS, Aldyl A and Aldyl HD pipe?

A. 80 Yes. The intent of the accelerated leak survey of the three types of plastic pipe was to extend the useful life of these pipes. The use of accelerated leak surveys has been a successful, cost-effective alternative to pipe replacement. The 40-year criteria and resulting percentages should be applied to the adjustment to accelerated leak surveys and should cease once the pipe has attained the average age of 40 years.

ABS has attained an average life of 40 years and the disallowance percentage should not be applied. Adjustment No. 11 applies the percentages resulting from the 40-year criteria to Aldyl A and Aldyl HD test year accelerated leak survey costs.

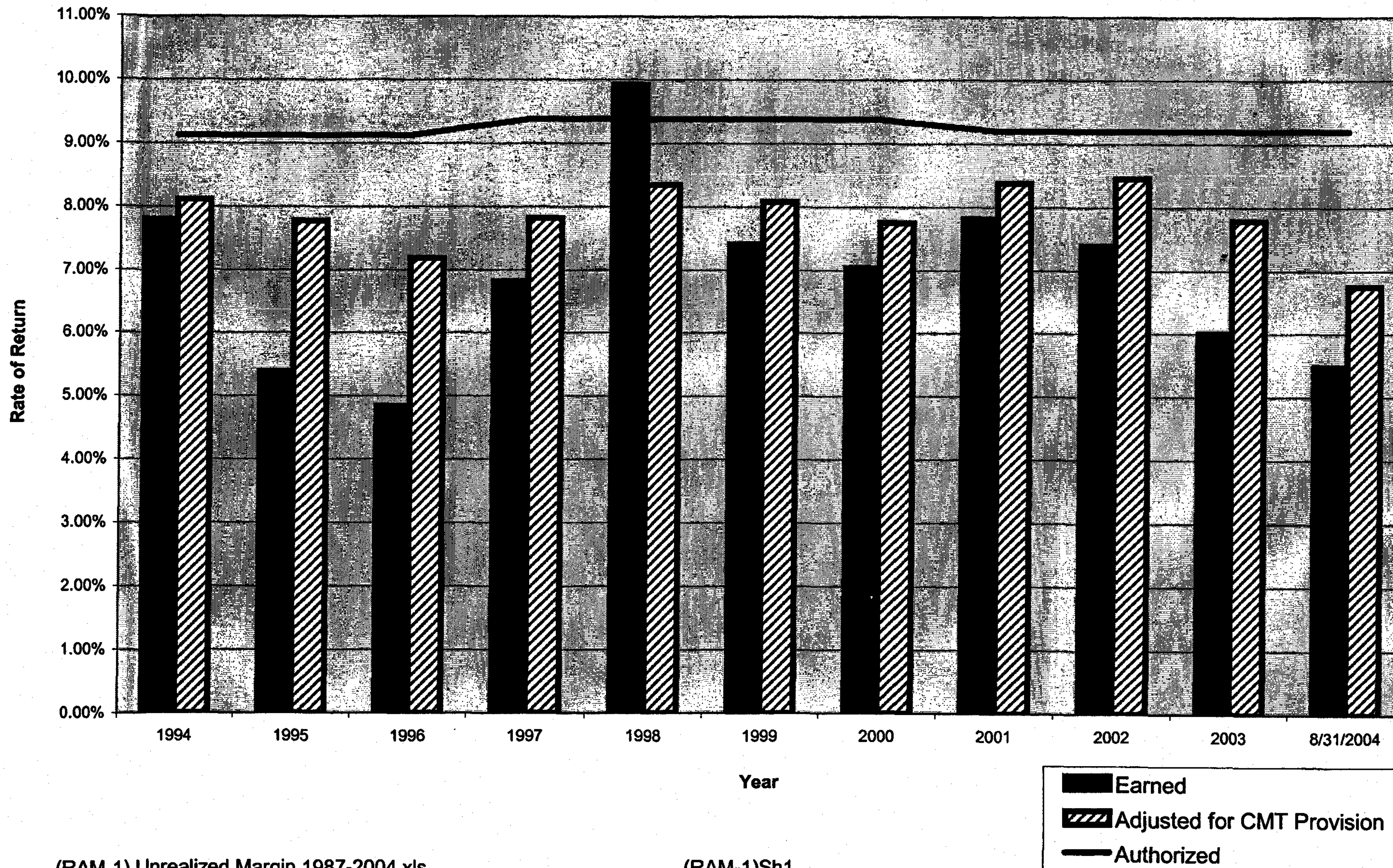
Q. 81 Should the 40-year criteria and resulting percentages be applied to test year leak repair costs?

A. 81 Yes. The resulting percentage derived using the 40-year criteria should also be applied to leak repair costs for Aldyl A and Aldyl HD pipe. Since both the ABS and 1960s steel pipe systems have attained an average useful life of 40 years, their leak repair cost should not be subject to exclusion in this or any future rate case.

Q. 82 Does this conclude your prepared direct testimony?

A. 82 Yes, it does.

SOUTHWEST GAS CORPORATION
ARIZONA
EARNED VS. AUTHORIZED RATE OF RETURN
FOR THE YEARS ENDED 1994 THROUGH 2003 AND THE TWELVE MONTHS ENDED AUGUST 31, 2004



SOUTHWEST GAS CORPORATION
ARIZONA
RESULTS OF OPERATIONS
FOR THE YEARS 1994 THROUGH 2003 AND THE TWELVE MONTHS ENDED AUGUST 31, 2004
($ in Millions)

Line No.	Description	December										12 ME	Line No.
		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	8/31/04	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
1	Margin	$ 200.5	$ 192.7	$ 201.9	$ 222.9	$ 267.5	$ 259.3	$ 266.8	$ 297.9	$ 311.5	$ 308.1	$ 320.1	1
2	Operating Expenses	163.4	164.3	174.6	183.6	207.2	209.2	216.8	237.7	251.7	256.7	269.6	2
3	**Regulatory Net Income (Loss)**	**$ 37.1**	**$ 28.4**	**$ 27.3**	**$ 39.3**	**$ 60.3**	**$ 50.1**	**$ 50.0**	**$ 60.2**	**$ 59.8**	**$ 51.4**	**$ 50.5**	3
4	Less: Interest Expense	26.3	28.5	27.6	30.6	30.2	30.0	33.1	37.8	37.1	36.1	35.5	4
5	Less: Preferred Dividends	0.3	0.1	2.9	2.8	2.7	2.7	2.7	2.7	2.6	3.3	4.0	5
6	Net Financial Income (Loss)	$ 10.5	$ (0.2)	$ (3.2)	$ 5.9	$ 27.4	$ 17.4	$ 14.2	$ 19.7	$ 20.1	$ 12.0	$ 11.0	6
7	Regulatory Rate Base	$ 475.5	$ 527.4	$ 564.0	$ 575.8	$ 608.2	$ 676.5	$ 710.1	$ 768.9	$ 808.4	$ 856.4	$ 923.8	7
8	Actual ROR on Reg. Rate Base	7.80%	5.38%	4.84%	6.82%	9.92%	7.41%	7.04%	7.82%	7.40%	6.00%	5.47%	8
9	Authorized Rate of Return	9.13%	9.13%	9.13%	9.38%	9.38%	9.38%	9.38%	9.20%	9.20%	9.20%	9.20%	9
10	Actual Common Equity	$ 156.8	$ 164.9	$ 188.9	$ 191.3	$ 211.9	$ 243.1	$ 251.3	$ 266.5	$ 278.1	$ 292.8	$ 309.3	10
11	Return on Common Equity	6.62%	-0.30%	-1.61%	2.98%	12.66%	7.10%	5.69%	7.40%	7.23%	4.11%	3.56%	11
12	Authorized Return on Common Eq.	10.75% C 11.00% S	10.75% C 11.00% S	10.75% C 11.00% S	11.25%	11.25%	11.25%	11.25%	11.00%	11.00%	11.00%	11.00%	12

EXHIBIT NO. ____ (RAM-1)
Sheet 3 of 6

SOUTHWEST GAS CORPORATION
ARIZONA
RESULTS OF OPERATIONS ADJUSTED FOR CMT PROVISION
FOR THE YEARS 1994 THROUGH 2003 AND THE TWELVE MONTHS ENDED AUGUST 31, 2004
($ in Millions)

Line No.	Description	December 1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	12 ME 8/31/2004	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
1	Margin With CMT	$ 202.0	$ 205.3	$ 215.1	$ 228.6	$ 257.9	$ 263.8	$ 271.9	$ 302.1	$ 320.0	$ 323.4	$ 332.0	1
2	Operating Expenses	163.4	164.3	174.6	183.6	207.2	209.2	216.8	237.7	251.7	256.7	269.6	2
3	**Regulatory Net Income (Loss) with CMT**	**$ 38.6**	**$ 41.0**	**$ 40.5**	**$ 45.0**	**$ 50.7**	**$ 54.6**	**$ 55.1**	**$ 64.4**	**$ 68.3**	**$ 66.7**	**$ 62.4**	3
4	Less: Interest Expense	26.3	28.5	27.6	30.6	30.2	30.0	33.1	37.8	37.1	36.1	35.5	4
5	Less: Preferred Dividends	0.3	0.1	2.9	2.8	2.7	2.7	2.7	2.7	2.6	3.3	4.0	5
6	Net Financial Income (Loss) with CMT	$ 12.0	$ 12.4	$ 10.0	$ 11.6	$ 17.8	$ 21.9	$ 19.3	$ 23.9	$ 28.6	$ 27.3	$ 22.9	6
7	Regulatory Rate Base	$ 475.5	$ 527.4	$ 564.0	$ 575.8	$ 608.2	$ 676.5	$ 710.1	$ 768.9	$ 808.4	$ 856.4	$ 923.8	7
8	Actual ROR with CMT on Reg. Rate Base	8.12%	7.78%	7.19%	7.82%	8.34%	8.07%	7.75%	8.38%	8.45%	7.79%	6.75%	8
9	Authorized Rate of Return	9.13%	9.13%	9.13%	9.38%	9.38%	9.38%	9.38%	9.20%	9.20%	9.20%	9.20%	9
10	Actual Common Equity with CMT	$ 156.8	$ 164.9	$ 188.9	$ 191.3	$ 211.9	$ 243.1	$ 251.3	$ 266.5	$ 278.1	$ 292.8	$ 309.3	10
11	Return on Common Equity	7.65%	7.53%	5.31%	6.07%	8.42%	9.02%	7.66%	8.98%	10.30%	9.33%	7.41%	11
12	Authorized Return on Common Eq.	10.75% C 11.00% S	10.75% C 11.00% S	10.75% C 11.00% S	11.25%	11.25%	11.25%	11.25%	11.00%	11.00%	11.00%	11.00%	12

SOUTHWEST GAS CORPORATION
DISTRICT 42 PHOENIX ARIZONA
UNREALIZED MARGIN DUE TO DECLINING AVERAGE RESIDENTIAL USAGE
FOR THE YEARS 1987 THROUGH 2004

Line No.	Year	A.C.C. Docket Number	Test Year Ended	Effective Date	Average Customer Therm Usage Auth.	Average Customer Therm Usage Actual	Average Customer Therm Usage Difference	Average Customers Billed	(000,000's) Therms	Tariff Rate	Unrealized Margin Yearly	Unrealized Margin Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
1	1987	86 - 301	12/31/1986	9/1/1987	552	492	(60.3)	259,633	(15.7) $	0.31882 $	(5.0) $	(5.0)	1
2	1988				552	486	(66.2)	257,774	(17.1)	0.31882	(5.4)	(10.4)	2
3	1989				552	463	(88.8)	256,094	(22.7)	0.31882	(7.2)	(17.7)	3
4	1990	89 - 102	7/31/1989	9/1/1990	523	464	(59.3)	256,336	(15.2)	0.33359	(5.1)	(22.8)	4
5	1991				494	466	(27.6)	259,159	(7.2)	0.34836	(2.5)	(25.2)	5
6	1992				494	435	(59.0)	262,770	(15.5)	0.34836	(5.4)	(30.7)	6
7	1993	92 - 253	3/31/1992	9/1/1993	475	423	(52.3)	263,784	(13.8)	0.36415	(5.0)	(35.7)	7
8	1994				456	442	(14.3)	267,323	(3.8)	0.37994	(1.5)	(37.1)	8
9	1995				456	371	(85.0)	279,480	(23.8)	0.37994	(9.0)	(46.2)	9
10	1996				456	372	(83.8)	299,734	(25.1)	0.37994	(9.5)	(55.7)	10
11	1997	96 - 596	7/31/1996	9/1/1997	424	383	(40.7)	318,432	(13.0)	0.40182	(5.2)	(60.9)	11
12	1998				392	429	36.6	335,851	12.3	0.42370	5.2	(55.7)	12
13	1999				392	374	(17.6)	356,527	(6.3)	0.42370	(2.7)	(58.4)	13
14	2000				392	368	(23.8)	379,451	(9.0)	0.42370	(3.8)	(62.2)	14
15	2001	00 - 0309	12/31/1999	11/1/2001	391	370	(21.3)	398,773	(8.5)	0.42370	(3.6)	(65.8)	15
16	2002				383	345	(37.6)	433,068	(16.3)	0.45851	(7.5)	(73.2)	16
17	2003				383	322	(61.2)	433,068	(26.5)	0.45851	(12.2)	(85.4)	17
18	Aug-04				383	332	(51.0)	447,898	(22.8)	0.45851	(10.5)	(95.9)	18
19	2005				383								19
20	2006				347								20

Note: The average authorized usage in years of where rates changed represents the average of the previous authorized and the new authorized.

SOUTHWEST GAS CORPORATION
DISTRICT 36 TUCSON ARIZONA
UNREALIZED MARGIN DUE TO DECLINING AVERAGE RESIDENTIAL USAGE
FOR THE YEARS 1987 THROUGH 2004

Line No.	Year (a)	A.C.C. Docket Number (b)	Test Year Ended (c)	Effective Date (d)	Average Customer Usage Auth. (e)	Average Customer Usage Actual (f)	Average Customer Usage Diff. (g)	Average Cust. Billed (h)	(000,000's) Therms (i)	Tariff Rate (j)	Unrealized Margin Yearly (k)	Unrealized Margin Total (l)	Line No.
1	1987	86 - 300	31-Dec-86	1-Sep-87	561	528	(33.0)	149,292	(4.9) $	0.25657 $	(1.3) $	(1.3)	1
2	1988				561	511	(50.0)	152,500	(7.6)	0.25657	(2.0)	(3.2)	2
3	1989				561	476	(85.0)	154,541	(13.1)	0.25657	(3.4)	(6.6)	3
4	1990	89 - 103	31-Jul-89	1-Sep-90	545	488	(57.0)	158,113	(9.0)	0.27064	(2.4)	(9.0)	4
5	1991				529	500	(29.0)	161,561	(4.7)	0.28471	(1.3)	(10.4)	5
6	1992	90 - 322	31-Aug-90	31-Mar-92	504	460	(43.8)	164,888	(7.2)	0.31192	(2.3)	(12.6)	6
7	1993				466	449	(17.0)	167,597	(2.8)	0.35274	(1.0)	(13.6)	7
8	1994	93 - 272	30-Jun-93	15-Jul-94	460	459	(0.5)	172,833	(0.1)	0.36808	(0.0)	(13.7)	8
9	1995				453	401	(52.0)	180,242	(9.4)	0.38342	(3.6)	(17.2)	9
10	1996				453	401	(52.0)	185,473	(9.6)	0.38342	(3.7)	(20.9)	10
11	1997	96 - 596	31-Jul-96	1-Sep-97	438	431	(6.5)	189,513	(1.2)	0.40356	(0.5)	(21.4)	11
12	1998				422	475	53.0	193,418	10.3	0.42370	4.3	(17.1)	12
13	1999				422	400	(22.0)	199,799	(4.4)	0.42370	(1.9)	(19.0)	13
14	2000				422	408	(14.0)	207,830	(2.9)	0.42370	(1.2)	(20.2)	14
15	2001	00 - 0309	12/31/1999	11/1/2001	420	413	(7.0)	213,978	(1.5)	0.42370	(0.6)	(20.8)	15
16	2002				383	372	(10.7)	217,371	(2.3)	0.45851	(1.1)	(21.9)	16
17	2003				383	352	(31.2)	221,620	(6.9)	0.45851	(3.2)	(25.1)	17
18	Aug-04				383	369	(13.7)	225,446	(3.1)	0.45851	(1.4)	(26.5)	18
19	2005				383								19
20	2006				347								20

Note: The average authorized usage in years of where rates changed represents the average of the previous authorized and the new authorized.

EXHIBIT NO. ____ (RAM-1)
Sheet 5 of 6

SOUTHWEST GAS CORPORATION
ARIZONA
NET INCOME EXCESS / SHORTFALL
COMPARING EXPECTED (AUTHORIZED) INCOME TO REALIZED
FOR THE PERIOD 1994 THROUGH OCTOBER 2004

Line No	Year	Rate Base	ROR Auth.	Regulatory Net Income Expected	Regulatory Net Income Realized	Net Income Excess / (Shortfall)	Line No
	(a)	(b)	(c)	(d)	(e)	(f)	
1	1994	$ 475,500,000	9.13%	$ 43,413,150	$ 37,100,000	$ (6,313,150)	1
2	1995	527,400,000	9.13%	48,151,620	28,400,000	(19,751,620)	2
3	1996	564,000,000	9.38%	52,903,200	27,300,000	(25,603,200)	3
4	1997	575,800,000	9.38%	54,010,040	39,300,000	(14,710,040)	4
5	1998	608,200,000	9.38%	57,049,160	60,300,000	3,250,840	5
6	1999	676,500,000	9.38%	63,455,700	50,100,000	(13,355,700)	6
7	2000	710,100,000	9.38%	66,607,380	50,000,000	(16,607,380)	7
8	2001	768,900,000	9.20%	70,738,800	60,200,000	(10,538,800)	8
9	2002	808,400,000	9.20%	74,372,800	59,800,000	(14,572,800)	9
10	2003	856,400,000	9.20%	78,788,800	51,400,000	(27,388,800)	10
11	2004	923,800,000	9.20%	84,989,600	50,500,000	(34,489,600)	11
12						$ (145,590,650)	12

SOUTHWEST GAS CORPORATION
ARIZONA
REGULATORY LAG EXPERIENCED DURING THE YEARS 1990 THROUGH 2004

Line No.	Docket Number U-1551-	Test Period End	Effective Date New Rates	Regulatory Lag Months	Increase Requested	Authorized	Regulatory Lag Before Tax	Regulatory Lag After Tax	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	
1	90-322	31-Aug-90	31-Mar-92	19	$ 21,136,318	$ 8,342,000	$ 13,208,167	$ 7,924,900	1
2	92-253	31-Mar-92	1-Sep-93	17	15,914,088	6,511,152	9,224,132	5,534,479	2
3	93-272	30-Jun-93	15-Jul-94	**12**	10,053,206	4,325,000	4,325,000	2,595,000	3
4	96-596	31-Jul-96	1-Sep-97	13	49,305,467	32,000,000	34,666,667	20,800,000	4
5	00-0309	31-Dec-99	1-Nov-01	22	37,138,762	21,600,582	39,601,067	23,760,640	5
6	Average Lag			17	$ 133,547,841	$ 72,778,734	$ 101,025,032	$ 60,615,019	6
7	04-XXXX	31-Aug-04	31-Mar-06	17	$ 71,000,000	$ 71,000,000	$ 100,583,333	$ 60,350,000	7
8	04-XXXX	31-Aug-04	31-Aug-05	**12**	$ 71,000,000	$ 71,000,000	$ 71,000,000	$ 42,600,000	8

Note: The average lag between test year end and rate relief has been 17 months for the five rate cases filed and processed since 1990. If the 17 month lag is applied to the rate relief request, regulatory lag will impact after tax retained earnings by $60 million. If the shortest regulatory lag (12 months) experienced during the five previous rate cases is applied to this the requested rate relief, regulatory lag will impact retained earnings by $42.6 million, $18 million less than the average lag of the five previous rate cases.

SOUTHWEST GAS CORPORATION
ARIZONA
PIPE DISALLOWANCE PERCENTAGES
SERVICES

	Proposed Mains Disallowance				Alternate	Current Mains Disallowance			
Year	Aldyl HD	Aldyl A	ABS	1960's Steel	Current Aldyl HD	Aldyl HD	Aldyl A	ABS	1960's Steel
Yrs Write-Off	40	40	40	40	51	89	57	54	49
2000	50.00%	16.25%	5.00%	5.00%	62.00%	69.00%	29.50%	17.50%	12.50%
2001	47.50%	15.00%	3.75%	3.75%	60.00%	68.00%	28.50%	16.50%	11.50%
2002	45.00%	13.75%	2.50%	2.50%	58.00%	67.00%	27.50%	15.50%	10.50%
2003	42.50%	12.50%	1.25%	1.25%	56.00%	66.00%	26.50%	14.50%	9.50%
2004	40.00%	11.25%	0.00%	0.00%	54.00%	65.00%	25.50%	13.50%	8.50%
2005	37.50%	10.00%			52.00%	64.00%	24.50%	12.50%	7.50%
2006	35.00%	8.75%			50.00%	63.00%	23.50%	11.50%	6.50%
2007	32.50%	7.50%			48.00%	62.00%	22.50%	10.50%	5.50%
2008	30.00%	6.25%			46.00%	61.00%	21.50%	9.50%	4.50%
2009	27.50%	5.00%			44.00%	60.00%	20.50%	8.50%	3.50%
2010	25.00%	3.75%			42.00%	59.00%	19.50%	7.50%	2.50%
2011	22.50%	2.50%			40.00%	58.00%	18.50%	6.50%	1.50%
2012	20.00%	1.25%			38.00%	57.00%	17.50%	5.50%	0.50%
2013	17.50%	0.00%			36.00%	56.00%	16.50%	4.50%	0.00%
2014	15.00%				34.00%	55.00%	15.50%	3.50%	
2015	12.50%				32.00%	54.00%	14.50%	2.50%	
2016	10.00%				30.00%	53.00%	13.50%	1.50%	
2017	7.50%				28.00%	52.00%	12.50%	0.50%	
2018	5.00%				26.00%	51.00%	11.50%	0.00%	
2019	2.50%				24.00%	50.00%	10.50%		
2020	0.00%				22.00%	49.00%	9.50%		
2021					20.00%	48.00%	8.50%		
2022					18.00%	47.00%	7.50%		
2023					16.00%	46.00%	6.50%		
2024					14.00%	45.00%	5.50%		
2025					12.00%	44.00%	4.50%		
2026					10.00%	43.00%	3.50%		
2027					8.00%	42.00%	2.50%		
2028					6.00%	41.00%	1.50%		
2029					4.00%	40.00%	0.50%		
2030					2.00%	39.00%	0.00%		
2031					0.00%	38.00%			
2032						37.00%			
2033						36.00%			
2034						35.00%			
2035						34.00%			
2036						33.00%			
2037						32.00%			
2038						31.00%			
2039						30.00%			
2040						29.00%			
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2062						7.00%			
2063						6.00%			
2064						5.00%			
2065						4.00%			
2066						3.00%			
2067						2.00%			
2068						1.00%			
2069						0.00%			

SOUTHWEST GAS CORPORATION
ARIZONA
PROPOSED AMENDMENT TO 1993 SETTLEMENT AGREEMENT PIPE DISALLOWANCE

	Disallowance Percent Reduced Annually Annual Reduction 2.50% (100% / 40 Avg. Life)				Percent Sharing Shareholder / Rate Payer			
					50.0%	50.0%	0.0%	50.0%
Year	Aldyl A	ABS	Aldyl HD	1960's Steel	Aldyl A	ABS	Aldyl HD	1960's Steel
Avg. Yr Install	1973	1964	1980	1960	1973	1964	1980	1964
1960								
1961								
1962								
1963								
1964		100.00%		100.00%		100.00%		100.00%
1965		97.50%		97.50%		97.50%		97.50%
1966		95.00%		95.00%		95.00%		95.00%
1967		92.50%		92.50%		92.50%		92.50%
1968		90.00%		90.00%		90.00%		90.00%
1969		87.50%		87.50%		87.50%		87.50%
1970		85.00%		85.00%		85.00%		85.00%
1971		82.50%		82.50%		82.50%		82.50%
1972		80.00%		80.00%		80.00%		80.00%
1973	100.00%	77.50%		77.50%	100.00%	77.50%		77.50%
1974	97.50%	75.00%		75.00%	97.50%	75.00%		75.00%
1975	95.00%	72.50%		72.50%	95.00%	72.50%		72.50%
1976	92.50%	70.00%		70.00%	92.50%	70.00%		70.00%
1977	90.00%	67.50%		67.50%	90.00%	67.50%		67.50%
1978	87.50%	65.00%		65.00%	87.50%	65.00%		65.00%
1979	85.00%	62.50%		62.50%	85.00%	62.50%		62.50%
1980	82.50%	60.00%	100.00%	60.00%	82.50%	60.00%	100.00%	60.00%
1981	80.00%	57.50%	97.50%	57.50%	80.00%	57.50%	97.50%	57.50%
1982	77.50%	55.00%	95.00%	55.00%	77.50%	55.00%	95.00%	55.00%
1983	75.00%	52.50%	92.50%	52.50%	75.00%	52.50%	92.50%	52.50%
1984	72.50%	50.00%	90.00%	50.00%	72.50%	50.00%	90.00%	50.00%
1985	70.00%	47.50%	87.50%	47.50%	70.00%	47.50%	87.50%	47.50%
1986	67.50%	45.00%	85.00%	45.00%	67.50%	45.00%	85.00%	45.00%
1987	65.00%	42.50%	82.50%	42.50%	65.00%	42.50%	82.50%	42.50%
1988	62.50%	40.00%	80.00%	40.00%	62.50%	40.00%	80.00%	40.00%
1989	60.00%	37.50%	77.50%	37.50%	60.00%	37.50%	77.50%	37.50%
1990	57.50%	35.00%	75.00%	35.00%	57.50%	35.00%	75.00%	35.00%
1991	55.00%	32.50%	72.50%	32.50%	55.00%	32.50%	72.50%	32.50%
1992	52.50%	30.00%	70.00%	30.00%	52.50%	30.00%	70.00%	30.00%
1993	50.00%	27.50%	67.50%	27.50%	50.00%	27.50%	67.50%	27.50%
1994	47.50%	25.00%	65.00%	25.00%	47.50%	25.00%	65.00%	25.00%
1995	45.00%	22.50%	62.50%	22.50%	45.00%	22.50%	62.50%	22.50%
1996	42.50%	20.00%	60.00%	20.00%	42.50%	20.00%	60.00%	20.00%
1997	40.00%	17.50%	57.50%	17.50%	40.00%	17.50%	57.50%	17.50%
1998	37.50%	15.00%	55.00%	15.00%	37.50%	15.00%	55.00%	15.00%
1999	35.00%	12.50%	52.50%	12.50%	35.00%	12.50%	52.50%	12.50%
2000	32.50%	10.00%	50.00%	10.00%	16.25%	5.00%	50.00%	10.00%
2001	30.00%	7.50%	47.50%	7.50%	15.00%	3.75%	47.50%	7.50%
2002	27.50%	5.00%	45.00%	5.00%	13.75%	2.50%	45.00%	5.00%
2003	25.00%	2.50%	42.50%	2.50%	12.50%	1.25%	42.50%	2.50%
2004	22.50%	0.00%	40.00%	0.00%	11.25%	0.00%	40.00%	0.00%
2005	20.00%		37.50%		10.00%		37.50%	
2006	17.50%		35.00%		8.75%		35.00%	
2007	15.00%		32.50%		7.50%		32.50%	
2008	12.50%		30.00%		6.25%		30.00%	
2009	10.00%		27.50%		5.00%		27.50%	
2010	7.50%		25.00%		3.75%		25.00%	
2011	5.00%		22.50%		2.50%		22.50%	
2012	2.50%		20.00%		1.25%		20.00%	
2013	0.00%		17.50%		0.00%		17.50%	
2014			15.00%				15.00%	
2015			12.50%				12.50%	
2016			10.00%				10.00%	
2017			7.50%				7.50%	
2018			5.00%				5.00%	
2019			2.50%				2.50%	
2020			0.00%				0.00%	

Aldridge

Table of Contents
of
Prepared Direct Testimony
of
RANDI L. ALDRIDGE

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
of
RANDI L. ALDRIDGE

INTRODUCTION/BACKGROUND

Q. 1 Please state your name and business address.

A. 1 My name is Ms. Randi L. Aldridge. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150-0002.

Q. 2 By whom are you employed and in what capacity?

A. 2 I am employed by Southwest Gas Corporation (Southwest or the Company) in the Revenue Requirements department. My title is Senior Specialist/Revenue Requirements.

Q. 3 Please state your educational background and business experience.

A. 3 I graduated from the University of Washington in Seattle, Washington with a Bachelor of Arts in Business Administration, Accounting. My areas of concentration were accounting and finance. I graduated from the University of Nevada, Las Vegas with a Masters in Business Administration (MBA), with Beta Gamma Sigma honors. I am a Certified Management Accountant (CMA) and a member of the Institute of Management Accountants.

One year before completing my bachelor's degree, I accepted employment at Washington Mutual Savings Bank in Seattle, Washington as an Asset/Liability Management intern. Upon graduation in 1993, I accepted a full-time position as a Financial Analyst Trainee in the Financial Forecasting department. In 1994, I was promoted to Financial Analyst I. My responsibilities included assisting in the budget and forecasting process, and various financial analyses.

In February 1995, I accepted a position as a Budget Analyst in the Budget and Forecasting department at PriMerit Bank (at that time a subsidiary of Southwest) in Las Vegas, Nevada. In April 1996, I transferred to Southwest as a Corporate Accountant I in the Accounting Control department. In January 1998, I was promoted to Analyst I/ Accounting. In February 1998, I transferred to the Revenue Requirements department as an Analyst. In January 2001, I was promoted to Specialist, and in July 2003, I was promoted to my present position.

During my time at Southwest, I have attended several training and technical conferences related to utility ratemaking and regulatory issues, as well as accounting issues. In addition, I have taught the Cost of Service Problem for "The Basics" conference presented by the Center for Public Utilities at New Mexico State University and the National Association of Regulatory Utility Commissioners on several occasions.

Q. 4 Please summarize the nature of your present responsibilities and duties with Southwest.

A. 4 I am responsible for assisting in the preparation of general rate case filings for state and federal jurisdictions, the preparation of written and oral expert testimony, the research, preparation, and presentation of various financial analyses, studies, and reports, as well as other special projects.

Q. 5 Have you previously testified before any regulatory commission?

A. 5 Yes, I have previously testified before the California Public Utilities Commission (CPUC) and the Public Utilities Commission of Nevada (PUCN).

Q. 6 What is the purpose of your prepared direct testimony in this proceeding?

A. 6 I will sponsor and present testimony describing the Company's natural gas operations, together with a description of the cost responsibility and allocations of capital and expense costs.

I also sponsor and present testimony with respect to the following schedules and supporting workpapers (WP) included in this rate application:

(a) Rate Base: Schedule B-1, Adjusted Original Cost and RCND Rate Base; Schedule B-2, Summary Cost of Gas Plant (excluding Adjustment Nos. 11 and 21); Schedule B-3, Summary RCND Cost of Gas Plant; Schedule B-4, Reconstructed Cost of Gas Plant; Schedule B-5, Summary of Working Capital; and Schedule B-6, Other Rate Base Items;

(b) Operating Income: Schedule C-1, Adjusted Test Year

Income Statement (excluding Sheet 2); Schedule C-2, Summary of Operating Income Adjustments (excluding Adjustment Nos. 1, 2, and 10-12); and Schedule C-3, Computation of Gross Revenue Conversion Factor;

(c) <u>Financial Statements and Statistical Schedules</u>: Schedules E-1 through E-9;

(d) <u>Projections and Forecasts</u>: Schedules F-1 through F-4; and

(e) <u>System Allocable Depreciation Study</u>: Schedule I.

<u>DESCRIPTION OF SOUTHWEST'S NATURAL GAS UTILITY OPERATIONS</u>

Q. 7 Please describe Southwest's natural gas operations.

A. 7 Southwest is primarily a natural gas local distribution company, providing service to over 1.5 million customers in three states. At the end of the test year, Southwest served over 843,000 customers in Arizona, or over 55 percent of its total customer base. Southwest consists of six ratemaking jurisdictions subject to the regulation of the Arizona Corporation Commission (Commission), the PUCN, the CPUC, and the Federal Energy Regulatory Commission (FERC). Southwest is separated into five operating divisions, two each in Arizona and Nevada, and one in California. Each division operates independently of the others. All divisions are supported by staff located at the Corporate Headquarters in Las Vegas, Nevada. Paiute Pipeline Company (Paiute), a wholly-owned subsidiary of Southwest, operates and maintains transmission and storage facilities that are used to deliver natural gas to local distribution companies (including Southwest) and other end-users in northern Nevada. Paiute is operated and staffed out of Southwest's Northern Nevada Division. Southwest Gas Transmission Company (SGTC) provides gas transportation service through an eight-mile transmission facility, and is regulated by the FERC. For retail ratemaking purposes at the state level, Southwest's retail gas utility operations are divided into five rate jurisdictions: Arizona, Southern Nevada, Northern Nevada, Southern California, and Northern California.

COST RESPONSIBILITY AND ALLOCATIONS

Q. 8 Briefly describe how costs associated with Southwest's natural gas operations are treated in this rate application.

A. 8 Costs, both capital and expense, are incurred either directly at the division level or at the corporate level. Costs incurred at the division level are charged directly to the ratemaking jurisdiction incurring the costs. Costs at the corporate level are either charged directly to the specific rate jurisdiction, if the cost was incurred on its behalf, or allocated to the rate jurisdiction if the cost is common or beneficial to all of the Company's rate jurisdictions. The costs that are charged directly to a rate jurisdiction are referred to as Corporate Direct costs. The costs that are common to all rate jurisdictions are referred to as Common or System Allocable costs.

Q. 9 What do System Allocable costs consist of?

A. 9 System Allocable costs are primarily corporate administrative and general (A&G) expenses, and the costs associated with the intangible and general plant used to support the corporate administrative staff.

Q. 10 How does the Company allocate these Common costs among its various rate jurisdictions?

A. 10 System Allocable amounts are first allocated to Paiute using the Modified Massachusetts Formula (MMF), a FERC-authorized methodology, and through a rental charge for use of intangible and general plant. Second, A&G expenses are allocated to SGTC, also based on the MMF. Finally, the remaining System Allocable costs are allocated amongst the Company's retail ratemaking jurisdictions using the 4-Factor Allocation Methodology (4-Factor).

Q. 11 Please provide additional detail concerning how System Allocable costs are charged to Paiute and SGTC.

A. 11 System Allocable costs are allocated and charged to Paiute through the use of the MMF, with the exception of Account 924 (Property Insurance), which is allocated using an insurable property factor. The MMF, as shown in Schedule C-1, Sheet 19 is the arithmetic average of three equally weighted components: direct operating labor, margin, and gross plant. In addition to Paiute and SGTC, it includes all of the Company's retail rate jurisdictions. WP Schedule C-2, Adjustment No. 9, Sheets 3 and 4, provide the development of the property insurance allocation factor. A new MMF percentage is calculated annually, together with a new property insurance factor, for use throughout the following calendar year. System Allocable costs allocated and charged to Paiute are transferred to and recorded on Paiute's books monthly. Consequently, System Allocable A&G expenses that are shown on Southwest's books are net of the allocations to Paiute.

Southwest also charges Paiute a rental charge for its allocated share of System Allocable intangible and general plant. The rental revenue received from Paiute is allocated and recorded to each rate jurisdiction based on the 4-Factor methodology. The rental revenue is recorded in Account 493 (Rent from Gas Property).

Southwest also allocates A&G expenses to SGTC via use of the MMF, as shown in Schedule C-1, Sheet 19. This MMF consists of the same three equally weighted components as those used for Paiute. It includes the costs for SGTC, all of Southwest's natural gas operations, and those of Paiute. This methodology was approved by the FERC in SGTC's last general rate application (RP-01-73-000). Unlike Paiute (because the amounts are so small), a separate allocator is not used for Property Insurance. This calculation is also done annually and is charged to SGTC on an annual basis in December of each year. The amount determined to be allocable to SGTC is credited to Account 930.2 (Miscellaneous General Expense) on Southwest's books. The allocator for SGTC is applied to not only the A&G expenses, but also to the components that make up the rental charge described above for Paiute (see Statement N, Sheet 12). Therefore, a separate rental calculation is not required for SGTC.

For this rate application, the MMF, property insurance allocator, and the Paiute rental charge were calculated using end of test year data.

Q. 12 Although not technically an allocation, how does Southwest charge its non-utility subsidiaries for administration or other activities that are undertaken on their behalf?

A. 12 Labor charges of Company administrative personnel are charged directly to its non-utility subsidiaries as incurred. Facilities and administrative loadings are added to all labor charged to non-utility subsidiaries. Incremental costs incurred by Southwest are also charged to non-utility subsidiaries if the cost was incurred on their behalf. The costs of Board of Directors' meetings are charged based upon an average cost per director and the average amount of time spent in the meeting.

Q. 13 Please explain the 4-Factor Allocation Methodology.

A. 13 The 4-Factor is based on the average of four equally-weighted components. Those components are: (a) direct operating expense; (b) average gross plant;

(c) direct operating labor; and (d) average number of customers. The 4-Factor has been used for ratemaking purposes by Southwest since the 1950s, and has been accepted and approved by each of Southwest's jurisdictional state regulatory commissions. Schedule C-1, Sheet 18 provides the development of the 4-Factor allocation percentages for the test year, which in this case is the 12 months ended August 31, 2004.

RATE BASE

Q. 14 What is the amount of rate base Southwest is requesting be approved by the Commission in this proceeding?

A. 14 Southwest has proposed and will support a fair value rate base of $1,171,427,301. The fair value rate base was determined by giving equal weight (50/50) to the original cost rate base of $925,212,447 and the reconstruction cost new rate base of $1,417,642,156.

Q. 15 Please describe and explain Southwest's Schedule B-1.

A. 15 Schedule B-1 is a high-level summary of the various components that comprise rate base. Rate base is presented on this Schedule at original cost, reconstruction cost new, and at fair value. All measurements were performed for the 12 months ended August 31, 2004. Details of the various rate base components can be found in Schedules B-2 through B-6.

Q. 16 Please describe and explain Southwest's Schedule B-2.

A. 16 Schedule B-2 is a summary of the Company's gas plant in service (GPIS), at original cost, together with the related accumulated amortization and depreciation reserve (accumulated reserve). As noted earlier, all measurements were done for the 12 months ended August 31, 2004. The schedule contains the recorded amounts for both direct and System Allocable GPIS and the related accumulated reserve, the adjustments necessary to accurately reflect the Company's investment needed to serve test year customers, the associated adjusted balances, the allocation of System Allocable amounts to the Arizona rate jurisdiction, and, finally, the test year balances as adjusted and allocated to Arizona.

There are three rate base adjustments reflected in this schedule. First, there is an adjustment (Adjustment No. 20) to reflect the addition of amounts of non-revenue producing completed construction not classified (CCNC) that technically existed in construction work-in-progress (CWIP) at the end of the test year, along with an adjustment to System Allocable Miscellaneous Intangible Plant to add projects in CWIP expected to close to plant in service (to synchronize the plant with the adjustment to System Allocable amortization expense in Adjustment No. 17). Second, there is the adjustment (Adjustment No. 11) to remove a portion of plant related to specific pipe replacement programs. Third, an adjustment (Adjustment No. 21) was made to remove amounts from the cost of service related to the Phoenix Light Rail project. Company witness Robert A. Mashas will discuss Adjustment

Nos. 11 and 21 in his prepared direct testimony.

Q. 17 What is the amount of the CCNC/CWIP adjustment requested by the Company?

A. 17 In total the CCNC/CWIP adjustment (Adjustment No. 20) results in an increase of $2,789,294 in plant in service. This consists of two components: a direct Arizona component of $1,819,949 and a System Allocable component (after 4-Factor) of $969,345.

Q. 18 Please explain why the adjustment made to reflect the inclusion of non-revenue producing CCNC in rate base should be accepted by the Commission.

A. 18 The gas plant included in the CCNC portion of this adjustment reflects construction expenditures made before the end of the test year. There are no expenditures for tangible plant included in the adjustment that were incurred after August 31, 2004. The tangible plant represented by these expenditures was either in-service at the end of the test year or shortly thereafter. However, the actual closing to GPIS was made after the end of the test year, largely due to delays in the field in entering the required information into the Company's computer systems.

The plant requested to be included in rate base is non-revenue producing plant. In other words, it represents plant that was constructed to improve service or enhance reliability and safety for existing customers, and not constructed to serve new customers. Southwest will not realize any incremental operating revenues from the construction and addition of this plant. Examples of the plant included in the adjustment include: replacement mains, franchise requirements, pressure reinforcements, measuring and regulating station equipment, and general plant.

Customers existing in Southwest's system at the end of the test year are the primary beneficiaries of these construction expenditures. Consequently, the inclusion of this non-revenue producing plant in rate base more accurately matches the Company's investment needed to serve the customers in its system at the end of the test year, and should be allowed by the Commission.

Q. 19 Please explain why the Commission should accept Southwest's adjustment to include in rate base the non-revenue producing System Allocable Miscellaneous Intangible Plant CWIP.

A. 19 In Decision No. 64172, the Commission allowed an adjustment proposed by Staff and the Residential Utility Consumer Office (RUCO) that removed several software projects that became fully amortized shortly after the end of the test year. In that proceeding, the Company pointed out that the Staff and RUCO did not propose to include amortizations for new projects that commenced during the same post-test year period. The Commission believed that Staff and RUCO struck the correct balance by removing these fully amortized projects since the

Commission allowed the Work Management System (WMS) Phase I project in rate base, together with its associated amortization expense. In this proceeding, the Company does not have the equivalent of a WMS Phase I project to serve as a "balance." Therefore, it is equitable to propose removing from amortization expense those software projects that will be fully amortized by December 31, 2004. Furthermore, it is proper to <u>add</u> to rate base the estimated plant in service and to add the related amortization expense for those projects in CWIP that are estimated to be closed to plant prior to December 31, 2004. This is a conservative adjustment because many small software projects spend a relatively short time in CWIP. This adjustment strikes a fair balance between project amortizations that will expire shortly after the end of the test year, and projects commencing amortization and serving customers approximately one year prior to rates from this proceeding going into effect.

Q. 20 Please describe and explain Southwest's Schedules B-3 and B-4.

A. 20 Schedule B-3 is a summary of the reconstruction cost new study. The schedule contains both the Direct and System Allocable plant assigned to Arizona. The development of the reconstruction cost new data is utilized to develop the fair value rate base as traditionally calculated by the Commission. The detail supporting Schedule B-3 is contained in Schedule B-4. Schedule B-4 contains the Handy-Whitman indices that were used to trend original cost plant to obtain the reconstruction cost new data, and the reconstruction cost new data by vintage year, and by FERC account.

Q. 21 Please describe and explain Southwest's Schedule B-5.

A. 21 Schedule B-5 presents a summary of the Company's calculation of its requested working capital allowance for the test year ended August 31, 2004. The working capital allowance is made up of three components: (1) cash working capital, (2) materials and supplies, and (3) prepayments. Southwest is requesting a working capital allowance of $881,148.

Cash working capital was determined through a comprehensive lead-lag study. In performing the lead-lag study, Southwest examined every non-gas invoice over $10,000 that was processed during the test year and examined every gas invoice processed during the test year. As a result, approximately 85 percent of total adjusted operating expenses were reviewed to determine the net lag attributable to operating expenses. The lead-lag study produced a negative cash working capital amount of $11,082,156.

The materials and supplies balance requested by the Company, based on a 13-month average, is $9,222,489. The prepayments balance requested by the Company, based on a 13-month average balance is $2,740,815. The use of

13-month average balances for materials and supplies, prepayments, and miscellaneous rate base items in Schedule B-6 has been accepted by this Commission in prior rate proceedings.

Q. 22 Please describe and explain Southwest's Schedule B-6.

A. 22 Schedule B-6 contains the pages that support the calculation of three miscellaneous rate base items. Those items are: (1) the 13-month average balance of customer advances for construction, (2) the 13-month average balance of customer deposits, and (3) accumulated deferred income taxes. Each of these items reduces rate base, and all are calculated for the test year ended August 31, 2004. The total adjusted rate base reduction for these three items is $167,630,841.

OPERATING INCOME

Q. 23 Please describe Schedule C-1.

A. 23 Schedule C-1 provides a test year operating income statement as recorded and as adjusted. It also contains detailed supporting data by account for each functional area listed on the income statement.

Q. 24 Please describe Schedule C-2.

A. 24 Schedule C-2 contains a summary schedule of operating income adjustments and individual sheets detailing the adjustments proposed in this proceeding.

Q. 25 Please list the operating income adjustments you are supporting.

A. 25 I am supporting the following operating income adjustments:

Adjustment No.	Description
3	Labor/Loading Annualization
4	Customer Billing Annualization
5	Uncollectible Accounts Normalization
6	Promotional Expenses
7	American Gas Association (AGA) Dues
8	Sarbanes-Oxley Section 404 Compliance
9	Paiute/SGTC Allocation
13	Rate Case Expense
14	Miscellaneous Adjustments
15	Employee Vehicle Compensation
16	Out-of-Period Expenses
17	Annualized Depreciation and Amortization
18	Property Tax Annualization
19	Interest on Customer Deposits

Q. 26 Who is supporting the adjustments to operating income in Adjustment No. 10, Self-Insurance, Adjustment No. 11, Pipe Replacement, Leak Survey and Repair, and Adjustment No. 12, Transmission Integrity Management Program (TRIMP)?

A. 26 Company witness Mr. Mashas is supporting Adjustment Nos. 10 through 12.

Q. 27 Please describe Adjustment No. 3, Labor and Labor Loading Annualization.

A. 27 Adjustment No. 3 annualizes the labor and related labor loadings of Arizona and corporate staff employees employed by the Company at August 31, 2004.

The labor and labor loading annualization adjustment includes three separate components. First, a salary annualization is made for all Arizona and corporate staff employees at salaries in effect at the end of the last pay period prior to August 31, 2004.

Secondly, it annualizes labor loadings at the end of the test year. Finally, the labor adjustment reflects an assumed two percent general wage increase that will be effective in June 2005, along with an approximate one percent increase in wages as a result of within-grade wage movement during the 12 months subsequent to the end of the test year (i.e. through August 2005).

Q. 28 Please define labor loadings.

A. 28 Labor loadings represent pensions, benefits and payroll taxes paid by the Company. Pensions, benefits (including paid time-off), and payroll taxes are accumulated at the corporate level and distributed among the various jurisdictions through a labor loading process. For each labor dollar charged to an account, an additional amount (i.e. labor loading) is charged to that account to distribute the cost of pensions, benefits, and payroll taxes.

Q 29 How are labor loadings for Arizona and corporate staff employees annualized?

A. 29 For most benefits, total Company recorded test year costs were used as the basis for the labor loading annualization. However, for pensions, post employment benefits other than pension (PBOP), and Supplemental Executive Retirement Plan (SERP), Southwest's most recent actuarial studies were used as the basis for the labor loading annualization. In addition, payroll taxes and indirect time were adjusted for the impact of annualizing payroll and overtime.

There are two methods used to allocate labor loading costs to each jurisdiction. First, the cost of pensions, PBOP, SERP and executive deferred compensation, and employee investment plan (401k) are allocated based on each jurisdiction's labor cost as a percentage of total Company labor. Second, for the remaining benefits, a cost per employee was calculated based on recorded cost divided by the average number of total Company employees during the test year. This cost per employee is then multiplied by the number of jurisdictional employees at the end of the test year to determine an annualized amount.

Q. 30 Were there any adjustments made to labor loadings where the cost was based on recorded test year data?

A. 30 Yes. An adjustment was made to remove several Miscellaneous Benefits from the cost of service. These items relate to gifts for employees and retirees, employee events and awards, and other costs that the Commission has disallowed in prior rate cases. This adjustment was made consistent with Decision No. 64172.

Q. 31 Once the annualized labor and labor loadings were calculated, how was the adjustment determined?

A. 31 The annualized labor and labor loadings were assigned to each account based on the historical test year relationships. For example, during the test year, approximately 81 percent of Arizona direct labor and labor loadings were charged to operations and maintenance (O&M) accounts. Therefore, 81 percent of the annualized Arizona direct labor and labor loadings were assigned to operations and maintenance accounts. The difference between the annualized labor and labor loadings assigned to the O&M accounts and recorded labor and labor loadings is the adjustment for that account. As approximately 81 percent of the annualized Arizona direct labor and labor loadings were assigned to O&M, the remaining 19 percent was assigned to capital and deferred accounts, and does not impact the revenue requirement requested in this rate application. A similar assignment is performed for corporate staff annualized labor and labor loadings to determine the adjustment required.

Q. 32 Why is it appropriate to adjust labor expense for the 2005 wage increase and within-grade movement?

A. 32 Under current Commission guidelines for processing major rate applications, it is expected that the hearing in this proceeding will be conducted after June 2005. Historically, the Company has granted general wage increases effective each June. Therefore, the year 2005 wage increase will be known and measurable prior to the hearing in this proceeding, and Staff and other intervenors will have an opportunity to verify the actual amount of any increase.

Q. 33 Does this post-test year adjustment distort the sanctity of the test year?

A. 33 No. This adjustment only applies to employees on the payroll at August 31, 2004, the end of the test year. It <u>does not</u> apply to any employees hired after August 31, 2004 to meet customer growth, changes to work requirements, etc. Therefore, the number of employees at the end of the test year is synchronized with test year customers that they are serving. This adjustment simply recognizes the fact that by the time the rates from this docket become effective, test year customers will be served by test year-end employees who, on average, will be paid over three percent more than the wages in effect at the end of the test year.

Q. 34 Have previous Commission rulings in the Company's rate applications addressed this adjustment?

A. 34 Yes. Since the 1990s, the Company has made five filings for general rate changes to its Arizona rates. In no case were post-test year wage increases rejected by the Commission.

Q. 35 Please explain Adjustment No. 4, Customer Billing Annualization.

A. 35 Adjustment No. 4, Customer Billing Annualization, annualizes the incremental costs associated with the customer billing function. These incremental costs include: bill stock, toner, envelopes, postage, etc. The incremental cost was applied to the difference between recorded and annualized bills.

Q. 36 Please explain Adjustment No. 5, Uncollectible Accounts

Annualization.

A. 36 Adjustment No. 5, Uncollectible Accounts Annualization, annualizes uncollectible accounts expense (Account 904) to reflect the test year net closing bill write-offs as a percentage of gross revenues. The write-off percent applied to present revenues determines the annualized amount, which is then compared to recorded uncollectible expense to determine the adjustment amount.

Q. 37 Please explain Adjustment No. 6, Promotional Expenses.

A. 37 Adjustment No. 6, Promotional Expenses, removes expenses related to promotional marketing and advertising programs from the cost of service that have not been allowed to be recovered from customers in previous rate applications.

Q. 38 Please explain Adjustment No. 7, American Gas Association (AGA) Dues.

A. 38 Adjustment No. 7, AGA Dues, removes the portion of the Company's dues to the AGA that has been identified as promotional in nature. This adjustment is consistent with previous Commission decisions not allowing the recovery of the promotional portion of the Company's AGA dues.

Q. 39 Please explain Adjustment No. 8, Sarbanes-Oxley Section 404 Compliance (Section 404 Compliance).

A. 39 Adjustment No. 8, Section 404 Compliance, consists of two parts. The first part removes incremental, non-recurring expenses related to the initial assessment and review of internal controls recorded during the test year. This assessment and review was necessary in order to comply with the requirements in Section 404 of the Sarbanes-Oxley Act of 2002 (the Act). The Company requests that this amount, together with related additional post-test year expenses required to fully implement the Act, be classified as a regulatory asset, giving the Company the opportunity to recover these costs via a regulatory amortization over a three-year period. These costs consist of fees paid to outside consultants the Company engaged to assist it in meeting the compliance requirements of the Act. The requested regulatory amortization is fully calculated in Adjustment No. 17, Annualized Depreciation and Amortization.

The second part of this adjustment adds expected incremental and recurring Section 404 Compliance costs, related to increased annual audit fees, to test year expenses. Section 404 Compliance requires the Company's independent auditors to attest to the adequacy of the Company's internal controls on an annual basis. This increase is estimated to be $400,000-$500,000. As a result, the mid-point of this range, $450,000 was used for this portion of the adjustment. The actual amount will be known and measurable prior to the hearing in this proceeding.

Q. 40 Please explain Adjustment No. 9, Paiute and SGTC Allocation.

A. 40 Adjustment No. 9, Paiute and SGTC Allocation, annualizes the A&G amounts allocated to Paiute and SGTC through the

MMF allocation methodology. The annualization utilizes a MMF rate calculated as of August 31, 2004. This adjustment is consistent with the methodology accepted by the Commission in each of the Company's last seven general rate cases.

Q. 41 Please explain Adjustment No. 13, Rate Case Expense.

A. 41 The Company estimated the incremental costs that would be incurred to process this general rate case, and divided this amount by a three-year period (roughly equal to one rate case cycle) to calculate an annual amortization to Account 928. The adjustment is the difference between this new amortization amount and the amount of rate case expense amortized on the Company's books during the test year.

Q. 42 Please explain Adjustment No. 14, Miscellaneous Adjustments.

A. 42 Adjustment No. 14, Miscellaneous Adjustments, removes certain costs from test year expenses that the Company is not requesting recovery of in this proceeding, such as amounts paid to chambers of commerce and expenses for gym memberships, donations, and various meals.

Q. 43 Please explain Adjustment No. 15, Employee Vehicle Compensation.

A. 43 Adjustment No. 15, Employee Vehicle Compensation, removes from test year expenses the amounts included in employee income for the personal use of Company vehicles that fall under Category D in the Company's Standard Practice (SP)

No. 100.1. This amount is a proxy for the amounts the Company incurred for gasoline and maintenance costs for personal use of Category D vehicles during the test year.

Q. 44 Please define Category D vehicles.

A. 44 Category D vehicles are those vehicles treated as used entirely for personal business. The employees who drive these vehicles are typically officers, directors, and managers. The employee must substantiate the total and business miles on a monthly basis; otherwise, the entire value of the availability of a Category D vehicle will be included in the employee's gross income. Properly documented business miles are not included in the employee's gross income.

Q. 45 Why were expenses removed for only Category D vehicles, and not for Category B vehicles?

A. 45 The Company requires certain employees to use Company vehicles for commuting. Commuting is the only personal use allowed. This category of Company vehicles is referred to in SP 100.1 as Category B. The recent implementation of mobile computing has allowed certain employees to start and end their work days from home (employees participating in the Company's "Start Work from Home" program), saving commuting time to the Company's facilities and getting more service orders completed in a day; thus, increasing the productivity of these employees. This clearly benefits customers since this practice <u>saves time</u> by allowing more work to be done by each participating employee, and <u>saves money</u> by delaying the need for the Company to hire additional employees. In addition, there is a societal benefit of less traffic and pollution resulting from reduced commuting miles. The Company believes that the nominal amount ($3 per regular work day) attributed to personal use of these vehicles is more than offset by the increased productivity of these employees; therefore, it has not included personal use related to Category B vehicles in this adjustment.

Q. 46 Please explain Adjustment No. 16, Out-of-Period Expenses.

A. 46 Adjustment No. 16, Out-of-Period Expenses, adjusts test year expenses for two items. One item paid one month prior to the test year for a September 2004 rental payment was adjusted into the test year so the test year would contain 12 rental payments. The second item was removed from test year expenses to eliminate two annual payments for the same item during the test year.

Q. 47 Which transactions were reviewed for this adjustment?

A. 47 All Arizona jurisdictional expenses exceeding $50,000 were evaluated to determine whether an adjustment was necessary. This threshold was selected to evaluate only the transactions that would have a material impact on the cost of service.

Q. 48 What is the Company requesting for its annual depreciation and amortization expense?

A. 48 Southwest recorded $73,461,654 of depreciation and amortization expense for Arizona in the test year. This amount consisted of $64,380,219 of direct expense and $8,194,311 of System Allocable expense (amount after the 4-Factor allocation to Arizona), and $887,124 of regulatory amortizations. In this proceeding, the Company is requesting an annual depreciation and amortization expense of $75,949,648 made up of a direct component of $67,338,861, and a System Allocable component of $7,062,583, and $1,548,204 of regulations amortizations. Consequently, the total adjustment proposed by the Company for depreciation and amortization expense is $2,487,994.

Q. 49 What is included in the Company's adjustment to its depreciation and amortization expense?

A. 49 Adjustment No. 17 consists of all of the adjustments to test period depreciation and amortization expense, including regulatory amortizations. This adjustment annualizes depreciation and amortization expense based on plant existing at the end of the test year, after adjustments. In addition, the Company proposes new System Allocable depreciation rates based on a current depreciation study. Finally, adjustments have been made to remove the expiring regulatory amortization for the Service Investigation program which will end October 2005, and to add regulatory amortizations related to Sarbanes-Oxley Section 404 incremental compliance costs and TRIMP costs.

Q. 50 Please explain the portion of the depreciation and amortization adjustment related to the System Allocable depreciation study.

A. 50 In 2003, the Company commissioned a depreciation study for its Nevada jurisdictions and its System Allocable plant based on plant balances as of December 31, 2002. Southwest is required to file a depreciation study once every four years in accordance with Nevada Administrative Code 703.276, as are all similarly situated public utilities in the State of Nevada. The Company's depreciation study was undertaken and conducted by AUS Consultants - Weber Fick and Wilson Division. On or about March 8, 2004, the depreciation study was filed with the PUCN under Docket No. 04-3011. On August 30, 2004, the PUCN accepted and adopted the System Allocable depreciation rates proposed by Southwest, effective September 1, 2004.

System Allocable plant, as previously noted, represents that intangible and general plant that is used to support overall Company operations and provides benefits to all rate jurisdictions. Consequently, the plant, and its related expense, is allocated to all rate jurisdictions via use of the 4-Factor Methodology. The use of different depreciation rates in each state for System Allocable plant, which is common to all of the Company's rate jurisdictions, would create an administrative burden for the Company, and may also contribute to unintended ratemaking problems (e.g., cost-shifting and/or auditing difficulties). In addition, the depreciation study undertaken represents a relatively current analysis of the Company's System Allocable plant, as it takes into consideration the rapid changes in computing and communications technology and declining salvage values from obsolescence, as well as the Company's more recent experience regarding retirements and removals. As a result, Southwest requests the Commission approve the proposed System Allocable depreciation rates that are contained in the depreciation study, and that were recently approved by the PUCN. The System Allocable depreciation study, which I support and sponsor, is included in Southwest's rate application in Volume II, Supporting Schedules under Tab I. The adjustment necessary to adopt the proposed System Allocable depreciation rates results in a decrease to Arizona depreciation expense of $818,528 (after 4-Factor allocation).

Q. 51 What are the major changes to depreciation rates contained in the System Allocable depreciation study?

A. 51 Different rates are proposed for all general plant accounts; however, there are only three that have a significant impact on depreciation and amortization expense. Two of the three have proposed depreciation and amortization rates significantly lower than those authorized today. Only one account is proposed to have a depreciation rate significantly higher than that currently authorized.

Office Furniture and Equipment (Account 391) is proposed to increase from a 3.99 percent depreciation rate to an 8.16 percent depreciation rate. The effect on the Arizona jurisdictional revenue requirement is an increase of $186,222. Computer Hardware and Software (Account 391.1) is proposed to decrease from a current depreciation rate of 30.01 percent to a rate of 16.15 percent. The effect on the Arizona jurisdictional revenue requirement is a decrease of $1,083,243. Finally, while not technically part of the depreciation study itself, since it is non-depreciable plant, the PUCN approved the Company's request for a 15-year amortization of its WMS rather than a 10-year amortization. WMS is recorded in Miscellaneous Intangible Plant (Account 303). The effect on the Arizona jurisdictional revenue requirement is a decrease of $601,001.

Q. 52 Please explain the adjustment necessary to annualize depreciation and amortization expense for the test year.

A. 52 This adjustment is necessary to synchronize the depreciation and amortization expense with the plant in service at the end of the test year, as adjusted. Like many utilities, Southwest employs a depreciation convention based on the month the plant is actually placed in service. Southwest begins depreciation on plant the month subsequent to the month it is first placed in service, and, in turn, takes a full month's depreciation in the month it is removed or retired from service. As a result, plant that is placed in service or retired after the beginning of the year (e.g. June 2004) only has a partial year's depreciation expense recorded on the books of the Company. To allow Southwest the opportunity to recover its reasonable and necessary operating expenses, and to avoid charging ratepayers for assets removed or retired from service, depreciation and amortization must be annualized based on end of test year plant balances, as adjusted. The annualization adjustment proposed by Southwest accomplishes these objectives.

Q. 53 What is the revenue requirement impact from the proposed adjustment to annualize depreciation and amortization expense?

A. 53 Southwest's depreciation and amortization annualization was calculated for two separate component parts. For plant that directly and physically serves the Arizona jurisdiction (Arizona direct), the annualization adjustment results in an increase of depreciation and amortization expense of $2,958,642, and an increase of $661,080 for regulatory amortizations. For System Allocable plant, the necessary annualization adjustment (with the proposed depreciation and amortization rates and after 4-Factor allocation) results in a decrease in depreciation and amortization expense of $1,131,728 allocated to Arizona. The total proposed depreciation and amortization adjustment is an increase of $2,487,994.

Q. 54 Please explain Adjustment No. 18, Property Tax.

A. 54 Adjustment No. 18, Property Tax, annualizes property taxes on the Company's adjusted investment in plant and materials as of the end of the test year. For Arizona properties, the Company determines an estimated full cash value by using adjusted net plant in service at August 31, 2004, adding customer CIAC and materials and supplies, and subtracting transportation equipment and land rights. The estimated full cash value is then multiplied by the statutorily required assessment rate to determine the assessed value. The assessed value is then multiplied by the 2004 property tax rate, as adjusted, to determine an annualized property tax expense.

Q. 55 How was the 2004 property tax rate adjusted?

A. 55 There were two bond issues that were recently passed by Arizona voters, they are: 1) Maricopa Community College; and 2) Community College in Yuma County. As a result of these two bond issues, the Arizona property tax rate increased from 12.63 percent of assessed value to 12.77 percent of assessed value to reflect the impact of these two bond issues.

Q. 56 Please explain Adjustment No. 19, Interest on Customer Deposits.

A. 56 Adjustment No. 19, Interest on Customer Deposits, synchronizes interest expense on customer deposits with the amount of customer deposits used as a rate base deduction. The Company is proposing an interest rate of three percent to calculate annualized interest expense, versus the currently authorized rate of six percent. Interest expense is treated as an above-the-line expense pursuant to prior Commission orders.

Q. 57 How was the proposed three percent interest rate on customer deposits determined?

A. 57 Three percent is roughly equal to the three-year Constant Maturity Treasury Rate in October 2004, which is proposed to correspond with the rate case cycle which is approximately three years.

Q. 58 Please describe Schedule C-3.

A. 58 Schedule C-3, Sheet 1 provides the computation of the gross revenue conversion factor. The gross revenue conversion factor represents the ratio of gross revenue required to produce a $1 change in test year net operating income. Sheet 2 of Schedule C-3 provides the computation of the effective state and federal income tax rates utilized in the application.

Q. 59 Does this conclude your prepared direct testimony?

A. 59 Yes, it does.

Wood

Southwest Gas Corporation
Docket No. G-01551A-04-__

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
of
THEODORE K. WOOD

INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Theodore K. Wood. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150-0002.

Q. 2 By whom are you employed and in what capacity?

A. 2 I am employed by Southwest Gas Corporation (Southwest or the Company) as Manager in the Treasury Services department.

Q. 3 Please summarize your educational background and business experience.

A. 3 I graduated from the University of Nevada, Reno (UNR) in 1985 with a Bachelor of Science degree with a major in agricultural economics. In 1989, I earned a Masters of Science degree from UNR in agricultural economics with a minor in finance. I have attained the professional designations of Chartered Financial Analyst (CFA), Certified Rate of Return Analyst (CRRA), Certified Management Accountant (CMA), Certified in Financial Management (CFM), and Certified Treasury Professional (CTP). I am a member of the Institute of Management Accountants, the CFA Institute, Association for Financial

Professionals, Financial Management Association, and the Society of Regulatory and Utility Financial Analysts. In addition, I currently serve on the Board of Regents of the Institute of Certified Management Accountants, which governs the CMA and CFM certification programs.

From 1985 to 1988, I was employed as a research associate in the Department of Agricultural Economics at the University of Nevada in Reno, Nevada. My primary role was to assist with ongoing research projects in the Department including secondary data collection, statistical analysis, FORTRAN programming, and the development of microcomputer spreadsheets for farm management decision analysis.

In 1989, I was employed by First Interstate Bank of Nevada in Reno, Nevada, as a financial analyst in the Finance Department. My duties entailed maintenance of the general ledger system, creation of monthly management and financial reports, and special projects.

From 1990 to 1992, I was employed as a planning analyst with Valley Bank of Nevada, in Las Vegas, Nevada, in the Planning Department. My primary responsibilities included preparation of the annual budget, quarterly budget variance analysis, supporting the Asset/Liability Committee of the bank, and other financial analyses.

From 1992 to 1994, I was employed by PriMerit Bank, FSB, then a wholly-owned subsidiary of Southwest, as a Senior Financial Analyst in the Budget and Forecasting

Department. My primary responsibilities included creation and maintenance of a microcomputer-based budgeting system, preparation of the annual budget, monthly budget variance analysis, product profitability analysis, and other special projects.

In 1994, I accepted a Senior Financial Analyst position in the Treasury Services department of Southwest. My responsibilities included daily cash management, preparation of financial forecasts and analyses, and assisting in the preparation of rate of return testimony for the Company's various ratemaking jurisdictions. I was promoted to Supervisor of the Treasury Services department in May 1997 and to Manager in June 2000. I supervise two other financial analysts in the Treasury Services department.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 Yes. I have previously testified before the California Public Utilities Commission (CPUC) and the Public Utilities Commission of Nevada (PUCN).

Q. 5 What is the purpose of your prepared direct testimony in this proceeding?

A. 5 The purpose of my prepared direct testimony is to support the Company's overall requested rate of return in this proceeding. Specifically, my prepared direct testimony details the requested capital structure, and the embedded cost of long-term debt and preferred equity used for determining the appropriate cost of capital for the Company's Arizona rate jurisdiction. It is comprised of four sections: (I) the development and use of an appropriate capital structure for ratemaking, (II) the development of the embedded cost of long-term debt, (III) the development of the embedded cost of preferred equity, and (IV) a review of the Company's 2003 preferred refinancing. Southwest witness Frank J. Hanley will discuss the development of the cost of common equity.

Q. 6 Are you sponsoring any schedules and exhibits in support of your prepared direct testimony?

A. 6 Yes. I am sponsoring the schedules under Tab D and the financial supporting Exhibit No.___(TKW-1) through Exhibit No.___(TKW-9), which are attached to my testimony. These schedules were prepared by me or under my supervision.

Q. 7 Have you determined a reasonable rate of return necessary for Southwest to earn a fair return on its Arizona distribution properties?

A. 7 Yes. An overall rate of return of 9.40 percent for the Arizona jurisdiction is reasonable in this proceeding. This rate of return is calculated as follows:

Southwest Gas Corporation
Arizona Rate Jurisdiction

Component	Ratio	Cost	Weighted Cost
Long-Term Debt	53.00%	7.49%	3.97%
Preferred Equity	5.00%	8.20%	0.41%
Common Equity	42.00%	11.95%	5.02%
Total	100.00%		9.40%

Q. 8 Is the Company including in this case any proposal which, if approved by the Commission, would result in a modification of your determination of a reasonable rate of return?

A. 8 Yes. The Company is proposing a Conservation Margin Tracker (CMT) provision, which is detailed in the prepared direct testimony of Southwest witness Edward B. Gieseking. This provision will afford the Company greater earnings stability. Southwest witness Steven M. Fetter discusses the concept of the Company's proposed CMT from both a regulatory policy and credit rating agency perspective in his prepared direct testimony. Mr. Hanley, in his prepared direct testimony, addresses the impact of the proposed CMT provision on his recommended return on common equity. Based on the reduction in risk, his recommended return on common equity would be reduced from 11.95 percent to 11.70 percent if the CMT is approved by the Arizona Corporation Commission (Commission). Correspondingly, the resulting overall rate of return would be adjusted to 9.29 percent, given the acceptance of the CMT provision.

Q. 9 Why is this rate of return appropriate and necessary for Southwest?

A. 9 This rate of return is necessary in order to maintain the Company's financial integrity, to allow the Company to attract new capital and to permit Southwest's equity holders the opportunity to earn a fair and reasonable rate of return.

Moreover, this rate of return will meet the standard of reasonableness set forth by the United States Supreme Court in *Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) *(Bluefield)*. The court ruled in that case that:

> The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.

Furthermore, this rate of return will meet the comparability standard set by the court in the *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591 (1944) *(Hope)*. In that case, the court ruled:

> . . . the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.

An explanation regarding the practical application of these two court rulings to a diversified utility such as Southwest is appropriate at this time. The Company has, since the late 1950s, filed rate cases as a "diversified" utility. The multi-jurisdictional rate case filings have been based on the fact that Southwest, as a natural gas utility, serves three states with several different ratemaking areas. The Company requests only gas distribution utility required rates of return in all filings within each jurisdiction. The debt and preferred equity costs requested in this filing are utility-only costs. Southwest's practices provide assurance that the costs of utility operations attributable to each of Southwest's jurisdictions are properly insulated from the impact of non-utility activities.

The appropriate regulatory capital structure requested by Southwest in this proceeding is supported by the following: (1) credit rating agency criteria; (2) the Company's actual capital structure and relative risk as compared with the capital structures and relative risk of two proxy groups of local distribution companies (LDCs) used in Mr. Hanley's testimony; (3) consideration of Southwest's operating environment; (4) regulatory precedent; (5) modern finance theory; and (6) the fairness and reasonableness of this approach. Each of these key factors is discussed in detail in my testimony to justify the development of the hypothetical capital structure.

My recommended hypothetical capital structure, together with Mr. Hanley's recommended cost of equity, are essential to provide the Company with a realistic opportunity to earn a fair and reasonable overall rate of return.

In summary, Southwest's requested rate of return in this proceeding is fair to both customers and shareholders, and it properly reflects the risks and returns appropriate for its gas distribution properties in the Company's Arizona rate jurisdiction.

I. RECOMMENDED CAPITAL STRUCTURE

Q. 10 Please discuss the recommended capital structure used to develop the overall allowed rate of return in this proceeding.

A. 10 The recommended capital structure used to determine the rate of return in this proceeding consists of 53 percent long-term debt, 5 percent preferred equity, and 42 percent common equity.

Q. 11 Is this the actual capital structure of Southwest?

A. 11 No, it is not. Southwest is a diversified company consisting of multi-jurisdictional natural gas distribution operations in three states, a natural gas pipeline, and a wholly-owned construction subsidiary. The consolidated balance sheet of the Company is a function of the operating environment and past financial performance in each of the Company's regulatory jurisdictions and of its non-regulated subsidiary. The use of a hypothetical capital structure allows for the proper setting of rates solely for the natural gas distribution assets of the company.

Q. 12 Please summarize the Company's actual capital structure as of August 31, 2004.

A. 12 The Company's actual capital structure at August 31, 2004, the test period average capital structure, and the recommended capital structure are as follows:

. . . . .

	Actual 8/31/04	Test Period Average	Recommended
Long-Term Debt	60.8%	60.2%	53.0%
Preferred Equity	5.1%	5.3%	5.0%
Common Equity	34.1%	34.5%	42.0%
Total	100.0%	100.0%	100.0%

The first column of capital structure ratios shows the Company's actual capital structure ratios at the end of the test period, and the second column displays the test period average capital structure ratios for the period ending August 31, 2004. It is important to point out that the percentage of equity in the capital structure at the end of August is typically near the low point for the year. This is due to the seasonal nature of the Company's business, in which most of the income is earned during the winter heating season (November-April). Exhibit No.___(TKW-1) displays the capital structure by month and the average for the test period (September 1, 2003 - August 31, 2004). The test year average capital structure had a common equity ratio of 34.5 percent.

Q. 13 Why is the use of a hypothetical capital structure essential in this proceeding?

A. 13 My recommended hypothetical capital structure, together with Mr. Hanley's recommended cost of equity, are essential to provide the Company with the opportunity to earn a fair and reasonable overall rate of return. This is important for three principal reasons. The Company must compete for new capital to fund the continuing significant customer growth. In addition, current investors must have the opportunity to earn a fair and reasonable rate of return in order for them to maintain their current investment in the Company relative to choosing comparable, equally risky, alternative investments. The Company must also have the opportunity to earn a fair and reasonable rate of return in order to maintain and, over time, improve its credit ratings, which, in the long-run, is of interest to all stakeholders.

(1) Credit Rating Agency Criteria

Q. 14 What are the Company's current long-term unsecured credit ratings?

A. 14 Currently, Southwest's long-term unsecured credit ratings are "BBB" from Fitch, Inc. (Fitch), "Baa2" from Moody's Investor Services (Moody's) and "BBB-" from Standard & Poor's Rating Services (S&P). The Fitch and Moody's ratings are just one level above the threshold for an investment grade rating, while the S&P rating is at the lowest investment grade rating.

In addition, credit rating agencies provide a ratings outlook, which is an assessment of the direction of the credit rating over the intermediate to longer term. The current rating outlook provided by Fitch and S&P is "stable." Moody's, on February 27, 2004, changed its ratings outlook from "stable" to "negative."

Q. 15 What was the rationale for Moody's change in the ratings outlook for the Company?

A. 15 Moody's stated the rationale for the change in outlook was due to:

> The change in rating outlooks for SWX is prompted by the following factors: 1) SWX's recent announcement that it recorded lower earnings in fiscal 2003 compared with the prior year, 2) experienced warmer than normal temperatures in its service areas that affected profitability during the past two years, with fiscal 2003 being one of the warmest in over a hundred years, 3) the company continues to have greater financial leverage than its similarly rated LDC peers, resulting in suppressed coverage measures and 4) cash flow net of total capital expenditures has been negative for several years, as the company is challenged to service a rapidly growing customer base approximating 5% in annual growth which causes recurring regulatory lags."[1/]

In addition, Moody's stated what could be cause for a ratings downgrade to be:

> Continuing high leverage, continuing earnings volatility on account of weather variations and eroding margins from declining customer consumption, continuing lags in recovery of capital investment costs."[2/]

Q. 16 What is the Company's target credit rating?

A. 16 It is management's long-run goal to achieve an "A" credit rating. The short-run goal, at a minimum, is to maintain an investment grade credit rating. The Company has

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1/ Moody's Investor Services Credit Opinion: Southwest Gas Corporation, February 27, 2004.

2/ Ibid

experienced strong customer growth for an extended period of time, which has made it difficult to rapidly improve the Company's capital structure due to the need to raise new capital to finance growth-related capital expenditures, as well as capital expenditures necessary to maintain and improve the existing infrastructure. This issue has been recognized by S&P in its assessment of the Company's credit quality as found in their research report titled "*Key to Success in the U.S. Gas Distribution Industry*" published September 25, 2003. It states:

> High growth within a service territory due to population influx and new construction could lead to greater profitability or rate stability for LDCs. However, as evidenced by Southwest Gas' struggles, high growth 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.

Q. 17 Why is it important for Southwest to maintain its investment grade bond rating?

A. 17 It is essential that Southwest's bond rating remain investment grade. An investment grade credit rating is required for the Company to ensure that it can reliably and efficiently raise capital to finance capital expenditures, accommodate its seasonal working capital requirements, facilitate its gas procurement function, and meet its obligations to serve customers.

In the Company's 2003 Annual Report it stated that it anticipated capital expenditures during the three-year period ending December 31, 2006 would be approximately $690 million. Falling below an investment grade credit rating would jeopardize the Company's ability to raise the required capital for this level of capital expenditures and will considerably increase the cost of funds.

Since the winter of 2000-2001, the price and volatility of natural gas has increased significantly. This has added additional complexity for the Company in managing its liquidity position and has required the Company to finance significantly higher purchased gas cost adjustment (PGA) balances, which are typically recovered over a 12- to 24-month period. The loss of an investment grade rating would increase the gas procurement cost as gas suppliers would likely require the Company to post collateral to purchase gas. This would require the Company to acquire additional credit capacity at a time when credit would be limited and at a significantly higher cost, as a result of being non-investment grade.

Clearly, it is in the best interest of customers and investors for the Company to remain investment grade as failing to do so would significantly increase its cost of capital and its gas procurement costs, all of which would translate into higher rates for customers and higher risks for investors.

Q. 18 How does the recommended hypothetical capital structure compare to S&P's financial guidelines?

A. 18 In comparison to S&P's Utility Group Financial Targets, [see Exhibit No.___(TKW-2)], a "BBB" utility with a business profile of "3" such as Southwest's profile, has a target range of total debt to capital ratio of 55.0 to 65.0 percent. Conversely, the range of target total equity to total capital ratio (1 minus the total debt to capital ratio) is 45.0 to 35.0 percent. S&P classifies capital securities into either debt or equity. Securities, such as the Company's preferred securities, in whole or in part, are classified as debt or equity. Currently, S&P assigns a 40 percent "equity credit" to the Company's preferred securities. Based on this treatment, the Company's recommended hypothetical capital structure of 42 percent common and 5 percent preferred equity, translates into a 44 percent total equity to total debt ratio. This equity ratio is in the range of S&P's target equity ratios for a "BBB" utility.

Based on S&P's guideline capital ratios, the Company's recommended hypothetical capital structure is representative of a "BBB" utility. The use of this hypothetical capital structure will support the Company's ability to maintain its existing investment grade rating and provide it with a reasonable opportunity over time to improve its credit rating.

Q. 19 Will the use of the hypothetical capital structure for ratemaking be an important factor considered by rating agencies?

A. 19 Yes. S&P has stated that they analyze rate case decisions as the key indicator of the level of regulatory support for the creditworthiness of utilities. As stated in a recent article by Todd Shipman of S&P:

> Once a decision is reached, Standard & Poor's analyzes its effect on the financial forecast for the company, and also to assess whether the actions and precedents being set by the commission in its decision will have a long-term effect on Standard & Poors's opinion of the regulatory environment in that jurisdiction. The analysis of the rate case fundamentally explores a two-fold question: are the new rates based on a rate of return consistent with the company's ratings, and is the utility being afforded a legitimate opportunity to actually earn that rate of return?
>
> On the former question, the analyst looks to equity returns being authorized for other utilities of the same credit quality, as well as the capital structure employed to arrive at the overall rate of return being used to set rates."[3/]

(2) Relative Risk Comparison to Other LDCs

Q. 20 How does the recommended hypothetical capital structure compare to a representative group of Southwest's peers?

A. 20 The five-year average permanent capital structures of the two proxy groups used by Mr. Hanley in his testimony to estimate the cost of common equity are as follows:

. . . . .

3/ Todd A. Shipman, "*Energy Risk - Fresh Look at US Utility Regulation*," PowerMarkers.com, February 2, 2004. See Exhibit No.___(TKW-3), Sheet 1 to Sheet 3.

Type of Capital	SWG Hypothetical	Proxy Group of Five LDCs [1/]	Proxy Group of Eleven LDCs [2/]
	Permanent Capital Structure Ratios		
Long-Term Debt	53.00%	48.59%	48.63%
Preferred Stock	5.00%	0.68%	1.04%
Common Equity	42.00%	50.73%	50.33
Total	100.00%	100.00%	100.00%

1/ Five-year (1999-2003) average permanent capital structure of a proxy group of five local gas distribution companies included in Mr. Hanley's testimony. See Mr. Hanley's Exhibit No.___ (FJH-4), Sheet 1 of 4.

2/ Five-year (1999-2003) average permanent capital structure of a proxy group of eleven local gas distribution companies included in Mr. Hanley's testimony. See Mr. Hanley's Exhibit No.___ (FJH-5), Sheet 1 of 5.

Southwest's actual capital structure [shown in Exhibit No.___(TKW-1)] contains far more leverage when compared to the average capital structures of the proxy groups of local gas distribution companies included in this table. Furthermore, the Company's robust growth exceeds that of any of the companies in the proxy groups. This exposes the Company to incomparable downward pressure on its capital structure due to the magnitude of growth-related capital expenditures. As such, the 42 percent common equity ratio is not so high that it is a burden to customers, nor is it so low that the debt and equity holders are exposed to severe and unreasonable risk.

Q. 21 Are there other factors, other than capital structure comparisons, that indicate the Company's financial performance and position relative to its peers?

A. 21 Yes. The comparative average credit ratings, funds from operations interest coverage, and S&P's business profile scores (a higher score indicates more risk) for the proxy groups and the Company are shown below:

Description	SWG Actual	Proxy Group of Five LDCs 1/	Proxy Group of Eleven LDCs 2/
Credit Ratings [1]:			
S&P	BBB-	A	A
Moody's	Baa2	A2	
Interest Coverage[2]	3.20	4.68	4.60
S&P Bus. Profile[1]	3.0	1.8	2.0

[1] See F. Hanley's Exhibit__(FJH-11), Sheet 2 of 9.

[2] Five-year (1999-2003) average funds from operations interest coverage ratio. See F. Hanley's Exhibit__(FJH-3), Sheet 1 of 2, Exhibit__(FJH-4), Sheet 1 of 4, and Exhibit__(FJH-5), Sheet 1 of 5.

As noted in the table, the Company's position is considerably weaker in comparison to the proxy groups. In addition, as shown on Exhibit No.___(FJH-1), Sheet 5 of 5, the proxy group statistics for return on common equity indicate that, during the time period 1998-2003, the Company's realized returns on common equity in the Arizona jurisdiction were far below the composite returns of its peers. The differences can be largely attributed to Southwest having a volumetric rate design, declining average customer usage, and the gradual financial attrition associated with inflation and other costs relating to maintaining and upgrading the Company's distribution system.

(3) Southwest's Operating Environment

Q. 22 Please discuss the Company's operating environment.

A. 22 Consideration of the Company's operating environment should be given for the use of a hypothetical capital structure. Southwest has been and continues to be one of the fastest growing local gas distribution companies in the nation, which has required significant amounts of capital expenditures. This, combined with declining average customer usage[4/], several warmer-than-normal heating seasons and the impact from regulatory lag, has resulted in sub-standard financial results, all of which have impeded the Company's tangible efforts to improve its financial condition.

To put into perspective the rapid level of growth experienced by the Company during the period 1994 to August 31, 2004, on a total Company basis, the Company has spent approximately $2.13 billion dollars in capital expenditures and has added about 623,000 new customers. For the Company's Arizona jurisdiction, the Company has spent approximately $1.02 billion dollars in capital expenditures and has added about 295,000 new customers. During the same time period, the average realized rate of return on equity has been 5.04 percent for the Arizona jurisdiction (see Company witness Robert A. Mashas's Exhibit No.___(RAM-1), Sheet 2).[5/]

4/ Please see the direct testimony of Company witness James Cattanach, who discusses the phenomenon of declining average residential customer usage.

5/ Please see the direct testimony of Company witness Robert Mashas, who addresses the impact of unrealized margin, regulatory lag, and the proposed CMT on the Company's historical financial performance.

Q. 23 How has regulatory lag impacted the Company's financial condition?

A. 23 The Company has had to file periodically for rate relief as a result of not being able to realize its authorized rate of return. This has resulted in the Company experiencing regulatory lag. The amount of time between the time a revenue deficiency is experienced and new rates are established is defined as regulatory lag. In the Company's Arizona jurisdiction, the Company has filed for and received rate relief five times in the ten-year period of 1992 through 2001. Company witness Mr. Mashas, in his prepared direct testimony, has calculated that during this time period, the average time period between the end of the test period and the effective date of new rates in Arizona to be 17 months. The cumulative after-tax impact of regulatory lag on earnings to the Company was estimated to be $60.6 million. As such, the impact of regulatory lag experienced by the Company has been significant.

The Company recognizes that it is not the fault of the Commission nor its staff that rates are established based on historical ratemaking methodologies. However, the Company simply reminds the Commission of the impact regulatory lag has had and continues to have on the Company and its ability to improve its financial condition.

Q. 24 What evidence exists to demonstrate the Company's commitment to improve its capital structure?

A. 24 The Company has made tangible efforts to improve its capital structure during this time, as the Company has increased its outstanding shares of common stock by approximately 69 percent[6/] and has not raised the common stock dividend per share since May of 1994. In addition, the Company has issued trust originated preferred securities to help bolster its capital structure.

In May 2004, the Company established a three-year, $60 million Common Equity Shelf Program (ESP). An ESP is a service offered by institutional bankers that provides for the issuance of relatively small amounts of new common equity continuously and discreetly as part of the regular daily trading flows. All aspects of the ESP are under the Company's control including the number of shares, trading period, and minimum sales price. The sales of common stock are made in "at the market" offerings in sales made directly on the New York Stock Exchange or sales made to or through a market maker or an electronic communication network. In addition, shares of common stock may be offered and sold by such other methods, including privately placed negotiated transactions.

The Company began issuing shares via the ESP in June 2004. As of August 31, 2004, the Company had issued

6/ See Exhibit No.___(TKW-4), which displays Southwest's common stock issuances for the period 1994-August 31, 2004.

approximately $13 million of common equity through this program. The ESP will augment the average $15-20 million of common equity issued annually under the Company's existing Dividend Reinvestment Plan, Customer Stock Purchase Plan, and Employee Investment Plan.

The Company has been, and continues to remain, committed to improve its capital structure. However, there is a limit to how much common equity the Company can issue. Operating in a high-growth environment, the Company needs a realistic opportunity to increase its common equity from internally generated retained earnings.

Q. 25 Given the rapid growth environment, what are the key factors that will enable the Company to continue to attract the capital necessary to meet growth-related capital expenditure requirements?

A. 25 Generally, investors will choose between alternative investments based on the risk and reward characteristics of the available investment opportunities. Consequently, the Company must compete with other utilities and alternative investment opportunities to attract equity capital.

For Southwest to successfully attract equity capital, it must demonstrate an ability to achieve a competitive return on that equity capital. As a regulated natural gas utility, the Company's overall authorized return on equity for its shareholders is ultimately determined by the authorized rate base in each jurisdiction multiplied by the applicable authorized equity ratio in the capital structure and the applicable authorized cost of equity.

Mr. Hanley has provided testimony in this proceeding regarding a fair and reasonable cost of common equity, considering the Company's specific risk factors and costs of common equity for proxy groups of "similar" natural gas utilities. His recommended return on common equity also factors in the requested hypothetical capital structure with a common equity ratio of 42 percent. The cost of common equity and the common equity weighting in the capital structure must be viewed together in determining a fair and reasonable return that is likely to attract the equity capital that the Company will require on a going forward basis.

Accordingly, if investors are to have the opportunity to earn a fair and reasonable rate of return, as the standards in the _Bluefield_ and _Hope_ cases support, any adjustment downward from the requested 42 percent common equity ratio would require a corresponding increase in the cost of common equity, and vice versa. For these reasons, the requested hypothetical capital structure, with a 42 percent common equity ratio, and Mr. Hanley's recommended cost of common equity of 11.95 percent, are interdependent and critical to the Company in this proceeding.

. . . . .

(4) **Regulatory Precedent**

Q. 26 Has the Commission accepted the use of a hypothetical capital structure for ratemaking in the Company's Arizona jurisdiction?

A. 26 Yes. In the Company's last Arizona general rate case, Docket No. G-01551A-00-0309, the Commission adopted a hypothetical capital structure for ratemaking. In the decision (Decision No. 64172), the Commission stated:

> Staff and RUCO recommend a hypothetical capital structure consisting of 40 percent equity, 55 percent debt and 5 percent preferred stock. The Commission has utilized this same hypothetical capital structure in the last two rate cases. These parties believe that although the Company's capital structure has improved over the years, the Company remains so highly leveraged that it is not reasonable to set rates based on its actual capital structure. 7/

Additionally, the Commission stated its rationale for employing the hypothetical capital structure as follows:

> We believe that the hypothetical capital structure recommended by RUCO and Staff is appropriate. Employing a hypothetical capital structure containing 40 percent equity balances the need to protect the Company's financial integrity, with the desire to allow ratepayers to benefit from the relative lower cost of debt versus equity. 8/

Q. 27 Have the Company's other regulatory bodies accepted the use of a hypothetical capital structure?

7/ ACC Decision No. 64172, p. 17.
8/ ACC Decision No. 64172, p. 18.

A. 27 Yes. Both the CPUC and the PUCN have accepted the use of a hypothetical capital structure for ratemaking purposes.

In the Company's most recent California general rate case, Decision No. 04-03-034 pursuant to Application No. 02-02-12, Southwest was authorized a hypothetical capital structure for ratemaking purposes that contains 42 percent common equity, 5 percent preferred equity and 53 percent long-term debt, exactly the same as the Company is requesting in this proceeding. The decision states:

> In D.02-11-027 we adopted hypothetical capital structures very different from the existing capital structures for PG&E, Edison, SDG&E and Sierra, and we stated that the capital structure is designed to attract capital, improve credit ratings to investment grade, and maintain an investment grade setting.[9] We believe these same purposes apply to Southwest's capital structure. Therefore, we will adopt a hypothetical capital structure for Southwest to reflect its current financial, business, and regulatory risks.[10]

In the Company's last Nevada general rate case, Decision for Docket No. 02-02-12, Southwest was authorized a hypothetical capital structure for ratemaking purposes that contains 40 percent common equity, 6.6 percent preferred equity and 53.4 percent debt. The PUCN explained its rationale for utilizing a hypothetical capital structure:

9/ D.02-11-027, p. 11.

10/ CPUC Decision No. 04-03-034, p. 59-60.

> The strongest reason to use a hypothetical capital structure is to ensure that Southwest is not disadvantaged when compared to other investment opportunities . . . the Commission recognizes that Southwest's revenues have suffered due to increased efficiencies and decline in per customer usage, which will likely continue into the future. To compensate Southwest for this loss of revenues and to encourage Southwest to continue to support efficiency gains, the Commission finds that for the purpose of setting rates in this case, an equity ratio of 40 percent should be used.[11/]

(5) **Consistency with Modern Finance Theory**

Q. 28 Please briefly describe the modern financial theory concerning capital structure, the cost of equity, and the overall cost of capital.

A. 28 To gain an understanding of the relationship between capital structure, the cost of equity, and the overall cost of capital, it is best to start with the classic Modigliani-Miller (MM) proposition that the cost of capital of a firm is independent of its capital structure. This proposition is based on perfect market conditions where there are no taxes and no bankruptcy.

> For example, assume a firm is financed only by equity and has a 10 percent cost of equity, therefore it would have a cost of capital equal to 10 percent. If the firm elected to employ lower cost debt and changed its capital structure to be 40 percent debt and 60 percent equity, and the cost of debt was 7 percent, what happens to the cost of equity and the overall cost of capital? Under the MM proposition, the overall cost of capital would remain the same, at 10 percent, and the cost of equity would increase to 12 percent. Now if the

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11/ PUCN Decision for Docket No. 02-02-12, pages 9-10.

firm increased the ratio to 50 percent debt and 50 percent equity, assume the cost of debt increases to 7.25 percent due to the increased amount of leverage, the cost of equity would increase to 12.75 percent and the overall cost of capital would remain at 10 percent. The calculations of the weighted cost of capital for these examples are shown as follows.

Component	Weight	Rate	Weighted Rate
Equity	100.00%	10.00%	10.00%
Debt	0.00	0.00	0.00
Total	100.00%		10.00%

Component	Weight	Rate	Weighted Rate
Equity	60.00%	12.00%	7.20%
Debt	40.00	7.00	2.80
Total	100.00%		10.00%

Component	Weight	Rate	Weighted Rate
Equity	50.00%	12.75%	6.38%
Debt	50.00	7.25	3.62
Total	100.00%		10.00%

What can be seen from these examples is that capital structure does affect the cost of debt and equity, however the changes in those costs are exactly offset by changes in the weights of each capital structure component. The costs of both debt and equity increase with greater amounts of debt because both debt holders and shareholders are exposed to greater risk. The key insight provided by the MM theory is that the cost of capital is a function of the risk of the firm's assets and the "law of one price" should hold, as the cost of capital is based on the level of risk of the assets and not how the firm is financed.

The modern theory of capital structure, which includes taxes and bankruptcy, says the cost of capital is not constant, but becomes a U-shaped curve. Under what is known as the "static trade-off theory," the cost of capital begins to decline as debt is first used in the capital structure due to the tax-deductibility of interest and reaches a minimum value at the point the increased risk and costs of financial distress begin to increase the overall cost of capital. With the static trade-off theory there exists an optimal capital structure which results in the minimum cost of capital and the maximum firm value. The important point of both theories is that there is a dynamic relationship between capital structure, the costs of the individual types of capital, and the resulting overall cost of capital. It is universally accepted that the cost of equity increases as the amount of leverage is increased in the balance sheet.

Q. 29 Can you explain why it is not valid, based on modern finance theory, to employ the Company's actual capital structure with the estimated required return on common equity based on Mr. Hanley's proxy group companies?

A. 29 Given the relationship between capital structure and the cost of equity previously discussed, the difference in the Company's actual capital structure relative to the proxy group average results in a significantly higher level of financial risk for the Company. Absent any adjustment for the difference in financial risk, applying the estimated required return on equity derived from the proxy group to the Company's actual capital structure is inappropriate, as the required return on common equity is positively related to the debt-to-equity ratio of the firm.

A prominent finance scholar, Stewart Myers, who has published a number of studies on capital structure theory, states the following:

> The cost of equity does depend on capital structure. Comparisons of cost of equity estimates or allowed or actual returns make sense only if differences in financial leverage are accounted for. When a given utility's debt ratio increases, the cost of equity also increases and the allowed return must be adjusted upwards. This adjustment is required to preserve a fair return to equity investors. [12/]

Similarly, Bradford Cornell states:

> ... the cost of equity capital depends on the investment risk of the equity, which depends, in turn, on the company's capital structure. More highly levered companies will have riskier equity and higher cost of equity capital. If the dividend discount model is to be applied to a "comparable" company, the appraiser must verify that the comparable company has a similar capital structure. If it does not, the cost of capital estimated for the comparable cannot be applied to the appraisal target without an adjustment to reflect the impact of leverage on risk." [13]

In addition, the standards cited in the *Bluefield* and *Hope* cases support this test of comparability in the level of risk and rate of return.

12/ Stewart C. Myers, "*Capital Structure and the Cost of Capital for Regulated Companies,*" prepared for The New York Energy Collaborative, December 4, 1992.

13/ Bradford Cornell, Corporate Valuation, 1993, McGraw Hill, NY, p.199.

Q. 30 For utility ratemaking, what kinds of risk-adjustments can be made to account for the differences in Southwest's financial and business risk as compared to Mr. Hanley's proxy groups of LDCs?

A. 30 For ratemaking purposes, to adjust for the differences in the financial and business risk of Southwest compared to that of the proxy groups of LDCs, there are three possible adjustments. They are:

1. Employ a risk-adjusted hypothetical capital structure;
2. Employ a risk-adjusted allowed rate of return on common equity; or
3. Employ a partial risk adjustment to both the capital structure and the allowed ROE.

The Company is recommending alternative number 3, to employ a partial risk-adjustment to both the capital structure and the allowed ROE. The Company's recommended capital structure is near, but still below, the average capital structures of the proxy groups and is consistent with credit rating agency criteria for a "BBB" credit rating. Further, the Company believes this treatment is consistent with the *Bluefield* and *Hope* standards.

(6) Fair and Reasonable Approach

Q. 31 How does the overall rate of return based on the recommended hypothetical capital structure and Mr. Hanley's recommended cost of equity balance the interests of both customers and investors of the Company?

A. 31 The components of my recommended capital structure were developed in an attempt to balance the interests of both investors and customers. The Company's financial health is, over time, important in determining the rates it must charge its customers. Also, the Company's credit ratings are significantly influenced by the financial strength of the Company, and the Company's cost of debt and preferred equity capital are, in large part, determined by the Company's credit ratings. With higher credit ratings, the Company's cost of capital and the rates it charges its customers, all other things being equal, would be lower.

With my recommended capital structure and Mr. Hanley's recommended cost of equity, the Company will have a fair and reasonable opportunity to earn an overall rate of return that will help strengthen Southwest's financial condition and, over time, improve the Company's credit ratings and reduce the overall cost of capital. All to the ultimate benefit of customers through lower rates.

It is also important that investors be given the opportunity to earn a rate of return that is commensurate with the level of risk associated with their investment. Investor confidence in Southwest is important for both its existing shareholders and for the Company's ability to issue new common equity in the future. If the overall allowed rate of return is set below the Company's actual cost of capital, then in the short-run, the Company's customers will pay lower prices for natural gas service to the detriment of the Company's current investors.

However, in the long-run, without an adequate level of return, the Company may not be able to attract sufficient financing at reasonable rates to continue to fund the required capital expenditures and maintain its quality of customer service.

The Company cannot solely rely on issuing new equity to improve its capital structure, but must also increase common equity through retained earnings. My recommended capital structure, together with Mr. Hanley's recommended cost of common equity, will augment the Company's tangible efforts to improve its financial condition. In the long-run, this will benefit both the Company's customers and investors.

Q. 32 Please summarize the Company's justification for the recommended hypothetical capital structure.

A. 32 The Company's justification for a hypothetical capital structure is as follows:

- Southwest is a multi-jurisdictional utility company consisting of gas distribution utility operations in three states, and a wholly-owned construction company subsidiary;
- The hypothetical capital structure is consistent with rating agency criteria for a "BBB" credit rating;
- The relative higher investment risk of Southwest as compared to the proxy groups of LDCs;
- Consideration should be given to the Company's operating environment which includes high growth,

the impact of declining average usage, several years of warmer-than-normal heating seasons, and regulatory lag and their impact on the Company's financial condition;

- Regulatory precedent for the Company's use of a hypothetical capital structure for ratemaking;
- The use of a hypothetical capital structure for ratemaking is consistent with modern finance theory; and
- The use of the recommended hypothetical capital structure is fair and reasonable to both customers and investors.

In addition, the Company will be required to access the capital markets in order to fund continued growth and infrastructure investment. To attract capital and maintain current investment, Southwest must, at a minimum, maintain its credit ratings and continue to strive to improve them to provide current and potential investors with compelling reasons to invest in the Company versus some other investment alternative. The most important reason for an investor to invest in Southwest is his or her belief that the Company will provide an opportunity to earn a competitive risk-adjusted rate of return on that investment.

The Company's recommendation for a capital structure comprised of 42 percent common equity, 5 percent preferred equity and 53 percent long-term debt, with a cost of equity of 11.95 percent (11.70 percent with the proposed CMT), is appropriate considering all of the above-mentioned factors. The Company believes the resulting overall rate of return is equitable to both shareholders and customers and will help maintain the Company's financial integrity. Maintaining an investment grade credit rating is beneficial for all stakeholders.

II. EMBEDDED COST OF LONG-TERM DEBT

Q. 33 Have you determined the appropriate cost rate for long-term debt capital?

A. 33 Yes. Southwest's appropriate rate for long-term debt in this proceeding is 7.49 percent. This rate is summarized on line 1, column (c), of Schedule D-1, Sheet 1 of 2. Schedule D-2, Sheets 1 through 4, contains the development of the long-term debt cost rate. The cost of long-term debt is comprised of the cost of fixed-rate debentures, fixed-rate medium-term notes, and a variable-rate term facility.

Q. 34 Please describe the development of the cost rates of debentures and notes.

A. 34 The Company had four outstanding debenture and note issues totaling $550 million of gross principal, at the end of the test year (August 31, 2004). The debentures and notes had a weighted average cost of 8.39 percent, as shown on line 5, column (e), of Schedule D-2, Sheet 2 of 4.

Q. 35 Please describe the cost rate of the medium-term notes.

A. 35 The Company established a $150 million medium-term note program in November 1997. The name is somewhat of a misnomer as medium-term notes can be issued with maturities of nine months to 30-years. The Company issued all of its medium-term note program and had seven outstanding medium-term note issues totaling $150 million of gross principal at August 31, 2004. The medium-term notes had a weighted average cost of 7.50 percent, as shown on line 13, column (e), of Schedule D-2, Sheet 2 of 4.

Q. 36 How are the effective cost rates of debentures, notes, and medium-term notes calculated?

A. 36 The effective cost rates of debentures, notes, and medium-term notes are calculated through the use of the yield to maturity (YTM) or effective interest rate method.

Q. 37 Please describe the YTM method.

A. 37 The YTM method is based on an internal rate of return calculation which takes into account the actual cash flows of each debt security. Specifically, the Company receives a cash inflow at the debt's issuance consisting of the face value less any associated issuance expenses and debt discount. The Company's cash outflows consist of interest payments and principal repayments. The effective rate is the percentage rate that discounts those cash outflows to the net cash inflow the Company receives at issuance. Once the effective rate is calculated, it is then multiplied by the net proceeds (i.e., the principal amount outstanding less any unamortized discounts) to determine the total expense per payment period for each issue. The weighted average cost is then determined by weighting the effective cost of each issue by the current net proceeds amount.

When used for ratemaking, the YTM cost rate results in a cost of an issue which remains constant over its life. The calculations for the effective cost of debentures, notes, and medium-term notes are shown in Exhibit No.___(TKW-5), Sheet 1 through Sheet 13.

Q. 38 Please describe and discuss the development of the cost rate for the variable-rate term facility debt.

A. 38 The Company has a three-year (May 2004 - May 2007) $250 million revolving credit facility. In addition, the Company has a $50 million uncommitted F-2 commercial paper program, which is supported by the revolving credit facility. The Company continues to view $100 million of the facilities as a permanent intermediate-term component of its debt portfolio and, accordingly, the Company has classified it as long-term debt. The remaining $150 million of the facility continues to be used to fund recurring, seasonal working capital needs.

At the end of the test period, the Company had outstanding $100 million as part of the long-term debt portion of the facilities. Of this amount, $50 million was outstanding as LIBOR (London Interbank Offered Rate) loans and $50 million was outstanding as commercial paper. The all-in effective rate of the long-term debt portion of the facility at the end of the test year was

2.59 percent, as shown on line 1, column (c) of Schedule D-2, Sheet 3 of 4. This all-in rate includes the interest on the loans, an annual fee, and unused commitment fees for amounts outstanding as commercial paper and amortization of debt expenses incurred to establish the facilities. Exhibit No.___(TKW-6), Sheet 1 to Sheet 4, displays the calculation of the effective cost of the LIBOR loans and commercial paper under the term facility.

Q. 39 Why are the Clark County and Big Bear Industrial Revenue Bonds (IDRBs) excluded in calculating the cost of long-term debt?

A. 39 Southwest has issued IDRBs in two of its rate jurisdictions. The IDRB issues and applicable rate jurisdictions are as follows: (1) the Clark County, Nevada IDRBs (93 Series A, 99 Series A, B & C, 2003 Series A,B,C,D & E, and 2004 Series A) for its Southern Nevada rate jurisdiction, and (2) the City of Big Bear, California IDRBs (93 Series A) for its Southern California rate jurisdiction. As reflected in the IDRB indentures and financing agreements, the proceeds from the issuance of this type of debt are restricted to funding qualified construction expenditures for additions and improvements in the specific distribution systems to which the IDRBs relate.

In addition, there are strict Internal Revenue Service (IRS) rules which stipulate that the benefits of the tax-exempt, lower cost IDRBs must accrue to customers in the specific jurisdiction to which the IDRBs apply. Deviation from the requirements of this IRS ruling could result in the loss of the IDRB tax-exempt status. This would in turn cause the Company to refinance its debt at a much higher cost.

Q. 40 How have Southwest's regulatory bodies treated the cost of IDRBs in past regulatory proceedings?

A. 40 Southwest has historically excluded the IDRBs from the cost of debt calculation in all regulatory jurisdictions, except for the specific jurisdictions (Southern Nevada for Clark County IDRBs and Southern California for City of Big Bear IDRBs), to which the relevant IDRBs apply. This Commission, the PUCN, the CPUC, and the Federal Energy Regulatory Commission have accepted this treatment for IDRBs in past regulatory proceedings.

III. <u>EMBEDDED COST OF PREFERRED EQUITY</u>

Q. 41 Please discuss the development of the cost of preferred equity.

A. 41 The Company's requested cost of preferred equity is 8.20 percent, as shown on line 2, column (c) of Schedule D-1, Sheet 1 of 2. In August 2003, the Company issued, through a public offering, $100 million in trust originated preferred securities (TOPrS), of which $60 million of the proceeds were used to refinance the Company's then existing 9.125 percent preferred securities, which had an effective all-in cost of 9.51 percent. The $100 million in securities have a $25 per share liquidation value and pay a dividend at an annual rate of 7.70 percent paid quarterly. The effective all-in cost of these securities is 8.20 percent and is determined using the YTM method previously described. Included in the effective cost are the issuance expenses and the economically incurred costs from refinancing the $60 million of preferred securities. The details of the Company's 2003 preferred refinancing are presented later in my testimony. Exhibit No.___(TKW-7) details the calculation of the effective cost for preferred equity.

Q. 42 What are the main benefits of issuing preferred securities in the form of TOPrS?

A. 42 Generally, the benefits are two-fold: the positive tax treatment of these securities and the favorable rating agency treatment. Dividends paid on traditional preferred stock by the issuer are not tax-deductible and would require the effective cost to be grossed-up for taxes in determining the revenue requirement. The TOPrS were issued by a wholly-owned business trust of the Company (Southwest Gas Capital II), the sole purpose of which was to issue such securities. By using the trust structure, the Company is able to deduct for tax purposes the payments made in connection with the securities. As a result, the tax-deductibility feature provides an overall lower revenue requirement for customers as compared to traditional preferred stocks.

Due to certain equity-like characteristics of the

TOPrS securities, S&P affords a certain level of "equity credit" in its evaluation of the credit quality of a company. These equity-like characteristics include a longer-maturity (typically 30 years), subordination of interest payments to the trust, and deferability of distributions to security holders for up to five years. Currently, S&P assigns a 40 percent "equity credit" for TOPrS.

Q. 43 Are the TOPrS securities convertible into common stock?

A. 43 No. The Company's TOPrS securities contain no conversion feature.

IV. **<u>2003 PREFERRED SECURITIES REFINANCING</u>**

Q. 44 Please discuss the preferred securities refinancing that the Company undertook during 2003.

A. 44 With the favorable low interest rate environment in 2003, the Company refinanced $60 million of callable TOPrS, which had a dividend rate of 9.125 percent and an effective all-in cost of 9.51 percent.

Q. 45 Please describe the Company's analysis to determine the economics of refinancing the preferred securities.

A. 45 The Company's economic analysis of the refinancing was based on a methodology that determined the net present value (NPV) savings of the incremental after-tax cash flows associated with refinancing the preferred securities. Incremental after-tax cash flows were comprised of interest savings, upfront after-tax refinancing costs, and the incremental benefit from the tax shield associated with debt expense amortization. The annual net incremental after-tax cash flows were then discounted using the after-tax dividend rate of the security used to refinance. The sum of these annual discounted after-tax cash flows represented the NPV from refinancing.

Since the calculated NPV from the refinancing was positive, the refinancing is determined to be economic. The NPV savings associated with the refinancing will be passed on to the Company's customers through the ratemaking process in the form of a lower embedded cost of preferred securities.

Q. 46 Please explain the Company's NPV computation.

A. 46 The NPV from refinancing was computed by discounting the difference between the after-tax cash flows from the new issues and the after-tax cash flows from the refunded issues. The following model was used to calculate the NPV savings for the refunded issues:

NPV Model

$$\text{NPV} = \sum_{t=1}^{\text{Maturity}} \frac{\text{Interest Savings} - \text{Upfront Refinancing Costs} + \text{Debt Expense Amortization Tax Shield}}{(1+(1-\text{tax rate}) \times \text{Discount Rate})^{t}}$$

where:

Interest Savings = (1-tax rate) x (dividend rate on old issue – dividend rate on new issue) x outstanding principal amount refunded.

Upfront Refinancing Costs = ((1-tax rate) x call premium) - (tax rate x unamortized debt issuance expense balance) + new issue expense

Debt Expense Amortization Tax Shield = (debt expense amortization new debt - debt expense amortization old debt) x (tax rate)

The after-tax interest savings/(cost) was calculated by multiplying the outstanding principal amount of the refunded issue by the difference between the dividend rate on the new issue and the dividend rate on the old issue, the product of which was multiplied by (1-tax rate). The upfront refinancing costs are the total of the after-tax call premium plus new issue costs, less the tax shield from expensing the unamortized balance of debt costs associated with the old issue.

Another benefit/(cost) from the refinancing, considered in the analysis, was the tax shield computed on the difference between the amortization of the new issuance expense and the amortization of the refinancing expense.

Q. 47 How was the discount rate used in the NPV analysis determined?

A. 47 The discount rate was the new dividend rate of 7.7 percent, which was adjusted to an after-tax basis. The use of the dividend rate as the discount rate is consistent with Commission Decision No. 57745, in which the Commission stated that it was appropriate to use the actual coupon rates of the new debt as the discount rate in the NPV calculation.

Q. 48 What is the NPV and revenue requirement savings calculated from refinancing the $60 million of TOPrS?

A. 48 The Company calculated the NPV savings of refinancing the $60 million of TOPrs to be approximately $5.8 million. The revenue requirement savings for the test period in this proceeding is $606,014. Exhibit No.___(TKW-8) presents the calculation of the NPV savings for the TOPrs and Exhibit No.___(TKW-9) displays the calculation of the revenue requirement savings.

Q. 49 Would you please summarize the customer benefits derived from the 2003 preferred refinancing?

A. 49 The benefits achieved from the Company's 2003 preferred refinancing are described below:

(1) The NPV savings for refinancing the $60 million of TOPrS was calculated to be approximately $5.8 million. The revenue requirement savings for the test period were calculated to be $606,014 for the Arizona jurisdiction; and

(2) The maturity of the new TOPRs was extended by approximately 18 years over the refinanced TOPrS and the refinancing issue contains a call option, providing flexibility to retire or refinance the issue in the future.

Q. 50 Does this conclude your prepared direct testimony?

A. 50 Yes, it does.

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Southwest Gas Corporation
Docket No. G-01551A-04-___

BEFORE THE ARIZONA CORPORATION COMMISSION

Table of Contents
to the Financial Supporting Exhibits
of
THEODORE K. WOOD

SOUTHWEST GAS CORPORATION
CAPITAL STRUCTURE
FOR THE TEST PERIOD ENDING AUGUST 31, 2004

	2003 September	2003 October	2003 November	2004 December	2004 January	2004 February	2004 March	2004 April	2004 May	2004 June	2004 July	2004 August	Average
Capitalization ($000's)													
Common Equity	$ 595,425	$ 593,734	$ 609,028	$ 630,467	$ 648,496	$ 664,797	$ 669,840	$ 671,168	$ 670,188	$ 667,131	$ 663,719	$ 662,979	$ 645,581
Preferred Securities	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000	100,000
Long-Term Debt	1,097,078	1,116,940	1,117,012	1,117,057	1,117,112	1,117,168	1,117,224	1,117,281	1,117,338	1,117,395	1,181,374	1,181,437	1,126,201
Total	$ 1,792,502	$ 1,810,674	$ 1,826,040	$ 1,847,524	$ 1,865,608	$ 1,881,965	$ 1,887,064	$ 1,888,449	$ 1,887,526	$ 1,884,526	$ 1,945,093	$ 1,944,415	$ 1,871,782
Capital Ratios													
Permanent Capital													
Common Equity	33.2%	32.8%	33.4%	34.1%	34.8%	35.3%	35.5%	35.5%	35.5%	35.4%	34.1%	34.1%	34.5%
Preferred Securities	5.6%	5.5%	5.5%	5.4%	5.4%	5.3%	5.3%	5.3%	5.3%	5.3%	5.1%	5.1%	5.3%
Long-Term Debt	61.2%	61.7%	61.2%	60.5%	59.8%	59.4%	59.2%	59.2%	59.2%	59.3%	60.8%	60.8%	60.2%
Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Standard & Poor's Utility Group Financial Targets

Funds From Operations Interest Coverage

Business Profile	"AA"		"A"		"BBB"		"BB"	
1	3.0	2.5	2.5	1.5	1.5	1.0		
2	4.0	3.0	3.0	2.0	2.0	1.0		
3	4.5	3.5	3.5	2.5	2.5	1.5	1.5	1.0
4	5.0	4.2	4.2	3.5	3.5	2.5	2.5	1.5
5	5.5	4.5	4.5	3.8	3.8	2.8	2.8	1.8
6	6.0	5.2	5.2	4.2	4.2	3.0	3.0	2.0
7	8.0	6.5	6.5	4.5	4.5	3.2	3.2	2.2
8	10.0	7.5	7.5	5.5	5.5	3.5	3.5	2.5
9			10.0	7.0	7.0	4.0	4.0	2.8
10			11.0	8.0	8.0	5.0	5.0	3.0

Funds from Operations to Total Debt

Business Profile	"AA"		"A"		"BBB"		"BB"	
1	20.0	15.0	15.0	10.0	10.0	5.0		
2	25.0	20.0	20.0	12.0	12.0	8.0		
3	30.0	25.0	25.0	15.0	15.0	10.0	10.0	5.0
4	35.0	28.0	28.0	20.0	20.0	12.0	12.0	8.0
5	40.0	30.0	30.0	22.0	22.0	15.0	15.0	10.0
6	45.0	35.0	35.0	28.0	28.0	18.0	18.0	12.0
7	55.0	45.0	45.0	30.0	30.0	20.0	20.0	15.0
8	70.0	55.0	55.0	40.0	40.0	25.0	25.0	15.0
9			65.0	45.0	45.0	30.0	30.0	20.0
10			75.0	55.0	55.0	40.0	40.0	25.0

Total Debt to Total Capital

Business Profile	"AA"		"A"		"BBB"		"BB"	
1	48.0	55.0	55.0	60.0	60.0	70.0		
2	45.0	52.0	51.0	58.0	58.0	68.0		
3	42.0	50.0	47.5	55.0	55.0	65.0	65.0	70.0
4	38.0	45.0	43.0	52.0	52.0	62.0	62.0	68.0
5	35.0	42.0	41.5	50.0	50.0	60.0	60.0	65.0
6	32.0	40.0	39.5	48.0	48.0	58.0	58.0	62.0
7	30.0	38.0	37.5	45.0	45.0	55.0	55.0	60.0
8	25.0	35.0	35.0	42.0	42.0	52.0	52.0	58.0
9			30.0	40.0	40.0	50.0	50.0	55.0
10			24.0	35.0	35.0	48.0	48.0	52.0

Business Profile - the business profile score assesses the qualitative attributes of a firm, with "1" being considered lowest risk and "10" highest risk.

Source: *Standard & Poor's Utilities Perspectives,* June 7, 2004

POWERMARKETERS.COM

Electric & Natural Gas Transmission Maps

The Power Marketing Association OnLine

The POWER REPORT ...continuously updated online

Energy Risk - Fresh Look at US Utility Regulation (RiskCenter.com - Feb. 2)

02 02, 2004 - PowerMarketers Industry Publications

Location: New York Author: Todd A Shipman, CFA Date: Monday, February 2, 2004

Standard & Poor's Ratings Services has been tracking the ups and downs of utility regulation for years, and in the past year or so has noted the recent upswing in the amount of attention that regulators and their activities are attracting.

With the renewed and increasing influence that regulators are asserting on the creditworthiness of utilities, especially as many managements scramble back under the protective umbrella of comprehensive regulation, Standard & Poor's offers this primer on how we analyze the effect of regulation on utility credit ratings. The entire range of regulatory actions and inactions is examined, but inevitably it is the analysis of rate case decisions that provides the key indicator of the level of support.

First, however, it is useful to remember the legal status of utility regulatory bodies when developing the basic analytical approach to their activities and decisions. Most utility commissions are, in a legal sense, "creatures of the legislature"; that is, the role they play is essentially legislative and not judicial. The responsibility for setting utility rates and for other various functions is actually that of legislators, but has been delegated to regulators for practical reasons. Thus, despite the trappings of a court (testimony, rules of evidence, administrative law "judges") and a long history of accumulated case law governing their activities, the decision-making process of utility commissioners more often resembles that of legislators, with its emphasis on compromise and political considerations, than that of jurists who weigh evidence, construe the law, follow legal precepts, and the like.

The implication for the analyst is that the behavior of regulators can more often be explained by looking to political factors than to analyzing legal precedents or assessing the arguments of opposing parties. That's why Standard & Poor's analysts spend considerable time meeting with regulators and staff members and accumulating knowledge about the local and regional political climate and its effect on a utility, in addition to analyzing the impact of a particular rate decision or other commission pronouncements. Nevertheless, rate cases, once thought to be obsolete as competition spread across the country, appear to be returning to the forefront again.

For major rate cases that can directly affect ratings, the analyst will follow the developments in a rate proceeding from the initial filing. The company's request for rate relief, the local public reaction to the filing, the rebuttals of important parties and intervenors, and the conduct of the hearings are all monitored, assessed, and commented upon, if necessary, as the case proceeds through its schedule. The ability of the commission to render a fair and balanced decision that appropriately considers the interests of all the participants in the process can sometimes be affected by incidents that occur while the case is developing. Standard & Poor's tracks whether the case is drawing a lot of attention, influential parties are staking out extreme positions, or outside events such as upcoming elections are affecting the chances of a rate decision that is consistent with the financial projections the ratings are based on.

Once a decision is reached, Standard & Poor's analyzes its effect on the financial forecast for the company, and also to assess whether the actions and precedents being set by the commission in its decision will have a long-term effect on Standard & Poor's opinion of the regulatory environment in that jurisdiction. The analysis of the rate case fundamentally explores a two-fold question: are the new rates based on a rate of return consistent with the company's ratings, and is the utility being afforded a legitimate opportunity to actually earn that rate of return?

On the former question, the analyst looks to equity returns being authorized for other utilities of the same credit quality, as well as the capital structure employed to arrive at the overall rate of return being used to set rates. On the latter, the test year and all of the adjustments made to the company's filed data are inspected to arrive at the final conclusion. Generally, decisions that feature the most up-to-date information in determining rates, including current test years and all "known-and-measurable" changes, are viewed as providing companies with the best chance to earn a reasonable and cash-rich return.

Importantly, credit analysis also incorporates the cash-flow effect of a decision, especially if it is the result of a full or partial settlement between the parties. A common method to achieve the compromise often sought by the parties or the regulators is to defer cost recovery into the future, which can preserve earnings but weaken cash flow. Standard & Poor's places much emphasis on cash flow protection measures when assessing credit quality, and a rate decision that ostensibly looks favorable for investors can sometimes come at the expense of bondholders. Attention to the details is crucial in analyzing a rate decision because some that appear to be favorable on the surface can hide the "bite" that regulators took in the less conspicuous parts of the case, such as a change in the depreciation rate.

Finally, one of the most important issues affecting ratings may or may not be part of the rate-case process, but is constantly tracked by Standard & Poor's: the recovery of fuel and purchased-power and gas costs. The analysis concentrates on stability of cash flows and the relative certainty of full recovery of these items, the largest expenses for almost all utilities, in arriving at a consensus on the level of a utility's business risk.

The stability that leads to improved credit quality can be supported by legislators and regulators either through rate design or by carving out fuel and commodity expenses and treating them separately from the normal rate case process. Rate design is established as part of a rate-case decision, and can be used to promote stability by allocating a greater percentage of fixed costs for recovery through the standard monthly charge. The more common method is a separate clause in the tariff that fluctuates automatically or near-automatically as commodity costs rise and fall. The presence of a fuel and purchased-power or gas clause that helps a utility manage its exposure to commodity price moves is positive for credit ratings. Not all are created equal, however, and each mechanism is studied to determine how closely it allows for matching of customer rates with expenses.

Many other factors outside the scope of this commentary can play an important part in the overall assessment of the regulatory environment in which a utility operates. Incentive ratemaking, special rate riders to recover extraordinary costs (e.g., environmental compliance), deregulation developments, the degree to which regulation insulates a utility from its parent, legislative initiatives, and other non-ratemaking considerations can all affect Standard & Poor's opinion of the quality of regulation. The ability of management to control its regulatory risk and the historical attitude of regulators toward the interests of utility bondholders also enter into the analysis. In the end, the regulation of public utilities is the defining element of the industry and is often the determining factor in the ratings of a utility.

SOUTHWEST GAS CORPORATION
COMMON STOCK ISSUANCES 1994-2003
(Dollars and Shares in Thousands)

Line No.	Year	Shares Outstanding	Shares Issued	Proceeds ($000's)	Line No.
	(a)	(b)	(c)	(d)	
1	1993	20,997			1
2	1994	21,282	285	4,773	2
3	1995	24,467	3,185	44,844	3
4	1996	26,733	2,266	38,767	4
5	1997	27,387	654	12,205	5
6	1998	30,410	3,023	67,180	6
7	1999	30,985	575	14,997	7
8	2000	31,710	725	15,595	8
9	2001	32,493	783	17,061	9
10	2002	33,289	796	18,174	10
11	2003	34,232	943	21,290	11
12	2004[1]	35,531	1,299	27,087	
13	Total		14,534	$ 281,973	12

[1] As of August 31, 2004.

SOUTHWEST GAS CORPORATION
Effective Cost Calculation of
7.5 % Debenture, Due 8/1/2006

Internal Rate of Return = Effective Rate 8.96%

Semi-Annual Payment	Outstanding Principal	Unamortized Balance: Debt Expense	Unamortized Balance: Reacquired Debt Expense	Unamortized Balance: Discount	Carrying Value	Redemption	Interest Expense	Amortization of: Debt Expense	Amortization of: Reacquired Debt Expense	Amortization of: Discount	Total Expense	Annual Cost	Cash Flows
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
08/01/1996	$ 75,000,000	$ 150,000	$ 5,881,631	$ 1,105,500	$ 67,862,869	$ -	$ -	$ -	$ -	$ -	$ -		$ 67,862,869
02/01/1997	75,000,000	145,209	5,693,760	1,070,188	68,090,843	-	2,812,500	4,791	187,870	35,312	3,040,474	8.96%	(2,812,500)
08/01/1997	75,000,000	140,203	5,497,472	1,033,294	68,329,030	-	2,812,500	5,006	196,288	36,894	3,050,687	8.96%	(2,812,500)
02/01/1998	75,000,000	134,973	5,292,390	994,748	68,577,889	-	2,812,500	5,230	205,082	38,547	3,061,359	8.96%	(2,812,500)
08/01/1998	75,000,000	129,508	5,078,120	954,474	68,837,898	-	2,812,500	5,465	214,270	40,274	3,072,509	8.96%	(2,812,500)
02/01/1999	75,000,000	123,799	4,854,250	912,395	69,109,556	-	2,812,500	5,709	223,870	42,078	3,084,158	8.96%	(2,812,500)
08/01/1999	75,000,000	117,833	4,620,349	868,432	69,393,385	-	2,812,500	5,965	233,900	43,963	3,096,329	8.96%	(2,812,500)
02/01/2000	75,000,000	111,601	4,375,969	822,499	69,689,931	-	2,812,500	6,232	244,380	45,933	3,109,046	8.96%	(2,812,500)
08/01/2000	75,000,000	105,089	4,120,641	774,508	69,999,763	-	2,812,500	6,512	255,329	47,991	3,122,332	8.96%	(2,812,500)
02/01/2001	75,000,000	98,286	3,853,872	724,366	70,323,476	-	2,812,500	6,803	266,768	50,141	3,136,213	8.96%	(2,812,500)
08/01/2001	75,000,000	91,178	3,575,152	671,979	70,661,692	-	2,812,500	7,108	278,721	52,388	3,150,717	8.96%	(2,812,500)
02/01/2002	75,000,000	83,751	3,283,943	617,244	71,015,062	-	2,812,500	7,427	291,208	54,735	3,165,870	8.96%	(2,812,500)
08/01/2002	75,000,000	75,991	2,979,688	560,056	71,384,264	-	2,812,500	7,759	304,255	57,187	3,181,702	8.96%	(2,812,500)
02/01/2003	75,000,000	67,884	2,661,801	500,307	71,770,007	-	2,812,500	8,107	317,887	59,749	3,198,243	8.96%	(2,812,500)
08/01/2003	75,000,000	59,414	2,329,672	437,881	72,173,033	-	2,812,500	8,470	332,129	62,426	3,215,526	8.96%	(2,812,500)
02/01/2004	75,000,000	50,564	1,982,663	372,657	72,594,116	-	2,812,500	8,850	347,010	65,223	3,233,583	8.96%	(2,812,500)
08/01/2004	75,000,000	41,318	1,620,106	304,512	73,034,064	-	2,812,500	9,246	362,557	68,145	3,252,449	8.96%	(2,812,500)
02/01/2005	75,000,000	31,657	1,241,306	233,313	73,493,724	-	2,812,500	9,661	378,800	71,199	3,272,160	8.96%	(2,812,500)
08/01/2005	75,000,000	21,564	845,534	158,925	73,973,978	-	2,812,500	10,093	395,772	74,389	3,292,754	8.96%	(2,812,500)
02/01/2006	75,000,000	11,018	432,030	81,204	74,475,748	-	2,812,500	10,546	413,504	77,721	3,314,271	8.96%	(2,812,500)
08/01/2006	75,000,000	-	-	-	75,000,000	75,000,000	2,812,500	11,018	432,030	81,204	3,336,752	8.96%	(77,812,500)
						$ 75,000,000	$ 56,250,000	$ 150,000	$ 5,881,631	$ 1,105,500	$ 63,387,131		

SOUTHWEST GAS CORPORATION
Effective Cost Calculation of
8.0% Debenture, Due 8/1/2026

Internal Rate of Return = Effective Rate 8.89%

Semi-Annual Payment	Outstanding Principal	Unamortized Balance: Debt Expense	Unamortized Balance: Reacquired Debt Expense	Unamortized Balance: Discount	Carrying Value	Redemption	Interest Expense	Amortization of: Debt Expense	Amortization of: Reacquired Debt Expense	Amortization of: Discount	Total Expense	Annual Cost	Cash Flows
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
08/01/1996	$ 75,000,000	$ 150,000	$ 5,898,405	$ 894,750	$ 68,056,845	$ -	$ -	$ -	$ -	$ -	$ -		$ 68,056,845
02/01/1997	75,000,000	149,470	5,877,575	891,590	68,081,364	-	3,000,000	530	20,830	3,160	3,024,520	8.89%	(3,000,000)
08/01/1997	75,000,000	148,917	5,855,819	888,290	68,106,974	-	3,000,000	553	21,756	3,300	3,025,609	8.89%	(3,000,000)
02/01/1998	75,000,000	148,339	5,833,097	884,843	68,133,721	-	3,000,000	578	22,723	3,447	3,026,747	8.89%	(3,000,000)
08/01/1998	75,000,000	147,736	5,809,364	881,243	68,161,657	-	3,000,000	604	23,732	3,600	3,027,936	8.89%	(3,000,000)
02/01/1999	75,000,000	147,105	5,784,577	877,483	68,190,835	-	3,000,000	630	24,787	3,760	3,029,178	8.89%	(3,000,000)
08/01/1999	75,000,000	146,447	5,758,688	873,556	68,221,309	-	3,000,000	658	25,889	3,927	3,030,474	8.89%	(3,000,000)
02/01/2000	75,000,000	145,759	5,731,649	869,454	68,253,137	-	3,000,000	688	27,039	4,102	3,031,829	8.89%	(3,000,000)
08/01/2000	75,000,000	145,041	5,703,408	865,170	68,286,380	-	3,000,000	718	28,241	4,284	3,033,243	8.89%	(3,000,000)
02/01/2001	75,000,000	144,291	5,673,912	860,696	68,321,101	-	3,000,000	750	29,496	4,474	3,034,720	8.89%	(3,000,000)
08/01/2001	75,000,000	143,508	5,643,106	856,023	68,357,364	-	3,000,000	783	30,807	4,673	3,036,263	8.89%	(3,000,000)
02/01/2002	75,000,000	142,689	5,610,930	851,142	68,395,239	-	3,000,000	818	32,176	4,881	3,037,875	8.89%	(3,000,000)
08/01/2002	75,000,000	141,835	5,577,324	846,044	68,434,797	-	3,000,000	855	33,606	5,098	3,039,558	8.89%	(3,000,000)
02/01/2003	75,000,000	140,942	5,542,225	840,720	68,476,114	-	3,000,000	893	35,099	5,324	3,041,316	8.89%	(3,000,000)
08/01/2003	75,000,000	140,010	5,505,566	835,159	68,519,266	-	3,000,000	932	36,659	5,561	3,043,152	8.89%	(3,000,000)
02/01/2004	75,000,000	139,036	5,467,277	829,351	68,564,336	-	3,000,000	974	38,288	5,808	3,045,070	8.89%	(3,000,000)
08/01/2004	75,000,000	138,019	5,427,287	823,284	68,611,409	-	3,000,000	1,017	39,990	6,066	3,047,073	8.89%	(3,000,000)
02/01/2005	75,000,000	136,957	5,385,520	816,949	68,660,574	-	3,000,000	1,062	41,767	6,336	3,049,165	8.89%	(3,000,000)
08/01/2005	75,000,000	135,848	5,341,897	810,331	68,711,924	-	3,000,000	1,109	43,623	6,617	3,051,350	8.89%	(3,000,000)
02/01/2006	75,000,000	134,689	5,296,335	803,420	68,765,556	-	3,000,000	1,159	45,562	6,911	3,053,632	8.89%	(3,000,000)
08/01/2006	75,000,000	133,479	5,248,748	796,201	68,821,571	-	3,000,000	1,210	47,587	7,219	3,056,015	8.89%	(3,000,000)
02/01/2007	75,000,000	132,215	5,199,047	788,662	68,880,076	-	3,000,000	1,264	49,702	7,539	3,058,505	8.89%	(3,000,000)
08/01/2007	75,000,000	130,895	5,147,137	780,787	68,941,181	-	3,000,000	1,320	51,910	7,874	3,061,105	8.89%	(3,000,000)
02/01/2008	75,000,000	129,516	5,092,919	772,563	69,005,002	-	3,000,000	1,379	54,217	8,224	3,063,820	8.89%	(3,000,000)
08/01/2008	75,000,000	128,076	5,036,293	763,973	69,071,658	-	3,000,000	1,440	56,627	8,590	3,066,657	8.89%	(3,000,000)
02/01/2009	75,000,000	126,572	4,977,149	755,001	69,141,277	-	3,000,000	1,504	59,143	8,972	3,069,619	8.89%	(3,000,000)
08/01/2009	75,000,000	125,001	4,915,378	745,631	69,213,990	-	3,000,000	1,571	61,772	9,370	3,072,713	8.89%	(3,000,000)
02/01/2010	75,000,000	123,360	4,850,861	735,844	69,289,935	-	3,000,000	1,641	64,517	9,787	3,075,944	8.89%	(3,000,000)
08/01/2010	75,000,000	121,647	4,783,477	725,623	69,369,254	-	3,000,000	1,714	67,384	10,222	3,079,319	8.89%	(3,000,000)
02/01/2011	75,000,000	119,857	4,713,098	714,947	69,452,098	-	3,000,000	1,790	70,379	10,676	3,082,844	8.89%	(3,000,000)
08/01/2011	75,000,000	117,988	4,639,592	703,796	69,538,625	-	3,000,000	1,869	73,506	11,150	3,086,526	8.89%	(3,000,000)
02/01/2012	75,000,000	116,035	4,562,819	692,150	69,628,996	-	3,000,000	1,952	76,773	11,646	3,090,371	8.89%	(3,000,000)
08/01/2012	75,000,000	113,996	4,482,634	679,987	69,723,384	-	3,000,000	2,039	80,185	12,164	3,094,388	8.89%	(3,000,000)
02/01/2013	75,000,000	111,866	4,398,885	667,282	69,821,966	-	3,000,000	2,130	83,748	12,704	3,098,582	8.89%	(3,000,000)
08/01/2013	75,000,000	109,642	4,311,415	654,014	69,924,930	-	3,000,000	2,224	87,470	13,269	3,102,963	8.89%	(3,000,000)
02/01/2014	75,000,000	107,319	4,220,057	640,155	70,032,469	-	3,000,000	2,323	91,358	13,858	3,107,539	8.89%	(3,000,000)
08/01/2014	75,000,000	104,892	4,124,639	625,681	70,144,787	-	3,000,000	2,427	95,418	14,474	3,112,318	8.89%	(3,000,000)
02/01/2015	75,000,000	102,358	4,024,981	610,564	70,262,097	-	3,000,000	2,534	99,658	15,118	3,117,310	8.89%	(3,000,000)

SOUTHWEST GAS CORPORATION
Effective Cost Calculation of
8.0% Debenture, Due 8/1/2026

Effective Rate
Internal Rate of Return = 8.89%

Semi-Annual Payment	Outstanding Principal	Unamortized Balance: Debt Expense	Unamortized Balance: Reacquired Debt Expense	Unamortized Balance: Discount	Carrying Value	Redemption	Interest Expense	Amortization of: Debt Expense	Amortization of: Reacquired Debt Expense	Amortization of: Discount	Total Expense	Annual Cost	Cash Flows
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
08/01/2015	75,000,000	99,711	3,920,894	594,774	70,384,621	-	3,000,000	2,647	104,087	15,789	3,122,523	8.89%	(3,000,000)
02/01/2016	75,000,000	96,946	3,812,181	578,283	70,512,589	-	3,000,000	2,765	108,713	16,491	3,127,968	8.89%	(3,000,000)
08/01/2016	75,000,000	94,059	3,698,637	561,059	70,646,245	-	3,000,000	2,887	113,544	17,224	3,133,656	8.89%	(3,000,000)
02/01/2017	75,000,000	91,043	3,580,047	543,070	70,785,840	-	3,000,000	3,016	118,590	17,989	3,139,595	8.89%	(3,000,000)
08/01/2017	75,000,000	87,893	3,456,187	524,281	70,931,639	-	3,000,000	3,150	123,860	18,789	3,145,799	8.89%	(3,000,000)
02/01/2018	75,000,000	84,603	3,326,822	504,657	71,083,918	-	3,000,000	3,290	129,365	19,624	3,152,279	8.89%	(3,000,000)
08/01/2018	75,000,000	81,167	3,191,708	484,162	71,242,964	-	3,000,000	3,436	135,114	20,496	3,159,046	8.89%	(3,000,000)
02/01/2019	75,000,000	77,578	3,050,589	462,755	71,409,078	-	3,000,000	3,589	141,119	21,407	3,166,114	8.89%	(3,000,000)
08/01/2019	75,000,000	73,830	2,903,199	440,397	71,582,574	-	3,000,000	3,748	147,390	22,358	3,173,496	8.89%	(3,000,000)
02/01/2020	75,000,000	69,915	2,749,259	417,045	71,763,781	-	3,000,000	3,915	153,940	23,352	3,181,207	8.89%	(3,000,000)
08/01/2020	75,000,000	65,827	2,588,477	392,655	71,953,041	-	3,000,000	4,089	160,782	24,390	3,189,260	8.89%	(3,000,000)
02/01/2021	75,000,000	61,556	2,420,551	367,182	72,150,712	-	3,000,000	4,270	167,927	25,473	3,197,671	8.89%	(3,000,000)
08/01/2021	75,000,000	57,096	2,245,161	340,576	72,357,167	-	3,000,000	4,460	175,390	26,605	3,206,455	8.89%	(3,000,000)
02/01/2022	75,000,000	52,437	2,061,977	312,789	72,572,797	-	3,000,000	4,658	183,184	27,788	3,215,631	8.89%	(3,000,000)
08/01/2022	75,000,000	47,572	1,870,652	283,766	72,798,011	-	3,000,000	4,866	191,325	29,023	3,225,213	8.89%	(3,000,000)
02/01/2023	75,000,000	42,490	1,670,824	253,453	73,033,233	-	3,000,000	5,082	199,828	30,313	3,235,222	8.89%	(3,000,000)
08/01/2023	75,000,000	37,182	1,462,115	221,794	73,278,909	-	3,000,000	5,308	208,708	31,660	3,245,676	8.89%	(3,000,000)
02/01/2024	75,000,000	31,639	1,244,132	188,727	73,535,502	-	3,000,000	5,543	217,984	33,067	3,256,594	8.89%	(3,000,000)
08/01/2024	75,000,000	25,849	1,016,461	154,191	73,803,499	-	3,000,000	5,790	227,671	34,536	3,267,997	8.89%	(3,000,000)
02/01/2025	75,000,000	19,802	778,672	118,120	74,083,407	-	3,000,000	6,047	237,789	36,071	3,279,907	8.89%	(3,000,000)
08/01/2025	75,000,000	13,486	530,315	80,445	74,375,753	-	3,000,000	6,316	248,357	37,674	3,292,346	8.89%	(3,000,000)
02/01/2026	75,000,000	6,890	270,922	41,097	74,681,092	-	3,000,000	6,597	259,394	39,348	3,305,339	8.89%	(3,000,000)
08/01/2026	75,000,000	-	-	-	75,000,000	75,000,000	3,000,000	6,890	270,922	41,097	3,318,908	8.89%	(78,000,000)
						$ 75,000,000	$ 180,000,000	$ 150,000	$ 5,898,405	$ 894,750	$ 186,943,155		

SOUTHWEST GAS CORPORATION
Effective Cost Calculation of
8.375 % Notes Due 2011

	Effective Rate
Internal Rate of Return =	8.6098%

		Unamortized Balance						Amortization of					
Semi-Annual Payment	Outstanding Principal	Reacquired Debt Expense	Discount	Debt Expense	Net Proceeds	Redemption	Interest Expense	Reacquired Debt Expense	Discount	Debt Expense	Total Expense	Annual Cost	Cash Flows
02/13/2001	$ 200,000,000	$ 0	$ 2,818,000	$ 288,784	$ 196,893,216	$ 0	$ 0		$ 0	$ 0	$ 0		$ 196,893,216
08/15/2001	200,000,000	0	2,726,322	279,389	196,994,289	0	8,375,000	0	91,678	9,395	8,476,073	4.30%	(8,375,000)
02/15/2002	200,000,000	0	2,630,697	269,589	197,099,713	0	8,375,000	0	95,625	9,799	8,480,424	4.30%	(8,375,000)
08/15/2002	200,000,000	0	2,530,956	259,368	197,209,676	0	8,375,000	0	99,741	10,221	8,484,962	4.30%	(8,375,000)
02/15/2003	200,000,000	0	2,426,921	248,707	197,324,372	0	8,375,000	0	104,035	10,661	8,489,696	4.30%	(8,375,000)
08/15/2003	200,000,000	0	2,318,408	237,586	197,444,006	0	8,375,000	0	108,514	11,120	8,494,634	4.30%	(8,375,000)
02/15/2004	200,000,000	0	2,205,223	225,987	197,568,790	0	8,375,000	0	113,185	11,599	8,499,784	4.30%	(8,375,000)
08/15/2004	200,000,000	0	2,087,166	213,889	197,698,945	0	8,375,000	0	118,057	12,098	8,505,156	4.30%	(8,375,000)
02/15/2005	200,000,000	0	1,964,026	201,270	197,834,704	0	8,375,000	0	123,140	12,619	8,510,759	4.30%	(8,375,000)
08/15/2005	200,000,000	0	1,835,585	188,108	197,976,307	0	8,375,000	0	128,441	13,162	8,516,603	4.30%	(8,375,000)
02/15/2006	200,000,000	0	1,701,615	174,379	198,124,006	0	8,375,000	0	133,970	13,729	8,522,699	4.30%	(8,375,000)
08/15/2006	200,000,000	0	1,561,878	160,058	198,278,064	0	8,375,000	0	139,737	14,320	8,529,057	4.30%	(8,375,000)
02/15/2007	200,000,000	0	1,416,125	145,122	198,438,753	0	8,375,000	0	145,753	14,936	8,535,689	4.30%	(8,375,000)
08/15/2007	200,000,000	0	1,264,098	129,543	198,606,360	0	8,375,000	0	152,027	15,579	8,542,607	4.30%	(8,375,000)
02/15/2008	200,000,000	0	1,105,526	113,292	198,781,182	0	8,375,000	0	158,572	16,250	8,549,822	4.30%	(8,375,000)
08/15/2008	200,000,000	0	940,127	96,343	198,963,530	0	8,375,000	0	165,398	16,950	8,557,348	4.30%	(8,375,000)
02/15/2009	200,000,000	0	767,609	78,663	199,153,728	0	8,375,000	0	172,519	17,679	8,565,198	4.30%	(8,375,000)
08/15/2009	200,000,000	0	587,663	60,223	199,352,114	0	8,375,000	0	179,945	18,440	8,573,386	4.30%	(8,375,000)
02/15/2010	200,000,000	0	399,971	40,988	199,559,040	0	8,375,000	0	187,692	19,234	8,581,926	4.30%	(8,375,000)
08/15/2010	200,000,000	0	204,200	20,926	199,774,874	0	8,375,000	0	195,772	20,062	8,590,834	4.30%	(8,375,000)
02/15/2011	200,000,000	0	0	0	200,000,000	200,000,000	8,375,000	0	204,200	20,926	8,600,126	4.30%	(208,375,000)
						$ 200,000,000	$ 167,500,000	$ 0	$ 2,818,000	$ 288,784	$ 170,606,784		

SOUTHWEST GAS CORPORATION
Effective Cost Calculation of
7.625% New Debenture, Due May 15, 2012

Internal Rate of Return = Effective Rate 7.79%

		Unamortized Balance						Amortization of					
Semi-Annual Payment	Outstanding Principal	Reacquired Debt Expense	Discount	Debt Expense	Net Proceeds	Redemption	Interest Expense	Reacquired Debt Expense	Discount	Debt Expense	Total Expense	Annual Cost	Cash Flows
05/15/2002	$ 200,000,000	$ 0	$ 2,052,000	$ 270,042	$ 197,677,958	$ 0	$ 0		$ 0	$ 0	$ 0		$ 197,677,958
11/15/2002	200,000,000	0	1,982,352	260,876	197,756,772	0	7,625,000	0	69,648	9,166	7,703,814	3.90%	(7,625,000)
06/15/2003	200,000,000	0	1,909,989	251,354	197,838,657	0	7,625,000	0	72,363	9,523	7,706,885	3.90%	(7,625,000)
11/15/2003	200,000,000	0	1,834,806	241,460	197,923,734	0	7,625,000	0	75,183	9,894	7,710,077	3.90%	(7,625,000)
05/15/2004	200,000,000	0	1,756,694	231,180	198,012,126	0	7,625,000	0	78,113	10,280	7,713,392	3.90%	(7,625,000)
11/15/2004	200,000,000	0	1,675,537	220,500	198,103,963	0	7,625,000	0	81,157	10,680	7,716,837	3.90%	(7,625,000)
05/15/2005	200,000,000	0	1,591,217	209,403	198,199,379	0	7,625,000	0	84,320	11,096	7,720,416	3.90%	(7,625,000)
11/15/2005	200,000,000	0	1,503,612	197,874	198,298,514	0	7,625,000	0	87,606	11,529	7,724,135	3.90%	(7,625,000)
05/15/2006	200,000,000	0	1,412,592	185,896	198,401,512	0	7,625,000	0	91,020	11,978	7,727,998	3.90%	(7,625,000)
11/15/2006	200,000,000	0	1,318,025	173,451	198,508,524	0	7,625,000	0	94,567	12,445	7,732,012	3.90%	(7,625,000)
05/15/2007	200,000,000	0	1,219,772	160,521	198,619,706	0	7,625,000	0	98,252	12,930	7,736,182	3.90%	(7,625,000)
11/15/2007	200,000,000	0	1,117,691	147,087	198,735,222	0	7,625,000	0	102,082	13,434	7,740,515	3.90%	(7,625,000)
05/15/2008	200,000,000	0	1,011,631	133,130	198,855,239	0	7,625,000	0	106,060	13,957	7,745,017	3.90%	(7,625,000)
11/15/2008	200,000,000	0	901,438	118,629	198,979,933	0	7,625,000	0	110,193	14,501	7,749,694	3.90%	(7,625,000)
05/15/2009	200,000,000	0	786,950	103,562	199,109,487	0	7,625,000	0	114,487	15,066	7,754,554	3.90%	(7,625,000)
11/15/2009	200,000,000	0	668,001	87,909	199,244,090	0	7,625,000	0	118,949	15,654	7,759,603	3.90%	(7,625,000)
05/15/2010	200,000,000	0	544,416	71,645	199,383,939	0	7,625,000	0	123,585	16,264	7,764,849	3.90%	(7,625,000)
11/15/2010	200,000,000	0	416,015	54,747	199,529,238	0	7,625,000	0	128,401	16,898	7,770,299	3.90%	(7,625,000)
05/15/2011	200,000,000	0	282,610	37,191	199,680,199	0	7,625,000	0	133,405	17,556	7,775,961	3.90%	(7,625,000)
11/15/2011	200,000,000	0	144,006	18,951	199,837,043	0	7,625,000	0	138,604	18,240	7,781,844	3.90%	(7,625,000)
05/15/2012	200,000,000	0	0	(0)	200,000,000	200,000,000	7,625,000	0	144,006	18,951	7,787,957	3.90%	(207,625,000)
						$ 200,000,000	$ 152,500,000	$ 0	$ 2,052,000	$ 270,042	$ 154,822,042		

SOUTHWEST GAS CORPORATION
Effective Cost Calculation of
7.59% Medium Term Note Series A, Due 1/17/2017

Internal Rate of Return = Effective Rate 7.68%

Semi-Annual Payment	Outstanding Principal	Unamortized Balance Reacquired Debt Expense	Unamortized Balance Discount	Unamortized Balance Debt Expense	Carrying Value	Redemption	Interest Expense	Amortization of Reacquired Debt Expense	Amortization of Discount	Amortization of Debt Expense	Total Expense	Annual Cost	Cash Flows
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
01/17/1997	$ 25,000,000	$ -	$ 187,500	$ 33,400	$ 24,779,100	$ -	$ -	$ -	$ -	$ -	$ 0		$ 24,779,100
04/01/1997	25,000,000	-	186,657	33,250	24,780,093	-	390,042	-	843	150.09	391,034	7.68%	(390,042)
10/01/1997	25,000,000	-	184,576	32,879	24,782,545	-	948,750	-	2,082	371	951,203	7.68%	(948,750)
04/01/1998	25,000,000	-	182,414	32,494	24,785,092	-	948,750	-	2,162	385	951,297	7.68%	(948,750)
10/01/1998	25,000,000	-	180,169	32,094	24,787,737	-	948,750	-	2,245	400	951,395	7.68%	(948,750)
04/01/1999	25,000,000	-	177,838	31,679	24,790,483	-	948,750	-	2,331	415	951,496	7.68%	(948,750)
10/01/1999	25,000,000	-	175,418	31,248	24,793,334	-	948,750	-	2,420	431	951,601	7.68%	(948,750)
04/01/2000	25,000,000	-	172,905	30,800	24,796,295	-	948,750	-	2,513	448	951,711	7.68%	(948,750)
10/01/2000	25,000,000	-	170,295	30,335	24,799,370	-	948,750	-	2,610	465	951,825	7.68%	(948,750)
04/01/2001	25,000,000	-	167,585	29,852	24,802,562	-	948,750	-	2,710	483	951,943	7.68%	(948,750)
10/01/2001	25,000,000	-	164,771	29,351	24,805,878	-	948,750	-	2,814	501	952,065	7.68%	(948,750)
04/01/2002	25,000,000	-	161,849	28,831	24,809,320	-	948,750	-	2,922	521	952,192	7.68%	(948,750)
10/01/2002	25,000,000	-	158,815	28,290	24,812,895	-	948,750	-	3,034	540	952,325	7.68%	(948,750)
04/01/2003	25,000,000	-	155,665	27,729	24,816,606	-	948,750	-	3,151	561	952,462	7.68%	(948,750)
10/01/2003	25,000,000	-	152,393	27,146	24,820,461	-	948,750	-	3,272	583	952,604	7.68%	(948,750)
04/01/2004	25,000,000	-	148,996	26,541	24,824,463	-	948,750	-	3,397	605	952,752	7.68%	(948,750)
10/01/2004	25,000,000	-	145,468	25,913	24,828,619	-	948,750	-	3,527	628	952,906	7.68%	(948,750)
04/01/2005	25,000,000	-	141,806	25,260	24,832,934	-	948,750	-	3,663	652	953,065	7.68%	(948,750)
10/01/2005	25,000,000	-	138,002	24,583	24,837,415	-	948,750	-	3,803	678	953,231	7.68%	(948,750)
04/01/2006	25,000,000	-	134,053	23,879	24,842,068	-	948,750	-	3,949	704	953,403	7.68%	(948,750)
10/01/2006	25,000,000	-	129,951	23,149	24,846,900	-	948,750	-	4,101	731	953,582	7.68%	(948,750)
04/01/2007	25,000,000	-	125,693	22,390	24,851,917	-	948,750	-	4,259	759	953,767	7.68%	(948,750)
10/01/2007	25,000,000	-	121,271	21,602	24,857,127	-	948,750	-	4,422	788	953,960	7.68%	(948,750)
04/01/2008	25,000,000	-	116,679	20,784	24,862,536	-	948,750	-	4,592	818	954,160	7.68%	(948,750)
10/01/2008	25,000,000	-	111,911	19,935	24,868,154	-	948,750	-	4,768	849	954,367	7.68%	(948,750)
04/01/2009	25,000,000	-	106,960	19,053	24,873,987	-	948,750	-	4,951	882	954,583	7.68%	(948,750)
10/01/2009	25,000,000	-	101,819	18,137	24,880,043	-	948,750	-	5,141	916	954,807	7.68%	(948,750)
04/01/2010	25,000,000	-	96,481	17,186	24,886,333	-	948,750	-	5,338	951	955,039	7.68%	(948,750)
10/01/2010	25,000,000	-	90,937	16,199	24,892,864	-	948,750	-	5,543	987	955,281	7.68%	(948,750)
04/01/2011	25,000,000	-	85,181	15,174	24,899,645	-	948,750	-	5,756	1,025	955,531	7.68%	(948,750)
10/01/2011	25,000,000	-	79,204	14,109	24,906,687	-	948,750	-	5,977	1,065	955,792	7.68%	(948,750)
04/01/2012	25,000,000	-	72,998	13,003	24,913,999	-	948,750	-	6,206	1,106	956,062	7.68%	(948,750)
10/01/2012	25,000,000	-	66,553	11,855	24,921,592	-	948,750	-	6,445	1,148	956,343	7.68%	(948,750)
04/01/2013	25,000,000	-	59,861	10,663	24,929,476	-	948,750	-	6,692	1,192	956,634	7.68%	(948,750)
10/01/2013	25,000,000	-	52,912	9,425	24,937,663	-	948,750	-	6,949	1,238	956,937	7.68%	(948,750)
04/01/2014	25,000,000	-	45,696	8,140	24,946,164	-	948,750	-	7,216	1,285	957,251	7.68%	(948,750)
10/01/2014	25,000,000	-	38,204	6,805	24,954,991	-	948,750	-	7,493	1,335	957,577	7.68%	(948,750)
04/01/2015	25,000,000	-	30,423	5,419	24,964,157	-	948,750	-	7,780	1,386	957,916	7.68%	(948,750)
10/01/2015	25,000,000	-	22,344	3,980	24,973,676	-	948,750	-	8,079	1,439	958,268	7.68%	(948,750)
04/01/2016	25,000,000	-	13,955	2,486	24,983,559	-	948,750	-	8,389	1,494	958,633	7.68%	(948,750)
10/01/2016	25,000,000	-	5,244	934	24,993,822	-	948,750	-	8,711	1,552	959,013	7.68%	(948,750)
01/17/2017	25,000,000	-	-	-	25,000,000	25,000,000	558,708	-	5,244	934	564,886	7.68%	(25,558,708)
						$ 25,000,000	$ 37,950,000	$ -	$ 187,500	$ 33,400	$ 38,170,900		

SOUTHWEST GAS CORPORATION
Effective Cost Calculation of
7.78% Medium Term Note Series A, Due 2/3/2022

Internal Rate of Return = Effective Rate 7.86%

Semi-Annual Payment	Outstanding Principal	Unamortized Balance: Reacquired Debt Expense	Unamortized Balance: Discount	Unamortized Balance: Debt Expense	Carrying Value	Redemption	Interest Expense	Amortization of: Reacquired Debt Expense	Amortization of: Discount	Amortization of: Debt Expense	Total Expense	Annual Cost	Cash Flows
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
02/03/1997	$ 25,000,000	$ -	$ 187,500	$ 33,400	$ 24,779,100	$ -	$ -	$ -	$ -	$ -	$ -		$ 24,779,100
04/01/1997	25,000,000	-	187,096	33,328	24,779,576	-	313,361	-	404	72	313,837	7.86%	(313,361)
10/01/1997	25,000,000	-	185,825	33,102	24,781,073	-	972,500	-	1,271	226	973,997	7.86%	(972,500)
04/01/1998	25,000,000	-	184,504	32,866	24,782,629	-	972,500	-	1,321	235	974,056	7.86%	(972,500)
10/01/1998	25,000,000	-	183,132	32,622	24,784,246	-	972,500	-	1,373	244	974,117	7.86%	(972,500)
04/01/1999	25,000,000	-	181,705	32,368	24,785,927	-	972,500	-	1,426	254	974,181	7.86%	(972,500)
10/01/1999	25,000,000	-	180,223	32,104	24,787,673	-	972,500	-	1,483	264	974,247	7.86%	(972,500)
04/01/2000	25,000,000	-	178,682	31,829	24,789,489	-	972,500	-	1,541	274	974,315	7.86%	(972,500)
10/01/2000	25,000,000	-	177,081	31,544	24,791,375	-	972,500	-	1,601	285	974,387	7.86%	(972,500)
04/01/2001	25,000,000	-	175,416	31,248	24,793,336	-	972,500	-	1,664	296	974,461	7.86%	(972,500)
10/01/2001	25,000,000	-	173,687	30,939	24,795,374	-	972,500	-	1,730	308	974,538	7.86%	(972,500)
04/01/2002	25,000,000	-	171,889	30,619	24,797,492	-	972,500	-	1,798	320	974,618	7.86%	(972,500)
10/01/2002	25,000,000	-	170,021	30,286	24,799,693	-	972,500	-	1,868	333	974,701	7.86%	(972,500)
04/01/2003	25,000,000	-	168,079	29,940	24,801,981	-	972,500	-	1,942	346	974,788	7.86%	(972,500)
10/01/2003	25,000,000	-	166,061	29,581	24,804,359	-	972,500	-	2,018	360	974,878	7.86%	(972,500)
04/01/2004	25,000,000	-	163,963	29,207	24,806,830	-	972,500	-	2,097	374	974,971	7.86%	(972,500)
10/01/2004	25,000,000	-	161,783	28,819	24,809,398	-	972,500	-	2,180	388	975,068	7.86%	(972,500)
04/01/2005	25,000,000	-	159,518	28,415	24,812,067	-	972,500	-	2,266	404	975,169	7.86%	(972,500)
10/01/2005	25,000,000	-	157,163	27,996	24,814,841	-	972,500	-	2,355	419	975,274	7.86%	(972,500)
04/01/2006	25,000,000	-	154,716	27,560	24,817,724	-	972,500	-	2,447	436	975,383	7.86%	(972,500)
10/01/2006	25,000,000	-	152,172	27,107	24,820,721	-	972,500	-	2,543	453	975,496	7.86%	(972,500)
04/01/2007	25,000,000	-	149,529	26,636	24,823,835	-	972,500	-	2,643	471	975,614	7.86%	(972,500)
10/01/2007	25,000,000	-	146,782	26,147	24,827,072	-	972,500	-	2,747	489	975,737	7.86%	(972,500)
04/01/2008	25,000,000	-	143,926	25,638	24,830,436	-	972,500	-	2,855	509	975,864	7.86%	(972,500)
10/01/2008	25,000,000	-	140,959	25,109	24,833,932	-	972,500	-	2,968	529	975,996	7.86%	(972,500)
04/01/2009	25,000,000	-	137,875	24,560	24,837,565	-	972,500	-	3,084	549	976,134	7.86%	(972,500)
10/01/2009	25,000,000	-	134,669	23,989	24,841,342	-	972,500	-	3,205	571	976,276	7.86%	(972,500)
04/01/2010	25,000,000	-	131,338	23,396	24,845,266	-	972,500	-	3,331	593	976,425	7.86%	(972,500)
10/01/2010	25,000,000	-	127,876	22,779	24,849,345	-	972,500	-	3,462	617	976,579	7.86%	(972,500)
04/01/2011	25,000,000	-	124,277	22,138	24,853,585	-	972,500	-	3,598	641	976,739	7.86%	(972,500)
10/01/2011	25,000,000	-	120,537	21,472	24,857,991	-	972,500	-	3,740	666	976,906	7.86%	(972,500)
04/01/2012	25,000,000	-	116,651	20,779	24,862,570	-	972,500	-	3,887	692	977,079	7.86%	(972,500)
10/01/2012	25,000,000	-	112,611	20,060	24,867,329	-	972,500	-	4,040	720	977,259	7.86%	(972,500)
04/01/2013	25,000,000	-	108,413	19,312	24,872,275	-	972,500	-	4,198	748	977,446	7.86%	(972,500)
10/01/2013	25,000,000	-	104,049	18,535	24,877,416	-	972,500	-	4,363	777	977,641	7.86%	(972,500)
04/01/2014	25,000,000	-	99,514	17,727	24,882,759	-	972,500	-	4,535	808	977,843	7.86%	(972,500)
10/01/2014	25,000,000	-	94,801	16,887	24,888,312	-	972,500	-	4,713	840	978,053	7.86%	(972,500)
04/01/2015	25,000,000	-	89,903	16,015	24,894,083	-	972,500	-	4,898	873	978,271	7.86%	(972,500)
10/01/2015	25,000,000	-	84,812	15,108	24,900,080	-	972,500	-	5,091	907	978,498	7.86%	(972,500)
04/01/2016	25,000,000	-	79,521	14,165	24,906,314	-	972,500	-	5,291	943	978,734	7.86%	(972,500)
10/01/2016	25,000,000	-	74,022	13,186	24,912,793	-	972,500	-	5,499	980	978,979	7.86%	(972,500)
04/01/2017	25,000,000	-	68,306	12,168	24,919,526	-	972,500	-	5,715	1,018	979,233	7.86%	(972,500)
10/01/2017	25,000,000	-	62,367	11,110	24,926,524	-	972,500	-	5,940	1,058	979,498	7.86%	(972,500)
04/01/2018	25,000,000	-	56,193	10,010	24,933,797	-	972,500	-	6,173	1,100	979,773	7.86%	(972,500)
10/01/2018	25,000,000	-	49,777	8,867	24,941,356	-	972,500	-	6,416	1,143	980,059	7.86%	(972,500)
04/01/2019	25,000,000	-	43,109	7,679	24,949,212	-	972,500	-	6,668	1,188	980,356	7.86%	(972,500)
10/01/2019	25,000,000	-	36,179	6,445	24,957,377	-	972,500	-	6,930	1,235	980,665	7.86%	(972,500)
04/01/2020	25,000,000	-	28,976	5,162	24,965,862	-	972,500	-	7,203	1,283	980,986	7.86%	(972,500)
10/01/2020	25,000,000	-	21,490	3,828	24,974,681	-	972,500	-	7,486	1,333	981,319	7.86%	(972,500)
04/01/2021	25,000,000	-	13,710	2,442	24,983,847	-	972,500	-	7,780	1,386	981,666	7.86%	(972,500)
10/01/2021	25,000,000	-	5,624	1,002	24,993,374	-	972,500	-	8,086	1,440	982,026	7.86%	(972,500)
02/03/2022	25,000,000	-	-	-	25,000,000	25,000,000	659,139	-	5,624	1,002	665,765	7.86%	(25,659,139)
						$ 25,000,000	$ 48,625,000	$ -	$ 187,500	$ 33,400	$ 48,845,900		

SOUTHWEST GAS CORPORATION
Effective Cost Calculation of
7.92% Medium Term Note, Due June 4, 2027

Internal Rate of Return = Effective Rate 8.00%

Semi-Annual Payment (a)	Outstanding Principal (b)	Unamortized Balance: Reacquired Debt Expense (c)	Unamortized Balance: Discount (d)	Unamortized Balance: Debt Expense (e)	Carrying Value (f)	Redemption (g)	Interest Expense (h)	Amortization of: Reacquired Debt Expense (i)	Amortization of: Discount (j)	Amortization of: Debt Expense (k)	Total Expense (l)	Annual Cost (m)	Cash Flows (n)
06/04/1997	$ 25,000,000	$ -	$ 187,500	$ 45,761	$ 24,766,739	$ -	$ -	$ -	$ -	$ -	$ -		$ 24,766,739
10/01/1997	25,000,000	-	186,988	45,636	24,767,375	-	643,500	-	512	125	644,137	8.00%	(643,500)
04/01/1998	25,000,000	-	186,180	45,439	24,768,381	-	990,000	-	808	197	991,005	8.00%	(990,000)
10/01/1998	25,000,000	-	185,340	45,234	24,769,426	-	990,000	-	840	205	991,045	8.00%	(990,000)
04/01/1999	25,000,000	-	184,466	45,021	24,770,513	-	990,000	-	874	213	991,087	8.00%	(990,000)
10/01/1999	25,000,000	-	183,557	44,799	24,771,644	-	990,000	-	909	222	991,131	8.00%	(990,000)
04/01/2000	25,000,000	-	182,612	44,568	24,772,820	-	990,000	-	945	231	991,176	8.00%	(990,000)
10/01/2000	25,000,000	-	181,629	44,329	24,774,043	-	990,000	-	983	240	991,223	8.00%	(990,000)
04/01/2001	25,000,000	-	180,607	44,079	24,775,315	-	990,000	-	1,022	250	991,272	8.00%	(990,000)
10/01/2001	25,000,000	-	179,543	43,819	24,776,637	-	990,000	-	1,063	260	991,323	8.00%	(990,000)
04/01/2002	25,000,000	-	178,437	43,550	24,778,013	-	990,000	-	1,106	270	991,376	8.00%	(990,000)
10/01/2002	25,000,000	-	177,287	43,269	24,779,444	-	990,000	-	1,150	281	991,431	8.00%	(990,000)
04/01/2003	25,000,000	-	176,091	42,977	24,780,932	-	990,000	-	1,196	292	991,488	8.00%	(990,000)
10/01/2003	25,000,000	-	174,847	42,673	24,782,479	-	990,000	-	1,244	304	991,548	8.00%	(990,000)
04/01/2004	25,000,000	-	173,554	42,358	24,784,089	-	990,000	-	1,294	316	991,609	8.00%	(990,000)
10/01/2004	25,000,000	-	172,208	42,029	24,785,763	-	990,000	-	1,346	328	991,674	8.00%	(990,000)
04/01/2005	25,000,000	-	170,809	41,688	24,787,504	-	990,000	-	1,399	342	991,741	8.00%	(990,000)
10/01/2005	25,000,000	-	169,353	41,333	24,789,314	-	990,000	-	1,455	355	991,811	8.00%	(990,000)
04/01/2006	25,000,000	-	167,840	40,963	24,791,197	-	990,000	-	1,514	369	991,883	8.00%	(990,000)
10/01/2006	25,000,000	-	166,266	40,579	24,793,155	-	990,000	-	1,574	384	991,958	8.00%	(990,000)
04/01/2007	25,000,000	-	164,629	40,179	24,795,192	-	990,000	-	1,637	400	992,037	8.00%	(990,000)
10/01/2007	25,000,000	-	162,926	39,764	24,797,310	-	990,000	-	1,703	416	992,118	8.00%	(990,000)
04/01/2008	25,000,000	-	161,155	39,332	24,799,513	-	990,000	-	1,771	432	992,203	8.00%	(990,000)
10/01/2008	25,000,000	-	159,314	38,882	24,801,804	-	990,000	-	1,842	449	992,291	8.00%	(990,000)
04/01/2009	25,000,000	-	157,398	38,415	24,804,187	-	990,000	-	1,915	467	992,383	8.00%	(990,000)
10/01/2009	25,000,000	-	155,407	37,929	24,806,665	-	990,000	-	1,992	486	992,478	8.00%	(990,000)
04/01/2010	25,000,000	-	153,335	37,423	24,809,242	-	990,000	-	2,072	506	992,577	8.00%	(990,000)
10/01/2010	25,000,000	-	151,180	36,897	24,811,922	-	990,000	-	2,154	526	992,680	8.00%	(990,000)
04/01/2011	25,000,000	-	148,940	36,350	24,814,710	-	990,000	-	2,241	547	992,788	8.00%	(990,000)
10/01/2011	25,000,000	-	146,609	35,782	24,817,609	-	990,000	-	2,330	569	992,899	8.00%	(990,000)
04/01/2012	25,000,000	-	144,186	35,190	24,820,624	-	990,000	-	2,424	592	993,015	8.00%	(990,000)
10/01/2012	25,000,000	-	141,665	34,575	24,823,760	-	990,000	-	2,521	615	993,136	8.00%	(990,000)
04/01/2013	25,000,000	-	139,044	33,935	24,827,021	-	990,000	-	2,621	640	993,261	8.00%	(990,000)
10/01/2013	25,000,000	-	136,317	33,270	24,830,413	-	990,000	-	2,726	665	993,392	8.00%	(990,000)
04/01/2014	25,000,000	-	133,482	32,578	24,833,940	-	990,000	-	2,835	692	993,527	8.00%	(990,000)
10/01/2014	25,000,000	-	130,533	31,858	24,837,609	-	990,000	-	2,949	720	993,669	8.00%	(990,000)
04/01/2015	25,000,000	-	127,466	31,110	24,841,424	-	990,000	-	3,067	748	993,815	8.00%	(990,000)
10/01/2015	25,000,000	-	124,277	30,331	24,845,392	-	990,000	-	3,190	778	993,968	8.00%	(990,000)
04/01/2016	25,000,000	-	120,960	29,521	24,849,519	-	990,000	-	3,317	810	994,127	8.00%	(990,000)
10/01/2016	25,000,000	-	117,510	28,679	24,853,811	-	990,000	-	3,450	842	994,292	8.00%	(990,000)
04/01/2017	25,000,000	-	113,922	27,804	24,858,275	-	990,000	-	3,588	876	994,464	8.00%	(990,000)
10/01/2017	25,000,000	-	110,190	26,893	24,862,917	-	990,000	-	3,732	911	994,642	8.00%	(990,000)
04/01/2018	25,000,000	-	106,309	25,946	24,867,745	-	990,000	-	3,881	947	994,828	8.00%	(990,000)
10/01/2018	25,000,000	-	102,273	24,961	24,872,766	-	990,000	-	4,036	985	995,021	8.00%	(990,000)
04/01/2019	25,000,000	-	98,076	23,936	24,877,988	-	990,000	-	4,198	1,024	995,222	8.00%	(990,000)
10/01/2019	25,000,000	-	93,710	22,871	24,883,419	-	990,000	-	4,366	1,065	995,431	8.00%	(990,000)
04/01/2020	25,000,000	-	89,170	21,763	24,889,067	-	990,000	-	4,540	1,108	995,648	8.00%	(990,000)
10/01/2020	25,000,000	-	84,448	20,610	24,894,942	-	990,000	-	4,722	1,152	995,874	8.00%	(990,000)

SOUTHWEST GAS CORPORATION
Effective Cost Calculation of
7.92% Medium Term Note, Due June 4, 2027

Internal Rate of Return = Effective Rate 8.00%

		Unamortized Balance						Amortization of					
Semi-Annual Payment	Outstanding Principal	Reacquired Debt Expense	Discount	Debt Expense	Carrying Value	Redemption	Interest Expense	Reacquired Debt Expense	Discount	Debt Expense	Total Expense	Annual Cost	Cash Flows
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
04/01/2021	25,000,000	-	79,537	19,412	24,901,051	-	990,000	-	4,911	1,199	996,109	8.00%	(990,000)
10/01/2021	25,000,000	-	74,430	18,165	24,907,405	-	990,000	-	5,107	1,246	996,354	8.00%	(990,000)
04/01/2022	25,000,000	-	69,118	16,869	24,914,013	-	990,000	-	5,312	1,296	996,608	8.00%	(990,000)
10/01/2022	25,000,000	-	63,594	15,521	24,920,885	-	990,000	-	5,524	1,348	996,872	8.00%	(990,000)
04/01/2023	25,000,000	-	57,849	14,119	24,928,033	-	990,000	-	5,745	1,402	997,147	8.00%	(990,000)
10/01/2023	25,000,000	-	51,873	12,660	24,935,466	-	990,000	-	5,975	1,458	997,433	8.00%	(990,000)
04/01/2024	25,000,000	-	45,659	11,144	24,943,197	-	990,000	-	6,214	1,517	997,731	8.00%	(990,000)
10/01/2024	25,000,000	-	39,196	9,566	24,951,237	-	990,000	-	6,463	1,577	998,040	8.00%	(990,000)
04/01/2025	25,000,000	-	32,475	7,926	24,959,599	-	990,000	-	6,721	1,640	998,362	8.00%	(990,000)
10/01/2025	25,000,000	-	25,485	6,220	24,968,296	-	990,000	-	6,990	1,706	998,696	8.00%	(990,000)
04/01/2026	25,000,000	-	18,214	4,445	24,977,340	-	990,000	-	7,270	1,774	999,044	8.00%	(990,000)
10/01/2026	25,000,000	-	10,653	2,600	24,986,747	-	990,000	-	7,561	1,845	999,406	8.00%	(990,000)
04/01/2027	25,000,000	-	2,790	681	24,996,529	-	990,000	-	7,864	1,919	999,783	8.00%	(990,000)
06/04/2027	25,000,000	-	-	-	25,000,000	25,000,000	346,500	-	2,790	681	349,971	8.00%	(25,346,500)
						$ 25,000,000	$ 59,400,000	$ -	$ 187,500	$ 45,761	$ 59,633,261		

SOUTHWEST GAS CORPORATION
Effective Cost Calculation of
6.89% Medium Term Note Series A, Due 9/24/07

Internal Rate of Return = Effective Rate 7.00%

Semi-Annual Payment (a)	Outstanding Principal (b)	Unamortized Balance: Reacquired Debt Expense (c)	Unamortized Balance: Discount (d)	Unamortized Balance: Debt Expense (e)	Carrying Value (f)	Redemption (g)	Interest Expense (h)	Amortization of: Reacquired Debt Expense (i)	Amortization of: Discount (j)	Amortization of: Debt Expense (k)	Total Expense (l)	Cost (m)	Cash Flows (n)
09/23/1997	$ 17,500,000	$ -	$ 102,325	$ 40,200	$ 17,357,475	$ -	$ -	$ -	$ -	$ -	$ -		$ 17,357,475
04/01/1998	17,500,000	-	98,547	38,715	17,362,738	-	629,669	-	3,778	1,484	634,932	7.00%	(629,669)
10/01/1998	17,500,000	-	94,797	37,242	17,367,961	-	602,875	-	3,750	1,473	608,098	7.00%	(602,875)
04/01/1999	17,500,000	-	90,916	35,717	17,373,367	-	602,875	-	3,881	1,525	608,281	7.00%	(602,875)
10/01/1999	17,500,000	-	86,899	34,139	17,378,962	-	602,875	-	4,017	1,578	608,470	7.00%	(602,875)
04/01/2000	17,500,000	-	82,741	32,506	17,384,753	-	602,875	-	4,158	1,633	608,666	7.00%	(602,875)
10/01/2000	17,500,000	-	78,438	30,815	17,390,747	-	602,875	-	4,303	1,691	608,869	7.00%	(602,875)
04/01/2001	17,500,000	-	73,984	29,065	17,396,951	-	602,875	-	4,454	1,750	609,079	7.00%	(602,875)
10/01/2001	17,500,000	-	69,374	27,254	17,403,372	-	602,875	-	4,610	1,811	609,296	7.00%	(602,875)
04/01/2002	17,500,000	-	64,602	25,380	17,410,018	-	602,875	-	4,772	1,875	609,521	7.00%	(602,875)
10/01/2002	17,500,000	-	59,663	23,440	17,416,897	-	602,875	-	4,939	1,940	609,754	7.00%	(602,875)
04/01/2003	17,500,000	-	54,552	21,431	17,424,017	-	602,875	-	5,112	2,008	609,995	7.00%	(602,875)
10/01/2003	17,500,000	-	49,261	19,353	17,431,386	-	602,875	-	5,291	2,078	610,244	7.00%	(602,875)
04/01/2004	17,500,000	-	43,785	17,202	17,439,013	-	602,875	-	5,476	2,151	610,502	7.00%	(602,875)
10/01/2004	17,500,000	-	38,118	14,975	17,446,907	-	602,875	-	5,668	2,227	610,769	7.00%	(602,875)
04/01/2005	17,500,000	-	32,251	12,670	17,455,078	-	602,875	-	5,866	2,305	611,046	7.00%	(602,875)
10/01/2005	17,500,000	-	26,180	10,285	17,463,535	-	602,875	-	6,072	2,385	611,332	7.00%	(602,875)
04/01/2006	17,500,000	-	19,895	7,816	17,472,288	-	602,875	-	6,284	2,469	611,628	7.00%	(602,875)
10/01/2006	17,500,000	-	13,391	5,261	17,481,348	-	602,875	-	6,504	2,555	611,935	7.00%	(602,875)
04/01/2007	17,500,000	-	6,659	2,616	17,490,725	-	602,875	-	6,732	2,645	612,252	7.00%	(602,875)
09/24/2007	17,500,000	-	-	-	17,500,000	17,500,000	579,430	-	6,659	2,616	588,705	7.00%	(18,079,430)
						$ 17,500,000	$ 12,060,849	$ -	$ 102,325	$ 40,200	$ 12,203,374		

SOUTHWEST GAS CORPORATION
Effective Cost Calculation of
6.76% Medium Term Note Series A, Due 9/24/27
Put Date September 24, 2007

Internal Rate of Return = Effective Rate 6.88%

Semi-Annual Payment	Outstanding Principal	Unamortized Balance: Reacquired Debt Expense	Unamortized Balance: Discount	Unamortized Balance: Debt Expense	Carrying Value	Redemption	Interest Expense	Amortization of: Reacquired Debt Expense	Amortization of: Discount	Amortization of: Debt Expense	Total Expense	Annual Cost	Cash Flows
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
09/23/1997	$ 7,500,000	$ -	$ 46,875	$ 17,228	$ 7,435,897	$ -	$ -	$ -	$ -	$ -	$ -		$ 7,435,897
04/01/1998	7,500,000	-	45,133	16,588	7,438,279	-	264,767	-	1,742	640	267,149	6.88%	(264,767)
10/01/1998	7,500,000	-	43,405	15,953	7,440,642	-	253,500	-	1,728	635	255,863	6.88%	(253,500)
04/01/1999	7,500,000	-	41,618	15,296	7,443,086	-	253,500	-	1,787	657	255,944	6.88%	(253,500)
10/01/1999	7,500,000	-	39,769	14,617	7,445,614	-	253,500	-	1,849	679	256,028	6.88%	(253,500)
04/01/2000	7,500,000	-	37,857	13,914	7,448,229	-	253,500	-	1,912	703	256,115	6.88%	(253,500)
10/01/2000	7,500,000	-	35,879	13,187	7,450,934	-	253,500	-	1,978	727	256,205	6.88%	(253,500)
04/01/2001	7,500,000	-	33,833	12,435	7,453,732	-	253,500	-	2,046	752	256,298	6.88%	(253,500)
10/01/2001	7,500,000	-	31,717	11,657	7,456,626	-	253,500	-	2,116	778	256,394	6.88%	(253,500)
04/01/2002	7,500,000	-	29,527	10,853	7,459,620	-	253,500	-	2,189	805	256,494	6.88%	(253,500)
10/01/2002	7,500,000	-	27,263	10,020	7,462,717	-	253,500	-	2,265	832	256,597	6.88%	(253,500)
04/01/2003	7,500,000	-	24,920	9,159	7,465,920	-	253,500	-	2,342	861	256,703	6.88%	(253,500)
10/01/2003	7,500,000	-	22,497	8,269	7,469,234	-	253,500	-	2,423	891	256,814	6.88%	(253,500)
04/01/2004	7,500,000	-	19,991	7,348	7,472,661	-	253,500	-	2,506	921	256,928	6.88%	(253,500)
10/01/2004	7,500,000	-	17,398	6,395	7,476,207	-	253,500	-	2,593	953	257,045	6.88%	(253,500)
04/01/2005	7,500,000	-	14,717	5,409	7,479,874	-	253,500	-	2,682	986	257,167	6.88%	(253,500)
10/01/2005	7,500,000	-	11,943	4,389	7,483,668	-	253,500	-	2,774	1,020	257,294	6.88%	(253,500)
04/01/2006	7,500,000	-	9,073	3,335	7,487,592	-	253,500	-	2,869	1,055	257,424	6.88%	(253,500)
10/01/2006	7,500,000	-	6,105	2,244	7,491,651	-	253,500	-	2,968	1,091	257,559	6.88%	(253,500)
04/01/2007	7,500,000	-	3,035	1,115	7,495,850	-	253,500	-	3,070	1,128	257,699	6.88%	(253,500)
09/24/2007	7,500,000	-	-	-	7,500,000	7,500,000	243,642	-	3,035	1,115	247,792	6.88%	(7,743,642)
						$ 7,500,000	$ 5,071,408	$ -	$ 46,875	$ 17,228	$ 5,135,512		

EXHIBIT NO.___(TKW-5)
SHEET 12 OF 13

SOUTHWEST GAS CORPORATION
Effective Cost Calculation of
6.27% Medium Term Note Series A, Due 9/22/08

Internal Rate of Return = Effective Rate 6.40%

Semi-Annual Payment	Outstanding Principal	Unamortized Balance: Reacquired Debt Expense	Unamortized Balance: Discount	Unamortized Balance: Debt Expense	Carrying Value	Redemption	Interest Expense	Amortization of: Reacquired Debt Expense	Amortization of: Discount	Amortization of: Debt Expense	Total Expense	Annual Cost	Cash Flows
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
09/24/1998	$ 25,000,000	$ -	$ 156,250	$ 79,928	$ 24,763,822	$ -	$ -	$ -	$ -	$ -	$ -		$ 24,763,822
04/01/1999	25,000,000	-	150,331	76,900	24,772,769	-	814,229	-	5,919	3,028	823,177	6.40%	(814,229)
10/01/1999	25,000,000	-	144,443	73,889	24,781,668	-	783,750	-	5,887	3,012	792,649	6.40%	(783,750)
04/01/2000	25,000,000	-	138,368	70,781	24,790,852	-	783,750	-	6,076	3,108	792,933	6.40%	(783,750)
10/01/2000	25,000,000	-	132,098	67,573	24,800,329	-	783,750	-	6,270	3,207	793,227	6.40%	(783,750)
04/01/2001	25,000,000	-	125,627	64,263	24,810,109	-	783,750	-	6,471	3,310	793,531	6.40%	(783,750)
10/01/2001	25,000,000	-	118,950	60,847	24,820,203	-	783,750	-	6,678	3,416	793,844	6.40%	(783,750)
04/01/2002	25,000,000	-	112,058	57,322	24,830,619	-	783,750	-	6,891	3,525	794,166	6.40%	(783,750)
10/01/2002	25,000,000	-	104,947	53,684	24,841,369	-	783,750	-	7,112	3,638	794,500	6.40%	(783,750)
04/01/2003	25,000,000	-	97,607	49,930	24,852,463	-	783,750	-	7,339	3,754	794,844	6.40%	(783,750)
10/01/2003	25,000,000	-	90,033	46,055	24,863,911	-	783,750	-	7,574	3,874	795,199	6.40%	(783,750)
04/01/2004	25,000,000	-	82,217	42,057	24,875,726	-	783,750	-	7,817	3,998	795,565	6.40%	(783,750)
10/01/2004	25,000,000	-	74,150	37,931	24,887,920	-	783,750	-	8,067	4,126	795,943	6.40%	(783,750)
04/01/2005	25,000,000	-	65,825	33,672	24,900,503	-	783,750	-	8,325	4,258	796,333	6.40%	(783,750)
10/01/2005	25,000,000	-	57,234	29,277	24,913,488	-	783,750	-	8,591	4,395	796,736	6.40%	(783,750)
04/01/2006	25,000,000	-	48,368	24,742	24,926,890	-	783,750	-	8,866	4,535	797,151	6.40%	(783,750)
10/01/2006	25,000,000	-	39,218	20,062	24,940,720	-	783,750	-	9,150	4,680	797,580	6.40%	(783,750)
04/01/2007	25,000,000	-	29,776	15,232	24,954,992	-	783,750	-	9,442	4,830	798,023	6.40%	(783,750)
10/01/2007	25,000,000	-	20,031	10,247	24,969,722	-	783,750	-	9,745	4,985	798,479	6.40%	(783,750)
04/01/2008	25,000,000	-	9,975	5,103	24,984,922	-	783,750	-	10,056	5,144	798,951	6.40%	(783,750)
09/22/2008	25,000,000	-	-	-	25,000,000	25,000,000	744,563	-	9,975	5,103	759,640	6.40%	(25,744,563)
						$ 25,000,000	$ 15,666,292	$ -	$ 156,250	$ 79,928	$ 15,902,470		

SOUTHWEST GAS CORPORATION
Effective Cost Calculation of
7.75% Medium Term Note Series A, Due 9/30/05

Internal Rate of Return = Effective Rate 8.07%

Semi-Annual Payment (a)	Outstanding Principal (b)	Unamortized Balance: Reacquired Debt Expense (c)	Unamortized Balance: Discount (d)	Unamortized Balance: Debt Expense (e)	Carrying Value (f)	Redemption (g)	Interest Expense (h)	Amortization of: Reacquired Debt Expense (i)	Amortization of: Discount (j)	Amortization of: Debt Expense (k)	Total Expense (l)	Annual Cost (m)	Cash Flows (n)
10/02/2000	$ 25,000,000	$ 0	$ 125,000	$ 197,928	$ 24,677,072	$ 0	$ 0		$ 0	$ 0	$ 0		$ 24,677,072
04/01/2001	25,000,000	0	114,605	181,469	24,703,926	0	968,750	0	10,395	16,459	995,604	8.07%	(968,750)
10/01/2001	25,000,000	0	103,791	164,346	24,731,863	0	968,750	0	10,814	17,123	996,687	8.07%	(968,750)
04/01/2002	25,000,000	0	92,541	146,531	24,760,928	0	968,750	0	11,250	17,814	997,815	8.07%	(968,750)
10/01/2002	25,000,000	0	80,837	127,999	24,791,165	0	968,750	0	11,704	18,533	998,987	8.07%	(968,750)
04/01/2003	25,000,000	0	68,660	108,718	24,822,622	0	968,750	0	12,177	19,281	1,000,207	8.07%	(968,750)
10/01/2003	25,000,000	0	55,992	88,660	24,855,348	0	968,750	0	12,668	20,058	1,001,476	8.07%	(968,750)
04/01/2004	25,000,000	0	42,813	67,792	24,889,395	0	968,750	0	13,179	20,868	1,002,797	8.07%	(968,750)
10/01/2004	25,000,000	0	29,103	46,082	24,924,815	0	968,750	0	13,711	21,710	1,004,170	8.07%	(968,750)
04/01/2005	25,000,000	0	14,839	23,497	24,961,664	0	968,750	0	14,264	22,586	1,005,599	8.07%	(968,750)
09/30/2005	25,000,000	0	0	0	25,000,000	25,000,000	968,750	0	14,839	23,497	1,007,086	8.07%	(25,968,750)
						$ 25,000,000	$ 9,687,500	$ 0	$ 125,000	$ 197,928	$ 10,010,428		

SOUTHWEST GAS CORPORATION
Effective Cost Calculation - $100 Million Term Facility/CP Facility
As of August 31, 2004

Line No.	Principal (a)	(b)	(c)	(d)	Annualized Interest (e)	Line No.
	Libor Loans	LIBOR	Spread	Rate[1]		
1	$ 50,000,000	1.60%	0.88%	2.48%	$ 1,258,125	1
	CP Notes	Discount Rate				
2	$ 50,000,000	2.06%			$ 1,027,511	2
	Credit Facility Fees					
3	Amortization Expense				$ 178,964	3
4	Annual Fee				10,000	4
5	Unused Commitment Fees-CP				101,667	5
6	Total Annualized Fees				$ 290,631	6
7	Total Annualized Fees and Interest (366 day basis)				$ 2,576,267	7
8	Unamortized Debt Expense - 8/31/2004				$ 486,003	8
9	CP Discount				228,883	9
10	Net Proceeds - 8/31/2004				$ 99,285,114	10
11	All-In Effective Rate				2.59%	11

Notes:
[1] Money Market Rate - 360 day basis

SOUTHWEST GAS CORPORATION
Effective Cost Calculation - Term Facility
Outstanding Loans at August 31, 2004

Line No.	Origination (a)	Maturity (b)	Principal (c)	Rate [1] (d)	One Day Interest (e)	Annualized Interest Rate [2] (f)	Annualized Interest (g)	Line No.
1	07/06/2004	10/06/2004	50,000,000	2.48%	3,438	2.52%	1,258,125	1
	Credit Facility Fees							
2	One Time Arrangement Fee (3 Year Facility)				$ 80,000		$ 26,667	2
3	Annual Fee				10,000		10,000	3
4	Legal & Other Expense				161,891		53,964	4
5	Upfront Fees (3 Year Facility)				295,000		98,333	5
6	Total Annualized Fees				$ 546,891		188,964	6
7	Total Annualized Fees and Interest (366 day basis)						$ 1,447,089	7
8	Unamortized Debt Expense - 8/31/2004						$ 486,003	8
9	Net Proceeds						$ 49,513,997	9
10	All-In Effective Rate						2.92%	10

Notes
[1] Money Market Rate
[2] 366-Day Rate

SOUTHWEST GAS CORPORATION
Effective Cost Calculation - Term Facility
Commercial Paper
Outstanding at August 31, 2004

Line No.	Issue Date (a)	Maturity Date (b)	Face Value [1] (c)	Net Proceeds [1] (d)	Discount Rate (e)	Discount [1] (f)	Days Outstanding in Month (g)	Annualized Interest [1] (h)	Line No.
1	08/26/2004	09/01/2004	100,000.00	99,968.00	1.92%	32.00	6	1,952.00	1
2	07/06/2004	09/03/2004	290,000.00	289,130.24	1.83%	869.76	31	5,395.45	2
3	07/30/2004	09/03/2004	250,000.00	249,540.63	1.89%	459.38	31	4,803.75	3
4	08/26/2004	09/07/2004	300,000.00	299,806.00	1.94%	194.00	6	5,917.00	4
5	07/08/2004	09/08/2004	502,000.00	500,365.99	1.89%	1,634.01	31	9,645.93	5
6	07/20/2004	09/08/2004	150,000.00	149,608.33	1.88%	391.67	31	2,867.00	6
7	08/06/2004	09/10/2004	250,000.00	249,538.19	1.90%	461.81	26	4,829.17	7
8	07/13/2004	09/13/2004	150,000.00	149,509.17	1.90%	490.83	31	2,897.50	8
9	07/01/2004	09/15/2004	400,000.00	398,404.00	1.89%	1,596.00	31	7,686.00	9
10	07/16/2004	09/16/2004	200,000.00	199,335.22	1.93%	664.78	31	3,924.33	10
11	05/21/2004	09/17/2004	100,000.00	99,428.14	1.73%	571.86	31	1,758.83	11
12	08/13/2004	09/17/2004	250,000.00	249,521.18	1.97%	478.82	19	5,007.08	12
13	08/26/2004	09/17/2004	600,000.00	599,288.67	1.94%	711.33	6	11,834.00	13
14	08/13/2004	09/20/2004	1,720,000.00	1,716,423.36	1.97%	3,576.64	19	34,448.73	14
15	05/27/2004	09/21/2004	300,000.00	298,313.25	1.73%	1,686.75	31	5,276.50	15
16	06/15/2004	09/22/2004	680,000.00	676,297.40	1.98%	3,702.60	31	13,688.40	16
17	06/16/2004	09/22/2004	500,000.00	497,345.83	1.95%	2,654.17	31	9,912.50	17
18	06/17/2004	09/22/2004	510,000.00	507,320.38	1.95%	2,679.63	31	10,110.75	18
19	08/16/2004	09/23/2004	1,437,000.00	1,434,011.84	1.97%	2,988.16	16	28,780.72	19
20	06/25/2004	09/24/2004	500,000.00	497,472.22	2.00%	2,527.78	31	10,166.67	20
21	06/28/2004	09/27/2004	1,100,000.00	1,094,438.89	2.00%	5,561.11	31	22,366.67	21
22	07/27/2004	09/27/2004	1,800,000.00	1,793,893.00	1.97%	6,107.00	31	36,051.00	22
23	08/12/2004	09/27/2004	500,000.00	498,728.61	1.99%	1,271.39	20	10,115.83	23
24	06/30/2004	09/28/2004	150,000.00	149,242.50	2.02%	757.50	31	3,080.50	24
25	07/01/2004	09/29/2004	415,000.00	412,904.25	2.02%	2,095.75	31	8,522.72	25
26	08/09/2004	09/30/2004	750,000.00	747,898.33	1.94%	2,101.67	23	14,792.50	26
27	06/07/2004	10/05/2004	100,000.00	99,356.67	1.93%	643.33	31	1,962.17	27
28	07/07/2004	10/05/2004	300,000.00	298,485.00	2.02%	1,515.00	31	6,161.00	28
29	07/30/2004	10/06/2004	633,000.00	630,620.62	1.99%	2,379.38	31	12,806.65	29
30	08/04/2004	10/06/2004	367,000.00	365,728.35	1.98%	1,271.66	28	7,387.71	30
31	08/17/2004	10/07/2004	125,000.00	124,647.60	1.99%	352.40	15	2,528.96	31
32	08/09/2004	10/08/2004	250,000.00	249,183.33	1.96%	816.67	23	4,981.67	32
33	06/14/2004	10/12/2004	118,000.00	117,181.87	2.08%	818.13	31	2,495.31	33
34	07/12/2004	10/12/2004	300,000.00	298,451.33	2.02%	1,548.67	31	6,161.00	34
35	07/13/2004	10/12/2004	500,000.00	497,446.94	2.02%	2,553.06	31	10,268.33	35
36	07/14/2004	10/12/2004	300,000.00	298,485.00	2.02%	1,515.00	31	6,161.00	36
37	07/13/2004	10/13/2004	725,000.00	721,257.39	2.02%	3,742.61	31	14,889.08	37
38	07/14/2004	10/13/2004	1,100,000.00	1,094,383.28	2.02%	5,616.72	31	22,590.33	38
39	07/15/2004	10/13/2004	1,180,000.00	1,173,982.00	2.04%	6,018.00	31	24,473.20	39
40	08/25/2004	10/13/2004	3,653,000.00	3,643,105.44	1.99%	9,894.56	7	73,906.28	40
41	07/12/2004	10/15/2004	500,000.00	497,334.72	2.02%	2,665.28	31	10,268.33	41
42	07/27/2004	10/15/2004	1,000,000.00	995,622.22	1.97%	4,377.78	31	20,028.33	42

SOUTHWEST GAS CORPORATION
Effective Cost Calculation - Term Facility
Commercial Paper
Outstanding at August 31, 2004

Line No.	Issue Date (a)	Maturity Date (b)	Face Value [1] (c)	Net Proceeds [1] (d)	Discount Rate (e)	Discount [1] (f)	Days Outstanding in Month (g)	Annualized Interest [1] (h)	Line No.
43	08/17/2004	10/18/2004	100,000.00	99,653.83	2.01%	346.17	15	2,043.50	43
44	07/20/2004	10/19/2004	150,000.00	149,226.50	2.04%	773.50	31	3,111.00	44
45	06/23/2004	10/21/2004	100,000.00	99,336.67	1.99%	663.33	31	2,023.17	45
46	07/23/2004	10/21/2004	250,000.00	248,700.00	2.08%	1,300.00	31	5,286.67	46
47	07/27/2004	10/21/2004	1,000,000.00	995,293.89	1.97%	4,706.11	31	20,028.33	47
48	07/27/2004	10/25/2004	1,200,000.00	1,193,760.00	2.08%	6,240.00	31	25,376.00	48
49	08/12/2004	10/25/2004	1,000,000.00	995,868.33	2.01%	4,131.67	20	20,435.00	49
50	07/30/2004	10/28/2004	367,000.00	365,073.25	2.10%	1,926.75	31	7,835.45	50
51	07/01/2004	10/29/2004	112,000.00	111,245.87	2.02%	754.13	31	2,300.11	51
52	07/28/2004	11/03/2004	500,000.00	497,141.67	2.10%	2,858.33	31	10,675.00	52
53	08/12/2004	11/04/2004	1,000,000.00	995,310.00	2.01%	4,690.00	20	20,435.00	53
54	08/09/2004	11/08/2004	343,000.00	341,187.91	2.09%	1,812.09	23	7,288.18	54
55	07/15/2004	11/09/2004	400,000.00	397,348.00	2.04%	2,652.00	31	8,296.00	55
56	08/12/2004	11/10/2004	350,000.00	348,180.00	2.08%	1,820.00	20	7,401.33	56
57	07/16/2004	11/12/2004	350,000.00	347,639.83	2.04%	2,360.17	31	7,259.00	57
58	08/13/2004	11/12/2004	500,000.00	497,371.11	2.08%	2,628.89	19	10,573.33	58
59	08/13/2004	11/15/2004	660,000.00	656,415.47	2.08%	3,584.53	19	13,956.80	59
60	07/20/2004	11/17/2004	200,000.00	198,640.00	2.04%	1,360.00	31	4,148.00	60
61	08/11/2004	11/17/2004	500,000.00	497,168.89	2.08%	2,831.11	21	10,573.33	61
62	07/28/2004	11/23/2004	200,000.00	198,623.33	2.10%	1,376.67	31	4,270.00	62
63	07/29/2004	11/23/2004	367,000.00	364,495.23	2.10%	2,504.78	31	7,835.45	63
64	08/24/2004	11/29/2004	250,000.00	248,598.89	2.08%	1,401.11	8	5,286.67	64
65	08/25/2004	11/29/2004	150,000.00	149,168.00	2.08%	832.00	7	3,172.00	65
66	08/26/2004	11/30/2004	2,210,000.00	2,197,741.87	2.08%	12,258.13	6	46,734.13	66
67	08/27/2004	11/30/2004	11,686,000.00	11,621,856.84	2.08%	64,143.16	5	247,119.95	67
68	08/17/2004	12/15/2004	1,000,000.00	993,066.67	2.08%	6,933.33	15	21,146.67	68
69	Total		$ 50,000,000.00	$ 49,771,117.43	2.06%	$ 228,882.57	31	$ 1,027,510.94	69
	Credit Facility Fees								
70	Unused Commitment Fees		$ 50,000,000.00		0.200%		366	$ 101,666.67	70
71	Total Discount and Credit Facility Fees							$ 1,129,177.61	71
72	Net Proceeds							$ 49,771,117.43	72
73	All-In Effective Rate							2.27%	73

SOUTHWEST GAS CORPORATION
Effective Cost Calculation of
7.7% Trust Originated Preferred Securities, Due September 15, 2043

	Effective Rate
Internal Rate of Return =	2.05%
Annual Effective Rate =	8.20%

Quarterly Payment	Outstanding Principal	Unamortized Balance: Reacquired Debt Expense	Unamortized Balance: Discount	Unamortized Balance: Debt Expense	Net Proceeds	Redemption	Interest Expense	Amortization of: Reacquired Debt Expense	Amortization of: Discount	Amortization of: Debt Expense	Total Expense	Cost	Cash Flows
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
08/25/2003	$ 100,000,000	$ 2,221,449	$ 3,150,000	$ 537,824	$ 94,090,727	$ 0	$ 0		$ 0	$ 0	$ 0		$ 94,090,727
09/30/2003	100,000,000	2,220,737	3,148,990	537,651	94,092,622	0	748,611	712	1,010	172	750,506	2.05%	(748,611)
12/31/2003	100,000,000	2,218,890	3,146,371	537,204	94,097,534	0	1,925,000	1,847	2,619	447	1,929,912	2.05%	(1,925,000)
03/31/2004	100,000,000	2,217,006	3,143,699	536,748	94,102,547	0	1,925,000	1,885	2,672	456	1,930,013	2.05%	(1,925,000)
06/30/2004	100,000,000	2,215,083	3,140,972	536,282	94,107,663	0	1,925,000	1,923	2,727	466	1,930,116	2.05%	(1,925,000)
09/30/2004	100,000,000	2,213,120	3,138,189	535,807	94,112,884	0	1,925,000	1,963	2,783	475	1,930,221	2.05%	(1,925,000)
12/31/2004	100,000,000	2,211,117	3,135,349	535,322	94,118,212	0	1,925,000	2,003	2,840	485	1,930,328	2.05%	(1,925,000)
03/31/2005	100,000,000	2,209,073	3,132,451	534,827	94,123,649	0	1,925,000	2,044	2,898	495	1,930,437	2.05%	(1,925,000)
06/30/2005	100,000,000	2,206,987	3,129,493	534,322	94,129,197	0	1,925,000	2,086	2,958	505	1,930,549	2.05%	(1,925,000)
09/30/2005	100,000,000	2,204,859	3,126,475	533,807	94,134,860	0	1,925,000	2,129	3,018	515	1,930,662	2.05%	(1,925,000)
12/31/2005	100,000,000	2,202,686	3,123,394	533,281	94,140,638	0	1,925,000	2,172	3,080	526	1,930,779	2.05%	(1,925,000)
03/31/2006	100,000,000	2,200,470	3,120,251	532,744	94,146,535	0	1,925,000	2,217	3,144	537	1,930,897	2.05%	(1,925,000)
06/30/2006	100,000,000	2,198,207	3,117,043	532,197	94,152,553	0	1,925,000	2,262	3,208	548	1,931,018	2.05%	(1,925,000)
09/30/2006	100,000,000	2,195,899	3,113,769	531,638	94,158,695	0	1,925,000	2,309	3,274	559	1,931,141	2.05%	(1,925,000)
12/31/2006	100,000,000	2,193,542	3,110,428	531,067	94,164,962	0	1,925,000	2,356	3,341	570	1,931,267	2.05%	(1,925,000)
03/31/2007	100,000,000	2,191,138	3,107,019	530,485	94,171,358	0	1,925,000	2,404	3,409	582	1,931,396	2.05%	(1,925,000)
06/30/2007	100,000,000	2,188,684	3,103,539	529,891	94,177,886	0	1,925,000	2,454	3,479	594	1,931,527	2.05%	(1,925,000)
09/30/2007	100,000,000	2,186,180	3,099,988	529,285	94,184,547	0	1,925,000	2,504	3,551	606	1,931,661	2.05%	(1,925,000)
12/31/2007	100,000,000	2,183,625	3,096,365	528,666	94,191,344	0	1,925,000	2,555	3,624	619	1,931,798	2.05%	(1,925,000)
03/31/2008	100,000,000	2,181,017	3,092,667	528,035	94,198,281	0	1,925,000	2,608	3,698	631	1,931,937	2.05%	(1,925,000)
06/30/2008	100,000,000	2,178,356	3,088,893	527,390	94,205,361	0	1,925,000	2,661	3,774	644	1,932,079	2.05%	(1,925,000)
09/30/2008	100,000,000	2,175,640	3,085,042	526,733	94,212,585	0	1,925,000	2,716	3,851	658	1,932,225	2.05%	(1,925,000)
12/31/2008	100,000,000	2,172,868	3,081,112	526,062	94,219,958	0	1,925,000	2,772	3,930	671	1,932,373	2.05%	(1,925,000)
03/31/2009	100,000,000	2,170,040	3,077,101	525,377	94,227,482	0	1,925,000	2,828	4,011	685	1,932,524	2.05%	(1,925,000)
06/30/2009	100,000,000	2,167,153	3,073,008	524,678	94,235,160	0	1,925,000	2,886	4,093	699	1,932,678	2.05%	(1,925,000)
09/30/2009	100,000,000	2,164,208	3,068,831	523,965	94,242,996	0	1,925,000	2,946	4,177	713	1,932,836	2.05%	(1,925,000)
12/31/2009	100,000,000	2,161,201	3,064,569	523,237	94,250,993	0	1,925,000	3,006	4,263	728	1,932,997	2.05%	(1,925,000)
03/31/2010	100,000,000	2,158,134	3,060,219	522,495	94,259,153	0	1,925,000	3,068	4,350	743	1,933,161	2.05%	(1,925,000)
06/30/2010	100,000,000	2,155,003	3,055,779	521,737	94,267,481	0	1,925,000	3,131	4,439	758	1,933,328	2.05%	(1,925,000)
09/30/2010	100,000,000	2,151,808	3,051,249	520,963	94,275,980	0	1,925,000	3,195	4,530	773	1,933,499	2.05%	(1,925,000)
12/31/2010	100,000,000	2,148,548	3,046,626	520,174	94,284,653	0	1,925,000	3,260	4,623	789	1,933,673	2.05%	(1,925,000)
03/31/2011	100,000,000	2,145,220	3,041,908	519,368	94,293,504	0	1,925,000	3,327	4,718	806	1,933,851	2.05%	(1,925,000)
06/30/2011	100,000,000	2,141,825	3,037,093	518,546	94,302,536	0	1,925,000	3,396	4,815	822	1,934,032	2.05%	(1,925,000)
09/30/2011	100,000,000	2,138,360	3,032,179	517,707	94,311,754	0	1,925,000	3,465	4,914	839	1,934,218	2.05%	(1,925,000)
12/31/2011	100,000,000	2,134,823	3,027,165	516,851	94,321,161	0	1,925,000	3,536	5,014	856	1,934,407	2.05%	(1,925,000)
03/31/2012	100,000,000	2,131,215	3,022,048	515,977	94,330,761	0	1,925,000	3,609	5,117	874	1,934,600	2.05%	(1,925,000)
06/30/2012	100,000,000	2,127,532	3,016,825	515,086	94,340,557	0	1,925,000	3,683	5,222	892	1,934,797	2.05%	(1,925,000)
09/30/2012	100,000,000	2,123,773	3,011,496	514,176	94,350,555	0	1,925,000	3,758	5,329	910	1,934,998	2.05%	(1,925,000)
12/31/2012	100,000,000	2,119,938	3,006,057	513,247	94,360,757	0	1,925,000	3,835	5,439	929	1,935,203	2.05%	(1,925,000)
03/31/2013	100,000,000	2,116,024	3,000,507	512,300	94,371,169	0	1,925,000	3,914	5,550	948	1,935,412	2.05%	(1,925,000)
06/30/2013	100,000,000	2,112,030	2,994,843	511,332	94,381,795	-	1,925,000	3,994	5,664	967	1,935,625	2.05%	(1,925,000)
09/30/2013	100,000,000	2,107,953	2,989,063	510,346	94,392,638	0	1,925,000	4,076	5,780	987	1,935,843	2.05%	(1,925,000)
12/31/2013	100,000,000	2,103,793	2,983,164	509,338	94,403,704	0	1,925,000	4,160	5,899	1,007	1,936,066	2.05%	(1,925,000)
03/31/2014	100,000,000	2,099,548	2,977,145	508,311	94,414,997	0	1,925,000	4,245	6,020	1,028	1,936,293	2.05%	(1,925,000)
06/30/2014	100,000,000	2,095,216	2,971,001	507,262	94,426,521	0	1,925,000	4,332	6,143	1,049	1,936,524	2.05%	(1,925,000)
09/30/2014	100,000,000	2,090,795	2,964,732	506,191	94,438,282	0	1,925,000	4,421	6,269	1,070	1,936,761	2.05%	(1,925,000)
12/31/2014	100,000,000	2,086,283	2,958,334	505,099	94,450,284	0	1,925,000	4,512	6,398	1,092	1,937,002	2.05%	(1,925,000)
03/31/2015	100,000,000	2,081,678	2,951,805	503,984	94,462,532	0	1,925,000	4,604	6,529	1,115	1,937,248	2.05%	(1,925,000)

EXHIBIT NO.___(TKW-7)
SHEET 2 OF 4

SOUTHWEST GAS CORPORATION
Effective Cost Calculation of
7.7% Trust Originated Preferred Securities, Due September 15, 2043

Internal Rate of Return = 2.05% (Effective Rate)
Annual Effective Rate = 8.20%

Quarterly Payment (a)	Outstanding Principal (b)	Unamortized Balance: Reacquired Debt Expense (c)	Unamortized Balance: Discount (d)	Unamortized Balance: Debt Expense (e)	Net Proceeds (f)	Redemption (g)	Interest Expense (h)	Amortization of: Reacquired Debt Expense (i)	Amortization of: Discount (j)	Amortization of: Debt Expense (k)	Total Expense (l)	Cost (m)	Cash Flows (n)
06/30/2015	100,000,000	2,076,980	2,945,143	502,847	94,475,031	0	1,925,000	4,699	6,663	1,138	1,937,499	2.05%	(1,925,000)
09/30/2015	100,000,000	2,072,184	2,938,343	501,686	94,487,787	0	1,925,000	4,795	6,800	1,161	1,937,756	2.05%	(1,925,000)
12/31/2015	100,000,000	2,067,291	2,931,404	500,501	94,500,804	0	1,925,000	4,894	6,939	1,185	1,938,017	2.05%	(1,925,000)
03/31/2016	100,000,000	2,062,297	2,924,323	499,292	94,514,089	0	1,925,000	4,994	7,081	1,209	1,938,284	2.05%	(1,925,000)
06/30/2016	100,000,000	2,057,200	2,917,096	498,058	94,527,646	0	1,925,000	5,096	7,227	1,234	1,938,557	2.05%	(1,925,000)
09/30/2016	100,000,000	2,052,000	2,909,721	496,799	94,541,480	0	1,925,000	5,201	7,375	1,259	1,938,835	2.05%	(1,925,000)
12/31/2016	100,000,000	2,046,692	2,902,195	495,514	94,555,599	0	1,925,000	5,308	7,526	1,285	1,939,119	2.05%	(1,925,000)
03/31/2017	100,000,000	2,041,276	2,894,515	494,203	94,570,007	0	1,925,000	5,416	7,680	1,311	1,939,408	2.05%	(1,925,000)
06/30/2017	100,000,000	2,035,748	2,886,677	492,864	94,584,711	0	1,925,000	5,528	7,838	1,338	1,939,704	2.05%	(1,925,000)
09/30/2017	100,000,000	2,030,107	2,878,678	491,499	94,599,716	0	1,925,000	5,641	7,999	1,366	1,940,005	2.05%	(1,925,000)
12/31/2017	100,000,000	2,024,350	2,870,515	490,105	94,615,030	0	1,925,000	5,757	8,163	1,394	1,940,313	2.05%	(1,925,000)
03/31/2018	100,000,000	2,018,476	2,862,185	488,683	94,630,657	0	1,925,000	5,875	8,330	1,422	1,940,627	2.05%	(1,925,000)
06/30/2018	100,000,000	2,012,481	2,853,684	487,231	94,646,604	0	1,925,000	5,995	8,501	1,451	1,940,948	2.05%	(1,925,000)
09/30/2018	100,000,000	2,006,363	2,845,008	485,750	94,662,879	0	1,925,000	6,118	8,675	1,481	1,941,275	2.05%	(1,925,000)
12/31/2018	100,000,000	2,000,119	2,836,155	484,238	94,679,488	0	1,925,000	6,244	8,853	1,512	1,941,609	2.05%	(1,925,000)
03/31/2019	100,000,000	1,993,747	2,827,120	482,696	94,696,437	0	1,925,000	6,372	9,035	1,543	1,941,949	2.05%	(1,925,000)
06/30/2019	100,000,000	1,987,245	2,817,899	481,122	94,713,734	0	1,925,000	6,502	9,220	1,574	1,942,297	2.05%	(1,925,000)
09/30/2019	100,000,000	1,980,609	2,808,490	479,515	94,731,386	0	1,925,000	6,636	9,409	1,607	1,942,652	2.05%	(1,925,000)
12/31/2019	100,000,000	1,973,837	2,798,888	477,875	94,749,400	0	1,925,000	6,772	9,602	1,640	1,943,014	2.05%	(1,925,000)
03/31/2020	100,000,000	1,966,927	2,789,088	476,202	94,767,783	0	1,925,000	6,911	9,799	1,673	1,943,383	2.05%	(1,925,000)
06/30/2020	100,000,000	1,959,874	2,779,088	474,495	94,786,543	0	1,925,000	7,052	10,000	1,707	1,943,760	2.05%	(1,925,000)
09/30/2020	100,000,000	1,952,677	2,768,882	472,752	94,805,688	0	1,925,000	7,197	10,205	1,742	1,944,145	2.05%	(1,925,000)
12/31/2020	100,000,000	1,945,332	2,758,468	470,974	94,825,226	0	1,925,000	7,345	10,415	1,778	1,944,538	2.05%	(1,925,000)
03/31/2021	100,000,000	1,937,837	2,747,839	469,160	94,845,165	0	1,925,000	7,495	10,628	1,815	1,944,939	2.05%	(1,925,000)
06/30/2021	100,000,000	1,930,188	2,736,993	467,308	94,865,512	0	1,925,000	7,649	10,846	1,852	1,945,347	2.05%	(1,925,000)
09/30/2021	100,000,000	1,922,382	2,725,924	465,418	94,886,277	0	1,925,000	7,806	11,069	1,890	1,945,765	2.05%	(1,925,000)
12/31/2021	100,000,000	1,914,415	2,714,628	463,489	94,907,468	0	1,925,000	7,966	11,296	1,929	1,946,191	2.05%	(1,925,000)
03/31/2022	100,000,000	1,906,286	2,703,100	461,521	94,929,093	0	1,925,000	8,130	11,528	1,968	1,946,625	2.05%	(1,925,000)
06/30/2022	100,000,000	1,897,990	2,691,336	459,512	94,951,162	0	1,925,000	8,296	11,764	2,009	1,947,069	2.05%	(1,925,000)
09/30/2022	100,000,000	1,889,523	2,679,331	457,463	94,973,683	0	1,925,000	8,466	12,005	2,050	1,947,522	2.05%	(1,925,000)
12/31/2022	100,000,000	1,880,883	2,667,079	455,371	94,996,667	0	1,925,000	8,640	12,252	2,092	1,947,983	2.05%	(1,925,000)
03/31/2023	100,000,000	1,872,066	2,654,576	453,236	95,020,122	0	1,925,000	8,817	12,503	2,135	1,948,455	2.05%	(1,925,000)
06/30/2023	100,000,000	1,863,068	2,641,817	451,058	95,044,058	0	1,925,000	8,998	12,759	2,178	1,948,936	2.05%	(1,925,000)
09/30/2023	100,000,000	1,853,885	2,628,796	448,834	95,068,485	0	1,925,000	9,183	13,021	2,223	1,949,427	2.05%	(1,925,000)
12/31/2023	100,000,000	1,844,514	2,615,508	446,566	95,093,412	0	1,925,000	9,371	13,288	2,269	1,949,928	2.05%	(1,925,000)
03/31/2024	100,000,000	1,834,951	2,601,947	444,250	95,118,852	0	1,925,000	9,563	13,561	2,315	1,950,439	2.05%	(1,925,000)
06/30/2024	100,000,000	1,825,191	2,588,109	441,888	95,144,813	0	1,925,000	9,759	13,839	2,363	1,950,961	2.05%	(1,925,000)
09/30/2024	100,000,000	1,815,232	2,573,986	439,476	95,171,306	0	1,925,000	9,960	14,123	2,411	1,951,493	2.05%	(1,925,000)
12/31/2024	100,000,000	1,805,068	2,559,574	437,016	95,198,343	0	1,925,000	10,164	14,412	2,461	1,952,037	2.05%	(1,925,000)
03/31/2025	100,000,000	1,794,695	2,544,866	434,504	95,225,934	0	1,925,000	10,372	14,708	2,511	1,952,591	2.05%	(1,925,000)
06/30/2025	100,000,000	1,784,110	2,529,856	431,942	95,254,092	0	1,925,000	10,585	15,010	2,563	1,953,157	2.05%	(1,925,000)
09/30/2025	100,000,000	1,773,308	2,514,539	429,326	95,282,827	0	1,925,000	10,802	15,317	2,615	1,953,735	2.05%	(1,925,000)
12/31/2025	100,000,000	1,762,284	2,498,907	426,657	95,312,151	0	1,925,000	11,024	15,632	2,669	1,954,324	2.05%	(1,925,000)
03/31/2026	100,000,000	1,751,035	2,482,955	423,934	95,342,077	0	1,925,000	11,250	15,952	2,724	1,954,926	2.05%	(1,925,000)
06/30/2026	100,000,000	1,739,554	2,466,676	421,154	95,372,616	0	1,925,000	11,481	16,279	2,780	1,955,540	2.05%	(1,925,000)
09/30/2026	100,000,000	1,727,838	2,450,062	418,318	95,403,782	0	1,925,000	11,716	16,613	2,837	1,956,166	2.05%	(1,925,000)
12/31/2026	100,000,000	1,715,882	2,433,108	415,423	95,435,587	0	1,925,000	11,956	16,954	2,895	1,956,805	2.05%	(1,925,000)
03/31/2027	100,000,000	1,703,680	2,415,806	412,469	95,468,045	0	1,925,000	12,202	17,302	2,954	1,957,457	2.05%	(1,925,000)

SOUTHWEST GAS CORPORATION
Effective Cost Calculation of
7.7% Trust Originated Preferred Securities, Due September 15, 2043

Internal Rate of Return = 2.05%
Annual Effective Rate = 8.20%
Effective Rate

Quarterly Payment	Outstanding Principal	Unamortized Balance: Reacquired Debt Expense	Unamortized Balance: Discount	Unamortized Balance: Debt Expense	Net Proceeds	Redemption	Interest Expense	Amortization of: Reacquired Debt Expense	Amortization of: Discount	Amortization of: Debt Expense	Total Expense	Cost	Cash Flows
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
06/30/2027	100,000,000	1,691,228	2,398,150	409,454	95,501,168	0	1,925,000	12,452	17,657	3,015	1,958,123	2.05%	(1,925,000)
09/30/2027	100,000,000	1,678,521	2,380,131	406,378	95,534,970	0	1,925,000	12,707	18,019	3,076	1,958,803	2.05%	(1,925,000)
12/31/2027	100,000,000	1,665,553	2,361,743	403,238	95,569,466	0	1,925,000	12,968	18,388	3,140	1,959,496	2.05%	(1,925,000)
03/31/2028	100,000,000	1,652,319	2,342,977	400,034	95,604,670	0	1,925,000	13,234	18,766	3,204	1,960,203	2.05%	(1,925,000)
06/30/2028	100,000,000	1,638,814	2,323,827	396,765	95,640,595	0	1,925,000	13,505	19,150	3,270	1,960,925	2.05%	(1,925,000)
09/30/2028	100,000,000	1,625,031	2,304,283	393,428	95,677,257	0	1,925,000	13,782	19,543	3,337	1,961,662	2.05%	(1,925,000)
12/31/2028	100,000,000	1,610,966	2,284,339	390,023	95,714,672	0	1,925,000	14,065	19,944	3,405	1,962,414	2.05%	(1,925,000)
03/31/2029	100,000,000	1,596,613	2,263,986	386,548	95,752,854	0	1,925,000	14,354	20,353	3,475	1,963,182	2.05%	(1,925,000)
06/30/2029	100,000,000	1,581,965	2,243,215	383,001	95,791,818	0	1,925,000	14,648	20,771	3,546	1,963,965	2.05%	(1,925,000)
09/30/2029	100,000,000	1,567,017	2,222,019	379,382	95,831,582	0	1,925,000	14,948	21,197	3,619	1,964,764	2.05%	(1,925,000)
12/31/2029	100,000,000	1,551,762	2,200,387	375,689	95,872,162	0	1,925,000	15,255	21,631	3,693	1,965,580	2.05%	(1,925,000)
03/31/2030	100,000,000	1,536,194	2,178,312	371,920	95,913,574	0	1,925,000	15,568	22,075	3,769	1,966,412	2.05%	(1,925,000)
06/30/2030	100,000,000	1,520,307	2,155,784	368,074	95,955,835	0	1,925,000	15,887	22,528	3,846	1,967,261	2.05%	(1,925,000)
09/30/2030	100,000,000	1,504,094	2,132,794	364,148	95,998,964	0	1,925,000	16,213	22,990	3,925	1,968,128	2.05%	(1,925,000)
12/31/2030	100,000,000	1,487,548	2,109,333	360,142	96,042,976	0	1,925,000	16,546	23,461	4,006	1,969,013	2.05%	(1,925,000)
03/31/2031	100,000,000	1,470,663	2,085,390	356,055	96,087,892	0	1,925,000	16,885	23,943	4,088	1,969,916	2.05%	(1,925,000)
06/30/2031	100,000,000	1,453,432	2,060,957	351,883	96,133,729	0	1,925,000	17,231	24,434	4,172	1,970,837	2.05%	(1,925,000)
09/30/2031	100,000,000	1,435,847	2,036,022	347,625	96,180,505	0	1,925,000	17,585	24,935	4,257	1,971,777	2.05%	(1,925,000)
12/31/2031	100,000,000	1,417,902	2,010,575	343,281	96,228,242	0	1,925,000	17,945	25,446	4,345	1,972,736	2.05%	(1,925,000)
03/31/2032	100,000,000	1,399,589	1,984,607	338,847	96,276,957	0	1,925,000	18,313	25,968	4,434	1,973,715	2.05%	(1,925,000)
06/30/2032	100,000,000	1,380,900	1,958,106	334,322	96,326,672	0	1,925,000	18,689	26,501	4,525	1,974,715	2.05%	(1,925,000)
09/30/2032	100,000,000	1,361,827	1,931,062	329,705	96,377,406	0	1,925,000	19,072	27,044	4,618	1,975,734	2.05%	(1,925,000)
12/31/2032	100,000,000	1,342,364	1,903,463	324,993	96,429,181	0	1,925,000	19,464	27,599	4,712	1,976,775	2.05%	(1,925,000)
03/31/2033	100,000,000	1,322,501	1,875,297	320,184	96,482,018	0	1,925,000	19,863	28,165	4,809	1,977,837	2.05%	(1,925,000)
06/30/2033	100,000,000	1,302,231	1,846,554	315,276	96,535,938	0	1,925,000	20,270	28,743	4,908	1,978,921	2.05%	(1,925,000)
09/30/2033	100,000,000	1,281,545	1,817,222	310,268	96,590,965	0	1,925,000	20,686	29,332	5,008	1,980,027	2.05%	(1,925,000)
12/31/2033	100,000,000	1,260,435	1,787,288	305,157	96,647,120	0	1,925,000	21,110	29,934	5,111	1,981,155	2.05%	(1,925,000)
03/31/2034	100,000,000	1,238,892	1,756,740	299,942	96,704,427	0	1,925,000	21,543	30,548	5,216	1,982,307	2.05%	(1,925,000)
06/30/2034	100,000,000	1,216,907	1,725,565	294,619	96,762,909	0	1,925,000	21,985	31,175	5,323	1,983,482	2.05%	(1,925,000)
09/30/2034	100,000,000	1,194,471	1,693,751	289,187	96,822,591	0	1,925,000	22,436	31,814	5,432	1,984,682	2.05%	(1,925,000)
12/31/2034	100,000,000	1,171,574	1,661,284	283,644	96,883,497	0	1,925,000	22,896	32,467	5,543	1,985,906	2.05%	(1,925,000)
03/31/2035	100,000,000	1,148,209	1,628,152	277,987	96,945,653	0	1,925,000	23,366	33,133	5,657	1,987,155	2.05%	(1,925,000)
06/30/2035	100,000,000	1,124,364	1,594,340	272,214	97,009,083	0	1,925,000	23,845	33,812	5,773	1,988,430	2.05%	(1,925,000)
09/30/2035	100,000,000	1,100,030	1,559,834	266,322	97,073,814	0	1,925,000	24,334	34,506	5,891	1,989,731	2.05%	(1,925,000)
12/31/2035	100,000,000	1,075,196	1,524,621	260,310	97,139,873	0	1,925,000	24,833	35,213	6,012	1,991,059	2.05%	(1,925,000)
03/31/2036	100,000,000	1,049,854	1,488,685	254,175	97,207,286	0	1,925,000	25,343	35,936	6,136	1,992,414	2.05%	(1,925,000)
06/30/2036	100,000,000	1,023,991	1,452,013	247,913	97,276,083	0	1,925,000	25,862	36,673	6,261	1,993,796	2.05%	(1,925,000)
09/30/2036	100,000,000	997,599	1,414,588	241,523	97,346,290	0	1,925,000	26,393	37,425	6,390	1,995,207	2.05%	(1,925,000)
12/31/2036	100,000,000	970,664	1,376,396	235,002	97,417,938	0	1,925,000	26,934	38,192	6,521	1,996,647	2.05%	(1,925,000)
03/31/2037	100,000,000	943,178	1,337,420	228,348	97,491,055	0	1,925,000	27,487	38,976	6,655	1,998,117	2.05%	(1,925,000)
06/30/2037	100,000,000	915,128	1,297,645	221,557	97,565,671	0	1,925,000	28,050	39,775	6,791	1,999,617	2.05%	(1,925,000)
09/30/2037	100,000,000	886,502	1,257,053	214,626	97,641,818	0	1,925,000	28,626	40,591	6,930	2,001,147	2.05%	(1,925,000)
12/31/2037	100,000,000	857,289	1,215,630	207,554	97,719,527	0	1,925,000	29,213	41,424	7,073	2,002,709	2.05%	(1,925,000)
03/31/2038	100,000,000	827,477	1,173,357	200,336	97,798,830	0	1,925,000	29,812	42,273	7,218	2,004,303	2.05%	(1,925,000)
06/30/2038	100,000,000	797,054	1,130,216	192,970	97,879,760	0	1,925,000	30,423	43,140	7,366	2,005,929	2.05%	(1,925,000)
09/30/2038	100,000,000	766,006	1,086,191	185,454	97,962,349	0	1,925,000	31,047	44,025	7,517	2,007,589	2.05%	(1,925,000)
12/31/2038	100,000,000	734,322	1,041,263	177,783	98,046,632	0	1,925,000	31,684	44,928	7,671	2,009,283	2.05%	(1,925,000)
03/31/2039	100,000,000	701,988	995,414	169,955	98,132,644	0	1,925,000	32,334	45,850	7,828	2,011,012	2.05%	(1,925,000)

EXHIBIT NO.___(TKW-7)
SHEET 4 OF 4

SOUTHWEST GAS CORPORATION
Effective Cost Calculation of
7.7% Trust Originated Preferred Securities, Due September 15, 2043

Internal Rate of Return = 2.05%
Annual Effective Rate = 8.20%

Quarterly Payment (a)	Outstanding Principal (b)	Unamortized Balance: Reacquired Debt Expense (c)	Unamortized Balance: Discount (d)	Unamortized Balance: Debt Expense (e)	Net Proceeds (f)	Redemption (g)	Interest Expense (h)	Amortization of: Reacquired Debt Expense (i)	Amortization of: Discount (j)	Amortization of: Debt Expense (k)	Total Expense (l)	Cost (m)	Effective Rate: Cash Flows (n)
06/30/2039	100,000,000	668,990	948,624	161,966	98,220,420	0	1,925,000	32,997	46,790	7,989	2,012,776	2.05%	(1,925,000)
09/30/2039	100,000,000	635,316	900,874	153,813	98,309,997	0	1,925,000	33,674	47,750	8,153	2,014,577	2.05%	(1,925,000)
12/31/2039	100,000,000	600,951	852,145	145,493	98,401,411	0	1,925,000	34,365	48,729	8,320	2,016,414	2.05%	(1,925,000)
03/31/2040	100,000,000	565,882	802,416	137,003	98,494,700	0	1,925,000	35,070	49,729	8,491	2,018,289	2.05%	(1,925,000)
06/30/2040	100,000,000	530,093	751,668	128,338	98,589,902	0	1,925,000	35,789	50,749	8,665	2,020,202	2.05%	(1,925,000)
09/30/2040	100,000,000	493,570	699,878	119,496	98,687,057	0	1,925,000	36,523	51,789	8,842	2,022,155	2.05%	(1,925,000)
12/31/2040	100,000,000	456,297	647,026	110,472	98,786,204	0	1,925,000	37,272	52,852	9,024	2,024,148	2.05%	(1,925,000)
03/31/2041	100,000,000	418,261	593,091	101,263	98,887,386	0	1,925,000	38,037	53,936	9,209	2,026,181	2.05%	(1,925,000)
06/30/2041	100,000,000	379,444	538,049	91,865	98,990,642	0	1,925,000	38,817	55,042	9,398	2,028,257	2.05%	(1,925,000)
09/30/2041	100,000,000	339,831	481,878	82,275	99,096,017	0	1,925,000	39,613	56,171	9,590	2,030,374	2.05%	(1,925,000)
12/31/2041	100,000,000	299,405	424,555	72,487	99,203,552	0	1,925,000	40,425	57,323	9,787	2,032,536	2.05%	(1,925,000)
03/31/2042	100,000,000	258,151	366,056	62,500	99,313,294	0	1,925,000	41,255	58,499	9,988	2,034,741	2.05%	(1,925,000)
06/30/2042	100,000,000	216,050	306,357	52,307	99,425,286	0	1,925,000	42,101	59,699	10,193	2,036,992	2.05%	(1,925,000)
09/30/2042	100,000,000	173,086	245,434	41,905	99,539,575	0	1,925,000	42,964	60,923	10,402	2,039,289	2.05%	(1,925,000)
12/31/2042	100,000,000	129,240	183,262	31,290	99,656,209	0	1,925,000	43,846	62,173	10,615	2,041,633	2.05%	(1,925,000)
03/31/2043	100,000,000	84,495	119,814	20,457	99,775,234	0	1,925,000	44,745	63,448	10,833	2,044,026	2.05%	(1,925,000)
06/30/2043	100,000,000	38,833	55,064	9,402	99,896,701	0	1,925,000	45,663	64,749	11,055	2,046,467	2.05%	(1,925,000)
09/15/2043	100,000,000	(0)	(0)	0	100,000,000	100,000,000	1,604,167	38,833	55,065	9,402	1,707,465	2.05%	(101,604,167)
						$ 100,000,000	308,427,778	$ 2,221,449	$ 3,150,000	$ 537,824	$ 314,337,051		

Exhibit No.___(TKW-7).xls 7.70% TOPrS Effective Rate

EXHIBIT NO.___(TKW-8)
SHEET 1 OF 1

SOUTHWEST GAS CORPORATION
NET PRESENT VALUE OF REFUNDING
9.125% TRUST ORIGINATED PREFERRED SECURITIES (TOPrS), DUE 12/31/2025

Principal at Call	60,000,000
Current Rate	9.125%
Call Price	100.000
Call Premium	-
Unamortized Debt Exp.	2,221,449
New Issue Debt Exp.	2,427,824
New Rate	7.700%
Refunding Date	09/24/2003
Maturity Date	12/31/2025
Tax Rate	38%

Year	Average Principal	Interest Savings(1) Before Tax	Interest Savings(1) After Tax	Cost Of Refinancing (2)	Amortization Expense Tax Savings/(Cost)(4) Before Tax	Amortization Expense Tax Savings/(Cost)(4) After Tax	After Tax Cash Flows	Present Value Factor At(5) 4.7740%	Present Value
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
2003	$ 60,000,000	$ 213,750	$ 132,525	$ (1,583,673)	$ 2,319	$ 881	$ (1,450,267)	1.0000	$ (1,450,267)
2004	60,000,000	855,000	530,100		9,275	3,525	533,625	0.9544	509,310
2005	60,000,000	855,000	530,100		9,275	3,525	533,625	0.9109	486,104
2006	60,000,000	855,000	530,100		9,275	3,525	533,625	0.8694	463,954
2007	60,000,000	855,000	530,100		9,275	3,525	533,625	0.8298	442,814
2008	60,000,000	855,000	530,100		9,275	3,525	533,625	0.7920	422,638
2009	60,000,000	855,000	530,100		9,275	3,525	533,625	0.7559	403,380
2010	60,000,000	855,000	530,100		9,275	3,525	533,625	0.7215	385,000
2011	60,000,000	855,000	530,100		9,275	3,525	533,625	0.6886	367,458
2012	60,000,000	855,000	530,100		9,275	3,525	533,625	0.6572	350,715
2013	60,000,000	855,000	530,100		9,275	3,525	533,625	0.6273	334,735
2014	60,000,000	855,000	530,100		9,275	3,525	533,625	0.5987	319,482
2015	60,000,000	855,000	530,100		9,275	3,525	533,625	0.5714	304,925
2016	60,000,000	855,000	530,100		9,275	3,525	533,625	0.5454	291,032
2017	60,000,000	855,000	530,100		9,275	3,525	533,625	0.5205	277,771
2018	60,000,000	855,000	530,100		9,275	3,525	533,625	0.4968	265,114
2019	60,000,000	855,000	530,100		9,275	3,525	533,625	0.4742	253,034
2020	60,000,000	855,000	530,100		9,275	3,525	533,625	0.4526	241,505
2021	60,000,000	855,000	530,100		9,275	3,525	533,625	0.4320	230,501
2022	60,000,000	855,000	530,100		9,275	3,525	533,625	0.4123	219,998
2023	60,000,000	855,000	530,100		9,275	3,525	533,625	0.3935	209,974
2024	60,000,000	855,000	530,100		9,275	3,525	533,625	0.3756	200,407
2025	60,000,000	855,000	530,100		9,275	3,525	533,625	0.4968	265,114
Total		$ 19,023,750	$ 11,794,725	$ (1,583,673)	$ 206,374	$ 78,422	$ 10,289,474	NPV =	$ 5,794,698

NOTES
(1) After-Tax Interest Savings = Principal X (Original Coupon Rate - New Coupon Rate) X (1-Tax Rate)
(2) Cost of Refinancing = (Call Premium X (1-Tax Rate)) + New Issue Debt Expense - (Unamortized Debt Costs X (Tax Rate))
(3) After-Tax Amortization Savings/(Cost) = (Annual New Issue Debt Expense - Annual Unamortized Debt Expense) X Tax Rate
(4) Present Value Factor = New Coupon Rate X (1-Tax Rate)

Assumptions:
38% Corporate Tax Rate assumed.

SOUTHWEST GAS CORPORATION
REVENUE REQUIREMENT SAVINGS
2003 PREFERRED REFINANCING

Line No.	Description (a)	Rate (b)	Amount (c)	Line No.
1	Previous Preferred Effective Rate	9.5100%		1
2	Refinanced Preferred Effective Rate	8.2000%		2
3	Change in Effective Cost	1.3100%		3
4	Capital Structure Weight Preferred	5.0000%		4
5	Weighted Change in Effective Cost	0.0655%		5
6	Rate Base		$ 925,212,422	6
7	Revenue Requirement Savings		$ 606,014	7

Hanley

BEFORE THE

ARIZONA CORPORATION COMMISSION

DIRECT TESTIMONY

OF

FRANK J. HANLEY, CRRA
PRESIDENT
AUS CONSULTANTS - UTILITY SERVICES

CONCERNING

COMMON EQUITY COST RATE

RE: SOUTHWEST GAS CORPORATION

DOCKET NO. ________

TABLE OF CONTENTS

Southwest Gas Corporation
Docket No. __

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
of
<u>FRANK J. HANLEY</u>

I. INTRODUCTION

Q. 1 Please state your name, occupation and business address.

A. 1 My name is Frank J. Hanley and I am President of AUS Consultants – Utility Services. My business address is 155 Gaither Drive, P.O. Box 1050, Moorestown, New Jersey 08057.

Q. 2 Please summarize your educational background and professional experience.

A. 2 I have testified as an expert witness on rate of return and related financial issues before 33 state public utility commissions, including the Arizona Corporation Commission (the Commission), the Public Services Commission of the Territory of the U.S. Virgin Islands, and the Federal Energy Regulatory Commission. I have also testified before local and county regulatory bodies, an arbitration panel, a U.S. Bankruptcy Court, the U.S. Tax Court and a state district court. I have appeared on behalf of investor-owned companies, municipalities, and state public utility commissions. The details of these appearances, as well as my educational background, are shown in Appendix A supplementing this testimony.

Q. 3 What is the purpose of your testimony?

A. 3 The purpose of my testimony is to provide evidence on behalf of Southwest Gas Corporation (Southwest or the Company) in the form of a study of the common equity cost rate which it should be afforded an opportunity to earn on the common equity financed portion of its Arizona jurisdictional rate base and to support the reasonableness of the use of a hypothetical capital structure consisting of 53% debt, 5% preferred stock and 42% common equity capital as sponsored by Southwest Witness Mr. Theodore K. Wood.

Q. 4 What are your recommended common equity cost rates?

A. 4 They are 11.95% if the requested Conservation Margin Tracker (CMT) is not permitted to become effective and 11.70% if it is permitted to become effective. Both cost rates are applicable to the requested 42% hypothetical common equity ratio. My recommended cost rates would be higher if applicable to a lower common equity ratio due to greater financial risk.

Q. 5 Have you prepared exhibits which support your recommended common equity cost rates as well as the reasonableness of the requested hypothetical capital structure and the resultant overall costs of capital?

A. 5 Yes, they have been marked for identification as Exhibits __ (FJH-1) through (FJH-15).

Q. 6 What are the resultant requested overall costs of capital utilizing your common equity cost rates as well as the requested hypothetical capital structure and the debt and preferred equity cost rates sponsored by Southwest Witness Mr. Theodore K. Wood?

A. 6 As shown on Exhibit __ (FJH-1), Sheet 1, they are as follows: 9.40% if the requested CMT is not authorized and 9.29% if the requested CMT is authorized.

II. SUMMARY

Q. 7 Please summarize your testimony.

A. 7 My summarization is divided into five sections as follows: Southwest's Greater Risk, Capital Structure, Common Equity Cost Rate, Reality Check and Conclusion.

A. <u>Southwest's Greater Risk</u>

Southwest is more risky than the average gas distribution company (LDC), as evidenced by its earned returns on common equity which have been substantially below those of comparable LDCs, while those of its Arizona operations have been only slightly higher than Southwest's collectively. Those grossly substandard earnings have resulted in an actual capital structure which contains less than management's desired percentage of common equity despite extraordinary measures on its part to bolster the equity ratio.

In drawing conclusions about Southwest, it is important to do so in the context of comparison to other LDCs which are relatively comparable in risk. Two groups of LDCs were selected, a group of five and a group of eleven from Value Line's Gas Distribution Industry. Based on bond ratings and Standard & Poor's (S&P) business profiles, it is clear that Southwest is more risky than both proxy groups based on the following:

	Bond Ratings		
	Moody's	S&P	
	Bond Rating	Bond Rating	Business Profile
Southwest	Baa2	BBB-	3.0
Proxy Groups:			
Five	A2	A	1.8
Eleven	A2	A	2.0

Source: Exhibit __ (FJH-11), Sheet 2 of 9.

Susceptibility to the Impact of Weather
on Earnings Due to Lack of Weather Normalization Clauses (WNC),
Weather Stabilization Insurance (WSI), or Innovative Rate Design

	Weather Protection
Southwest	None
Proxy Groups:	
Five LDCs	3 with WNC plus 1 with WSI
Eleven LDCs	6 with WNC plus 3 with WSI plus 1 with weather mitigation rate design

Source: Exhibit __ (FJH-4), Sheet 3 of 4
Exhibit __ (FJH-5), Sheet 3 of 7

Comparative Impact of
Declining Per Customer Consumption and Weather as well as
Low Authorized Rates of Return on Actual Rates
Earned on Book Common Equity 1997-2003

	2003	2002	2001	2000	1999	1998	1997	Avg.
Southwest	6.10%	6.65%	5.79%	6.32%	6.89%	9.75%	2.87%	6.34%
Total Arizona Jurisdiction	4.11	7.23	7.40	5.69	7.10	12.66	2.98	6.74
Yield on Moody's Baa Rated P.U. Bonds	6.84	8.02	8.03	8.36	7.88	7.26	7.95	7.76
Proxy Groups:								
Five	11.88	12.29	13.55	10.66	12.34	11.26	12.78	12.11
Eleven	12.86	11.35	12.56	11.13	11.48	9.28	12.70	11.62

Source: Exhibit __ (FJH-1), Sheet 4 of 4

The foregoing tables show that Southwest has experienced a totally substandard level of returns on its common equity investment, which was so low as to be below the yield on Moody's Baa rated public utility bonds in six of the seven years as well as the average for the period, which has been attributable, among other things, to:

(1) Southwest's rapid growth and related essential capital expenditures;

(2) Significant regulatory lag as 90% of its business is subject to historical ratemaking paradigms which exacerbate such lag when combined with significant infrastructure development; and

(3) The loss of substantial net income attributable to declining customer usage (as discussed in detail in Southwest Witness Mr. Cattanach's testimony) and the related unrealized operating margins.

All of the foregoing is reflected in Southwest's lower (more risky) bond ratings and higher (more risky) business profile assigned by S&P vis-à-vis the proxy groups. Moreover, Moody's Investors Service, on February 27, 2004, changed the outlook for the ratings on Southwest's debt to negative from stable. That change recognized the foregoing and adverse impact on earnings and net cash flows. Greater credit risk also means greater risk to common shareholders.

B. Capital Structure

Southwest has made herculean efforts to boost its common equity ratio in the face of extremely difficult circumstances, i.e., extraordinary growth and significant loss of margin due to lack of protection against declining per customer usage. That impact has been compounded by the inability to achieve the allowed average rates of return on common equity capital. In an effort to offset these handicaps, Southwest has not increased its common dividend since the Spring of 1994 and has increased the number of common stock shares outstanding by 67% since December 31, 1994 so that 40.1% of all common shares outstanding at the end of the test year, August 31, 2004, have been issued subsequent to December 31, 1994.

Despite these efforts on the part of management, Southwest's (total company) actual average permanent capital structure during the twelve months ended August 31, 2004 consisted of just 34.5% common equity. If the cumulative loss of operating margins attributable to declining per customer usage had been earned, assuming all other things remained the same, its capital structure at August 31, 2004 would have contained a greater percentage of common equity capital.

Southwest's requested hypothetical capital structure ratios, which include 42.0% common equity, are reasonable when compared to S&P's new capital structure benchmarks for a BBB bond rating and a business profile of "3" which require a range of up to 45%. However, it must be kept in mind that the average LDC (and the two proxy groups) has an average bond rating of A and a business profile of about "2" which requires equity in the range of 42%-48% as derived from the information shown on Exhibit ___ (FJH-2), Sheet 14 of 15. Moreover, the requested hypothetical capital structure ratios which include 42% common equity are reasonable when compared to the average of about 44% maintained from 1999 through 2003 by the proxy groups, keeping in mind that those ratios are based on total capital including short-term debt. Based on permanent capital, the proxy groups maintained an average common equity ratio of about 50% during the 1999-2003 period as shown on Sheet 1 of Exhibit __ (FJH-4) and (FJH-5).

C. Common Equity Cost Rate

The Efficient Market Hypothesis (EMH) is the foundation of modern investment theory. It tells us that investors (except those who illegally use insider information) take into account all publicly-available information which is then fully reflected in securities' prices. Common sense affirms this proposition to be true as the markets consistently reflect the processing of new information. Inasmuch as the financial literature discusses various cost of common equity models – and actually encourages their use – it stands to reason that investors collectively rely upon the use of multiple models and not exclusively upon a single model. Consequently, reliance upon the four principal cost of common equity models discussed in the literature, and utilized by experts, regulators, analysts, academicians, etc., is essential. Those models are the Discounted Cash Flow Model (DCF), the Risk Premium Model (RPM), the Capital Asset Pricing Model (CAPM) and the Comparable Earnings Model (CEM) and all, as utilized by me, are market-based.

Although there are a number of forms of the DCF model which can be used, I rely upon the constant growth form. Forms of the model such as two- or three-stage growth models are inappropriate for LDCs that do not face transition to a fully competitive environment. Moreover, there is no empirical evidence which confirms that the rate of growth will change to arbitrary rate(s) such as the long-term growth rate in gross domestic product.

In addition, analysts' forecasts are for a maximum of five years into the future. Even casual observers of the market are aware that it is the expectation of earnings that is the primary driver of market prices. The growth in the DCF model is a substitute for expected growth in market price (capital appreciation). Thus, the constant growth DCF model, using analysts' forecasted growth in earnings, is most appropriate.

Application of all four cost of equity models resulted in a common equity cost rate of 11.95% after adjustment of the two proxy groups' cost rates to reflect Southwest's greater risk.

Those risk differences are taken into account by the bond yield differentials attributable to Southwest's lower bond rating, which is at the bottom of investment grade. Additionally, there is even greater risk to Southwest's common equity investors versus the proxy groups because of the adverse impact of declining per customer usage on Southwest's earnings. Consequently, an 11.95% common equity cost rate is appropriate if there should continue to be no protection from declining per customer usage. Should the requested CMT be permitted to become effective, I believe that it will be risk-reducing because it will stabilize revenues, volumes and hence, earnings and cash flows. I believe that a reasonable estimate of the value of the requested CMT, if approved, is a reduction of 25 basis points, or 0.25% in common equity cost rate, i.e., a reduction to 11.70% (11.95% - 0.25%).

D. <u>Reality Check</u>

As shown by the information contained in Exhibit __ (FJH-15), regulatory awards made to gas distribution companies during the period January 1, 2003 through September 30, 2004 averaged about 10.9% relative to a common equity ratio of nearly 48%. These companies that received the awards, on average, had debt rated A. Thus, these data indicate that my recommended common equity cost rates are reasonable when it is considered that Southwest has a bond rating of BBB- which is at the bottom of investment grade scale. In addition, when it is also considered that Southwest has had no WNC to protect against the impact of weather on its earnings, my recommendation(s) is (are) reasonable. Moreover, as shown on Sheet 7 of Exhibit __ (FJH-11), the consensus forecast of the country's leading economists indicates a relatively substantial increase in long-term interest rates over the next eighteen months. Accordingly, rising capital costs, such as long-term interest rates, indicate a higher cost of common equity capital.

E. <u>Conclusion</u>

The foregoing summary demonstrates that the requested hypothetical capital structure, which includes a 42% common equity component, the CMT and the 11.70% common equity cost rate (applicable if the CMT is approved and 11.95% if it is not) are reasonable and should be approved.

III. GENERAL PRINCIPLES

Q. 8 What general principles have you considered in arriving at your recommended common equity cost rate of 11.95% with no CMT and 11.70% if the requested CMT is approved?

A. 8 In non-price regulated industries, competition is the principal determinant in establishing the price of the product or service. For price-regulated utilities, the regulatory process becomes the substitute for the missing competition; however, the natural gas distribution business has become increasingly competitive. Investors reflect their awareness of the increased competition in the market prices they pay for securities. Analyses based on companies whose securities are traded is essential when evaluating capital structure and its component cost rates. The common equity cost rate should be adequate enough to fulfill investors' requirements and assure that the utility will be able to fulfill its obligations to its customers. The obligation to serve requires a level of earnings sufficient to maintain the integrity of presently invested capital and permit the attraction of needed new capital at a reasonable cost in competition with other comparable-risk seekers of capital. These standards for a fair rate of return have been established by the U.S. Supreme Court in the Hope[1] and Bluefield[2] cases.

IV. BUSINESS RISK

Q. 9 Please define business risk and explain why it is important to the determination of a fair rate of return.

A. 9 Business risk is a collective term encompassing all of the diversifiable risks of an enterprise except financial risk. Business risk is important to the determination of a fair rate of return because the greater the level of risk, the greater the rate of return demanded by investors consistent with the basic financial precept of risk and return.

Q. 10 Are there any extraordinary business risks which affect Southwest?

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[1] Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944).

[2] Bluefield Water Works Improvement Co. v. Public Serv. Comm'n, 262 U.S. 679 (1922).

A. 10 Yes. Southwest faces many of the same risks as other LDCs in today's increasingly competitive environment. These include the threat of bypass; uncertainty associated with the unbundling of services behind the city-gate; increased competition from, among others, gas marketers, interstate pipelines and electric utilities through integrated resource plans, and industry mergers and acquisitions. In addition, Southwest has the potential for significant revenue and earnings volatility (classic signs of greater business risk) due to its lack of protection from declining per customer usage and its rate of customer growth which is among the highest in the nation. Its lack of a protection against continuing declines in per customer consumption and weather's vagaries leads to much greater volatility in revenues and earnings.

In contrast to Southwest's total exposure to declining per customer usage and the vagaries of weather, the majority of my two proxy groups of LDCs do at least have weather protection. For the proxy group of five LDCs, three have Weather Normalization Clauses (WNC) and one has Weather Stabilization Insurance (WSI). For the proxy group of eleven Value Line LDCs, six have WNCs, three have WSI, and one has the ability to mitigate the effects of weather through rate design. (Refer to Sheet 3 of Exhibits __ (FJH-4) and (FJH-5), respectively.)

In addition to significant and declining per customer usage and weather risk, Southwest's extraordinary rate of growth in customers exacerbates its inability to realize authorized operating margins on new customers. New customers are purchasing newer, more energy efficient homes and natural gas appliances with high efficiency ratings. As a result, these new customers actually use less gas than had been assumed when authorized rates were established. Consequently, the lower realized operating margins attributable to the reduction in usage by new customers, along with the use of historical test periods and the related regulatory lag in the face of such rapid growth, have made it impossible for Southwest to achieve an adequate level of earnings. The extraordinarily low achieved rates of earnings on the common equity financed portion of the total Arizona rate base is apparent by comparison to the achieved rates of earnings on book common equity of the two proxy groups of LDCs. I have chosen to make such comparison beginning with 1997, the first full year without PriMerit Bank being part of Southwest, in order to obviate controversy. The comparative rates are shown on Exhibit __ (FJH-1), Sheet 4 of 4. As shown, Southwest's achieved ROEs have been very much lower than those of the proxy groups, while those of the total Arizona jurisdiction have been slightly higher on average, but lower than the average yield on Moody's Baa rated public utility bonds. As shown, the proxy groups achieved an average ROE over the seven periods of 12.11% and 11.62% while Southwest achieved an average of only 6.34% and the Arizona jurisdiction earned only 6.74% on average, which was also lower than the average yield on Moody's Baa rated public utility bonds during the same period.

The low achieved ROEs have been a major factor in Southwest's bottom of investment grade bond rating. They are directly attributable to inadequate achieved ROEs and an inability to earn them due to declining per customer usage and the lack of protection from the adverse impact of the vagaries of weather on revenues and earnings. Consequently, the need to compensate for the significant losses in operating margin through the issuance of long-term debt capital has resulted in an increase in financial risk despite all of management's efforts to minimize the impact.

V. FINANCIAL RISK

Q. 11 Please define financial risk and explain why it is important to the determination of a fair rate of return.

A. 11 Financial risk is the additional risk created by the introduction of debt into the capital structure. Standard & Poor's (S&P) corporate bond rating criteria is contained in Exhibit __ (FJH-2), which consists of 15 sheets. Sheet 14 contains S&P's newest (June 7, 2004) risk adjusted financial guidelines for ten levels of business profiles at different bond ratings with "1" being considered the lowest risk and "10" the highest risk.

Q. 12 Are bond ratings a good measure of investment risk?

A. 12 Yes. Similar bond ratings reflect similar combined business and financial risks. Although the specific business or financial risks may differ between companies, the same bond rating indicates that the combined risks are similar because the bond rating process gives recognition to diversifiable business and financial risks. S&P expressly states that the bond rating process encompasses a qualitative analysis of business and financial risks (see Sheets 3 through 9 of Exhibit __ (FJH-2). Differences in risk may still exist between companies with the same bond rating and are reflected in S&P's assigned business profile, i.e., the higher the assigned number (e.g., "1" through "10"), the greater the qualitative assessment of risk by S&P, and vice versa. The riskier the assigned business profile, the more stringent are the financial target ratios. It is worthy of note that Southwest's S&P bond rating is

"BBB-" and it has an assigned business profile of "3" in contrast to the average company in the two proxy groups of LDCs (which will be discussed infra) both of which have an average S&P bond rating of "A" and less risky business profiles of "1.8/2.0" (essentially a "2") assigned by S&P.

Although there is no perfect proxy by which one can differentiate common equity risk between companies, the bond rating provides excellent insight because it is the result of a thorough and comprehensive analysis of all diversifiable investment risks.

Q. 13 Please describe the efforts by Southwest's management to minimize the proportion of debt in its capital structure and to bolster its common equity ratio which you mentioned supra.

A. 13 Since December 31, 1994, Southwest has increased the number of common shares outstanding by 67.0%, or 14.249 million from 21.282 million to 35.531 million at August 31, 2004. Thus, 40.1% of common shares outstanding at August 31, 2004 have been issued in less than ten years. Moreover, in order to preserve its equity ratio as best it could, while minimizing the impact on capital structure ratios of the issuance of debt and preferred securities essential to fund customer growth, there has been no increase in the common dividend since the Spring of 1994.

VI. SOUTHWEST GAS CORPORATION

Q. 14 Have you reviewed financial data for Southwest?

A. 14 Yes. Southwest is principally engaged in natural gas operations providing distribution service in Arizona, Nevada and California as well as transportation service through Southwest's wholly-owned pipeline subsidiary, Paiute Pipeline

Company. Southwest serves over 1.5 million customers. Customer growth has been about 4% per annum, well above the national average.

I have shown Southwest's capitalization and financial statistics for the years 1999-2003, inclusive on Sheet 1 of 4 of Exhibit __ (FJH-3). Notes relevant to Sheet 1 are shown on Sheet 2. Sheets 3 and 4 show the capital structure ratios excluding and including short-term debt, respectively. As shown on Sheet 1, Southwest's average achieved rate of earnings on book common equity during the 1999-2003 period was only 6.25% and its average market/book ratio was 128.99%, while the average dividend payout ratio was 77.78%, about equal to the industry average; however, that is only because there has been no increase in the common dividend since Spring 1994, more than ten years.

VII. PROXY GROUPS

Q. 15 You previously mentioned that you also observe the market data for two proxy groups of LDCs in order to gain insight into a market-based common equity cost rate for Southwest. Please explain how you selected the proxy group of five LDCs.

A. 15 The basis of selection was to include those gas distribution companies: 1) which are assigned an SIC Code of 4924 (Natural Gas Distribution) by the Securities and Exchange Commission (SEC); 2) which have actively traded common stock; 3) which had more than 80% of their 2003 operating revenues derived from gas operations; 4) which are included in <u>Value Line Investment Survey (Standard Edition)</u> and ThomsonFN FirstCall; 5) which have not cut or omitted their cash common stock dividends during the five calendar years ending 2003 or through the time of the preparation of this testimony; 6) which, at the time of the preparation of this testimony, were not expected to be acquired by or merged into another company; and 7) which are included in S&P's Compustat PC Plus Research Insight Data Base. Five companies met all of the foregoing criteria and their financial profile is summarized in Exhibit __ (FJH-4).

Q. 16 Please describe Exhibit __ (FJH-4).

A. 16 Exhibit __ (FJH-4) contains average comparative capitalization and financial statistics for the proxy group of five LDCs for the years 1999 through 2003. The Exhibit consists of five sheets. Sheet 1 contains a summary of the comparative data for the years 1999-2003. Sheet 2 contains notes relevant to Sheet 1, as well as the selection criteria and identity of the individual companies in the proxy group as discussed supra. Sheet 3 contains the identification of those companies which have WNCs or WSIs in effect. Sheet 4 contains the capital structure ratios based upon permanent capital employed for each company as well as the group average by year and company/group average for the five years, while Sheet 5 contains the capital structure ratios based on total capital employed, including short-term debt.

As shown on Sheet 1, during the five-year period ending 2003, the achieved average earnings rate on book common equity (ROE) and market/book ratio were 12.19% and 179.91%, respectively, while the five-year average dividend payout ratio was 77.01%.

Q. 17 Please explain how the proxy group of eleven Value Line LDCs was selected.

A. 17 The basis of selection was to include those gas distribution companies: 1) which are included in Value Line Investment Survey's (Standard Edition) – Natural Gas (Distribution) Industry; 2) which have not cut or omitted their common stock dividend during the five calendar years ending 2003 and up to the time of the preparation of this direct testimony; 3) which at the time of the preparation of this testimony were not expected to be acquired by or merged into another company; 4) which in 2003 had at least 60% of operating revenues derived from gas operations; and 5) which are included in S&P's Compustat PC Plus Research Insight Data Base.

NUI Corp. and SEMCO Energy were eliminated because they cut their dividends. Southern Union was eliminated because it does not pay cash dividends. Atmos Energy Corporation, New Jersey Resources, and UGI Corp. were eliminated because less than 60% of their 2003 operating revenues were derived from gas operations. Of course, Southwest itself was eliminated because it is the Company at issue in this proceeding and is being viewed as a stand-alone company.

In all, from the eighteen companies in the Value Line group, seven were eliminated for the above reasons, leaving eleven companies whose financial profile is summarized in Exhibit __ (FJH-5).

Q. 18 Please describe Exhibit __ (FJH-5).

A. 18 Exhibit __ (FJH-5) contains average comparative capitalization and financial statistics for the proxy group of eleven Value Line LDCs for the years 1999 through 2003. It consists of seven sheets. Sheet 1 contains a summary of the comparative financial data for the years 1999-2003. Sheet 2 contains notes relevant to Sheet 1, as well as the selection criteria and identity of the individual companies in the proxy group. Sheet 3 contains the identification of those companies which have WNCs, WSIs, or weather mitigation rate design in effect. Sheets 4 and 5 contain capital structure ratios based upon permanent capital for each company (without regard to customer deposits) as well as the group averages by year and company/group average for the five years. Sheets 6 and 7 contain capital structure ratios for the same companies/periods as in Sheets 4 and 5 except that they are based on total capital, including short-term debt.

As shown on Sheet 1, during the five-year period ending 2003, the achieved average earnings rate on book common equity (ROE) and market/book ratio were 11.88% and 170.77%, respectively, while the average dividend payout ratio was 75.21%.

VIII. CAPITAL STRUCTURE

Q. 19 Do you believe the hypothetical capital structure ratios requested by Southwest and supported by Southwest Witness Mr. Theodore K. Wood are reasonable?

A. 19 Yes. I believe that the requested hypothetical capital structure ratios consisting of 53% debt, 5% preferred securities and 42% common equity are reasonable.

If such ratios are utilized, it is likely that Southwest's bond ratings would be higher and S&P's bond rating would not be one rating notch from dropping below investment grade, i.e., from the current BBB- (bottom of investment grade) to BB+ which is below investment grade, and which indicates speculative characteristics.[3] Southwest's requested Conservation Margin Tracker (CMT) will go a long way in improving its financial health and stability – by leading to a stronger capital structure with a greater percentage of common equity and a bond rating which will not be precipitously close to dropping below investment grade.

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[3] Standard & Poor's Bond Guide.

Southwest's requested hypothetical capital structure ratios consisting of 53.0% long-term debt capital, 5.0% preferred stock capital, and 42.0% common equity capital are reasonable when compared to S&P's capital structure benchmarks as follows:

Line No.		Southwest BBB- Rating, "3" Business Profile(*)	Proxy Groups A- Rating, "2" Business Profile(*)
(1)	Range of S&P Benchmark of Total Debt to Total Capital	55%-65%(*)	52%-58%
(2)	Implied Range of Total Equity (100% - range of total debt)	35%-45%	42%-48%
(3)	Midpoint of Range of Implied Total Equity	40%	45%
(4)	Requested Hypothetical Ratemaking Common Equity Ratio	42%	NA

(*) Source: Exhibit __ (FJH-2), Sheet 12 of 12 and Exhibit __ (FJH-11). Sheet 2 of 9.

The requested hypothetical common equity ratio of 42% will afford Southwest a reasonable opportunity to improve its bond rating from the bottom of investment grade to, hopefully, over time, an A bond rating so that it will have the wherewithal to compete for capital on an equal footing with its similar risk competitors, i.e., the proxy groups of LDCs. Moreover, these proxy groups of LDCs have actually maintained on average during the five years ended 2003, common equity ratios based on total capital of 44.49% (the group of five (Exhibit __ (FJH-4), Sheet 1 of 5) and 43.44% (the eleven Value Line LDCs (Exhibit __ (FJH-5, Sheet 1 of 7)).

IX. COMMON EQUITY COST RATE MODELS

A. The Efficient Market Hypothesis (EMH)

Q. 20 Are all of the models you employ market-based models?

A. 20 Yes. The DCF model is market-based as current market prices are employed. The Risk Premium Model (RPM) is market-based as the current and expected bond ratings and yields reflect the market's assessment of risk. To the extent betas are used to determine equity risk premium, the market's assessment is reflected because betas are derived from regression analyses of market prices. The Capital Asset Pricing Model (CAPM) model is market-based for much the same reason as the RPM except that the yield on U.S. Government Treasury Bonds is used in lieu of company-specific bond yields. My application of the Comparable Earnings Model (CEM) is also market-based because the selection process of comparable risk companies is based upon statistics which result from regression analyses of market prices. All of the models are, therefore, based upon the Efficient Market Hypothesis (EMH).

Q. 21 Please describe the conceptual basis of the EMH.

A. 21 The EMH is the cornerstone of modern investment theory. It was pioneered by Eugene F. Fama[4] in 1970. An efficient market is one in which security prices at all times reflect all the relevant information at that time. An efficient market implies that prices adjust instantaneously to the arrival of new information and that the

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4 Fama, Eugene F., "Efficient Capital Markets: A Review of Theory and Empirical Work", Journal of Finance, May 1970, 383-417.

process therefore reflects the intrinsic fundamental economic value of a security.[5]

The essential components of the EMH are:

1. Investors are rational and will invest in assets which provide the highest expected return for a particular level of risk.

2. Current market prices reflect all publicly available information.

3. Returns are independent in that today's market returns are unrelated to yesterday's returns as that information has already been processed.

4. The markets follow a random walk, i.e., the probability distribution of expected returns approximates the normal bell curve.

Brealey and Myers[6] state:

> When economists say that the security market is 'efficient", they are not talking about whether the filing is up to date or whether desktops are tidy. They mean that information is widely and cheaply available to investors and that all relevant and ascertainable information is already reflected in security prices.

There are three forms of the EMH, namely:

1. The "weak" form asserts that all past market prices and data are fully reflected in securities prices. In other words, technical analysis cannot enable an investor to "outperform the market".

2. The "semistrong" form asserts that all publicly available information is fully reflected in securities prices. In other words, fundamental analysis cannot enable an investor to "outperform the market".

3. The "strong" form asserts that all information, both public and private, is fully reflected in securities prices. In other words, even insider information cannot enable an investor to "outperform the market".

The "semistrong" form is generally held as true because the illegal use of insider information can enable an investor to "beat the market" and earn excessive returns, thereby disproving the "strong" form.

[5] Morin, Roger A., "Regulatory Finance – Utilities' Cost of Capital", Public Utilities Reports, Inc., 1994, p. 136.

Q. 22 Please explain the applicability of the EMH to your determination of common equity cost rate.

A. 22 Common sense affirms the semistrong form of the EMH, i.e., market prices paid for securities reflect all relevant information available to investors and that no degree of sophistication and/or analysis can enable investors to outperform the market. Consequently, it confirms that all perceived risks are taken into account by investors in the market prices they pay, which reflect the information inexpensively or freely available such as bond ratings, and analyses of the rating agencies and financial analysts, and the various methodologies employed to determine common equity cost rate as discussed in the academic and financial literature. Thus, in an attempt to emulate investors' actions, it is essential that multiple cost of common equity models be considered.

Q. 23 Is there specific support in the academic literature for the need to rely upon multiple cost of common equity models in arriving at a recommended common equity cost rate?

A. 23 Yes. For example, Phillips[7] states:

> Since regulation establishes a level of authorized earnings which, in turn, implicitly influences dividends per share, estimation of the growth rate from such data is an inherently circular process. *For these reasons, the DCF model 'suggests a degree of precision which is in fact not present' and leaves 'wide room for controversy and argument about the level of k'.* (italics added) (p. 396)

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6 Brealey, R.A. and Myers, S.C., "Principles of Corporate Finance". McGraw-Hill Publications, Inc., 1996, 323-324.

7 Charles F. Phillips, Jr., The Regulation of Public Utilities – Theory and Practice, 1993, Public Utility Reports, Inc., Arlington, VA, p. 396, 398.

> *Despite the difficulty of measuring relative risk, the comparable earnings standard is no harder to apply than is the market-determined standard. The DCF method, to illustrate, requires a subjective determination of the growth rate the market is contemplating. Moreover, as Leventhal has argued: 'Unless the utility is permitted to earn a return comparable to that available elsewhere on similar risk, it will not be able in the long run to attract capital'.* (italics added) (p. 398)

Also, Morin[8] states:

> *Sole reliance on the DCF model ignores the capital market evidence and financial theory formalized in the CAPM and other risk premium methods. The DCF model is one of many tools to be employed in conjunction with other methods to estimate the cost of equity. It is not a superior methodology that supplants other financial theory and market evidence. The broad usage of the DCF methodology in regulatory proceedings does not make it superior to other methods.* (italics added) (pp. 231-232)
>
> Each methodology requires the exercise of considerable judgment on the reasonableness of the assumption underlying the methodology and on the reasonableness of the proxies used to validate a theory. *The failure of the traditional infinite growth DCF model to account for changes in relative market valuation, discussed above, is a vivid example of the potential shortcomings of the DCF model when applied to a given company. It follows that more than one methodology should be employed in arriving at a judgment on the cost of equity and that these methodologies should be applied across a series of comparable risk companies. ...Financial literature supports the use of multiple methods.* (italics added) (p. 239)

Professor Eugene Brigham, a widely respected scholar and finance academician asserted:

> In practical work, it is often best to use all three methods – CAPM, bond yield plus risk premium, and DCF – and then apply judgement when the methods produce different results. People experienced in estimating capital costs recognize that both careful

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[8] Roger A. Morin, <u>Regulatory Finance – Utilities' Cost of Capital</u>, 1994, Public Utilities Reports, Inc., Arlington, VA, pp. 231-232, 239-240.

> analysis and very fine judgements are required. It would be nice to pretend that these judgements are unnecessary and to specify an easy, precise way of determining the exact cost of equity capital. Unfortunately, this is not possible. (pp. 239-240)

Another prominent finance scholar, Professor Stewart Myers, in his best-selling corporate finance textbook stated:

> *The constant growth formula and the capital asset pricing model are two different ways of getting a handle on the same problem.* (italics added) (p. 240)

In an earlier article, Professor Myers explained the point more fully:

> *Use more than one model when you can. Because estimating the opportunity cost of capital is difficult, only a fool throws away useful information. That means you should not use any one model or measure mechanically and exclusively.* Beta is helpful as one tool in a kit, to be used in parallel with DCF models or other techniques for interpreting capital market data. (italics added) (p. 240)

In view of the foregoing, it is clear that investors are aware of all of the models including comparable earnings. The EMH requires the assumption that investors use them all.

B. Discounted Cash Flow Model (DCF)

1. Theoretical Basis

Q. 24 What is the theoretical basis of the DCF model?

A. 24 DCF theory is based upon finding the present value of an expected future stream of net cash flows during the investment holding period discounted at the cost of capital, or the capitalization rate. The theory suggests that an investor buys a stock for an expected total return rate which is expected to be derived from cash flows in the form of dividends and appreciation in market price, i.e., the expected growth rate.

Thus, the dividend yield on market price plus a growth rate equals the capitalization rate. The capitalization rate is the total return rate expected by investors.

Q. 25 Please comment on the applicability of the DCF model in establishing the cost rate of common equity capital for Southwest.

A. 25 Southwest's market data is, of course, relevant. However, when determining common equity cost rates based on the proxy groups of LDCs, it is then necessary to adjust those cost rates so that they are reflective of Southwest's risk. In this instance, the two proxy groups have less business risk than Southwest, although with Southwest's requested hypothetical 42% common equity ratio, the level of financial risk is similar to the 44% common equity ratio of those less risky proxy groups.

The DCF model has a tendency to mis-specify investors' required return rate when the market value of common stock differs significantly from its book value, as will be discussed infra in detail. Market values and book values of common stocks are seldom at unity. For example, the average market values of the LDC proxy groups have been well in excess of their book values. As shown on Sheet 1 of Exhibit __ (FJH-4) and (FJH-5), the proxy groups of five and eleven LDCs sold at 181.89% and 174.17% of their book values in 2003.

A market-based DCF cost rate will result in a total annual dollar return on book common equity equal to the total annual dollar return expected by investors only when market and book values are equal. There are many macroeconomic factors which influence market values. Thus, regulatory allowed earnings can only influence market values but cannot control them (refer to Bonbright, et al. citation infra).

2. Applicability of a Market-Based Common Equity Cost Rate to a Book Value Rate Base

Q. 26 Does the academic literature support the contention that the market prices of common stocks are influenced by factors which are beyond the influence of the regulatory process?

A. 26 Yes. For example, Phillips[9] states:

> Many question the assumption that market price should equal book value, believing that '*the earnings of utilities should be sufficiently high to achieve market-to-book ratios which are consistent with those prevailing for stocks of unregulated companies*.' (italics added)

In addition, Bonbright[10] states:

> In the first place, commissions cannot forecast, except within wide limits, the effect their rate orders will have on the market prices of the stocks of the companies they regulate. In the second place, *whatever the initial market prices may be, they are sure to change not only with the changing prospects for earnings, but with the changing outlook of an inherently volatile stock market. In short, market prices are beyond the control, though not beyond the influence of rate regulation.* (italics added)

Q. 27 If market prices are beyond the control of rate regulation, does a DCF cost rate properly reflect investors' required rate of return when it is applied to a book value which is significantly different from its market value?

A. 27 No. In the DCF model, "K" or the total return rate, relates to the market price paid for a stock. Thus, market price is the basis upon which investors formulate their required rate of return. A regulated utility (under the traditional rate base/rate of

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9 Id., p. 395.

10 James C. Bonbright, Albert L. Danielsen and David R. Kamerschen, Principles of Public Utility Rates, 1998, Public Utilities Reports, Inc., Arlington, VA, p. 334.

return paradigm) is limited to earning on its net book value (depreciated original cost) rate base. Market values diverge from book values for many reasons unrelated to allowed and/or achieved rates of earnings on book common equity (ROEs). Thus, when market values are grossly disparate from their book values, a market-based DCF cost rate applied to the book value of common equity will not reflect investors' expected common equity cost rate based on market prices. This is true because there are many macroeconomic factors which influence the demand for, and hence the market prices of, common stocks in addition to company-specific earnings per share (EPS) and dividends per share (DPS). Consequently, a <u>market-based</u> DCF cost rate applied to the book value per share will either overstate investors' required common equity cost rate when market value is less than book value or understate investors' required common equity cost rate when market value is above book value.

Q. 28 Can you demonstrate how a market-based DCF cost rate either understates or overstates investors' required rate of return on book common equity when market value is above or below book value, respectively?

A. 28 Yes. Exhibit __ (FJH-6) demonstrates how a market-based DCF cost rate applied to a significantly different book value will either understate or overstate investors' required return rate on market price. It is, after all, upon the price that investors pay that they seek their desired return. This hypothetical illustration demonstrates that the expected market-based rate of growth is either under-achieved or over-achieved. In the first <u>hypothetical example</u>, when market price is 80% in excess of book value the investor expects a total return rate of 10.00% on market price of $24.00 based on a growth rate of 6.00% and a dividend yield of 4.00%. It is shown that when the

10.00% return rate is applied to the book value of $13.33, which is only 55.5% of the market value, the opportunity for total annual return is only $1.333 on book value and not $2.40 (10.00% return on $24.00 market value). With an annual dividend of $0.960, there is an opportunity to earn only $0.373 in growth which is just 1.55% on the $24.00 market price in contrast to the 6.00% growth rate in market price expected by investors.

Conversely, it is shown that if market value is only 80% of book value, a market-based DCF cost rate when applied to the far greater book value will result in a substantial over-attainment of growth, i.e., 8.50% instead of the 6.00% growth expected on the $24.00 market price.

In the instant matter, with market prices well in excess of their book values, a DCF cost rate applied to a much lower book value will not afford a reasonable opportunity to achieve the rate of growth utilized in the DCF model.

3. Constant Growth Model

Q. 29 Please explain the form of the DCF model you employ and why?

A. 29 I utilize the constant growth form of the model because it is by far the most widely utilized in public utility rate regulation. I believe it is widely utilized because most utilities are in a mature state, i.e., they are not in transition from one phase of growth to another. For example, a starting company will go through various phases of growth until it reaches maturity. Most utilities that are not transitioning from a regulated monopoly to a competitive environment are in the mature stage and there is no basis for using multi-stage growth DCF models. Moreover, for investors, long-term is really five years because five years is the maximum length of analysts' projections. Moreover, there is no empirical evidence which confirms that the rate of growth would change to some arbitrary rate(s), e.g., the long-term growth rate in gross domestic product. Consequently, in the instant matter, the constant growth model is most appropriate.

4. Application of the DCF Model

a. Dividend Yield

Q. 30 What unadjusted dividend yields do you utilize and why?

A. 30 The recent volatility of the stock market confirms that spot prices should not be relied upon exclusively. Conversely, reliance on too long an historical period would not be representative of the future due to the volatility of the stock market. Consequently, I rely on an average of spot prices at October 1, 2004 and average market prices for the months of August and September 2004 as shown by company/group on Exhibit __ (FJH-8). The average unadjusted dividend yields are 3.47% for Southwest, 4.34% and 4.18% for the proxy groups of five and eleven LDCs, respectively, as shown on Exhibit __ (FJH-7), Column 1. Details are shown by company on Exhibit __ (FJH-8).

b. Discrete Adjustment of Dividend Yield

Q. 31 Please explain the adjustments for discrete growth in dividends as shown in Column No. 2 of Exhibit __ (FJH-7).

A. 31 Due to the fact that dividends are paid quarterly, or periodically, as opposed to continuously (daily), an adjustment must be made. This is often referred to as the discrete, or the Gordon Periodic, version of the DCF model.

Since companies tend to increase their quarterly dividend at different times of the year, a reasonable assumption is to reflect one-half the annual dividend growth rate in the D_1 expression, or $D_{1/2}$. This is a conservative approach so as not to overstate the dividend yield as it should be representative of the next twelve-month period. Therefore, the actual average dividend yields in Column 1 of Exhibit __ (FJH-7) have been adjusted upward to reflect one-half the growth rates shown in Column 4. The resultant adjusted dividend yields are 3.59% for Southwest, 4.44% for the proxy group of five LDCs and 4.28% for the proxy group of eleven Value Line LDCs as shown in Column 3 of Exhibit __ (FJH-7). Although Southwest has been unable to increase its common dividend since Spring 1994, I have assumed a growth component here because it should have a level of earnings which will permit such increase consistent with the industry norm.

c. DCF Growth Rates

Q. 32 Please explain the basis of the growth rates which you used in your constant growth DCF model, as shown in Column 4 of Exhibit __ (FJH-7).

A. 32 It is shown on Exhibit __ (FJH-9), that on average, individuals own about 42% of the common shares of Southwest and about 52% of the common shares of the companies in both proxy groups of LDCs. Individual investors are more likely to rely on information provided by sophisticated securities' analysts than more sophisticated institutional investors. They recognize that analysts' forecasts provide greater insight into prospective growth in per share value than historical accounting measures of growth. Analysts' forecasts, which incorporate historical information, are readily available from Value Line and other sources such as ThomsonFN

FirstCall, the latter readily available on the internet at no cost which provides, in most instances, the estimates of a number of analysts. While investors are influenced by short-term earnings growth such as forecasts for the next 12 months, I believe that they are more influenced by the longer term five-year forecasts. Five years typically is the longest future period for which analysts' forecasts are available. The use of a long-term period such as five years is more consistent with the long-term investment horizon implicit in common stocks than single 12-month growth rates. It is clear that EPS growth rate expectations, although they do not fully account for changes in market value, are the most significant of all accounting measures of value. It should be clear, even to the casual market observer, that the market reacts favorably when EPS expectations are met or exceeded and unfavorably when they are not.

In view of the foregoing, I rely upon the average projected long-term growth rate in EPS from Value Line and ThomsonFN First Call as shown in Column 4 of Exhibit __ (FJH-7) and detailed by company and average for each proxy group on Sheet 1 of Exhibit __ (FJH-10). As shown on Sheet 1 of Exhibit __ (FJH-10), Southwest's average growth rate is 7.10% while the proxy groups of five and eleven LDCs average growth rates are 4.80% and 4.93%, respectively. Sheets 2 through 13 of Exhibit __ (FJH-10) contain the most recent Value Line Investment Survey for Southwest and the companies in each proxy group.

5. <u>Conclusion of DCF Cost Rate</u>

Q. 33 Please summarize the cost rates derived from your application of the constant growth DCF model to Southwest and the two proxy groups of LDCs.

A. 33 As shown in Column 6 of Exhibit __ (FJH-7), the DCF cost rates are 10.69% for Southwest; while the averages are 10.20% and 10.36% for the proxy groups of five and eleven LDCs, respectively. Details are also shown by company on Exhibit __ (FJH-7).

Q. 34 Please explain the reason for the difference between the indicated DCF return rates in Column 5 and the recommended DCF return rates in Column 6 of Exhibit __ (FJH-7).

A. 34 As mentioned briefly in my Summary supra, I have utilized regulatory awarded ROEs to LDCs between January 1, 2003 and September 30, 2004 as a reality check. That information will also be discussed infra in connection with Exhibit __ (FJH-15). As shown therein, the lowest regulatory awarded ROE was 9.90% in September 2003. Interest rates, and hence capital costs, are expected to rise during the next eighteen months as shown by the consensus forecasts of the Blue Chip Financial Forecasts' reporting economists. Thus, equity costs will be rising above recent levels. Consequently, I eliminated indicated DCF cost rates of 9.9% or lower from consideration as they are not indicative of any reasonable expected common equity cost rate. The need to do so emphasizes the veracity of my discussion supra regarding the problems associated with application of the DCF model as well as sole reliance on it, or any other cost of equity model. Hence, it is necessary to rely upon multiple cost of equity models.

C. The Risk Premium Model (RPM)

1. Theoretical Basis

Q. 35 Please describe the theoretical basis of the RPM.

A. 35 The RPM is based upon the theory that the cost of common equity capital is greater than the prospective company-specific cost rate for long-term debt capital. In other words, it is the expected cost rate for long-term debt capital plus a premium to compensate common shareholders for the added risk of being unsecured and last-in-line in any claim on the corporation's assets and earnings.

Q. 36 Some analysts state that the RPM is another form of the CAPM. Do you agree?

A. 36 Generally yes, but there is a very significant distinction between the two models. The RPM and CAPM both add a "risk premium" to an interest rate. However, the beta approach to the determination of an equity risk premium in the RPM should not be confused with the CAPM. Beta is a measure of systematic, non-diversifiable, market risk which is usually a much smaller percentage of total investment risk, the sum of both diversifiable and non-diversifiable risks. Diversifiable, i.e., unsystematic or company-specific risks are reflected in the RPM because the prospective company-specific long-term bond yield is the result of a bond rating process which includes an assessment of all diversifiable business and financial risks. This reality is verifiable by reading S&P's description of its bond rating process which is contained in Exhibit __ (FJH-2), at Sheets 3 through 9. In contrast, the use of a U.S. Government Security as the risk-free rate of return in the CAPM cannot reflect any diversifiable company-specific risk. Clearly, the RPM and CAPM are two separate and distinct cost of common equity models, a fact recognized in the financial literature.

Q. 37 Please describe your RPM analyses.

A. 37 They are shown in Exhibit __ (FJH-11), which consists of 9 sheets. As can be gleaned from Sheet 1, I have estimated the projected bond yield on Moody's A rated utility bonds to be 6.72%. As explained in Notes 3 and 4 on Sheet 1 of Exhibit __ (FJH-11), an adjustment of 0.36% is required to be made to the 6.72% yield on A rated public utility bonds to reflect Southwest's Moody's bond rating of Baa2 while no adjustment is required to be made to the 6.72% yield on A rated public utility bonds since each proxy group has an average Moody's bond rating of A2. Consequently, the resultant expected average bond yields are 7.08% for Southwest and 6.72% for each proxy group. I then calculated the equity risk premiums applicable to Southwest and each proxy group. The sum of the prospective bond yields and equity risk premiums equal the RPM-derived common equity cost rates applicable to Southwest and each proxy group.

2. <u>Estimation of Expected Bond Yield</u>

Q. 38 Please explain the basis of the expected bond yields of 7.08% applicable to Southwest and 6.72% applicable to each proxy group.

A. 38 Because the cost of common equity is prospective, the use of a prospective yield on similarly-rated long-term debt is appropriate. The average Moody's bond ratings (as well as S&P's bond ratings and business profiles) for Southwest and the average for each proxy group are shown on Exhibit __ (FJH-11), Sheet 2. They are Baa2 for Southwest and A2 for each proxy group. I relied upon the consensus forecasts of about 50 economists of the expected yields on Moody's Aaa rated corporate bonds for the six calendar quarters ending with the first calendar quarter of 2006 as derived from the October 1, 2004 <u>Blue Chip Financial Forecasts</u> (shown on Sheet 7 of

Exhibit __ (FJH-11). As shown on Line No. 1 of Sheet 1 of Exhibit __ (FJH-11), the average expected yield on Aaa rated corporate bonds is 6.25%. It is necessary to add the average yield differentials of Moody's A rated utility bonds over the average yield on Aaa rated corporate bonds because the Blue Chip economists do not forecast yields on A rated public utility bonds. After the yield on A rated public utility bonds is determined, it is necessary to adjust that yield to reflect Southwest's Baa2 bond rating as well as the A2 average bond rating of each proxy group. The bases of the adjustments are explained in Notes 2 through 4 on Sheet 1 of Exhibit __ (FJH-11). As shown on Line No. 5, Sheet 1 of Exhibit __ (FJH-11), the prospective bond yields are 7.08% applicable to Southwest and 6.72% applicable to each proxy group. It is then necessary to estimate the equity risk premiums applicable to those prospective bond yields.

3. Estimation of the Equity Risk Premium

Q. 39 Please explain the basis of the equity risk premiums which you have determined to be applicable to Southwest and each proxy group.

A. 39 I evaluated the results of two different historical equity risk premium studies, as well as Value Line's forecasted total annual return on the market over the prospective yield on high grade corporate bonds. These analyses are summarized on Sheet 5 of Exhibit __ (FJH-11). As shown on Line No. 3 of Sheet 5, the average equity risk premiums are 4.41% applicable to Southwest; 4.64% applicable to the proxy group of five LDCs; and 4.47% applicable to the proxy group of eleven Value Line LDCs.

Q. 40 Please explain the basis of the equity risk premiums shown on Line No. 1, Sheet 5 of Exhibit __ (FJH-11).

A. 40 Those premiums were determined utilizing betas. Equity risk premiums determined through the application of the beta approach are meaningful because the betas were derived from regression analyses of the market prices of common stocks over a recent five-year period. The market prices reflect investors' expectations over a long-term future investment horizon. Consequently, beta is a meaningful measure of prospective risk relative to the market as a whole and thus is a logical means by which to allocate a relative share of the total market's equity risk premium to a specific company or proxy group.

The average total market equity risk premium utilized was 6.49% as shown on Sheet 6, Line No. 7 of Exhibit __ (FJH-11). It is based upon an average of the long-term average historical equity risk premium of 6.30% and the forecasted market equity risk premium of 6.68% as shown on Sheet 6, Line Nos. 3 and 6, respectively, of Exhibit __ (FJH-11).

To derive the historical market equity risk premium, I used the most recent Ibbotson Associates' data on holding period returns for the S&P 500 Composite Index and the average yield on Aaa and Aa corporate bonds for the period 1926-2003. The use of holding period returns over a very long period of time is useful in the application of the beta approach. Ibbotson Associates, in its <u>Valuation Edition – 2003 Yearbook</u> provides sound reasoning why the use of a long-term historical time period is appropriate to estimate the expected equity risk premium. They demonstrate empirically through tests of serial correlation that equity risk premiums are random. They also demonstrate and explain why the arbitrary use of shorter time periods distorts the results of estimated long-term average market equity risk premiums. Moreover, the arbitrary use of shorter time periods is contrary to the long-term randomness of equity risk premiums. Consequently, the use of a long-term average equity risk premium provides stability in contrast to the volatility associated with the arbitrary use of shorter historical time periods. In addition, the use of a long-term average is consistent with the long-term investment horizon implicit in the cost of common equity capital, e.g., the premise of infinity in the standard DCF model used in rate regulation. Ibbotson Associates' full explanation of why the use of the long-term average equity risk premium is appropriate is provided at Sheets 5 through 8 of Exhibit __ (FJH-12).

In view of the foregoing and all of Ibbotson Associates' comments contained in Exhibit __ (FJH-12), it is clear that the arbitrary selection of shorter historical periods would be highly suspect. Such periods would likely contain the 1987 stock market crash, the collapse of the Soviet Union, the Persian Gulf War and the 2003 invasion of Iraq, extraordinary inflation rates and other significant events. Therefore, the arbitrary use of shorter historical time periods is unlikely to be representative of the amount of change <u>which could occur over a long period of time in the future</u> (the presumed long-term holding period for common stocks as is implicit in the various cost of equity models). Thus, the use of a very long past period to estimate the equity risk premium is consistent with the long-term investment horizon for utilities' common stocks. Consequently, the use of the long-term past to estimate equity risk premium is critical to proper estimation of the long-term future. The arithmetic mean of those long-term historical total return rates on the market as a whole is the appropriate mean for use in estimating the cost of capital because it provides essential insight into the potential variance of expected returns. A full explanation by Ibbotson Associates of why the arithmetic mean must be used when discounting future cash flows for estimating the cost of capital is contained in Sheets 2 through 4 of Exhibit __ (FJH-12).

Historical total returns and equity risk premiums differ in size and direction over time. It is precisely for this reason that the arithmetic mean is important. It is the arithmetic mean which provides insight into the variance and standard deviation of returns. It is the prospect for, and degree of, variance which provides the insight required by investors to estimate risk when contemplating making an investment. Insight into future variance based on historical returns can only be obtained by the use of the arithmetic mean. Absent valuable insight into the potential variance of returns, there can be no meaningful evaluation of prospective risk. If investors relied upon the geometric mean of historical returns, they would have no insight into the potential variance of future returns because the geometric mean relates the change over many periods to a constant rate of change, thereby obviating the year-to-year fluctuations, or variance, critical to risk analysis.

The basis of the historical market equity risk premium of 6.30% is detailed in Line Nos. 1 through 3, Sheet 6 of Exhibit __ (FJH-11).

Q. 41 Why do you also utilize a forecasted equity risk premium?

A. 41 In order to properly answer this question, I believe it is necessary to first explain two points with regard to the use of a long-term historical arithmetic equity risk premium. First, the long-term historical arithmetic average market equity risk premium is the most likely to be experienced over a long-term prospective period. A prospective element is contained in the use of beta because beta is derived from market prices which reflect expectations of the future. Secondly, beta is also utilized in conjunction with the *prospective yield* on A rated public utility bonds.

It is also appropriate to view the current potential for market price appreciation which may be possible for investors to experience in the current market environment. Such a period of up to about five years, based upon Value Line's forecasted market appreciation and dividend yield on its market universe, is something that investors would certainly be aware of because about 42% of Southwest's and 52% of the proxy groups' investors are individuals who are likely to rely upon Value Line as discussed <u>supra</u>. Because the potential for growth in the DCF model is market price appreciation, in estimating the equity risk premium in the RPM model it is also appropriate to take into account the forecasted equity risk premium.

The basis of the forecasted market equity risk premium of 6.68% is detailed in Line Nos. 4 through 6, Sheet 6 of Exhibit __ (FJH-11). The average of the historical and projected market equity risk premiums is 6.49% as shown on Line No. 7, Sheet 6 of Exhibit __ (FJH-11).

As shown on Line No. 9, Sheet 6 of Exhibit __ (FJH-11), application of Southwest's beta and the average beta of each proxy group to the average market equity risk premium of 6.49% results in equity risk premiums of 5.19% for Southwest, 5.13% for the proxy group of five LDCs and 4.80% for the proxy group of eleven Value Line LDCs.

Q. 42 Please describe the derivation of the holding period equity risk premiums of 3.62% for Southwest and 4.14% for each proxy group shown on Line No. 2, Sheet 5 of Exhibit __ (FJH-11).

A. 42 For the reasons described supra by Ibbotson Associates, I caused to be performed an analysis of the long-term historical holding period returns applicable to public utilities, i.e., the S&P Public Utility Index for the period 1928-2003, inclusive. The long-term average provides a good basis for future expectations as all types of events are included, even "unusual" ones. The analysis is summarized on Sheet 8 of Exhibit __ (FJH-11). After the adjustment necessary to reflect the average equity risk premium applicable to Moody's Baa rated public utility bonds for Southwest as shown on Line No. 2a, and A rated public utility bonds for the two proxy groups as shown on Line No. 2b of Exhibit __ (FJH-11), Sheet 8, the resultant adjusted equity risk premiums are 3.62% for Southwest and 4.14% for each proxy group.

Q. 43 What equity risk premiums are applicable to Southwest and each proxy group?

A. 43 The resultant equity risk premiums are: 4.41% for Southwest, 4.64% for the proxy group of five LDCs and 4.47% for the proxy group of eleven Value Line LDCs based on an average of Line Nos. 1 and 2 on Exhibit __ (FJH-11), Sheet 5 and shown on Line No. 3 of the same Sheet 5 as well as on Line No. 6, Sheet 1 of Exhibit __ (FJH-11).

4. Conclusion of RPM Cost Rates

Q. 44 What are the resultant RPM cost rates applicable to Southwest and each proxy group?

A. 44 As shown on Exhibit __ (FJH-11), Sheet 1, Line No. 7, they are 11.49% applicable to Southwest, 11.36% applicable to the proxy group of five LDCs and 11.19% applicable to the proxy group of eleven Value Line LDCs.

5. <u>The RPM Does Not Presume a Constant Equity Risk Premium</u>

Q. 45 Does the RPM assume a constant equity risk premium?

A. 45 No. The equity risk premium determined under the RPM varies inversely with interest rate changes since the prospective bond yield is subtracted from the estimated market return. Common sense affirms this to be so, due to common stock investors' expectation of greater returns during periods of declining interest rates and vice versa. In a sense, the equity risk premium is no different than the "g", or growth component, in the DCF model. The growth component "g" in a DCF cost rate calculated today, will invariably differ in subsequent time periods due to the availability of different growth rate data thereby confirming the reality that the "g" in the DCF model does change, even though it is presumed to be theoretically constant. In that regard, there is no difference between the RPM and DCF models in that both models assume an expectationally constant equity risk premium and growth rate, respectively, but in actuality *both* change regularly.

As Morin[11] states with regard to the DCF model:

> It is not necessary that g be constant year after year to make the model valid. *The growth rate may vary randomly around some average expected value. Random variations around trend are perfectly acceptable, as long as the mean expected growth is constant. The growth rate must be 'expectationally constant' to use formal statistical jargon.* (italics added)

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11 <u>Id.</u>, p. 111.

The foregoing confirms that the RPM is similar to the DCF model in the sense that both models contain the assumption of an "expectationally constant" risk premium and growth rate, respectively, despite the fact that each varies randomly around its mean. The mean referred to is the *arithmetic mean*, thereby indirectly *confirming that only the arithmetic mean is appropriate to use when estimating the cost of capital as discussed* *__supra__*.

D. The Capital Asset Pricing Model (CAPM)

1. Theoretical Basis

Q. 46 Please explain the theoretical basis of the CAPM.

A. 46 The CAPM defines risk as the covariability of a security's returns with the market's returns. This covariability is measured by beta ("β"), an index measure of an individual security's variability relative to the market as a whole. A beta less than 1.0 indicates lower variability than the market and a beta greater than 1.0 indicates greater variability than the market.

The CAPM assumes that all non-market, or unsystematic, risk can be eliminated through diversification. The risk that cannot be eliminated through diversification is called market, or systematic, risk. The model presumes that investors require compensation for risks that cannot be eliminated through diversification. Systematic risks are caused by events that affect the returns on all assets. In essence, the model is applied by adding a risk-free rate of return to a market risk premium. This market risk premium is adjusted proportionally to reflect the systematic risk of the individual security relative to the market as measured by beta.

The **traditional CAPM** is expressed as:

$$R_s = R_f + \beta(R_m - R_f)$$

Where R_s = Return rate on the common stock
R_f = Risk-free rate of return
R_m = Return rate on the market as a whole
β = Adjusted beta (volatility of the security relative to the market as a whole)

Numerous tests of the CAPM have confirmed its validity. These tests have measured the extent to which security returns and betas are related as predicted by the CAPM.

The **empirical CAPM (ECAPM)**, discussed by Morin, reflects the reality that the empirical Security Market Line (SML) described by the traditional CAPM is not as steeply sloped as the predicted SML. Morin[12] states:

> At the empirical level, there have been countless tests of the CAPM to determine to what extent security returns and betas are related in the manner predicted by the CAPM.[13] The results of the tests support the idea that beta is related to security returns, that the risk-return tradeoff is positive, and that the relationship is linear. The contradictory finding is that the empirical Security Market Line (SML) is not as steeply sloped as the predicted SML. With few exceptions, the empirical studies agree that the implied intercept term exceeds the risk-free rate and the slope term is less than predicted by the CAPM. That is, low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted.

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12 Id., at p. 321.

13 For a summary of the empirical evidence on the CAPM, see Jensen (1972) and Ross (1978). The major empirical tests of the CAPM were published by Friend and Blume (1975), Black, Jensen, and Scholes (1972), Miller and Scholes (1972), Blume and Friend (1973), Blume and Husic (1973), Fama and Macbeth (1973), Basu (1977), Reinganum (1981B), Litzenberger and Ramaswamy (1979), Banz (1981), Gibbons (1982), Stambaugh (1982), and Shanken (1985). CAPM evidence in the Canadian context is available in Morin (1981).

> Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:
>
> $$K = R_F + x(R_M - R_F) + (1 - X)\beta(R_M - R_F)$$
>
> Where x is a fraction to be determined empirically. ...the value of x that best explains the observed relationship is between 0.25 and 0.30. If x = 0.25, the equation becomes:
>
> $$K = RF + 0.25(RM - RF) + 0.75\beta(RM - RF)$$[14]
>
> * * * * *

The ECAPM is a return adjustment, i.e., a y-axis adjustment and thus does not increase the adjusted beta, which is an x-axis adjustment and accounts for regression bias.

As a result of the foregoing, I apply both versions of the model (CAPM and ECAPM) which are contained in Exhibit __ (FJH-13), which consists of 4 sheets.

2. Risk-Free Rate of Return

Q. 47 Please describe your selection of a risk-free rate of return.

A. 47 My applications of the CAPM and the ECAPM reflect a risk-free rate of 5.52%. It is based upon the average consensus forecast of the reporting economists in the October 1, 2004 issue of Blue Chip Financial Forecasts for the yields on 20-year U.S. Treasury Bonds for the six quarters ending with the first calendar quarter 2006 as shown in Note 2 on Sheet 4 of Exhibit __ (FJH-13).

Q. 48 Why is the average prospective yield on 20-year U.S. Treasury Bonds appropriate for use as the risk-free rate?

A. 48 The yield on 20-year T-Bonds is almost risk-free and its term is consistent with the long-term cost of capital to public utilities measured by the yields on public utility bonds and more closely matches the long-term investment horizon inherent in utilities' common stocks. Moreover, it is consistent with the long-term investment horizon, which is presumed to be infinite, in the standard DCF model employed in proceedings such as these. In addition, Ibbotson Associates[15] states:

> A common choice for the nominal riskless rate is the yield on a U.S. Treasury Security. The ability of the U.S. government to create money to fulfill its debt obligations under virtually any scenario makes U.S. Treasury securities practically default-free. While interest rate changes cause government obligations to fluctuate in price, investors face essentially no default risk as to either coupon payment or return of principal. The horizon of the chosen Treasury security should match the horizon of whatever is being valued. *When valuing a business that is being treated as a going concern, the appropriate Treasury yield should be that of a long-term Treasury bond.* Note that the horizon is a function of the investment, not the investor. If an investor plans to hold stock in a company for only five years, the yield on a five-year Treasury note would not be appropriate since the company will continue to exist beyond those five years. (italics added for emphasis)

In summary, the average expected yield on 20-year Treasury Bonds is the appropriate proxy for the risk-free rate in the CAPM because it is almost risk-free and has a long-term investment horizon consistent with utilities' common stocks (not individual investors) and is thus consistent with the infinite investment horizon assumed in the standard DCF model.

3. <u>Market Equity Risk Premium</u>

Q. 49 Please explain the basis for your estimation of the expected market equity risk premium.

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14 Id., at pp. 335-336.

15 Stocks, Bonds, Bills and Inflation: 2004 Yearbook – Valuation Edition, Ibbotson Associates, Chicago, IL, p. 53.

A. 49 I estimate investors' expected total return rate based on an average of forecasted and long-term historical return rates from which I subtract the risk-free rate. The result is a market equity risk premium, some proportion of which must be allocated to Southwest and each proxy group. I make the allocation of the market equity risk premium through the use of beta because beta is a measure of the risk of a security relative to the entire market.

The basis of the projected market equity risk premium is explained in detail in Note 1 on Sheet 4 of Exhibit __ (FJH-13). The 3-5 year total market appreciation projection, when converted to an annual rate plus the market's average dividend yield equals a forecasted total annual return rate of 12.93%. The long-term historical total annual arithmetic mean return rate of 12.40% on the market of large company stocks is from Ibbotson Associates' Stocks, Bonds, Bills and Inflation: Valuation Edition – 2004 Yearbook. The relevant risk-free rate was deducted from the total market return rate. For example, from the Value Line projected total market return of 12.93%, the forecasted average risk-free rate of 5.52% was deducted indicating a forecasted market risk premium of 7.41%. From the Ibbotson Associates' arithmetic mean long-term historical total return rate of 12.40%, the long-term historical income return rate on long-term U.S. Government Securities of 5.20% was deducted indicating an historical equity risk premium of 7.20%. Thus, the average of the projected and historical total market risk premiums of 7.41% and 7.20%, respectively, is 7.305%, or 7.31%, rounded.

4. Conclusion of CAPM Cost Rates

Q. 50 What are the results of your applications of the CAPM and ECAPM?

A. 50 They are shown on Exhibit __ (FJH-13), Sheet 1. The details for the CAPM and ECAPM are shown by company on Sheets 2 and 3 of Exhibit __ (FJH-13), respectively.

I rely upon the average of both the CAPM and ECAPM cost rates. As shown on Line No. 3, Sheet 1 of Exhibit __ (FJH-13), they are 11.55% for Southwest, 11.49% for the proxy group of five LDCs and 11.25% for the proxy group of eleven Value Line LDCs.

E. The Comparable Earnings Model (CEM)

1. Theoretical Basis

Q. 51 Please describe the theoretical basis of the CEM.

A. 51 The comparable earnings standard recognizes the fundamental economic concept of opportunity cost. This concept states that the cost of using any resource – land, labor and/or capital – for a specific purpose is the return that could have been earned in the next best alternative use. The opportunity cost to an investor in a utility's common stock is what that capital would yield in an alternative investment of similar risk. The opportunity cost principle is consistent with one of the fundamental principles of utility price regulation, i.e., it is intended to act as a surrogate for the competition of the marketplace.

The problem in using returns on book equity (the ROEs) of non-price regulated companies is determining whether such companies are similar in risk to the price-regulated utility. The ROEs of other similar, price-regulated firms should not be relied upon because they reflect the results of regulatory awards which may not be indicative of what could have been earned in a competitive market. Moreover, such use would be an exercise in circularity. Consequently, application of the CEM is most appropriately implemented by examining the ROEs of similar risk, domestic, non-price regulated firms.

As it is the perception of investors that competition continues to accelerate in the natural gas industry, the concept of observing the rates of earnings on book equity, or net worth, of comparable risk non-price regulated firms has greater relevance than ever despite a long regulatory history for the use of the comparable earnings method. Moreover, the use of ROEs of comparable non-price regulated firms is appropriate because:

(1) Under the rate base/rate of return paradigm, the rate of return (including the rate of return on common equity) is applied to a rate base measured at original (i.e., book) cost;

(2) As discussed supra, many factors influence market prices other than company-specific EPS and/or DPS. Thus, when market values differ from their book values, market-based DCF cost rates either understate or overstate the rates of earnings required on book equity (i.e., the common equity financed portion of an original cost rate base); and

(3) As also discussed supra, regulatory decisions can influence but cannot control market prices.

2. Application of the CEM

Q. 52 How did you approach your CEM analyses?

A. 52 My CEM analysis is set forth in Exhibit __ (FJH-14) which consists of five sheets. Sheets 1, 2 and 3 contain the relevant data for the domestic non-price regulated companies which are comparable in risk to Southwest and the proxy groups of five LDCs and eleven Value Line LDCs, respectively. Sheets 4 and 5 contain the notes relative to Sheets 1, 2 and 3. It is critical to the application of the CEM to select proxy groups of non-price regulated companies similar in total risk to the price-regulated utilities, i.e., Southwest and the two proxy groups of LDCs. The proxy groups of comparable domestic, non-price regulated firms should be broad-based in order to obviate individual company-specific aberrations. Utilities should be eliminated to avoid circularity since the rates of return on their book common equity are substantially influenced by the rate determinations of their respective regulatory commissions, many of which are the result of negotiated settlements and are not truly market-based results. They are often just the "fall-out", or balance wheel, of the many issues resolved through the settlement process.

3. <u>Selection of Market-Based Companies of Similar Risk</u>

Q. 53 Is your application of the CEM market-based?

A. 53 Yes. My application of the CEM is market-based because the selection of the comparable non-price regulated firms is based upon statistics derived from the market prices paid by investors. Specifically, I rely upon the betas and related statistics derived from Value Line regression analyses of weekly market prices over the most recent 260 weeks (five years). The bases of selection resulted in proxy groups of domestic, non-price regulated firms comparable to the price-regulated utilities, i.e., comparable in total risk, the sum of non-diversifiable market risk and diversifiable company-specific risks. As a result, there are 25 non-utility, non-price regulated companies comparable in total risk to Southwest, 36 companies comparable in total risk to the proxy group of five LDCs and 26 companies comparable in total risk to the proxy group of eleven Value Line LDCs. In selecting the non-price regulated firms I eliminated all those with expected ROEs of 20.00% or greater and those with expected ROEs less than 9.90% and determined that:

1. They be domestic, non-price regulated companies, i.e., non-utilities.
2. They be covered by Value Line Investment Survey (Standard Edition).
3. Their unadjusted betas lie within plus or minus two standard deviations of the unadjusted betas of Southwest and the average unadjusted beta of each proxy group of LDCs.
4. The standard errors of the regressions lie within plus or minus two standard deviations of the average standard error of the regression for Southwest and the average standard error of the regression of each proxy group of LDCs.

Betas are a measure of market, or systematic, risk. The standard errors of the regressions were used to measure each firm's company-specific risk (diversifiable, unsystematic risk). The standard errors of the regressions measure the extent to which events specific to a company affect its stock price. *Because market prices reflect investors' perceptions of total risk, all risk which is not systematic market risk (beta) is reflected in the standard error of the regression which is a measure of total non-systematic risk which is diversifiable. In essence, companies which have similar betas and standard errors of the regressions have similar total investment risk.* The betas and standard errors result from regression analyses of market prices which reflect all perceived risks consistent with the EMH. Consequently, the use of those regression statistics results in proxy groups of non-price regulated domestic firms which are similar in total investment risk to Southwest and each proxy group of LDCs. The use of two standard deviations captures 95.50% of the distribution of unadjusted betas and standard errors of the regressions, thereby assuring comparability of total investment risk.

The use of Student's t-statistic at the 95% confidence level resulted in the elimination of the highest expected ROE, i.e., the 43.5% for Moody's Corp. which is included in all three groups of non-price regulated companies comparable in total risk to Southwest and each proxy group of LDCs. As discussed supra, I also eliminated return rates of 20.00% or greater (which would also have eliminated Moody's Corp.'s 43.5%) and those lower than 9.90%. I did so because it is not likely that any gas distribution utility would be awarded an ROE of 20.00% or more; conversely, I also eliminated ROEs less than 9.90% because 9.90% was the lowest awarded ROE to an LDC by any state commission during the period January 1, 2003 through September 30, 2004 especially since it is clear that prospective capital costs, including the cost of equity, will continue to increase.

4. Conclusion of CEM Cost Rates

Q. 54 What are the most indicative CEM cost rates applicable to Southwest and each proxy group?

A. 54 As shown on Sheets 1, 2 and 3 of Exhibit __ (FJH-14), they are 13.65% relative to Southwest, 13.30% relative to the proxy group of five LDCs and 12.44% relative to the proxy group of eleven Value Line LDCs.

X. CONCLUSION OF COMMON EQUITY COST RATE

A. Conclusion of Common Equity Cost Rate Must be Based on the Application of Multiple Models and Consideration of all Risks

Q. 55 Please summarize why, in your opinion, the conclusion of common equity cost rate must be determined from the results of the application of multiple cost of common equity models.

A. 55 As discussed supra, the EMH and common sense mandate the use of multiple market-based cost of common equity models. All of the models which I have utilized are market-based.

1. The DCF Model utilizes market prices paid by investors.

2. The RPM utilizes the expected market yield on company-specific long-term debt and the equity risk premium based upon an expectation of the market equity risk premium.

3. The CAPM and ECAPM utilize total market returns, and betas which result from each individual stock's market price movement relative to the market.

4. The CEM is based upon the selection of comparable risk, non-price regulated domestic companies selected through the use of statistics derived from regression analyses of market prices paid by investors.

Investors are aware of all of these cost of common equity models which are in use and discussed in the financial literature. Therefore, belief in the EMH requires that all of them be taken into account.

Q. 56 What is your recommended common equity cost rate?

A. 56 My recommended common equity cost rate is 11.95% applicable to Southwest's proposed hypothetical common equity ratio of 42.00%. It is based on the application of all four cost of common equity models to Southwest and the two proxy groups of

LDCs. Equal weight was given to all four market-based cost of common equity models. The resultant average cost rates, before adjustments to the average cost rates of the proxy groups to reflect Southwest's additional risk, are 11.85% for Southwest itself, 11.59% for the proxy group of five LDCs and 11.31% for the proxy group of eleven Value Line companies as shown on Line No. 5 of Exhibit __ (FJH-1), Sheet 2.

Adjustments are required in order for the average cost rates of the proxy groups to be applicable to Southwest because of those groups' higher average bond ratings which reflect better achieved rates of earnings on greater actual common equity ratios. There are two adjustments which are necessary and they are shown on Line Nos. 6A and 6B of Exhibit __ (FJH-1), Sheet 2. The first adjustment of 0.36% (explained in Note 6 on Sheet 3 of Exhibit __ (FJH-1)) is necessary in order to reflect Southwest's lower Moody's bond rating of Baa2 vis-à-vis the higher average Moody's bond rating of A2 for each proxy group.

In addition, bond rating differences alone do not reflect the fact that effectively, a great majority of companies in each proxy group have protection against the vagaries of weather, either through weather normalization clauses, weather stabilization insurance, or innovative rate design. Southwest has no protection against the impact of the vagaries of weather on revenues, earnings and cash flows. The lack of protection from the vagaries of the weather (in addition to declining per customer usage) is a significant factor in Southwest's more risky S&P assigned business profile of "3" versus an average 1.8 for the proxy group of five and 2.0 for the proxy group of eleven Value Line LDCs. The adjustments on Line

6A of Exhibit __ (FJH-1), Sheet 2 reflect only the difference in bond rating but not Southwest's more risky business profile which directly impacts common shareholders' risks. Consequently, I believe it is necessary to further adjust the cost rates of the proxy groups upward by 0.15% and 0.20% (as explained in detail in Note 7, Sheet 3 of Exhibit __ (FJH-1) because Southwest does not have, nor has it had, any protection from the vagaries of weather. I believe such protection reduces common equity cost rate risk by 0.25%. Conversely, because Southwest does not have a WNC in place, the cost rates of the proxy groups must be adjusted upward on a pro rata basis to reflect Southwest's greater common equity risk. Thus, the total adjustments (sum of Line Nos. 6A and 6B on Sheet 2 of Exhibit __ (FJH-1) aggregate 0.51% and 0.56% for the proxy groups of five LDCs and eleven Value Line LDCs, respectively. As a result of those upward adjustments, the common equity cost rate applicable to the proxy group of five LDCs is 12.10% and that applicable to the proxy group of eleven Value Line LDCs is 11.87% as shown on Line No. 7 of Exhibit __ (FJH-1), Sheet 2. Southwest's average common equity cost rate of 11.85% shown on Line Nos. 5 and 7 on Sheet 3, requires no adjustment. I rely on an average of all three of those cost rates, or 11.95% as being applicable to Southwest.

If this Commission were to adopt Southwest's actual capital structure ratios, either the average during or at the end of the August 31, 2004 test year in lieu of the proposed hypothetical ratios, my recommended common equity cost rate would be higher than 11.95% because of the added financial risk, consistent with basic financial precepts.

Q. 57 Have you included in your recommended common equity cost rate any allowance for the costs associated with the issuance of new common stock, i.e., flotation costs?

A. 57 No. Recent increases in the number of shares has been through the Dividend Reinvestment and Stock Purchase Plan (DRSPP). While Southwest has no plans for a new public offering of common stock in the immediate future, additional shares have been, and are, expected to be issued from a shelf authorization over the next several years. The purchased shares do have a one percent sales commission associated with them. Nonetheless, in order to be conservative, I have made no adjustment to common equity cost rate to reflect such costs.

Q. 58 What is your recommended common equity cost rate if the requested CMT is approved?

A. 58 It is 11.70% and reflects a reduction in common equity cost rate of 0.25%. I have testified in other cases in the past that the implementation of a weather normalization clause would result in a reduction of 25 basis points (0.25%) in common equity cost rate. However, in Case 29679 (Opinion No. 88-19) (95 PUR 4th 128) re: National Fuel Gas Distribution Corporation, in which I offered a reduction of 0.25% in common equity cost rate, the New York Public Service Commission, in allowing the establishment of a weather normalization adjustment clause on a trial basis, disagreed and found that it had no impact on common equity cost rate when it stated:

> The weather normalization clause would not operate to maintain a particular earnings target; rather, it would simply stabilize revenues (and customer bills) by moderating the influence of weather.[7]
>
> 7 For this reason, the company's proposal to tie an arbitrary reduction to its projected cost of equity to the adoption of a weather normalization clause makes no sense.

Notwithstanding the foregoing decision of the New York Public Service Commission, I believe that the stabilization of revenues resulting from the implementation of the CMT, in the instant matter, would stabilize earnings by adjusting for weather and volumes, thereby somewhat improving the opportunity to earn the authorized operating margin. Thus, I believe that the CMT, if approved, would reduce the cost of common equity by 25 basis points, or 0.25%. Consequently, I believe that such a reduction is conservatively appropriate, especially in view of the fact that the New York Public Service Commission determined there was no reduction in common equity cost rate attributable to the implementation of a weather normalization clause, as discussed supra.

XI. REALITY CHECK

Q. 59 Have you performed a reality check to affirm that a common equity cost rates of 11.95%, with no CMT being in effect, and 11.70% with a CMT in effect are realistic?

A. 59 Yes, I have. On Exhibit __ (FJH-15), I have shown a summary of regulatory awards made to gas distribution companies by state regulatory commissions during the period January 1, 2003 through September 30, 2004. As shown, the average authorized rate of return on common equity was 10.86% relative to a 47.60% common equity ratio for all awards. The average award for all fully litigated cases was 10.91% relative to a 47.68% common equity ratio. Capital costs are beginning to increase and are expected to do so at least through early 2006 per the consensus forecasts of about 50 economists per the October 1, 2004 Blue Chip Financial

Forecasts (Exhibit __ FJH-11), Sheet 7). For example, the average yield on Aaa corporate bonds is expected to be 6.6% in the first quarter 2006 from about 5.4% in late September 2004, an increase of about 120 basis points. When an average awarded ROE of about 10.9% is adjusted to take into account investors' expectation of higher capital costs as well as Southwest's lower ratemaking (hypothetical) common equity ratio of 42% (versus nearly 48%) and Southwest's lower (more risky) bond rating, higher (more risky) business profile, and lack of protection from the vagaries of weather exacerbated by declining per customer usage, it is clear that my recommended cost(s) of common equity pass the reality check.

Q. 60 Are there other reasons why Southwest should be afforded an opportunity to earn a higher ROE than has been awarded to other LDCs as discussed supra?

A. 60 Yes. It is important to remember that Southwest's S&P bond rating is BBB- (minus) which is the very bottom of investment grade bond rating. The slightest further downgrade of even one rating notch by S&P would put the rating at BB+ which is below investment grade. A downgrade to below investment grade would be complete disaster for a utility such as Southwest which has an obligation to serve at all times because it needs to be able to raise capital on reasonable terms when required – not when it is convenient. It would be an even greater disaster for Southwest, one of the fastest growing LDCs in the country, which needs to raise capital frequently. At a minimum, capital if raised, would cost considerably more than would have to be paid by utilities with investment grade rated bonds seeking capital at the same time. At the worst, service to customers would be impaired if, in tight capital markets, all of the required capital could not be raised, which is quite possible. Consequently, Southwest must maintain access to the capital markets at all times on a reasonable basis even during tight money periods. Its credit rating should be enhanced over time and its debt should not be allowed to be downgraded to the speculative BB category. The ways to best preserve Southwest's financial integrity and, hopefully, to help it to improve over time are to recognize:

- that Southwest's requested capital structure and ROE will truly be of long-range benefit to its customers by preserving its investment grade status;
- that Southwest is more risky than the average LDC and specifically the two proxy groups of LDCs;
- that it has no protection against the adverse impact of declining per customer usage and weather's vagaries on revenues, earnings, and cash flows and that protection such as the requested CMT is essential to its financial health;
- that the use of a hypothetical capital structure which includes 42% common equity is a critical element to Southwest's financial well-being; and
- that the financial community needs to receive a positive signal from regulators that they recognize Southwest's problems attributable to: (1) the history of inadequate achieved ROEs; (2) an inability to increase its dividend for more than ten years; and (3) a bottom of investment grade bond rating; and by taking action to remedy them because, despite its best efforts, Southwest has been unable to overcome them.

Q. 61 Does that conclude your direct testimony?

A. 61 Yes, it does.

APPENDIX A

PROFESSIONAL QUALIFICATIONS

OF

FRANK J. HANLEY, CRRA
PRESIDENT

AUS CONSULTANTS - UTILITY SERVICES

PROFESSIONAL QUALIFICATIONS OF FRANK J. HANLEY

EDUCATIONAL BACKGROUND

I am a graduate of Drexel University where I received a Bachelor of Science Degree from the College of Business Administration. The principal courses required for this Degree include accounting, economics, finance and other related courses. I am also Certified by the Society of Utility and Regulatory Financial Analysts, formerly the National Society of Rate of Return Analysts, as a Rate of Return Analyst (CRRA).

PROFESSIONAL EXPERIENCE

In 1959, I was employed by American Water Works Service Company, Inc., which is a wholly-owned subsidiary of American Water Works Company, Inc., the largest investor-owned water works operation in the United States. I was assigned to its Treasury Department in Philadelphia until 1961. During that period of time, I was heavily involved in the development of cash flow projections and negotiations with banks for the establishment of lines of credit for all of the operating and subholding companies in the system, which normally aggregated more than $100 million per year.

In 1961, I was assigned to its Accounting Department where I remained until 1963. During that two-year period, I became intimately familiar with all aspects of a service company accounting system, the nature of the services performed, and the methods of allocating costs. In 1963, I was reassigned to its Treasury Department as a Financial Analyst. My duties consisted of those previously performed, as well as the expanded responsibilities of assisting in the preparation of testimony and exhibits to be presented to various public utility commissions in regard to fair rate of return and other financial matters. I also designed and recommended financing programs for many of American's operating subsidiaries and negotiated sales of long-term debt securities and preferred stock on their behalf either directly with institutional investors or through investment bankers. I was elected Assistant Treasurer of a number of operating subsidiaries in the Fall of 1967, just prior to accepting employment with the Communications and Technical Services Division of the Philco-Ford Corporation located in Fort Washington, Pennsylvania. While in the employ of the Philco-Ford organization, as a Senior Financial Analyst, I had responsibility for the pricing negotiations and analysis of acceptable rates of return to the corporation for all types of contract proposals with various agencies of the U.S. Government and foreign governments.

In the Summer of 1969, I accepted a position with the Financial Division of The Philadelphia National Bank. I was elected Financial Planning Officer of the bank in December 1970. While employed with The Philadelphia National Bank, my responsibilities included preparation of the annual and five-year profit plans. In the compilation of these plans, I had to perform detailed analyses and measure the various levels of profitability for each organizational unit. I also assisted correspondent banks in matters of recapitalization and merger, made recommendations and studies for their use before the various regulatory bodies having jurisdiction over them.

In September 1971, I joined AUS Consultants - Utility Services Group as Vice President. I was elected Senior Vice President in May 1975. I was elected President in September 1989.

EXPERT WITNESS QUALIFICATIONS

I have offered testimony as an expert witness on the subjects of fair rate of return and utility financial matters in approximately 300 various cases and dockets before the following agencies and courts: before the Alaska Public Utilities Commission and its successor the Regulatory Commission of

Alaska, the Arizona Corporation Commission, the Arkansas Public Service Commission, the California Public Utilities Commission, the Public Utilities Control Authority of Connecticut, the Delaware Public Service Commission, the Florida Public Service Commission, Hawaii Public Utilities Commission, the Idaho Public Utilities Commission, the Illinois Commerce Commission, the Indiana Public Utility Regulatory Commission, the Iowa Utilities Board, the Public Service Commission of Kentucky, the Maryland Public Service Commission, the Massachusetts Department of Public Utilities, the Michigan Public Service Commission, the Minnesota Public Utilities Commission, the Missouri Public Service Commission, the Public Utilities Commission of Nevada, the New Jersey Board of Public Utilities, the New Mexico State Corporation Commission, the Public Service Commission of the State of New York, the North Carolina Utilities Commission, the Ohio Public Utilities Commission, the Oklahoma Corporation Commission, the Pennsylvania Public Utility Commission, the Rhode Island Public Utilities Commission, the Tennessee Public Service Commission, the Public Service Board of the State of Vermont, the Virginia State Corporation Commission, the Public Services Commission of the Territory of the U.S. Virgin Islands, the Washington Utilities and Transportation Commission, the Public Service Commission of West Virginia, the Wisconsin Public Service Commission, the Federal Power Commission and its successor the Federal Energy Regulatory Commission. I have testified before the New Jersey Division of Tax Appeals and the United States Bankruptcy Court - Middle District of Pennsylvania with regard to the economic valuation of utility property. Also, I have testified before the U.S. Tax Court in Washington D.C. as an expert witness on the value of closely held utility common stock in a contested Federal Estate Tax case.

In addition, I have appeared as a Staff rate of return witness for the Arizona Corporation

Commission, the Delaware Public Service Commission and the Virgin Islands Public Services Commission. I have testified on the fair rate of return on behalf of the City of New Orleans, Louisiana, and also acted as project manager for my firm in representing the City in the 1980-1981 rate proceeding of New Orleans Public Services, Inc. The City of New Orleans then had, as it does now, regulatory authority with regard to the retail rates charged by New Orleans Public Service, Inc., for electric and natural gas service. I have also acted as a consultant to the District of Columbia Public Service Commission itself -- not in the capacity of Staff.

I have testified before a number of local and county regulatory bodies in various states on the subject of fair rate of return on behalf of cable television companies as well as before an arbitration panel in Ohio and a State District Court in Texas. I have testified before the Public Works Committee of the Nebraska State Senate in relation to Legislative Bill 731 which proposed permitting Public Power Districts and Municipalities to enter the Cable Television field.

PROFESSIONAL ASSOCIATIONS, PUBLICATIONS AND GUEST SPEAKER APPEARANCES

I am a Member of the Society of Utility and Regulatory Financial Analysts (SURFA), formerly known as the National Society of Rate of Return Analysts. I am a Certified Rate of Return Analyst (CRRA). I am on the Advisory Council of New Mexico State University's Center for Public Utilities which is endorsed by the National Association of Regulatory Utility Commissioners (NARUC). I am also a member of the Executive Advisory Council of the Rutgers University School of Business at Camden. AUS Consultants – Utility Services is an associate member of the American Gas Association (AGA) and I am a member of AGA's Rate and Strategic Issues Committee. I am also an associate member of the National Association of Water Companies and also an associate member of the Energy Association of Pennsylvania. AUS Consultants – Utility Services is an associate member of the New Jersey Utilities Association.

I often attend SURFA meetings during which considerable information on the subject of rate of return is exchanged. I have also attended corporate bond rating seminars held by Standard & Poor's Corporation. I continuously review financial publications of institutions such as Standard & Poor's, Moody's Investors' Service, Value Line Investment Survey, and periodicals of various agencies of the U.S. Government.

I co-authored an article with A. Gerald Harris entitled "Does Diversification Increase the Cost of Equity Capital?" which was published in the July 15, 1991 issue of Public Utilities Fortnightly. Also, an article which I co-authored with Pauline M. Ahern entitled "Comparable Earnings: New Life for an Old Precept" was published in the American Gas Association's Financial Quarterly Review, Summer 1994. I also authored an article entitled "Why Performance-Based Incentives Are Essential" which was published in THE CITY GATE, Fall 1995, a magazine published by the Pennsylvania Gas Association.

I have appeared as a guest speaker before an annual convention of the Mid-American Cable Television Association in Kansas City, Missouri and as a guest panelist on the small water companies' operation seminar of the National Association of Water Companies' 77th Annual Convention in Hollywood, Florida. I addressed the Second Annual Seminar on Regulation of Water Utilities sponsored by N.A.R.U.C., at the University of South Florida's St. Petersburg campus. I have spoken on fair rate of return to the Third and Fourth Annual Utilities Conferences, as well as the special conference on the cost of capital in El Paso, Texas sponsored by New Mexico State University. In

1983 I also made a presentation on the Cost of Capital in Atlantic City, New Jersey, at a seminar co-sponsored by Temple University. I have also addressed the Public Utility Law Section of the American Bar Association's Third Institute on Fundamentals of Ratemaking which was held in Washington, D.C. and I addressed a Conference on Cable Television sponsored by The University of Texas School of Law at Austin, Texas. Also, I addressed a meeting of the New England Water Works Association at Boxborough, Massachusetts, on the subject of Enterprise Financing. In addition, I was a speaker and mock witness in three different Utility Workshops for Attorneys sponsored by the Financial Accounting Institute held in Boston and Washington, D.C. I also was on a panel at the 23rd Financial Forum sponsored by the National Society of Rate of Return Analysts. The topic was Rate of Return Determination in the Diversified and/or Partially Deregulated Environment. I addressed the 83rd Annual Meeting of the Pennsylvania Gas Association in Hershey, PA. My topic was the Cost of Capital Implications of Demand Side Management. In June 1993, I lectured on the cost of capital at the American Gas Association's Gas Rate Fundamentals Course. In October 1993, I was a guest speaker at the University of Wisconsin's Center for Public Utilities -- my topic was "Diversification and Corporate Restructuring in the Electric Utility Industry - Trends and Cost of Capital Implications." In October 1994, I was a guest speaker on a panel at the Fourteenth Annual Electric & Natural Gas Conference in Atlanta, Ga., sponsored by the Bonbright Utilities Center of the University of Georgia and the Georgia Public Service Commission. The panel topic was "Responses to Competition and Incentive Rates." In October 1994, I was a guest speaker on a panel at a conference and workshop called "Navigating the Shoals of Cable Rate Regulation" sponsored by EXNET in Washington, D.C. The panel topic was "Rate of Return." Also, in March 1995, I was a guest speaker on a panel at a conference entitled, "Current Issues Challenging the Regulatory Process" sponsored by New Mexico State University - Center for Public Utilities. My panel topic concerned the electric industry and was titled, "Impact of a Competitive Structure on the Financial Markets". In May 1995, I was a guest speaker at the 87th Annual Meeting of the Pennsylvania Gas Association in Hershey, PA. My topic was "The Pennsylvania Economy and Utility Regulation: Impact on Industry, Consumers and Investors." In May 1996, I was on a panel at the 28th Financial Forum of the Society of Utility and Regulatory Financial Analysts. The panel's topic was "Revisiting the Risk Premium Approach" and was held in Richmond, Virginia. Since May 1996, I have participated as an instructor in 2-3 seminars per year on the "Basics of Regulation" (and the ratemaking process in a changing environment) and also in a program called "A Step Beyond the Basics", all sponsored by New Mexico State University's Center for Public Utilities and NARUC. In March 2002, I was a guest speaker before the Rate and Strategic Issues Committee of the American Gas Association in St. Petersburg, Florida. My topic was Rate of Return Strategies. In December 2002, I was a guest speaker at a seminar entitled, "Service Innovations and Revenue Enhancements for the Energy Distribution Business" sponsored by the American Gas Association in Washington, DC. My topic was "The Impact of Volatile Energy Markets on Rate of Return Strategies". In February 2003, I spoke at the Rutgers University-Camden, NJ M.B.A. Speaker Series. I addressed M.B.A. students and interested faculty on the role of the expert witness in the public utility ratemaking process. In November 2003, by invitation, I was a Guest Professor at Rutgers University – Camden for a class of undergraduate finance students.

BEFORE THE

ARIZONA CORPORATION COMMISSION

EXHIBITS
(FJH-1) THROUGH (FJH-15)

TO ACCOMPANY THE

DIRECT TESTIMONY

OF

FRANK J. HANLEY, CRRA
PRESIDENT
AUS CONSULTANTS - UTILITY SERVICES

CONCERNING

COMMON EQUITY COST RATE

RE: SOUTHWEST GAS CORPORATION

DOCKET NO. ________

Southwest Gas Corporation
Table of Contents
to the Financial Supporting Exhibits
of Frank J. Hanley

Southwest Gas Corporation
Summary of Cost of Capital and Fair Rate of Return
Based Upon a Hypothetical Regulatory Capital Structure

With no Conservation Margin Tracker (CMT) Authorized

Type of Capital	Ratios (1)	Cost Rate	Weighted Cost Rate
Long-Term Debt	53.00	7.49 (1)	3.97
Preferred Equity	5.00	8.20 (1)	0.41
Common Equity	42.00	11.95 (2)	5.02
Total	100.00 %		9.40 %

With a CMT

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	53.00	7.49 (1)	3.97
Preferred Equity	5.00	8.20 (1)	0.41
Common Equity	42.00	11.70 (2)	4.91
Total	100.00 %		9.29 %

Notes:

(1) FromSchedule D-1, Sheet 1 of 1
(2) Based upon informed judgment from the entire study, the principal results of which are summarized on Sheet 2 of Exhbit No___(FJH-1)

Southwest Gas Corporation
Brief Summary of Common Equity Cost Rate

Line No.	Principal Methods	Southwest Gas Corporation	Proxy Group of Five Gas Distribution Companies	Proxy Group of Eleven Value Line Gas Distribution Companies
1.	Discounted Cash Flow Model (1)	10.69 %	10.20 %	10.36 %
2.	Risk Premium Model (2)	11.49	11.36	11.19
3.	Capital Asset Pricing Model (3)	11.55	11.49	11.25
4.	Comparable Earnings Analysis (4)	13.65	13.30	12.44
5.	Indicated Common Equity Cost Rate before Investment Risk Adjustments	11.85 %	11.59 %	11.31 %
6.	Investment Risk Adjustments			
	A. Due to Southwest Gas Corporation's Lower Bond Rating	--	0.36 (5)	0.36 (6)
	B. Due to Southwest Gas Corporation's Lack of Protection from the Vagaries of Weather (7)	--	0.15 (7)	0.20 (7)
7.	Common Equity Cost Rate after Investment Risk Adjustment	11.85 %	12.10 %	11.87 %
8.	Recommendation without protection against weather and / or change in volumes		11.95 %	
9.	Reduction in risk if the requested CMT is approved (8)		(0.25)	
10.	Recommended common equity cost rate assuming approval of the requested CMT		11.70 %	

See Sheet 4 for notes.

Southwest Gas Corporation
Brief Summary of Common Equity Cost Rate

Notes:

(1) From Sheet 1 of Exhibit No. ___ (FJH-7).

(2) From Sheet 1 of Exhibit No. ___ (FJH-11).

(3) From Sheet 1 of Exhibit No. ___ (FJH-13).

(4) From Sheets 1, 2 and 3 of Exhibit No. ___ (FJH-14).

(5) The 11.59% indicated common equity cost rate based upon the proxy group of five LDCs is applicable to the average A2 Moody's bond rating of the group. As explained in Mr. Hanley's direct testimony, Southwest Gas Corporation has greater relative risk than the five LDCs as evidenced by the Company's Baa2 Moody's bond rating. Therefore, an indication of the magnitude of the investment risk adjustment is based upon the yield spread between A2 and Baa2 rated public utility bonds. The investment risk adjustment of 0.36% equals the two-thirds the average spread between A and Baa rated public utility bonds of 36 basis points (from Sheet 4 of Exhibit ___ (FJH-11)).

(6) The 11.31% indicated common equity cost rate based upon the proxy group of eleven Value Line LDCs is applicable to the average A2 Moody's bond rating of the group. As explained in Mr. Hanley's direct testimony, Southwest Gas Corporation has greater relative risk than the eleven Value Line LDCs as evidenced by the Company's Baa2 Moody's bond rating. Therefore, an indication of the magnitude of the investment risk adjustment is based upon the yield spread between A2 and Baa2 rated public utility bonds. The investment risk adjustment of 0.36% equals the average spread between A and Baa rated public utility bonds of 36 basis points (from Sheet 4 of Exhibit ___ (FJH-11)).

(7) As explained in Mr. Hanley's direct testimony, Southwest Gas Corporation does not enjoy protection from the vagaries of weather. Since the majority of the companies in both proxy groups have such clauses (see Sheet 3 of Exhibits ___ (FJH-4) and (FJH-5)), Southwest Gas Corporation has greater relative risk vis-à-vis the companies in the proxy groups, due to the greater variability of its earnings attributable to the vagaries of weather. In Mr. Hanley's judgment the added risk attributable to the lack of protection from the vagaries of weather is approximately 25 basis points. As shown on Sheet 3 of Exhibit ___(FJH-4), the equivalent of 3 companies in the proxy group of five LDCs have WNCs in place. This equates to about 60% of the full impact or basis points (0.25% * 60%) = 0.15%). It can be determined in similar fashion by reference to Sheet 3 of Exhibit ___(FJH-5), that the equivalent of 9 companies in the proxy group of eleven Value Line LDCs enjoy protection from weather, of 80% of the full impact or 20 basis points ((0.25% * 80%) = 0.20%).

(8) Reduction in common equity risk if the requested Conservation Margin Tracker (CMT) is approved as fully discussed in Mr. Hanley's accompanying direct testimony.

Southwest Gas Corporation
Comparison of Return on Average Book Common Equity for the Years 1997 through 2003 (1) for
Southwest Gas Corporation, the Arizona Jurisdiction, the Proxy Group of Five Gas Distribution Companies
and the Proxy Group of Eleven Value Line Gas Distribution Companies

	2003 (2)	2002	2001	2000	1999	1998	1997	7 YEAR AVERAGE
Southwest Gas Corporation	6.10 %	6.65 %	6.79 %	6.32 %	6.89 %	9.75 %	2.87 %	6.34 %
Arizona Jurisdiction (3)	4.11 %	7.23 %	7.40 %	5.69 %	7.10 %	12.66 %	2.98 %	6.74 %
Average Annual Yields, "Baa" Public Utility Bonds	6.84 %	8.02 %	8.03 %	8.36 %	7.88 %	7.26 %	7.95 %	7.76
Gas Distribution Companies								
AGL Resources, Inc.	16.30 %	14.91 %	13.76 %	11.09 %	11.31 %	12.63 %	12.66 %	
Cascade Natural Gas Corp.	8.03	9.13	14.32	13.16	12.02	8.11	9.16	
NICOR Inc.	15.55	17.84	17.25	6.21	16.05	15.45	17.30	
Northwest Natural Gas Company	8.61	8.73	10.38	10.29	10.08	6.35	11.34	
Piedmont Natural Gas Co., Inc.	10.93	10.82	12.04	12.57	12.26	13.74	13.42	
Average	11.88 %	12.29 %	13.56 %	10.66 %	12.34 %	11.26 %	12.78 %	12.11 %
Proxy Group of Eleven Value Line Gas Distribution Companies								
AGL Resources, Inc.	16.30 %	14.91 %	13.76 %	11.09 %	11.31 %	12.63 %	12.66 %	
Cascade Natural Gas Corp.	8.03	9.13	14.32	13.16	12.02	8.11	9.16	
Energen Corp.	17.03	13.27	15.40	13.91	11.99	11.50	11.86	
KeySpan Corp.	12.04	13.42	8.33	10.22	7.80	(6.88)	11.97	
Laclede Group, Inc.	11.83	7.78	10.64	9.15	9.63	10.96	13.18	
NICOR, Inc.	15.55	17.84	17.25	6.21	16.05	15.45	17.30	
Northwest Natural Gas Company	8.61	8.73	10.38	10.29	10.08	6.35	11.34	
Peoples Energy Corp.	12.57	11.05	12.27	11.18	12.27	10.90	14.08	
Piedmont Natural Gas Co., Inc.	10.93	10.82	12.04	12.57	12.25	13.74	13.42	
South Jersey Industries, Inc.	14.34	12.84	12.73	12.75	12.40	8.06	10.65	
WGL Holdings Inc.	14.18	5.03	10.99	11.93	10.44	11.25	14.06	
Average	12.86 %	11.36 %	12.56 %	11.13 %	11.48 %	9.28 %	12.70 %	11.62 %

Notes:
(1) Calculated as income available for common equity before extraordinary items divided by the average of the beginning and ending total common equity for each year.
(2) Twelve months ending September 30, 2003. For those companies with a fiscal year ending other than September 30, twelve months moving income available for common equity before extraordinary items was used in the calculation.
(3) From Company Witness Mashas' Exhibit ___(RAM-1), Sheet 2 of 6.

Source of Information: Standard & Poor's Compustat Services, Inc., PC Plus Research Insight Data Base.
Company Annual Forms 10K and / or Quarterly Forms 10Q

SOUTHWEST GAS'S APPLICATION CONTINUED

SEE BAR CODE 0000008995 FOR PART 2