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Docket #(s): G-01551A-07-0504

Exhibit # : A1-A26

Arizona Corporation Commission
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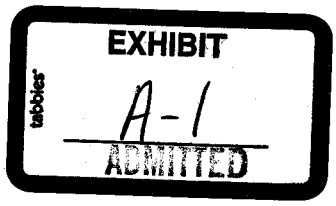


SOUTHWEST GAS CORPORATION

Docket No. G-01551A-07-____

2007
ARIZONA
GENERAL RATE CASE

Volume I
APPLICATION

August 31, 2007

2007
ARIZONA
GENERAL RATE CASE

Volume I

APPLICATION
ANNUAL REPORT
PROPOSED TARIFF SHEETS
CURRENT TARIFF SHEETS

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

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

IN THE MATTER OF THE APPLICATION OF 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 ARIZONA	)	DOCKET No. G-01551A-07-___

APPLICATION

Southwest Gas Corporation (Southwest or the Company) 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 distributing and transporting 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 the 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 fifty-four percent (54%) 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) 876-7011.

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 (702) 364-7163; and Karen Haller, Assistant General Counsel & Director of Legal Affairs, at the above Las Vegas address and telephone number (702) 364-3191.

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 Section 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 2006 Annual Report to Shareholders. Additionally, accompanying this Application are the testimony and exhibits which Southwest submits in support of this Application.

Nature of Relief Sought

Southwest seeks the establishment of rates and charges for the

provision of natural gas service in Arizona at just and reasonable levels to provide Southwest with a realistic 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 for the twelve months ended April 30, 2007, 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 and to attract the capital necessary to ensure continuation of reliable service to present and future customers. The historical test year in Southwest's last general rate case was the twelve-month period ended August 31, 2004.

Southwest's adjusted test year shows a revenue deficiency of approximately $50.2 million and an earned return of only 6.68 percent on its investment to provide utility service. Southwest requests a capital structure consisting of 51 percent debt, four percent preferred equity, and 45 percent common equity, with a requested return on common equity (ROE) of 11.25 percent and an overall return on original cost rate base of 9.45 percent and a 7.04 percent fair and reasonable return on a fair value rate base.

The testimony and exhibits accompanying this Application reflect that approximately $20.6 million of the revenue deficiency is attributable to increased costs of capital. Although Southwest has been successful in its efforts to control costs and to improve productivity since its last general rate case, the Company's financial resources have been strained. Southwest's capital

expenditures for its Arizona operations from August 31, 2004, the end of the test year in its last general rate case, through April 30, 2007, the end of the test year in this general rate case, exceed $371 million. During this 32-month period, the Company significantly improved its capital structure, improving its common equity ratio by 8.8 percentage points, from 34.1 percent to 42.9 percent common equity. However, with substantial customer growth expected to continue for the foreseeable future, Southwest's need to access the financial markets to fund a portion of its capital expenditures will be reduced if the Commission grants the relief requested in this general rate case.

During this period of continuing customer growth, Southwest's customer-to-employee ratio, a key measure of Southwest's productivity, has continued to improve substantially. On August 31, 2004, the test year ending date in Southwest's last general rate case, Southwest was serving approximately 736 customers per Arizona employee. In comparison, on April 30, 2007, the test year ending date in this general rate case, Southwest was serving 857 customers per Arizona employee, a 16.4 percent increase in productivity. Despite this significant increase in its customer-to-employee ratio, customer satisfaction, as determined by an independent third-party, remains in excess of 95 percent. Southwest has successfully controlled costs while maintaining its commitment to customer satisfaction. Ensuring that the Company is sufficiently strong financially to provide safe and reliable natural gas service is in the best interests of Southwest's customers. Existing rates are unjust and unreasonable and their continuance threatens Southwest's financial integrity.

Overall Purpose

The overall purpose of Southwest's Application is to secure reasonable ratemaking treatment which recognizes and alleviates the combined detrimental effects of increased costs of capital, declining average residential usage, and the vagaries of weather. These combined effects impair Southwest's ability to recover its fixed costs of doing business and earn its authorized rate of return.

In his direct testimony, Roger C. Montgomery explains, from a broad policy perspective, why it is critical that Southwest have a reasonable and realistic opportunity to earn the rate of return authorized by the Commission in this proceeding. Among other things, Mr. Montgomery stresses the importance of approving a rate design and regulatory mechanisms that address weather volatility and the continued steady decline in average residential usage over the last two decades. This declining average use is due, in large part, to conservation efforts by consumers and increased energy efficiencies in housing stock and appliances.

As part of this Application, Southwest proposes a revenue decoupling mechanism to address the negative effects of declining average usage on fixed cost recovery and revenues. Southwest also proposes a weather normalization mechanism to lessen the harmful impacts to customers and the Company from the variability of bills and fixed cost recovery associated with weather volatility.

Consistent with the overall purpose, a central focus of this Application is Southwest's critical need to compete effectively in the financial markets to secure the capital required to meet growth demands in one of the fastest growing states in the country. Not

only has Southwest been unable to earn its Commission-authorized rate of return, but its authorized ROE is significantly below the rates of return approved for other Arizona investor-owned energy utilities. Therefore, Southwest is requesting an authorized ROE more closely aligned with comparable natural gas utilities.

Approval of the proposed rate design and regulatory mechanisms will increase energy cost predictability for customers, improve Southwest's financial strength over time, and help the Company achieve parity with other Arizona energy utilities. If the Commission adopts the proposed rate design and regulatory mechanisms, Southwest will have a more realistic and reasonable opportunity to earn its authorized rate of return. Over time, this will allow the Company to improve its credit ratings. Improvements in the financial metrics will assist Southwest in lowering the overall cost of debt, which benefits Southwest's Arizona customers.

Witness Testimony

A complete and accurate explanation of the circumstances and conditions upon which Southwest relied 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:

(1) Roger Montgomery - Policy and general rate case overview;

(2) Robert Mashas - Overall deficiency/revenue requirement and various adjustments;

(3) Randi Aldridge - Cost of service and various adjustments;

(4) Laura Hobbs - Management Incentive Program (MIP) and Supplemental Executive Retirement Plan (SERP);

(5) Theodore Wood - Capital structure, cost of debt, and

overall rate of return;

(6) Frank Hanley - Cost of equity;

(7) Jamie Cattanach - Billing determinants and declining residential consumption per customer;

(8) Frank Maglietti - Class cost of service study and Purchased Gas Adjustment (PGA) mechanism;

(9) Ralph Miller - Revenue decoupling and energy efficiency; and

(10) A. Brooks Congdon - Rate design and regulatory/ratemaking mechanisms.

Request for Implementation of New Rates by October 1, 2008

Because Arizona uses a historical test year, the revenue requirement used to determine prospective rates in this proceeding reflects costs Southwest incurred in 2006 and the first four months of 2007. Combined with the August 31 filing date, the rates established from this proceeding will reflect costs approaching 24 months since first incurred and more than 14 months since the close of the test period, rather than reflecting the costs in Arizona at the time rates become effective. This delay contributes to the Company's inability to earn an authorized rate of return and highlights the need for timely relief.

Therefore, Southwest requests this Application be processed under a schedule which contemplates the implementation of new rates by October 1, 2008, prior to the winter heating season.

As indicated above, the rate of return experienced by Southwest from its Arizona operations for the test year ended April 30, 2007 was 6.68 percent. It is inevitable that, by October 1, 2008 [17 months after the end of the test year], Southwest's

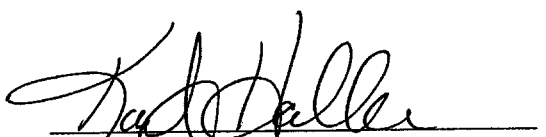
earnings from its Arizona operations will have continued to erode.

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 further requests that, upon conclusion of the hearing, the Commission promptly issue a 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 allow a reasonable opportunity for Southwest to realize the authorized rate of return.

RESPECTFULLY SUBMITTED this 31st day of August, 2007.

SOUTHWEST GAS CORPORATION



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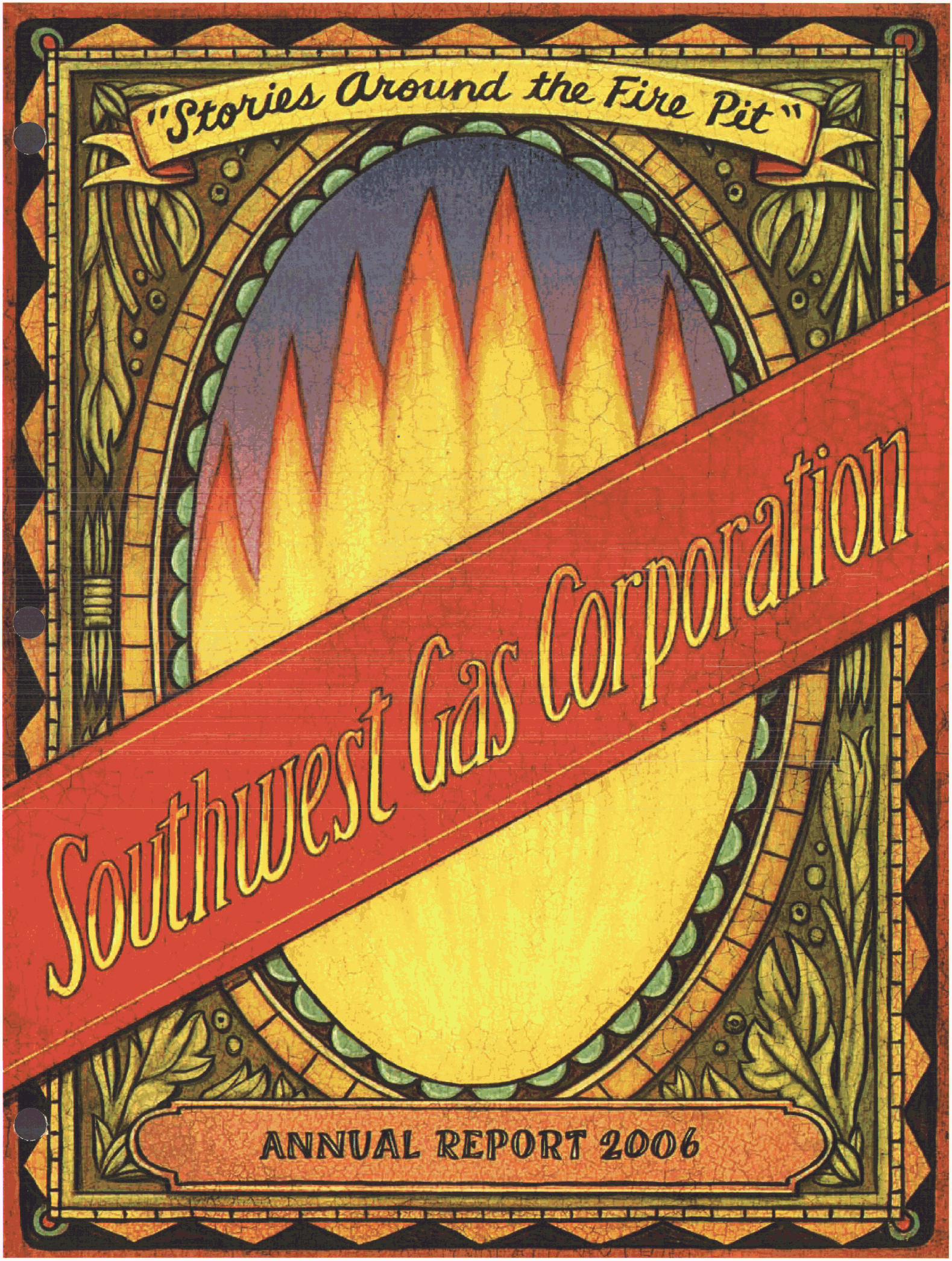
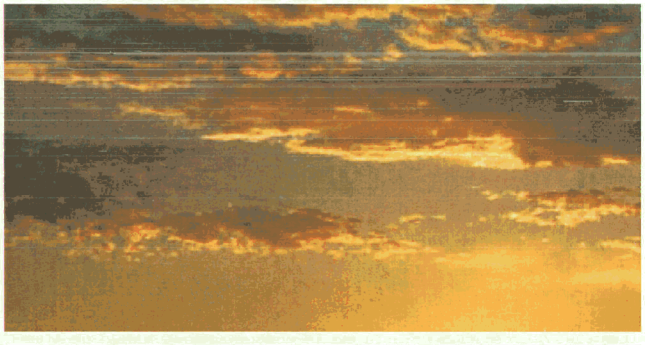

"Stories Around the Fire Pit"
Southwest Gas Corporation
ANNUAL REPORT 2006

For centuries,
people of all ages
have congregated
around the fire.

It's a place where
life's toughest
challenges can
be talked through,
and the greatest
moments recounted.

The dance and heat of the fire, shared by a circle of friends, create the perfect environment for conversation.



Natural gas fire pits bring the generations-old storytelling into the confines of your own backyard.

The tales that unfold in the glow of the flames are typically larger than life.

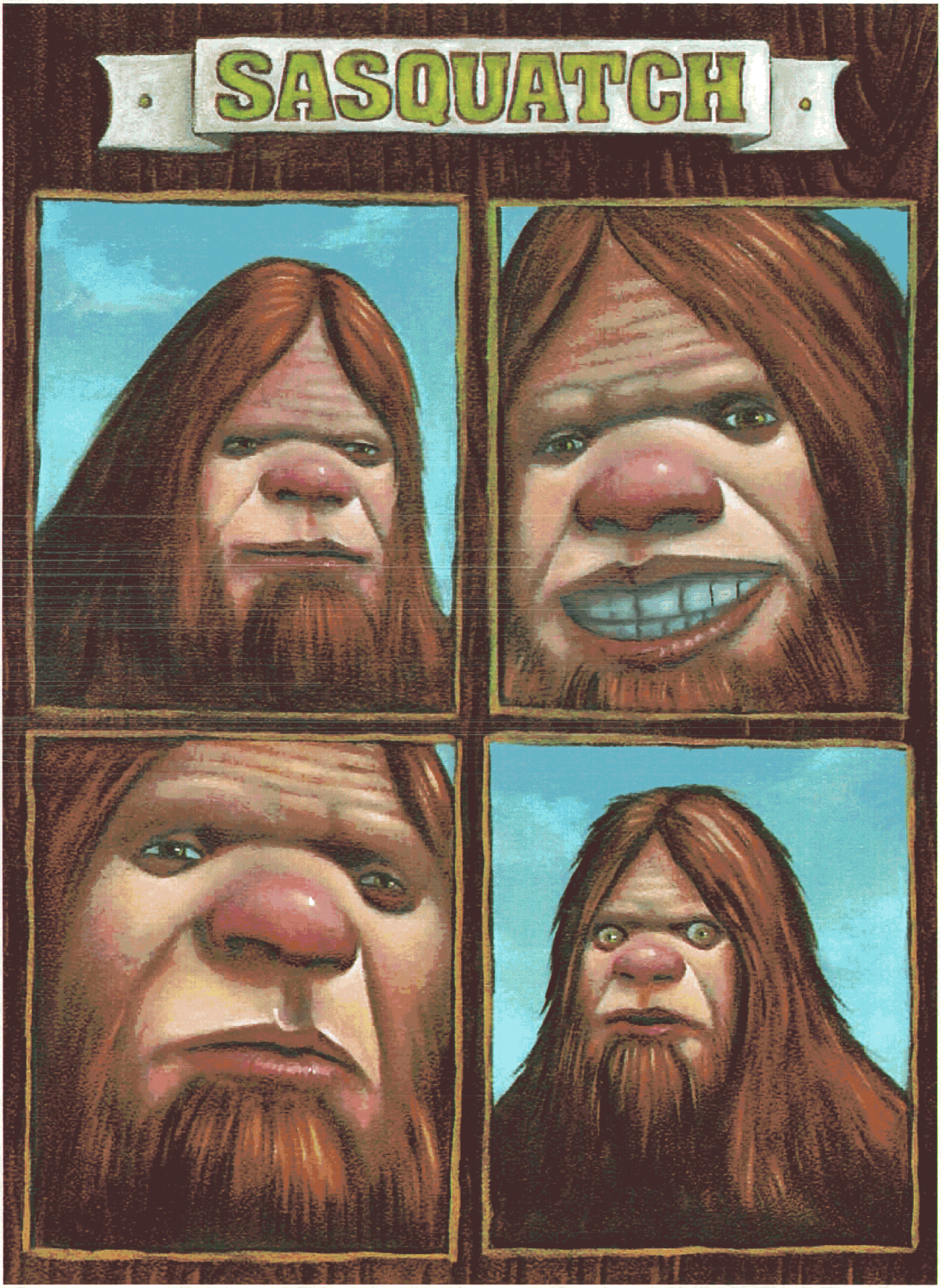
Pecos Bill is a legendary cowboy hero of the American Southwest. He personified the frontier virtues of strength, courage, ingenuity, audacity, endurance and humor. Through a series of superhuman feats, he was said to have played a key role in taming the Western frontier.

The youngest of 18 children of a Texas pioneer, Bill used a bowie knife as a teething ring and played with bears and other wild animals as an infant. After falling out of his parents' wagon near the Pecos River in Texas, he became lost and was raised by coyotes. In fact, he considered himself to be a coyote until a cowboy convinced him of his true identity.

After returning to civilized territory, Pecos Bill became the cowhand who invented all the tricks of the ranching trade. He taught gophers to dig postholes. He invented the branding iron to stop cattle rustling and the cowboy song to soothe the cattle. He killed snakes by feeding them mothballs filled with red pepper and nitroglycerin and, after inventing the lasso, he roped whole herds of cattle at a time. Once he used the entire Rio Grande to water his ranch, which included all of modern day New Mexico.

Pecos Bill used a rattle snake as a whip and rode everything in the West, including a mountain lion and a cyclone. His favorite steed, though, was named Widow-Maker and no one else could ride him. Pecos Bill's bride, Slue-Foot Sue, insisted on riding the horse on their wedding day. Widow-Maker threw Sue, who bounced so high on the hoops of her bridal gown that she hit her head on the moon. Sue bounced for days afterward with no signs of stopping. Pecos Bill realized that she would starve to death, so he shot her. Although Bill was married many times, he never did recover from the loss of Sue.

PECOS BILL


SASQUATCH

Some involve creatures that have been seen only by an unlucky few.

Sasquatch, also known as Bigfoot, is a half legend / half hoax figure that has been spotted in remote forested areas across America. Stories of Sasquatch sightings have surfaced for centuries, making one wonder if a species of unknown primates could survive undetected within the cracks of the modern world.

Called by a Native American word meaning "hairy giant," Sasquatch is renowned for its shy, reclusive nature. It forages for food at night, sleeps during the day and stays out of sight remarkably well given its size.

The beast is not known to be violent, but the humans who have encountered one report that it does pose an assault on the senses. First, the creature is fearsome to see. It stands between seven and eight feet tall and can weigh over 450 lbs. More than 700 footprints attributed to Sasquatch have been collected over the years. They average 15.6 inches long and 7.2 inches wide. Most people who have spotted Bigfoot or its counterparts have described the creature as being half-man/half-ape and having long, dark fur all over its body. Secondly, it is reported to have a very strong, very foul odor. In fact, in Florida, Sasquatch is known as the "Skunk Ape." Thirdly, the few humans who have heard Sasquatch's howl, say it is otherworldly. One outdoors writer described it as "The kind of scream no cougar or bear could ever squeeze from their throat...unless it was their last."

Other tall tales have encouraged the settlement of the American frontier. Perhaps the modern myths of Sasquatch are a reminder that we need not conquer the entire natural world – that its greater mysteries should remain unscathed.

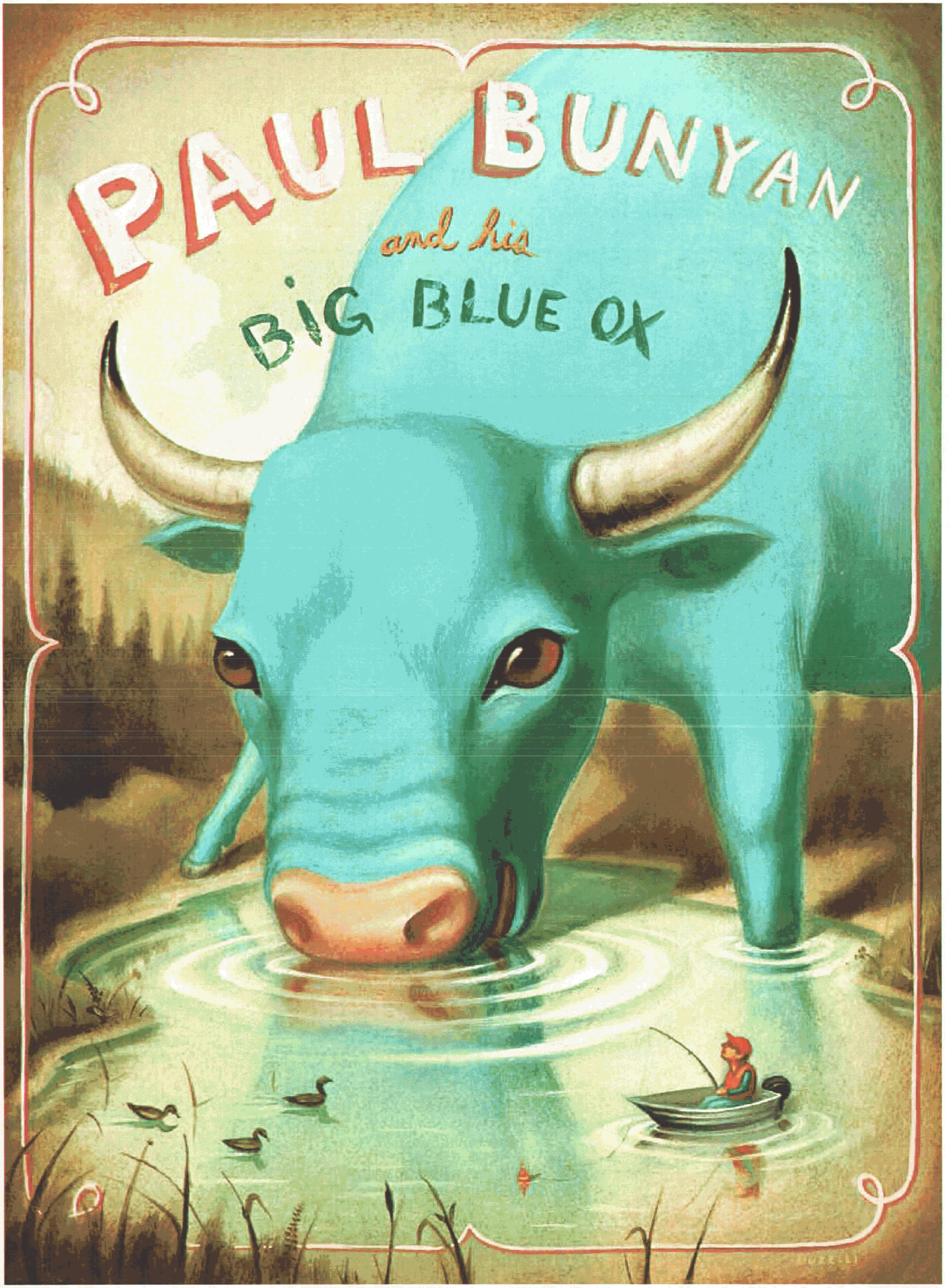
Others are mythical sagas of true heroes passed down by generations.

Paul Bunyan and his blue ox, Babe, have been around longer than Pecos Bill. They captured the best traits of the loggers – strength, resourcefulness, dedication, teamwork and productivity. Paul is the hero in a number of stories that end with swaths of land cleared, tamed and improved – and the rewards that go to those who do a job well.

Ordinarily, one stork can deliver several babies to their respective parents' homes. When Paul Bunyan was born, it took five giant storks, working overtime, to carry just him. Paul outgrew his father's clothes in a week and his own clothes were so large his parents used wagon wheels for buttons. A lumber wagon drawn by a team of oxen served as a baby carriage.

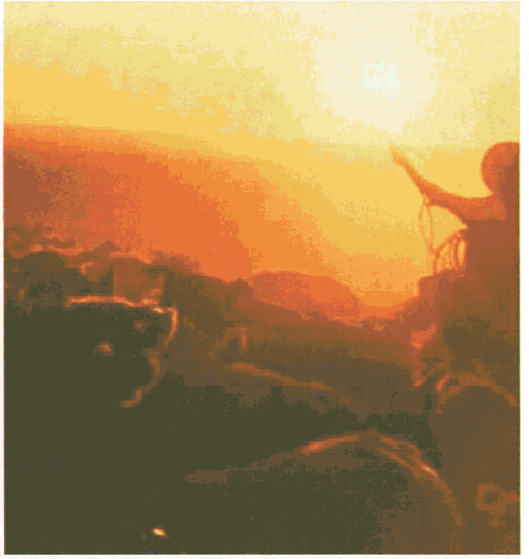
Paul cut his teeth on a peavy pole – used to roll logs – and, as a child, played with an axe and crosscut instead of more traditional toys. On his first birthday his father gave him a blue ox named Babe. Babe grew to be seven axe handles and a plug of tobacco wide between the eyes and, as a snack, would eat 30 bales of hay – wire and all. The tracks that Paul and Babe made gallivanting around Minnesota filled up and made the 10,000 lakes. Their travels took them West, too. They dug the Grand Canyon by dragging Paul's axe behind them, and created Mount Hood by piling rocks on top of their campfire to put it out.

They were famous for being so large – and for putting their weight into their work. Paul Bunyan could fell 23 trees with a single swing of his axe. And when he got his rhythm, he looked like a tornado in a toothpick factory. On one job – clearing North Dakota for Teddy Roosevelt – the winding road to the river slowed the crews. So Paul hooked Babe to the far end, and Babe marched in a straight line until that road ran as true as a crow flies.


PAUL BUNYAN
and his
BIG BLUE OX

Perhaps the best are the true stories, told one generation to the next,

until they are weaved into the fabric of our culture.



While stories
change with time,
the joy of sharing
them remains
eternal.

Fellow Shareholders, As another year passes, our story continues.

A marked improvement in operating results and positive movement in the Company's stock price combined for a very encouraging 2006. Much needed rate relief in Arizona, continued customer growth throughout our service areas, and another superb contribution from our pipeline construction subsidiary drove earnings to $2.07 per share, an increase of $0.92 per share over the $1.15 posted in 2005. The Company's stock price was positively affected by the rise in earnings and the strong performance of our industry sector and the overall market.

You will recall that the Arizona Corporation Commission (ACC) rendered its decision in the most recent Arizona general rate case in February 2006 and approved an annual increase in operating revenues of $49.3 million, effective March 1, 2006. While it will take a complete twelve months to capture the full benefit of this increase, that portion realized in 2006 went a long way toward improving the Company's financial results. Unfortunately, we were disappointed that the ACC did not approve the key rate design proposals the Company made to mitigate the effects of weather volatility and customer conservation resulting from higher natural gas prices and more efficient building standards in new construction. And while the weather improved over the prior year, it was still warmer than normal and, consequently, our operating margin in Arizona was negatively impacted.

As we mentioned in last year's report, to bring more stability to revenues and cash flows, the Company proposed several rate design alternatives in each of the most recent general rate cases in California, Nevada and Arizona. In California, the approved rate design substantially protects the authorized operating margin. In Nevada, while the approved rate design mitigates most of the exposure to weather variability, we continue to work with the commission and staff to further refine rate design and improve revenue stability. Although we were allowed to increase the monthly fixed basic service charge to customers in Arizona, the authorized rate design does not yet provide acceptable revenue stability. Fortunately, the ACC's final order acknowledged the need to study this issue further, and the Company was encouraged to continue pursuing rate design refinements with the ACC staff and other interested parties. We have established an ongoing dialogue with all interested parties on this important issue.

Effective marketing initiatives emphasizing the lifestyle benefits of natural gas appliances and amenities to builders have enabled the Company to consistently realize a system-wide average market share of new home construction in excess of 90 percent. This compares to an industry average of less than 70 percent.

Having experienced more than a decade of tremendous, near industry leading customer growth, we believe the management of growth has become one of our core competencies. In 2006, we experienced an increase of 71,000 customers throughout our service areas. This organic growth exceeded that of most natural gas distribution companies in the nation. The Company has aggressively managed this growth to ensure it is profitable. As the exclusive provider of natural gas in the areas we serve, we have the obligation to provide service to customers, subject to tariff requirements. However, when the economics for a sub-division do not meet the requirements under our tariffs, we require non-refundable contributions from builders in order to remain within our allowable capital investment. Furthermore, for nearly all residential sub-division developments, we obtain refundable advances from builders to cover the carrying costs of our significant infrastructure investments until meters are set and customers begin paying for service.

Based on the level of current builder commitments for 2007, the torrid growth levels of recent years appear to be moderating. However, given the projected, continued population growth in Arizona and Nevada, we are still anticipating a healthy growth rate going forward. Interestingly, Arizona recently surpassed Nevada as the fastest growing state in the nation in terms of percentage population growth...Nevada is now number two.

We are constantly analyzing our operating activities to improve efficiency and productivity. Through judicious investments in technology, we continue to realize significant improvements. For example, we launched a project this past summer to convert all customer meters to electronic meter reading. Over the past few years, the cost of the required technology decreased to a level that made the economics for the project compelling. The conversion is expected to be completed in 2009 and, through attrition and the use of temporary labor, we expect to complete the conversion with no adverse impact to remaining full-time employees.

During the fifteen years ended 2006, the Company more than doubled, adding 914,000 customers and, notably, only 282 employees...a ratio of 3,241 customers for every employee added. In 2006, we achieved an overall customer to employee ratio of 706 to 1, one of the top productivity ratios in the industry and, by this measure, more than a 50 percent improvement over the last decade. Furthermore, we experienced a decline in our operating costs per customer over the past three years, despite the rising costs of pipeline construction and compliance with new federal and state mandates. Remarkably, at the same time we've experienced these productivity and efficiency gains, the Company consistently achieved a customer satisfaction rating well above 90 percent... a tribute to the commendable efforts of our dedicated employees.

Northern Pipeline Construction Co., our wholly owned pipeline construction subsidiary, continued to post impressive operating results. Through profitable bid work, increased workload under existing contracts, the securing of new contracts and a positive equipment resale market, NPL achieved record net income of $12.4 million, or $0.31 per share during 2006. Given the initiatives NPL management has taken, and expected activity for 2007, we anticipate continued favorable operating results, although maybe not at record levels.

As you know, the Company has not increased the dividend on its common stock since 1994. The Board regularly reviews dividend policy and considers the adequacy and sustainability of the Company's earnings and cash flows; the strength of the Company's capital structure; the sustainability of the dividend through all business cycles; and whether the dividend is within a normal payout range for its industry. Based on the recent improvements in the Company's earnings, cash flows and capital structure, the Board of Directors determined that it would be appropriate and in the best interests of the shareholders to increase the dividend on common stock. At the February 27, 2007 Board meeting, the Company's annualized dividend was raised by $0.04 from $0.82 per share to $0.86 per share. The Board will continue to monitor the Company's earnings, cash flows and capital structure with an eye toward the possibility of further enhancing dividend payouts in the future.

We believe 2006 operating results confirm that our principal strategies are working. While we are very encouraged with our progress, there is still improvement to be made. We are determined to build on the momentum of our recent achievements by remaining focused on the following core strategies that have brought us success.

- Continue to work closely with regulators to improve the level and stability of earnings and cash flows
- Continue to aggressively manage growth
- Continue to maximize efficiency and productivity
- Continue to exceed our customers' expectations
- Remain watchful and positioned to seize strategic growth opportunities

As we reflect on the 75-year history of our Company, we have been part of a remarkable story... one that truly is legendary. We acknowledge all those who have contributed toward building a company we can all be proud of. We believe the future is bright. The Board and management are committed to building on that legacy and maintaining and enhancing the value of your investment in Southwest Gas Corporation.

Sincerely,

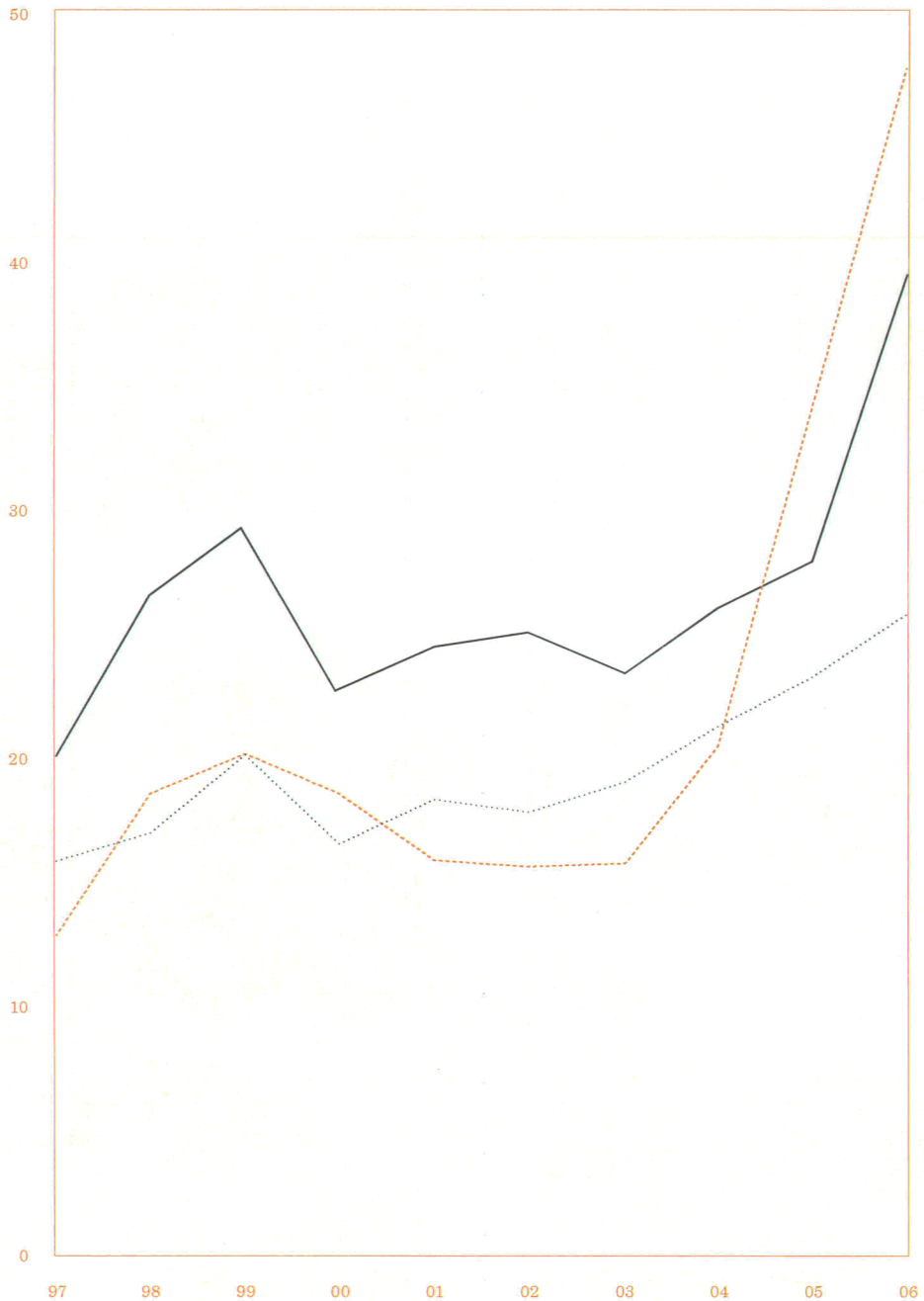
LeRoy C. Hanneman, Jr.
Chairman of the Board

Jeffery W. Shaw
Chief Executive Officer

Stock Prices & Trading Volume Per Year

stock prices in dollars, volume in millions

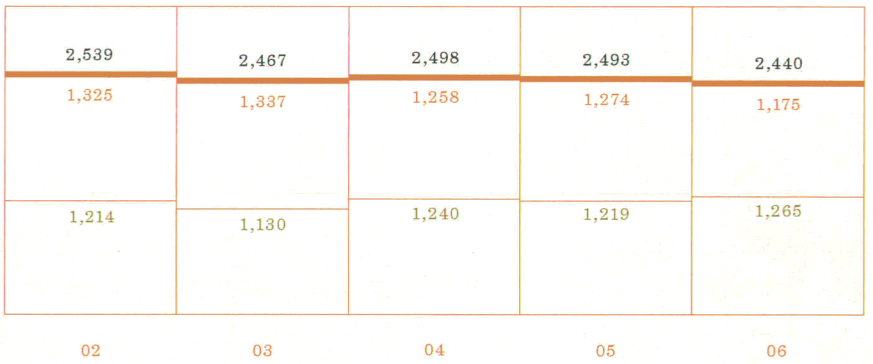
— High
····· Low
---- Volume



Financial Highlights

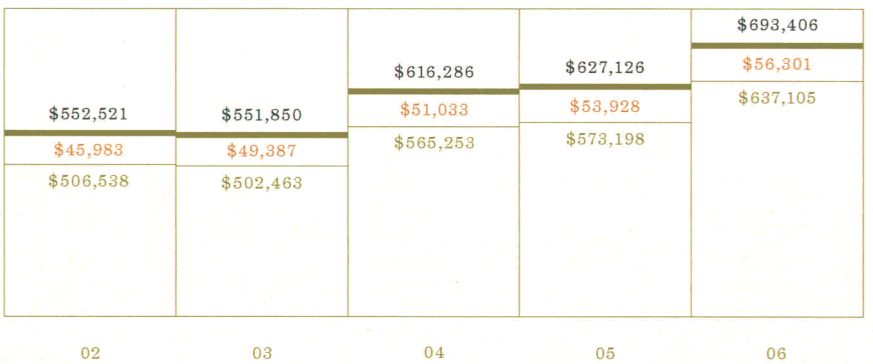
Throughput (in millions of therms)

Sales Transportation Total Combined



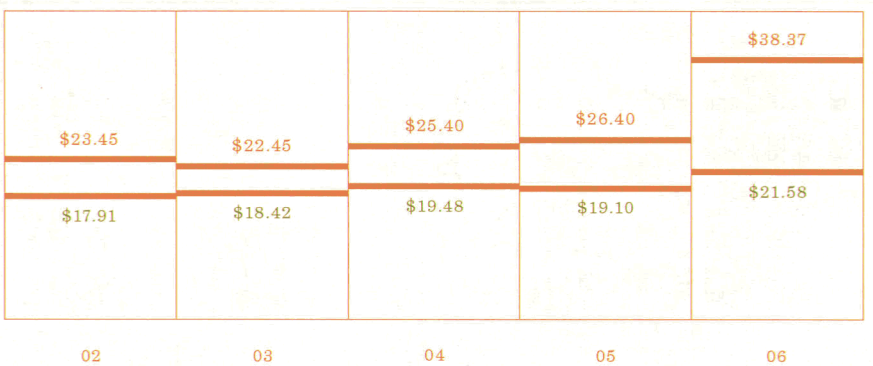
Margin (in thousands of dollars)

Sales Transportation Total Combined



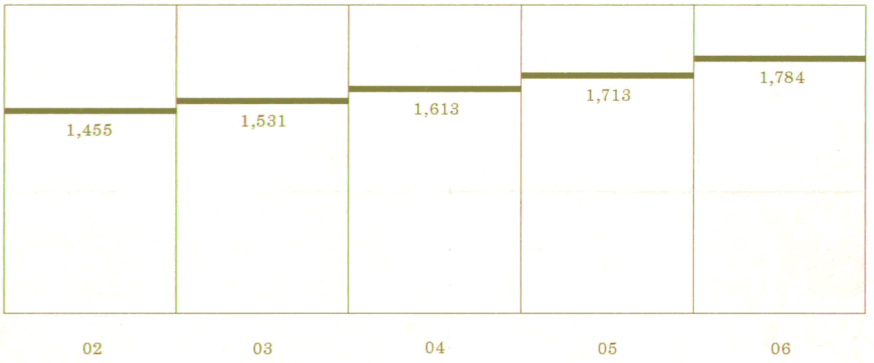
Market Price Relative to Book Value (in dollars)

Book Value Market Price

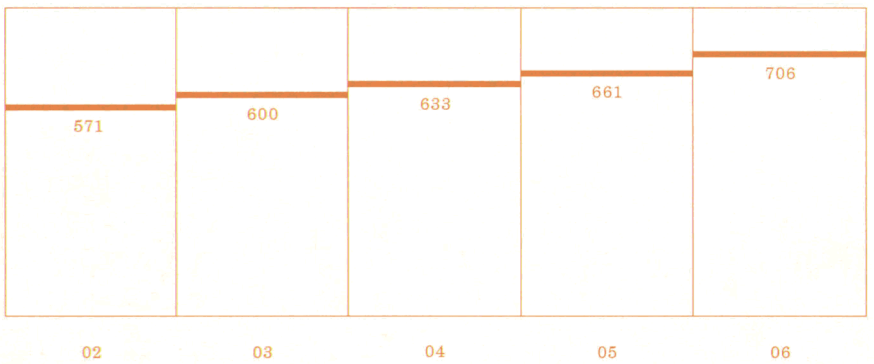


Financial Highlights

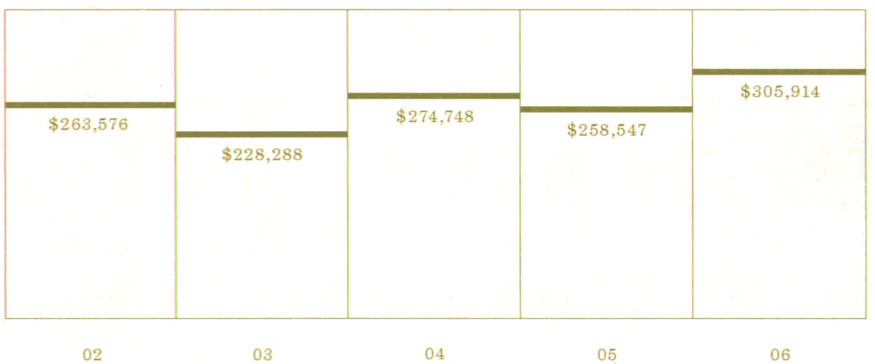
Number of Gas Customers (in thousands)



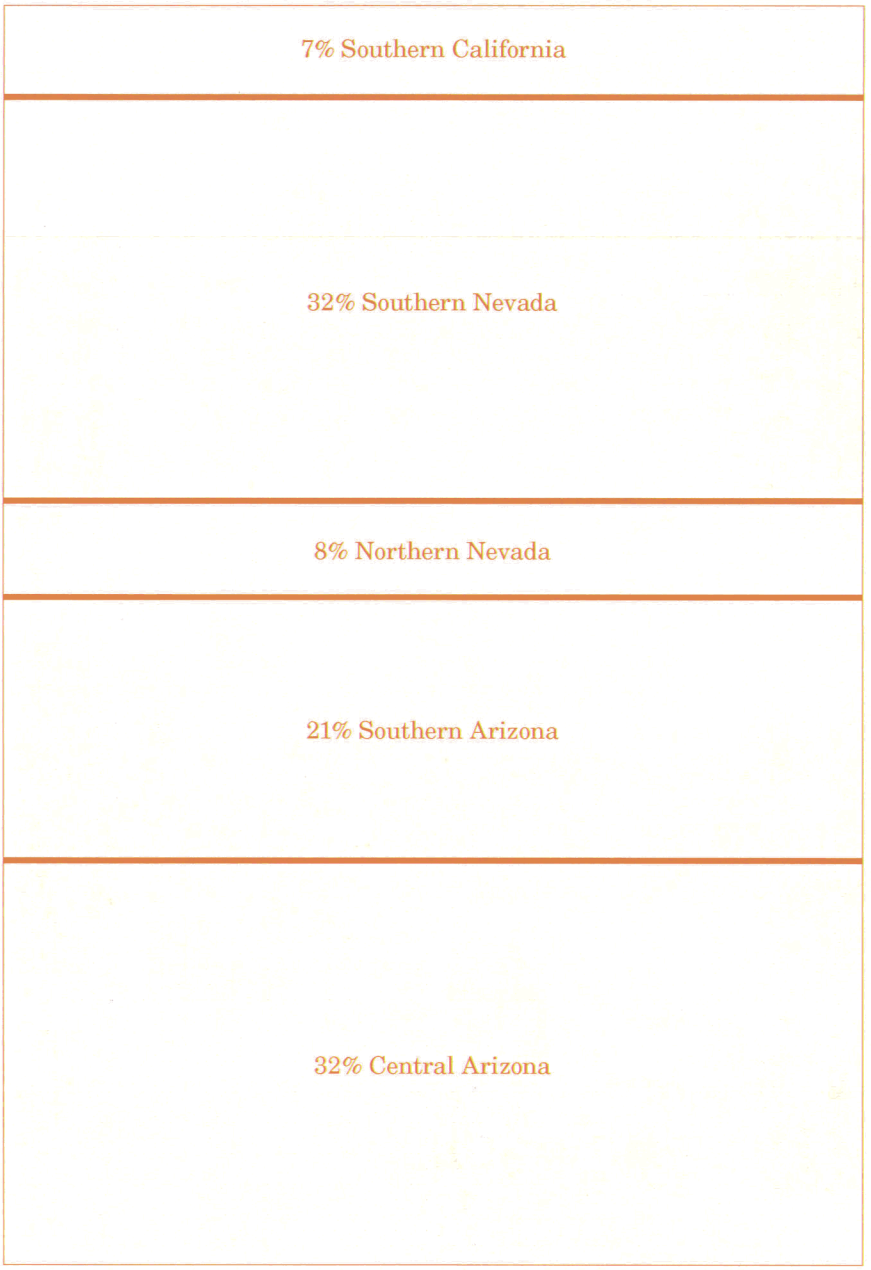
Customers per Employee



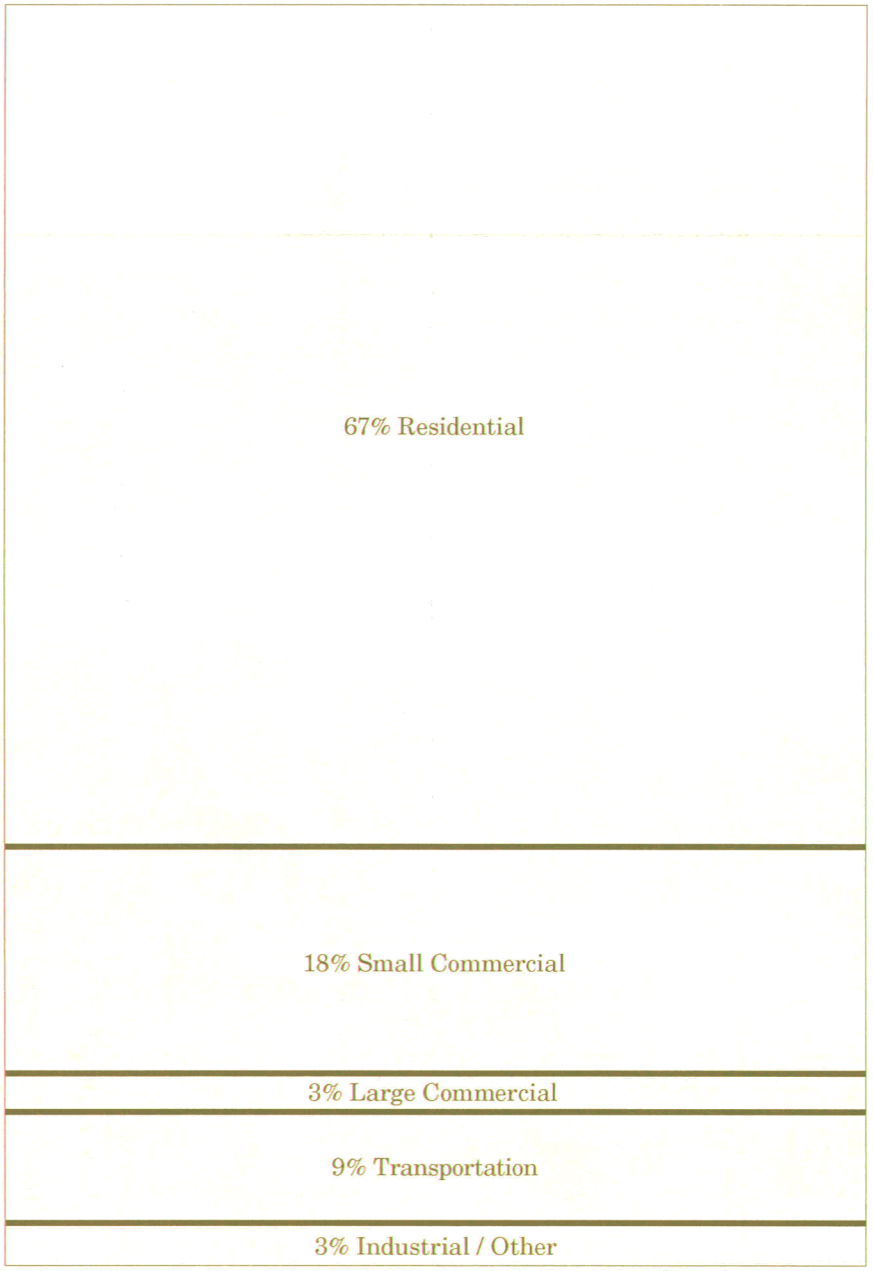
Construction Expenditures Gas Segment (in thousands of dollars)



Customers by Division
(December 31, 2006)

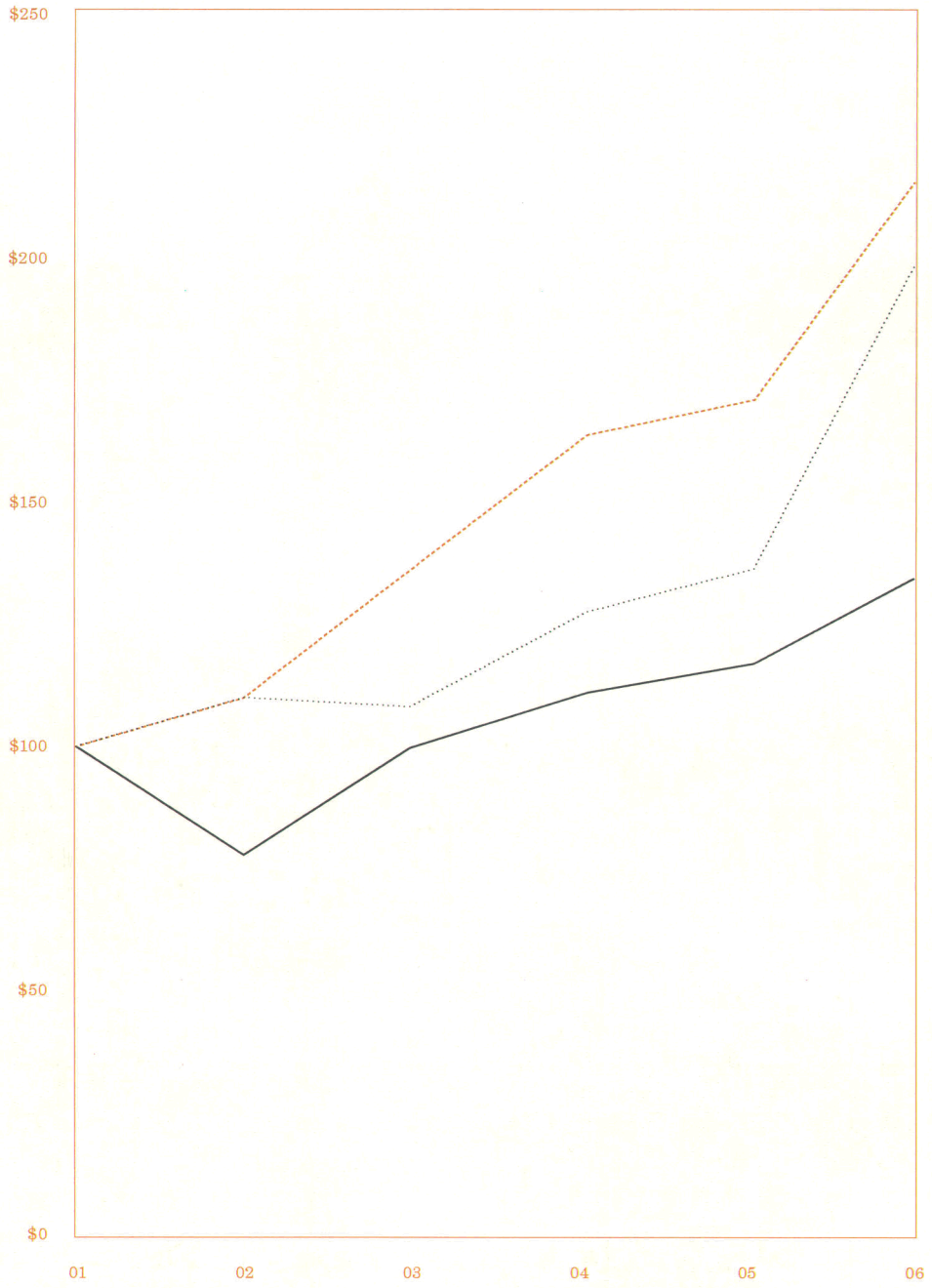


Margin by Customer Class
(2006)



Comparison of 5-Year Cumulative Total Returns

····· Southwest Gas
— S&P 500
---- S&P Small Cap Gas Index



The performance graph above compares the five-year cumulative total return on Company common stock, assuming reinvestment of dividends, with the total returns on the Standard & Poor's 500 Stock Composite Index ("S&P 500") and the S&P Small Cap Gas Index, consisting of the Company and ten other natural gas distribution companies.

(1) The Company is using the S&P Small Cap Gas Index as its peer-group index.
(2) The S&P Small Cap Gas Index, which is weighted by year-end market capitalization, consists of the following companies: Atmos Energy Corp.; Cascade Natural Gas Corp.; Energen Corp.; Laclede Group Inc.; New Jersey Resources Corp.; Northwest Natural Gas Co.; Piedmont Natural Gas Company; South Jersey Industries Inc.; Southern Union Company; the Company; and UGI Corp.

2006 Financial Data

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Consolidated Selected Financial Statistics

Year Ended December 31,	2006	2005	2004	2003	2002
(Thousands of dollars, except per share amounts)					
Operating revenues	$2,024,758	$1,714,283	$1,477,060	$1,231,004	$1,320,909
Operating expenses	1,815,576	1,563,635	1,307,293	1,095,899	1,174,410
Operating income	$ 209,182	$ 150,648	$ 169,767	$ 135,105	$ 146,499
Net income	$ 83,860	$ 43,823	$ 56,775	$ 38,502	$ 43,965
Total assets at year end	$3,484,965	$3,228,426	$2,938,116	$2,608,106	$2,432,928
Capitalization at year end					
Common equity	$ 901,425	$ 751,135	$ 705,676	$ 630,467	$ 596,167
Mandatorily redeemable preferred trust securities	—	—	—	—	60,000
Subordinated debentures	100,000	100,000	100,000	100,000	—
Long-term debt	1,286,354	1,224,898	1,162,936	1,121,164	1,092,148
	$2,287,779	$2,076,033	$1,968,612	$1,851,631	$1,748,315
Common stock data					
Common equity percentage of capitalization	39.4%	36.2%	35.8%	34.0%	34.1%
Return on average common equity	10.3%	5.9%	8.5%	6.3%	7.5%
Earnings per share	$ 2.07	$ 1.15	$ 1.61	$ 1.14	$ 1.33
Diluted earnings per share	$ 2.05	$ 1.14	$ 1.60	$ 1.13	$ 1.32
Dividends declared per share	$ 0.82	$ 0.82	$ 0.82	$ 0.82	$ 0.82
Payout ratio	40%	71%	51%	72%	62%
Book value per share at year end	$ 21.58	$ 19.10	$ 19.18	$ 18.42	$ 17.91
Market value per share at year end	$ 38.37	$ 26.40	$ 25.40	$ 22.45	$ 23.45
Market value per share to book value per share	178%	138%	132%	122%	131%
Common shares outstanding at year end (000)	41,770	39,328	36,794	34,232	33,289
Number of common shareholders at year end	23,610	23,571	23,743	22,616	22,119
Ratio of earnings to fixed charges	2.25	1.70	1.93	1.60	1.68

Natural Gas Operations

Year Ended December 31,	2006	2005	2004	2003	2002
(Thousands of dollars)					
Sales	$1,671,093	$1,401,329	$1,211,019	$ 984,966	$1,069,917
Transportation	56,301	53,928	51,033	49,387	45,983
Operating revenue	1,727,394	1,455,257	1,262,052	1,034,353	1,115,900
Net cost of gas sold	1,033,988	828,131	645,766	482,503	563,379
Operating margin	693,406	627,126	616,286	551,850	552,521
Expenses					
Operations and maintenance	320,803	314,437	290,800	266,862	264,188
Depreciation and amortization	146,654	137,981	130,515	120,791	115,175
Taxes other than income taxes	34,994	39,040	37,669	35,910	34,565
Operating income	$ 190,955	$ 135,668	$ 157,302	$ 128,287	$ 138,593
Contribution to consolidated net income	$ 71,473	$ 33,670	$ 48,354	$ 34,211	$ 39,228
Total assets at year end	$3,352,074	$3,103,804	$2,843,199	$2,528,332	$2,345,407
Net gas plant at year end	$2,668,104	$2,489,147	$2,335,992	$2,175,736	$2,034,459
Construction expenditures and property additions	$ 305,914	$ 258,547	$ 274,748	$ 228,288	$ 263,576
Cash flow, net					
From operating activities	$ 248,884	$ 214,036	$ 124,135	$ 187,122	$ 281,329
From investing activities	(277,980)	(254,120)	(272,458)	(249,300)	(243,373)
From financing activities	20,350	57,763	143,086	60,815	(49,187)
Net change in cash	$ (8,746)	$ 17,679	$ (5,237)	$ (1,363)	$ (11,231)
Total throughput (thousands of therms)					
Residential	677,605	650,465	667,174	593,048	588,215
Small commercial	309,856	300,072	303,844	279,154	280,271
Large commercial	128,255	111,839	104,899	100,422	121,500
Industrial/Other	149,243	156,542	163,856	157,305	224,055
Transportation	1,175,238	1,273,964	1,258,265	1,336,901	1,325,149
Total throughput	2,440,197	2,492,882	2,498,038	2,466,830	2,539,190
Weighted average cost of gas purchased ($/therm)	$ 0.79	$ 0.71	$ 0.57	$ 0.46	$ 0.38
Customers at year end	1,784,000	1,713,000	1,613,000	1,531,000	1,455,000
Employees at year end	2,525	2,590	2,548	2,550	2,546
Degree days—actual	1,826	1,735	1,953	1,772	1,912
Degree days—ten-year average	1,961	1,956	1,913	1,931	1,963

Management's Discussion and Analysis of Financial Condition and Results of Operations

Overview

The following discussion of Southwest Gas Corporation and subsidiaries (the "Company") includes information related to the Company's 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 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.

Executive Summary

The items discussed in this Executive Summary are intended to provide an overview of the results of the Company's operations and are covered in greater detail in later sections of management's discussion and analysis. As reflected in the table below, the natural gas operations segment accounted for an average of 83 percent of consolidated net income over the past three years. As such, management's discussion and analysis is primarily focused on that segment.

Consolidated Results of Operations

Year ended December 31, (Thousands of dollars, except per share amounts)	2006	2005	2004
Contribution to net income			
Natural gas operations	$71,473	$33,670	$48,354
Construction services	12,387	10,153	8,421
Consolidated	$83,860	$43,823	$56,775
Basic earnings per share			
Natural gas operations	$ 1.76	$ 0.88	$ 1.37
Construction services	0.31	0.27	0.24
Consolidated	$ 2.07	$ 1.15	$ 1.61

The main factors contributing to the increase in results of operations during 2006 include:

- higher operating margin resulting from the Arizona general rate increase;
- continued customer growth;
- a nonrecurring property tax settlement;
- increased contribution to net income from NPL; and
- 2005 included a $10 million pretax charge related to an injuries and damages case (see *Insurance Coverage* for additional information).

Partially offsetting the above positive factors was a 2.4 million increase in average shares outstanding between 2005 and 2006.

Principal Factors Affecting Operating Margin

Southwest's operating revenues are recognized from the distribution and transportation of natural gas (and related services) to customers. Operating margin is the measure of gas operating revenues less the net cost of gas sold. Management uses operating margin as a main benchmark in comparing operating results from period to period. The three principal factors affecting operating margin are general rate relief, weather, and customer growth.

General Rate Relief. 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. 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.

The following events highlight the impact of general rate relief on operating margin during 2006:

- In February 2006, the Arizona Corporation Commission ("ACC") rendered a general rate decision that increased rates in Arizona by $49.3 million annually effective March 2006. During 2006, general rate relief in Arizona provided a $35 million increase in operating margin.

- In June 2006, the California Public Utilities Commission ("CPUC") approved the Company's 2006 attrition year filing, granting annualized rate relief of $3 million, effective April 13, 2006, of which $2 million was recognized in 2006.

Weather. 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 in Arizona where rates remain leveraged, have a significant impact on the margin and associated net income of the Company. Differences in heating demand, caused primarily by weather variations between 2006 and 2005, accounted for a $3 million increase in operating margin. Temperatures during both years were warmer than normal.

Customer Growth. As of December 31, 2006, Southwest had 1,784,000 residential, commercial, industrial, and other natural gas customers, of which 965,000 customers were located in Arizona, 642,000 in Nevada, and 177,000 in California. Residential and commercial customers represented over 99 percent of the total customer base. During 2006, Southwest added 71,000 customers, a four percent increase, of which 35,000 customers were added in Arizona, 29,000 in Nevada, and 7,000 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 over four percent in 2007. During 2006, 54 percent of operating margin was earned in Arizona, 36 percent in Nevada, and 10 percent in California. During this same period, Southwest earned 85 percent of operating margin from residential and small commercial customers, 6 percent from other sales customers, and 9 percent from transportation customers. These general patterns are expected to continue.

Incremental margin ($26 million in 2006) has accompanied this customer growth, but the costs associated with creating and maintaining the infrastructure needed to accommodate these customers have also been significant. The timing of including these costs in rates is often delayed (regulatory lag) and can result in a reduction of current-period earnings.

Management has attempted to mitigate the regulatory lag associated with growth by collecting contributions and advances from home builders and by being judicious in its staffing levels through the effective use of technology. Exemplifying this in recent years has been Southwest's expanded use of electronic meter reading technology. This technology eliminates the need to gain physical access to meters in order to obtain monthly meter readings, thereby reducing the time associated with each meter read while improving their accuracy. By the end of 2006, over 40 percent of Southwest customers' meters were being read electronically. Reductions in staffing levels associated with these efficiencies have been accomplished through normal attrition. Some of these experienced employees have been redeployed to expand service and construction capabilities. Over the next few years, Southwest will continue to invest in electronic meter reading technology to achieve additional efficiencies.

During the past decade, while adding nearly 692,000 customers, Southwest only increased staffing levels by 105. During this same period, Southwest's customer to employee ratio has climbed from 451/1 to 706/1, an increase of over 50 percent. It has accomplished this without sacrificing service quality. Additional examples of technological improvements over the last few years include electronic order routing, an electronic mapping system and a work management system.

Customer growth requires significant capital outlays for new transmission and distribution plant and results in higher service costs associated with operating and maintaining such facilities. The following financing activities supported continued construction during 2006:

- During 2006, the Company issued 2.4 million shares of common stock through its various stock plans, receiving over $70 million in proceeds.
- In September 2006, the Company issued $56 million in Clark County, Nevada 4.75% Industrial Development Revenue Bonds ("IDRBs") Series 2006A. The proceeds from the IDRBs were used by Southwest to expand and upgrade facilities in Clark County, Nevada.
- During 2006, Southwest partially offset capital outlays by collecting approximately $48.6 million in net advances and contributions from customers and third-party contractors.

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 historically. Management continues to work with its regulatory commissions in designing rate structures that strive to provide affordable and reliable service to its customers while mitigating the volatility in prices to customers and stabilizing returns to investors. Such a rate structure is in place in California and progress has been made in Nevada. Southwest continues to pursue rate design changes in Arizona.

Property Tax Settlement

In April 2006, a settlement was reached regarding property tax valuation disputes in Arizona for tax years 2001-2005. A decrease to property tax expense of $3.7 million and an accrual of $746,000 of interest income was recorded. This entry resulted in nonrecurring after-tax income of approximately $0.07 per share in 2006.

Natural Gas Price Volatility

Southwest has experienced price volatility over the past five years, as the weighted-average delivered cost of natural gas

has ranged from a low of 38 cents per therm in 2002 to a high of 79 cents per therm in 2006. Price volatility is expected to continue throughout 2007. Sustained high prices can result in increased under-collected purchased gas adjustment ("PGA") balances and thereby temporarily reduce operating cash flows until rate relief is granted to recover the higher costs. During 2006, Southwest was able to increase gas cost recovery rates in all jurisdictions and has reduced uncollected PGA balances by $32 million since December 2005.

Stock-Based Compensation

During the first quarter of 2006, the Company began expensing all stock-based compensation costs. In 2006, gross expense was $4.9 million including $1.5 million for stock options and $3.4 million for performance shares. In 2005, expense related to stock-based compensation (performance shares) was $4.1 million.

2007 California Attrition Order

In October 2006, the Company made its 2007 annual California attrition filing requesting a $2.7 million increase in operating margin. The increase in customer rates was approved to be made effective January 2007. In connection with this filing, the Company also received approval to change the way operating margin is recognized under the Company's margin tracker mechanism. The change provides for authorized levels of margin to be recognized in equal monthly amounts throughout the year, rather than on a seasonally adjusted basis. This change will not impact the total amount of margin recognized annually; however it will affect the comparability of 2007 versus 2006 quarterly amounts. As a result, the $2.7 million authorized annual attrition increase to operating margin in 2007, as adjusted for the equalized margin tracker mechanism, is expected to result in the following year-over-year comparative changes (2007 versus 2006): a decrease of $7.7 million during the first quarter, and increases of $2.6 million, $7.4 million and $400,000 in the second, third and fourth quarters, respectively.

Results of Construction Services Operations

The Company's construction subsidiary, NPL, increased its contribution to consolidated net income by $2.2 million in 2006 when compared to the prior year. The increase was primarily due to overall revenue growth, coupled with an improvement in the number of profitable bid jobs, and a sustained favorable equipment resale market in the current year.

Results of Natural Gas Operations

Year Ended December 31, (Thousands of dollars)	2006	2005	2004
Gas operating revenues	$1,727,394	$1,455,257	$1,262,052
Net cost of gas sold	1,033,988	828,131	645,766
Operating margin	693,406	627,126	616,286
Operations and maintenance expense	320,803	314,437	290,800
Depreciation and amortization	146,654	137,981	130,515
Taxes other than income taxes	34,994	39,040	37,669
Operating income	190,955	135,668	157,302
Other income (expense)	10,049	5,087	1,611
Net interest deductions	85,567	81,595	78,137
Net interest deductions on subordinated debentures	7,724	7,723	7,724
Income before income taxes	107,713	51,437	73,052
Income tax expense	36,240	17,767	24,698
Contribution to consolidated net income	$ 71,473	$ 33,670	$ 48,354

2006 vs. 2005

Contribution from natural gas operations increased $37.8 million in 2006 compared to 2005. The improvement in contribution was primarily due to higher operating margin resulting from the Arizona general rate increase, a nonrecurring property tax settlement, and improved other income, partially offset by increased operating expenses and financing costs.

Operating margin increased $66 million in 2006 as compared to 2005. During 2006, the Company added 71,000 customers, an increase of four percent. New customers coupled with additional amounts from existing transportation and non-weather sensitive sales customers contributed $26 million in incremental operating margin. Rate relief in Arizona and California added $37 million. Differences in heating demand caused primarily by weather variations between periods resulted in a $3 million operating margin increase as warmer-than-normal temperatures were experienced during both periods (during 2006, operating margin was negatively impacted by $16 million, while the negative impact in 2005 was $19 million).

Operations and maintenance expense increased $6.4 million, or two percent, between periods reflecting general cost increases and incremental operating costs associated with serving additional customers. Factors contributing to the increase included insurance premiums, uncollectible expenses, employee-related costs, and incremental stock-based compensation costs. Operations and maintenance expense for 2005 included a $10 million nonrecurring provision for an injuries and damages case (see *Insurance Coverage* below for more information).

Depreciation expense increased $8.7 million, or six percent, as a result of construction activities. Average gas plant in service for 2006 increased $238 million, or seven percent, compared to 2005. The increase reflects ongoing capital expenditures for the upgrade of existing operating facilities and the expansion of the system to accommodate continued customer growth.

General taxes decreased $4 million, or 10 percent, primarily as a result of the nonrecurring property tax settlement (see *Property Tax Settlement* for additional information) and Arizona legislation signed in June 2006 that reduced property tax rates, retroactive to January 2006.

Other income (expense) increased $5 million compared to 2005. The current period includes a $2 million net increase in interest income primarily associated with the unrecovered balance of deferred purchased gas costs and $1 million of interest income on the property tax settlement discussed above.

Net financing costs increased $4 million primarily due to higher rates on variable-rate debt and an increase in average debt outstanding to help finance growth.

Income tax expense in 2006 includes a nonrecurring $1.7 million state income tax benefit.

2005 vs. 2004

Contribution from natural gas operations decreased $14.7 million in 2005 compared to 2004. The decrease was principally the result of higher operating expenses, including a nonrecurring provision for an injuries and damages case, partially offset by improved, but lower than expected, operating margin.

Operating margin increased approximately $11 million in 2005 as compared to 2004. During 2005, the Company added 81,000 customers (excluding 19,000 customers associated with an acquisition in the South Lake Tahoe area), a growth rate of five percent. New customers contributed $20 million in incremental margin. Differences in heating demand primarily caused by weather variations between periods resulted in a $17 million margin decrease as warmer-than-normal temperatures were experienced during 2005, especially in Arizona. Rate relief in California and Nevada provided $8 million in new operating margin.

Operations and maintenance expense increased $23.6 million, or eight percent, compared to 2004. A significant component of the variance related to a $10 million nonrecurring provision for an injuries and damages case (see *Insurance Coverage* below for more information). The increase also reflected general cost increases and incremental costs associated with providing service to a growing customer base. Factors contributing to the increase included higher insurance premiums, uncollectible expenses, employee-related costs, and compliance costs. Operations and maintenance expense for 2004 included $2.3 million in lease payments for an LNG facility which was purchased in December 2004.

Depreciation expense and general taxes increased $8.8 million, or five percent, as a result of construction activities. Average gas plant in service increased $248 million, or eight percent, as compared to 2004. The increase reflected ongoing capital expenditures for the upgrade of existing operating facilities, the expansion of the system to accommodate continued customer growth, and the purchase of the South Lake Tahoe properties.

Other income (expense) increased $3.5 million compared to 2004. Returns on long-term investments improved by approximately $1.2 million during 2005. Other income (expense) for 2005 also included an $800,000 improvement in interest income primarily associated with the unrecovered balance of deferred purchased gas costs and a $900,000 increase in the allowance for equity funds used during construction.

Net financing costs rose $3.5 million, or four percent, between years primarily due to an increase in average debt outstanding to help finance growth and higher rates on variable-rate debt.

Income tax expense in 2004 included $1.6 million of income tax benefits based on an analysis of current and deferred taxes following the completion of general rate cases and the closure of federal tax year 2000.

Rates and Regulatory Proceedings

Arizona General Rate Case. In February 2006, the ACC rendered a decision on the general rate case filed by Southwest in December 2004. The ACC approved a $49.3 million increase in operating revenues, effective March 2006. The decision did not include all of the rate design changes or the conservation tracker Southwest had requested. While the ACC did authorize an increase in the customer charge by $1.70 per month, the rate design approved for commodity sales continues to expose customers, investors and the Company to the risks associated with weather volatility. The ACC did however encourage Southwest to work with the ACC Staff and other interested parties prospectively to seek rate design alternatives that will provide benefits to all affected stakeholders. These collaborative discussions began during the third quarter of 2006 and will continue in the future. Southwest estimates that operating margin in 2006 reflected approximately $35 million of general rate relief in Arizona.

California Attrition Filings. In October 2005, Southwest made its 2006 annual attrition filing requesting a $4.5 million

increase in operating margin. The effective date of new rates was originally anticipated to be January 2006. The Division of Ratepayer Advocates ("DRA") filed a protest to the attrition filing disagreeing with certain aspects of the Company's calculation. As a result of the protest, the Energy Division suspended the filing. In December 2005, Southwest filed a motion requesting authorization to establish a memorandum account to track the related revenue shortfall between the existing and proposed rates in the attrition filing. The motion was approved effective April 13, 2006. In June 2006, the CPUC approved the revised 2006 attrition retroactive to the date of the memorandum account in April. Annualized rate relief of $3 million was granted of which approximately $2 million was recognized in 2006. Although the Company filed an application requesting that the memorandum account be made effective January 2006, consistent with the initial annual filing, this petition was denied during the fourth quarter, and as a result, the Company was unable to recover an estimated $1 million in operating margin resulting from the delayed effective date.

In October 2006, the Company made its 2007 annual attrition filing requesting a $2.7 million increase in operating margin. The increase in customer rates was approved to be made effective January 2007. In connection with this filing, the Company also received approval to change the way operating margin is recognized under the Company's margin tracker mechanism. The change provides for authorized levels of margin to be recognized in equal monthly amounts throughout the year, rather than on a seasonally adjusted basis. This change will not impact the total amount of margin recognized annually; however it will affect the comparability of 2007 versus 2006 quarterly amounts. As a result, the $2.7 million authorized annual attrition increase to operating margin in 2007, as adjusted for the equalized margin tracker mechanism, is expected to result in the following year-over-year comparative changes (2007 versus 2006): a decrease of $7.7 million during the first quarter, and increases of $2.6 million, $7.4 million and $400,000 in the second, third and fourth quarters, respectively.

Nevada Weather Normalization Adjustment Provision. In March 2005, Southwest filed an application requesting the Public Utilities Commission of Nevada ("PUCN") to approve a weather normalization adjustment provision in advance of the Company's next general rate case. This filing requested that winter season billing volumes for weather sensitive customers be adjusted to reflect consumption variations that can be attributed to departures from normal weather. In the second quarter of 2005, the PUCN opened an investigation/ rulemaking docket to address the issue of weather normalization, and in November 2005, the PUCN requested additional information. A joint report of the Regulatory Operations Staff and Bureau of Consumer Protection was filed in July 2006 recommending approval of a weather normalization adjustment provision. The PUCN subsequently declined to adopt the recommendation, effectively requiring the issue to be considered in future general rate case proceedings.

PGA Filings

The rate schedules in all of Southwest's service territories contain provisions that permit adjustments to rates as the cost of purchased gas changes. These deferred energy provisions and purchased gas adjustment clauses are collectively referred to as "PGA" clauses. 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. 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). In addition, since Southwest is permitted to accrue interest on PGA balances, the cost of incremental PGA-related short-term borrowings will be largely offset, and there should be no material negative impact to earnings.

Southwest had the following outstanding PGA balances receivable at the end of its two most recent fiscal years (millions of dollars):

	2006	2005
Arizona	$68.4	$ 46.8
Northern Nevada	1.1	12.6
Southern Nevada	4.1	39.4
California	3.4	10.6
	$77.0	$109.4

Arizona PGA Filings. In Arizona, Southwest adjusts rates monthly for changes in purchased gas costs, within pre-established limits measured on a twelve-month rolling average. During the first quarter of 2006, the ACC approved an increase in the pre-established limit from $0.10 to $0.13 per therm. In addition, the ACC approved the implementation of a temporary PGA surcharge of $0.11 per therm effective February 2006 to pass through higher costs of natural gas incurred during 2005. The PGA balance in Arizona has been steadily declining after reaching a high of $95.8 million in April 2006.

Nevada Deferred Energy Adjustment Filing. Nevada Senate Bill No. 238, which became effective in October 2005, provides for quarterly gas cost adjustments calculated on a twelve-month rolling average. Adjustments are subject to an annual prudence review and audit of the natural gas costs incurred. This new quarterly adjustment mechanism was effective in allowing Southwest to minimize the PGA balance by year end 2006.

California Gas Cost Filings. 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.

Other Filings

El Paso Transmission System. In June 2005, El Paso Natural Gas Company ("El Paso") filed a general rate case application with the Federal Energy Regulatory Commission ("FERC"). (Southwest is dependent upon El Paso for the transportation of natural gas for virtually all of its Arizona service territories, and through August 2006, part of its southern Nevada service territories.) As part of its application, which is the first since the conversion of full requirements customers like Southwest to contract demand services, El Paso proposed various tariff changes along with new service offerings. The annual increase in gas transportation costs to Southwest was approximately $19.1 million. The new rates became effective January 2006, subject to refund. However, the implementation of new services and certain overrun and imbalance penalty charges proposed in El Paso's application was phased-in during the period June 2006 through November 2006. In December 2006, El Paso filed a settlement offer with the FERC which would resolve many of the issues raised in the general rate case proceeding. Southwest expects to fully recover any increased costs resulting from a final order or settlement in the case.

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.

2006 Construction Expenditures

Southwest continues to experience high 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, 2006, total gas plant increased from $3 billion to $3.8 billion, or at an annual rate of seven percent. Customer growth was the primary reason for the plant increase as Southwest added 253,000 net new customers (including 19,000 customers acquired in the South Lake Tahoe area) during the three-year period.

During 2006, construction expenditures for the natural gas operations segment were $306 million. Approximately 76 percent of these 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 $215 million of the required capital resources pertaining to total capital expenditures in 2006. The remainder was provided from external financing activities and existing credit facilities.

2006 Financing Activity

The Company has a universal shelf registration statement providing for the issuance and sale of registered securities, which may consist of secured debt, unsecured debt, preferred stock, or common stock. At December 31, 2006, the Company had $95 million in securities available for issuance under the universal shelf registration statement.

In March 2006, the Company entered into a Sales Agency Financing Agreement with BNY Capital Markets, Inc. relating to the issuance and sale of up to $45 million aggregate amount of shares of the Company's common stock, from time to time over a three-year period ("Equity Shelf Program"). Sales of the shares are made at market prices prevailing at the time of sale. Net proceeds from the sale of shares of common stock under the Equity Shelf Program are used for general corporate purposes, including the acquisition of property for the construction, completion, extension or improvement of pipeline systems and facilities located in and around the communities Southwest serves. During 2006, approximately 947,000 shares were issued in at-the-market offerings through the Equity Shelf Program at an average price of $29.87 per share with gross proceeds of $28.3 million, agent commissions of $283,000, and net proceeds of $28 million.

During 2006, the Company issued approximately 1.5 million additional shares of common stock through the Dividend Reinvestment and Stock Purchase Plan ("DRSPP"), Employee Investment Plan, Management Incentive Plan, and Stock Incentive Plan. In addition, in 2006, Southwest offset capital outlays by collecting approximately $48.6 million in net advances and contributions from third-party contractors.

In September 2006, the Company issued $56 million in Clark County, Nevada 4.75% IDRBs Series 2006A pursuant to a financing agreement and indenture. The IDRBs were issued at a discount of 0.625% and are due September 1, 2036. The net proceeds from the IDRBs were used by Southwest to expand and upgrade facilities in Clark County, Nevada.

2007 Construction Expenditures and Financing

Southwest estimates construction expenditures during the three-year period ending December 31, 2009 will be approximately $880 million. Of this amount, approximately $337 million are expected to be incurred in 2007. During the three-year period, cash flow from operating activities (net of dividends) is estimated to fund over 90 percent of the gas operations' total construction expenditures, assuming timely recovery of currently deferred PGA balances. Southwest also has $43 million in long-term debt maturities over the three-year period. Maturities would increase to $50.5 million if an existing bondholder exercises a discretionary put option in 2007. The Company expects to raise $100 million to $125 million from its various common stock programs. Any remaining cash requirements are expected to be provided by existing credit facilities and/or 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.

Contractual Obligations

Obligations under long-term debt, gas purchase obligations and significant non-cancelable operating leases at December 31, 2006 were as follows (millions of dollars):

		Payments due by period			
	Total	2007	2008-2009	2010-2011	Thereafter
Contractual Obligations					
Subordinated debentures to Southwest Gas Capital II (Note 5) (a)	$ 383	$ 8	$ 15	$ 15	$ 345
Long-term debt (Note 6) (a)	2,414	102	183	471	1,658
Operating leases (Note 2)	32	5	9	5	13
Gas purchase obligations (b)	519	422	97	—	—
Pipeline capacity (c)	667	105	195	189	178
Other commitments	17	6	6	2	3
Total	$4,032	$648	$505	$682	$2,197

(a) Includes scheduled principal and interest payments over the life of the debt.

(b) Includes fixed-price and variable-rate gas purchase contracts covering approximately 140 million dekatherms. Fixed-price contracts range in price from $6 to $11 per dekatherm. Variable-price contracts reflect minimum contractual obligations.

(c) Southwest has pipeline capacity contracts for firm transportation service, both on a short- and long-term basis, with several companies 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 funding for pension and other postretirement benefits during calendar year 2007 is $24 million.

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 liquidity in future years include inflation, growth in Southwest's service territories, changes in the ratemaking policies of regulatory commissions, interest rates, variability of natural gas prices, changes in income tax laws, and the level of Company earnings. Of these factors natural gas prices have had the most significant impact on Company liquidity.

Over the past five years the weighted-average delivered cost of natural gas has ranged from a low of 38 cents per therm in 2002 to a high of 79 cents per therm in 2006. Price volatility is expected to continue throughout 2007. Southwest periodically enters into fixed-price term contracts to mitigate price volatility. About half of Southwest's annual normal weather supply needs are secured using short duration contracts (one year or less). For the 2006/2007 heating season, fixed price contracts ranged in price from $6 to $11 per dekatherm. Natural gas purchases not covered by fixed-price contracts are made under variable-price contracts with firm quantities and on the spot market. Prices for these contracts are not known until the month of purchase. Southwest does not currently utilize other stand-alone derivative financial instruments for speculative purposes, or for hedging. During 2007, Southwest intends to supplement its current volatility mitigation program with stand-alone derivative instruments. The combination of fixed-price contracts and derivative instruments should increase flexibility for Southwest and increase supplier diversification. The costs of such derivative financial instruments are expected to be recovered from customers.

The rate schedules in Southwest's service territories contain PGA clauses which permit adjustments to rates as the cost of purchased gas changes. The PGA mechanism allows Southwest to request 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, 2006, the combined balances in PGA accounts totaled an under-collection of $77 million versus an under-collection of $109 million at December 31, 2005. See **PGA Filings** for more information on recent regulatory filings. Southwest has the ability to draw on its $300 million credit facility to temporarily finance under-collected PGA balances.

This facility runs through April 2011. Southwest has designated $150 million of the facility as long-term debt and the remaining $150 million for working capital purposes. Southwest currently believes the $150 million designated for working capital purposes is adequate to meet liquidity needs. At December 31, 2006, $147 million was outstanding on the long-term portion and no borrowings were outstanding on the short-term portion of the credit facility.

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 securities ratings covenants that, if set in motion, would increase financing costs. See discussion below for the impact of a recent credit rating change.

Securities 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).

In May 2006, Moody's Investors Service, Inc. ("Moody's") lowered its rating on the Company's unsecured long-term debt to Baa3 from Baa2 and changed the outlook for the rating to stable from negative. The change in credit rating will result in an annualized estimated increase of $375,000 in interest expense on existing long-term debt. No debt covenants were affected by the downgrade. Moody's cited a long-term warming trend in the Company's service territories, regulatory lag, and weak credit measures as some of the factors behind the downgrade. Moody's applies a Baa rating to obligations which are considered medium grade obligations with adequate security. A numerical modifier of 1 (high end of the category) through 3 (low end of the category) is included with the Baa to indicate the approximate rank of a company within the range.

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, consulting, 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.

Insurance Coverage

The Company maintains liability insurance for various risks associated with the operation of its natural gas pipelines and facilities. In connection with these liability insurance policies, the Company has been responsible for an initial deductible or self-insured retention amount per incident, after which the insurance carriers would be responsible for amounts up to the policy limits. For the policy year August 2004 to July 2005, the self-insured retention amount associated with general liability claims was $1 million per incident plus payment of the first $10 million in aggregate claims above $1 million in the policy year. In May 2005, a leaking natural gas line was involved in a fire that severely injured an individual. The leak is believed to have been caused by a rock impinging upon a natural gas line that was installed for Southwest Gas and that is owned and operated by the Company. In December 2005, the plaintiffs filed a complaint against the Company claiming $3.4 million in medical bills, $12 million in future medical expenses, and unspecified claims for general and punitive damages. By December 2005, the Company had recorded a total liability related to this incident equal to the Company's maximum self-insured retention level of $11 million. In the fourth quarter of 2006, the case was settled. The amount of the settlement that exceeded $11 million was covered by insurance. The Company's current insurance contracts limit the self-insured retention to $1 million per incident plus payment of the first $5 million in aggregate claims above $1 million.

Results of Construction Services

Year Ended December 31, (Thousands of dollars)	2006	2005	2004
Construction revenues	$297,364	$259,026	$215,008
Cost of construction	271,743	237,356	196,792
Gross profit	25,621	21,670	18,216
General and administrative expenses	7,377	6,672	5,742
Operating income	18,244	14,998	12,474
Other income (expense)	4,086	3,009	2,131
Interest expense	1,686	1,009	645
Income before income taxes	20,644	16,998	13,960
Income tax expense	8,257	6,845	5,539
Contribution to consolidated net income	$ 12,387	$ 10,153	$ 8,421

2006 vs. 2005

The 2006 contribution to consolidated net income from construction services increased $2.2 million from 2005. The factors that drove the favorable results include a 15 percent increase in revenues, an improvement in the number of profitable bid jobs, and a favorable equipment resale market.

Revenues increased $38 million due primarily to an increased workload under several existing contracts and an improvement in the amount and profitability of new bid work. Gross profit increased approximately $4 million, or 18 percent, as a direct result of the increase in revenues. The construction revenues above include NPL contracts with Southwest totaling $80.6 million in 2006, $71.8 million in 2005, and $61.6 million in 2004. NPL accounts for the services provided to Southwest at contractual (market) prices.

General and administrative costs increased $705,000 due primarily to incremental costs associated with growth including labor and other administrative expenses. Other income increased $1.1 million as a result of an increase in gains on sale of equipment. Interest expense increased $677,000 due to additional long-term borrowing for the purchase of new equipment and higher interest rates.

Construction activity is cyclical and can be significantly impacted by changes in general and local economic conditions, including interest rates, employment levels, job growth, and local and federal tax rates. The slow-down in construction activities observed in regional and national markets at the end of 2006, if sustained, could negatively impact the amount of work received under existing blanket contracts, the amount of bid work, and the equipment resale market in 2007.

2005 vs. 2004

The 2005 contribution to consolidated net income from construction services increased $1.7 million from 2004. The increase was primarily due to overall revenue growth, coupled with an improvement in the number of profitable bid jobs and a favorable equipment resale market in 2005.

Revenues and gross profit for 2005 reflect an increased workload under existing contracts and an increase in the quantity and profitability of bid work. Favorable working conditions in several operating areas facilitated additional construction activity.

General and administrative costs increased $930,000 due primarily to the depreciation expense related to the implementation of new computer systems and compliance costs. Other income (expense) increased $878,000 as a result of an increase in gains on sale of equipment. Interest expense rose $364,000 due to additional long-term borrowing for the purchase of new equipment and higher interest rates.

Recently Issued Accounting Pronouncements

Below is a listing of recently issued accounting pronouncements by the Financial Accounting Standards Board ("FASB"). See **Note 1—Summary of Significant Accounting Policies** for more information regarding these accounting pronouncements and their potential impact on the Company's financial position and results of operations.

Title	Month of Issue	Effective Date
SFAS No. 155, "Accounting for Certain Hybrid Financial Instruments—an amendment of FASB Statements No. 133 and 140."	February 2006	January 2007
SFAS No. 156, "Accounting for Servicing of Financial Assets—an amendment of FASB Statement No. 140."	March 2006	January 2007
FIN No. 48, "Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109."	June 2006	January 2007
SFAS No. 157, "Fair Value Measurements."	September 2006	January 2008

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 and bases its estimates on historical experience and on various other assumptions that it believes to be reasonable under the circumstances, the results of which form the basis for making judgments. These estimates may change as new events occur, as more experience is acquired, as additional information is obtained, and as the Company's operating environment changes. The following are 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**.

Regulatory Accounting

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 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. The Company reviews these assets to assess their ultimate recoverability within the approved regulatory guidelines. 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 (which would be recognized as current-period expense).

Regulatory liabilities are recorded if it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process. The timing and inclusion of costs in rates is often delayed (regulatory lag) and results in a reduction of current-period earnings. Refer to **Note 4—Regulatory Assets and Liabilities** for a list of regulatory assets and liabilities.

Unbilled Revenues

Revenues related to the sale and/or delivery of natural gas are generally recorded when natural gas is delivered to customers. However, the determination of natural gas sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, revenues for natural gas that has been delivered but not yet billed are accrued. This unbilled revenue is estimated each month based on daily sales volumes, applicable rates, analyses reflecting significant historical trends, weather, and experience. In periods of extreme weather conditions, the interplay of these assumptions could impact the variability of the unbilled revenue estimates.

Accounting for Income Taxes

The income tax calculations of the Company require estimates due to known future tax rate changes, book to tax differences, and uncertainty with respect to regulatory treatment of certain property items. 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. Regulatory tax assets and liabilities are recorded to the extent the Company believes they will be recoverable from or refunded to customers in future rates. 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 Company regularly assesses financial

statement tax provisions and adjusts the tax provisions when necessary as additional information is obtained. A change in the regulatory treatment or significant changes in tax-related estimates, assumptions, or enacted tax rates could have a material impact on cash flows, the financial position, and/or results of operations of the Company.

Accounting for Pensions and Other Postretirement Benefits

Southwest has a noncontributory qualified retirement plan with defined benefits covering substantially all employees. In addition, Southwest has a separate unfunded supplemental retirement plan which is limited to officers. The Company's pension obligations and costs for these plans are affected by the amount of cash contributions to the plans, the return on plan assets, discount rates, and by employee demographics, including age, compensation, and length of service. Changes made to the provisions of the plans may also impact current and future pension costs. Actuarial formulas are used in the determination of pension obligations and costs and are affected by actual plan experience and assumptions about future experience. Key actuarial assumptions include the expected return on plan assets, the discount rate used in determining the projected benefit obligation and pension costs, and the assumed rate of increase in employee compensation. Relatively small changes in these assumptions (particularly the discount rate) may significantly affect pension obligations and costs for these plans.

Due to an increase in market interest rates for high-quality fixed income investments, the Company raised the discount rate to 6.00% at December 31, 2006 from 5.75% at December 31, 2005. The weighted-average rate of compensation increase was raised to 3.75% from 3.30%. The Company maintained its asset return assumption for 2007 at 8.50%. These offsetting changes will not result in a significant change in pension expense for 2007. Should interest rates rise in 2007, future pension expense and projected benefit obligations could decrease. Conversely, declining interest rates would put upward pressure on future pension expense and projected benefit obligations.

In September 2006, the FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans—an amendment of FASB Statements No. 87, 88, 106, and 132(R)", which requires employers to recognize the overfunded or underfunded positions of defined benefit postretirement plans, including pension plans, in their balance sheets. Under SFAS No. 158, any actuarial gains and losses, prior service costs and transition assets or obligations that were not recognized under previous accounting standards must be recognized in accumulated other comprehensive income under stockholders' equity, net of tax, until they are amortized as a component of net periodic benefit cost. SFAS No. 158 does not change how net periodic pension and postretirement costs are accounted for and reported in the income statement. The Company adopted the provisions of SFAS No. 158 effective December 31, 2006.

In accordance with SFAS No. 71, the Company has established a regulatory asset for the portion of the total amounts otherwise chargeable to accumulated other comprehensive income that are expected to be recovered through rates in future periods. The changes in actuarial losses and prior service credits pertaining to the regulatory asset will be recognized as an adjustment to the regulatory asset account as these amounts are recognized as components of net periodic pension costs each year. See **Note 9—Pension and Other Postretirement Benefits** for plan assumptions and further discussion of the impact of adopting SFAS No. 158.

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.

Certifications

The SEC requires the Company to file certifications of its Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") regarding reporting accuracy, disclosure controls and procedures, and internal control over financial reporting as exhibits to the Company's periodic filings. The CEO and CFO certifications for the period ended December 31, 2006 were included as exhibits to the 2006 Annual Report on Form 10-K which was filed with the SEC. The Company is also required to file an annual CEO certification regarding corporate governance listing standards compliance with the New York Stock Exchange ("NYSE"). The most recent annual CEO certification, dated May 10, 2006, was filed with the NYSE in May 2006.

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. In particular, statements regarding customer growth, estimated construction expenditures, the sources and amounts of financing, customer mix and revenue patterns, efficiencies resulting from new technology, construction services contribution, ability to receive more effective rate designs, the expected results of the projected impact in 2007 due to changes in the margin tracker mechanism, sufficiency of working

capital and ability to raise funds and receive external financing, and statements regarding future gas prices, future PGA balances, the effects of recent accounting pronouncements, and the timing and results of future rate approvals and guidelines are forward-looking statements. All forward-looking statements are intended to be subject to the safe harbor protection provided by the Reform Act.

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 rate design, 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, renewal of franchises, easements and rights-of-way, changes in operations and maintenance expenses, effects of accounting changes, future liability claims, 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. 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 1A. Risk Factors** in the Company's Annual Report on Form 10-K for the year ended December 31, 2006.

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

	2006		2005		Dividends Declared	
	High	Low	High	Low	2006	2005
First quarter	$29.04	$26.09	$26.13	$23.66	$0.205	$0.205
Second quarter	31.43	26.46	26.35	23.53	0.205	0.205
Third quarter	34.19	30.70	28.07	25.00	0.205	0.205
Fourth quarter	39.37	32.80	27.86	25.12	0.205	0.205
					$0.820	$0.820

The principal market on which the common stock of the Company is traded is the New York Stock Exchange. At February 15, 2007, there were 23,306 holders of record of common stock, and the market price of the common stock was $38.80.

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 2006. The dividend of 20.5 cents per share has been paid quarterly since September 1994. In February 2007, the Board of Directors increased the quarterly dividend payout to 21.5 cents per share, effective with the June 2007 payment.

Consolidated Balance Sheets

(Thousands of dollars, except par value)	December 31, 2006	2005
ASSETS		
Utility plant:		
Gas plant	$ 3,763,310	$ 3,516,587
Less: accumulated depreciation	(1,175,600)	(1,083,900)
Acquisition adjustments, net	1,992	2,173
Construction work in progress	78,402	54,287
Net utility plant (Note 2)	2,668,104	2,489,147
Other property and investments	136,242	118,094
Current assets:		
Cash and cash equivalents	18,786	29,603
Accounts receivable, net of allowances (Note 3)	225,928	198,081
Accrued utility revenue	73,300	68,400
Deferred purchased gas costs (Note 4)	77,007	109,415
Prepaids and other current assets (Note 4)	106,603	137,161
Total current assets	501,624	542,660
Deferred charges and other assets (Note 4)	178,995	78,525
Total assets	$ 3,484,965	$ 3,228,426
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common stock, $1 par (authorized–45,000,000 shares; issued and outstanding–41,770,291 and 39,328,291 shares) (Note 10)	$ 43,400	$ 40,958
Additional paid-in capital	698,258	628,248
Accumulated other comprehensive income (loss), net (Note 9)	(13,666)	(41,645)
Retained earnings	173,433	123,574
Total equity	901,425	751,135
Subordinated debentures due to Southwest Gas Capital II (Note 5)	100,000	100,000
Long-term debt, less current maturities (Note 6)	1,286,354	1,224,898
Total capitalization	2,287,779	2,076,033
Commitments and contingencies (Note 8)		
Current liabilities:		
Current maturities of long-term debt (Note 6)	27,545	83,215
Short-term debt (Note 7)	—	24,000
Accounts payable	265,739	259,476
Customer deposits	64,151	57,552
Accrued general taxes	45,895	40,526
Accrued interest	21,362	22,472
Deferred income taxes (Note 11)	15,471	68,166
Other current liabilities	55,901	65,546
Total current liabilities	496,064	620,953
Deferred income taxes and other credits:		
Deferred income taxes and investment tax credits (Note 11)	308,493	234,739
Taxes payable	5,951	7,551
Accumulated removal costs (Note 4)	125,000	105,000
Other deferred credits (Note 9)	261,678	184,150
Total deferred income taxes and other credits	701,122	531,440
Total capitalization and liabilities	$ 3,484,965	$ 3,228,426

The accompanying notes are an integral part of these statements.

Consolidated Statements Of Income

Year Ended December 31, (In thousands, except per share amounts)	2006	2005	2004
Operating revenues:			
Gas operating revenues	$1,727,394	$1,455,257	$1,262,052
Construction revenues	297,364	259,026	215,008
Total operating revenues	2,024,758	1,714,283	1,477,060
Operating expenses:			
Net cost of gas sold	1,033,988	828,131	645,766
Operations and maintenance	320,803	314,437	290,800
Depreciation and amortization	168,964	156,253	146,018
Taxes other than income taxes	34,994	39,040	37,669
Construction expenses	256,827	225,774	187,040
Total operating expenses	1,815,576	1,563,635	1,307,293
Operating income	209,182	150,648	169,767
Other income and (expenses):			
Net interest deductions	(87,253)	(82,604)	(78,782)
Net interest deductions on subordinated debentures (Note 5)	(7,724)	(7,723)	(7,724)
Other income (deductions)	14,152	8,114	3,751
Total other income and (expenses)	(80,825)	(82,213)	(82,755)
Income before income taxes	128,357	68,435	87,012
Income tax expense (Note 11)	44,497	24,612	30,237
Net income	$ 83,860	$ 43,823	$ 56,775
Basic earnings per share (Note 13)	$ 2.07	$ 1.15	$ 1.61
Diluted earnings per share (Note 13)	$ 2.05	$ 1.14	$ 1.60
Average number of common shares outstanding	40,566	38,132	35,204
Average shares outstanding (assuming dilution)	40,975	38,467	35,488

The accompanying notes are an integral part of these statements.

Consolidated Statements Of Cash Flows

Year Ended December 31, (Thousands of dollars)	2006	2005	2004
CASH FLOW FROM OPERATING ACTIVITIES:			
Net income	$ 83,860	$ 43,823	$ 56,775
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	168,964	156,253	146,018
Deferred income taxes	3,909	(5,514)	38,001
Changes in current assets and liabilities:			
Accounts receivable, net of allowances	(27,847)	(20,216)	(49,307)
Accrued utility revenue	(4,900)	982	(1,500)
Deferred purchased gas costs	32,408	(25,865)	(72,925)
Accounts payable	6,263	92,021	55,758
Accrued taxes	3,198	5,716	3,027
Other current assets and liabilities	24,156	(23,000)	(25,406)
Other	(8,657)	13,424	1,050
Net cash provided by operating activities	281,354	237,624	151,491
CASH FLOW FROM INVESTING ACTIVITIES:			
Construction expenditures and property additions	(345,325)	(294,369)	(302,688)
Other	33,199	1,985	6,106
Net cash used in investing activities	(312,126)	(292,384)	(296,582)
CASH FLOW FROM FINANCING ACTIVITIES:			
Issuance of common stock, net	72,452	64,136	58,687
Dividends paid	(33,500)	(31,228)	(28,836)
Issuance of long-term debt, net	92,400	145,256	147,135
Retirement of long-term debt	(84,397)	(31,442)	(83,437)
Temporary changes in long-term debt	(3,000)	—	—
Change in short-term debt	(24,000)	(76,000)	48,000
Net cash provided by financing activities	19,955	70,722	141,549
Change in cash and cash equivalents	(10,817)	15,962	(3,542)
Cash at beginning of period	29,603	13,641	17,183
Cash at end of period	$ 18,786	$ 29,603	$ 13,641
Supplemental information:			
Interest paid, net of amounts capitalized	$ 92,533	$ 86,465	$ 80,433
Income taxes paid (received), net	$ 39,682	$ 5,977	$ (12,640)

The accompanying notes are an integral part of these statements.

Consolidated Statements Of Stockholders' Equity And Comprehensive Income

(In thousands, except per share amounts)	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total	Comprehensive Income (Loss)
DECEMBER 31, 2003	34,232	$35,862	$510,521	$ —	$ 84,084	$630,467	
Common stock issuances	2,562	2,562	56,125			58,687	
Net income					56,775	56,775	$ 56,775
Additional minimum pension liability adjustment, net of $6.5 million of tax (Note 9)				(10,892)		(10,892)	(10,892)
Dividends declared Common: $0.82 per share					(29,361)	(29,361)	
2004 Comprehensive Income							$ 45,883
DECEMBER 31, 2004	36,794	38,424	566,646	(10,892)	111,498	705,676	
Common stock issuances	2,534	2,534	61,602			64,136	
Net income					43,823	43,823	$ 43,823
Additional minimum pension liability adjustment, net of $19 million of tax (Note 9)				(30,753)		(30,753)	(30,753)
Dividends declared Common: $0.82 per share					(31,747)	(31,747)	
2005 Comprehensive Income							$ 13,070
DECEMBER 31, 2005	39,328	40,958	628,248	(41,645)	123,574	751,135	
Common stock issuances	2,442	2,442	70,010			72,452	
Net income					83,860	83,860	$ 83,860
Additional minimum pension liability adjustment, net of $20.3 million of tax (Note 9)				33,047		33,047	33,047
Net adjustment to adopt SFAS No. 158, net of $3.1 million of tax (Note 9)				(5,068)		(5,068)	
Dividends declared Common: $0.82 per share					(34,001)	(34,001)	
2006 Comprehensive Income							$116,907
DECEMBER 31, 2006	41,770*	$43,400	$698,258	$(13,666)	$173,433	$901,425	

* At December 31, 2006, 1.3 million 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, 1 million common shares are registered for issuance upon the exercise of options granted under the Stock Incentive Plan (see Note 10). During 2006, approximately 947,000 shares were issued in at-the-market offerings through the Equity Shelf Program with gross proceeds of $28.3 million, agent commissions of $283,000, and net proceeds of $28 million.

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 composed of two segments: natural gas operations ("Southwest" or the "natural gas operations" segment) and construction services. Southwest is engaged in the business of purchasing, distributing and transporting 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. 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 natural 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.

Cash and Cash Equivalents. For purposes of reporting consolidated cash flows, cash and cash equivalents include cash on hand and financial instruments with a purchased maturity of three months or less.

Accumulated Removal Costs. 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 Securities and Exchange Commission's ("SEC") position on presentation of these amounts, management has reclassified $125 million and $105 million, as of December 31, 2006 and 2005, respectively, of estimated removal costs from accumulated depreciation to accumulated removal costs within the liabilities section of the balance sheet.

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 and state and local laws, regulations, and agreements. 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 as accrued utility revenue.

The Company acts as an agent for state and local taxing authorities in the collection and remission of a variety of taxes, including franchise fees, sales and use taxes, and surcharges. These taxes are not included in gas operating revenues, except for certain franchise fees in California operating jurisdictions which are not significant.

Construction Revenues. The majority of the NPL contracts are performed under unit price contracts. Generally, these contracts state prices per unit of installation. Typical installations are accomplished in two weeks or less. Revenues are recorded as installations are completed. Long-term 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.

Note 1 Summary of Significant Accounting Policies (Continued)

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. 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, including acquisition adjustments, are amortized when appropriate, over time periods authorized by regulators. Nonutility and construction services-related property and equipment are depreciated on a straight-line method based on the estimated useful lives of the related assets.

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 $2.8 million in 2006, $2 million in 2005, and $808,000 in 2004 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. The debt portion of AFUDC was $1.4 million, $1.1 million and $691,000 for 2006, 2005 and 2004, respectively. 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.

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.

	2006	2005	2004
(In thousands)			
Average basic shares	40,566	38,132	35,204
Effect of dilutive securities:			
Stock options	195	146	111
Performance shares	214	189	173
Average diluted shares	40,975	38,467	35,488

Derivatives. In managing its gas supply portfolios, Southwest uses fixed-price and variable-rate arrangements which qualify as derivative instruments as defined under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended (SFAS No. 133). However, such contracts qualify for the normal purchases and normal sales exception under SFAS No. 133 or have no significant market value. The Company does not currently utilize other stand-alone derivative financial instruments for speculative purposes or for hedging.

Recently Issued Accounting Pronouncements. In February 2006, the Financial Accounting Standards Board ("FASB") issued SFAS No. 155, "Accounting for Certain Hybrid Financial Instruments—an amendment of FASB Statements No. 133 and 140." SFAS No. 155 permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation and clarifies several other related issues. The provisions of SFAS No. 155 are effective for the Company for all financial instruments acquired or issued after January 1, 2007. The adoption of the standard is not expected to have a material impact on the financial position or results of operations of the Company.

In March 2006, the FASB issued SFAS No. 156, "Accounting for Servicing of Financial Assets—an amendment of FASB Statement No. 140." SFAS No. 156 addresses the recognition and measurement of separately recognized servicing assets and liabilities and provides an approach to simplify efforts to obtain hedge-like (offset) accounting. The provisions of SFAS No. 156 are effective for the Company for the recognition and initial measurement of servicing assets and liabilities acquired or issued after January 1, 2007. The adoption of the standard is not expected to have a material impact on the financial position or results of operations of the Company.

In June 2006, the FASB issued Financial Interpretation ("FIN") No. 48, "Accounting for Uncertainty in Income Taxes—an interpretation of FASB Statement No. 109." FIN No. 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with SFAS No. 109, "Accounting for Income Taxes," and prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN No. 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. FIN No. 48 is effective for the Company beginning January 1, 2007. The adoption of the standard is not expected to have a material impact on the financial position or results of operations of the Company.

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements." SFAS No. 157 defines fair value, establishes a framework for measuring fair value in GAAP, and expands disclosures about fair value measurements. The provisions of SFAS No. 157 are effective for the Company beginning January 1, 2008. The Company is evaluating what impact, if any, this standard might have on its financial position or results of operations.

Stock-Based Compensation. At December 31, 2006, the Company had two stock-based compensation plans which are described more fully in **Note 10—Stock-Based Compensation**. Prior to January 1, 2006, these plans were

Note 1 Summary of Significant Accounting Policies (Continued)

accounted for in accordance with APB Opinion No. 25, "Accounting for Stock Issued to Employees" and related interpretations. Effective January 1, 2006, the Company adopted SFAS No. 123 (revised 2004) "Share-Based Payment", using the modified prospective transition method. Accordingly, financial information for prior periods has not been restated. The adoption of SFAS No. 123 (revised 2004) did not have a material impact on the Company's financial position, results of operations, or cash flows. Under the modified prospective transition method, expense is recognized for any new awards granted after the effective date and for the unvested portion of awards granted prior to the effective date. Total stock-based compensation expense recognized in the consolidated statements of income for the year ended December 31, 2006 was $3.3 million (net of related tax benefits of $1.6 million). The pro forma effects of recognizing the estimated fair value of stock-based compensation for periods prior to the adoption of SFAS No. 123 (revised 2004) are presented below (thousands of dollars, except per share amounts):

	2005	2004
Net income, as reported	$43,823	$56,775
Add: Stock-based employee compensation expense included in reported net income, net of related tax benefits	2,469	1,825
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax benefits	(2,620)	(1,958)
Pro forma net income	$43,672	$56,642
Earnings per share:		
Basic—as reported	$ 1.15	$ 1.61
Basic—pro forma	1.15	1.61
Diluted—as reported	1.14	1.60
Diluted—pro forma	1.14	1.60

Note 2 Utility Plant

Net utility plant as of December 31, 2006 and 2005 was as follows (thousands of dollars):

December 31,	2006	2005
Gas plant:		
Storage	$ 17,545	$ 17,357
Transmission	243,989	239,872
Distribution	3,153,399	2,917,959
General	219,527	213,906
Other	128,850	127,493
	3,763,310	3,516,587
Less: accumulated depreciation	(1,175,600)	(1,083,900)
Acquisition adjustments, net	1,992	2,173
Construction work in progress	78,402	54,287
Net utility plant	$ 2,668,104	$ 2,489,147

Depreciation and amortization expense on gas plant was $145 million in 2006, $137 million in 2005, and $128 million in 2004.

Note 2 Utility Plant (Continued)

Operating Leases and Rentals. Southwest leases 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 2017 and 2009, respectively, with optional renewal terms available at the expiration dates. The rental payments for the corporate headquarters office complex are $2 million in each of the years 2007 through 2011 and $12.2 million cumulatively thereafter. The rental payments for the Phoenix administrative offices are $1.5 million for each of the years 2007 and 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 $19.2 million in 2006, $19 million in 2005, and $20.3 million in 2004. These amounts include NPL lease expenses of approximately $11.5 million in 2006, $11.5 million in 2005, and $9.8 million in 2004 for various short-term operating leases of equipment and temporary office sites.

The following is a schedule of future minimum lease payments for significant non-cancelable operating leases (with initial or remaining terms in excess of one year) as of December 31, 2006 (thousands of dollars):

Year Ending December 31,	
2007	$ 5,378
2008	4,868
2009	4,010
2010	2,568
2011	2,433
Thereafter	12,890
Total minimum lease payments	$32,147

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, 2006, the gas utility customer accounts receivable balance was $182 million. Approximately 54 percent of the gas utility customers were in Arizona, 36 percent in Nevada, and 10 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, 2003	$ 2,246
Additions charged to expense	2,586
Accounts written off, less recoveries	(2,860)
Balance, December 31, 2004	1,972
Additions charged to expense	3,787
Accounts written off, less recoveries	(3,458)
Balance, December 31, 2005	2,301
Additions charged to expense	5,805
Accounts written off, less recoveries	(5,085)
Balance, December 31, 2006	$ 3,021

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"). Southwest 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. Regulatory liabilities are recorded if it is probable that revenues will be reduced for amounts that will be credited to customers through the ratemaking process.

Note 4 Regulatory Assets and Liabilities (Continued)

The following table represents existing regulatory assets and liabilities (thousands of dollars):

December 31,	2006	2005
Regulatory assets:		
Accrued pension and other postretirement benefit costs * (Note 9)	$ 101,402	$ —
Deferred purchased gas costs	77,007	109,415
Accrued purchased gas costs **	40,500	75,300
SFAS No. 109—income taxes, net *	1,846	2,447
Unamortized premium on reacquired debt *	17,676	18,386
Other	30,099	28,236
	268,530	233,784
Regulatory liabilities:		
Accumulated removal costs	(125,000)	(105,000)
Other ***	(1,111)	(821)
Net regulatory assets (liabilities)	$ 142,419	$ 127,963

* Included in Deferred charges and other assets on the Consolidated Balance Sheet.
** Included in Prepaids and other current assets on the Consolidated Balance Sheet.
*** Included in Other deferred credits on the Consolidated Balance Sheet.

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

Note 5 Preferred Trust Securities and Subordinated Debentures

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 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, 2006, 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

Note 5 Preferred Trust Securities and Subordinated Debentures (Continued)

(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.

Although the Company owns 100 percent of the common voting securities of Trust II, under Interpretation No. 46 "Consolidation of Variable Interest Entities—an Interpretation of ARB No. 51", the Company is not considered the primary beneficiary of this trust and therefore Trust II is not consolidated. As a result, 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. Payments and amortizations associated with the Subordinated Debentures are classified on the consolidated statements of income as Net interest deductions on subordinated debentures.

Note 6 Long-Term Debt

December 31,	2006		2005	
	Carrying Amount	Market Value	Carrying Amount	Market Value
(Thousands of dollars)				
Debentures:				
7½% Series, due 2006	$ —	$ —	$ 75,000	$ 76,155
Notes, 8.375%, due 2011	200,000	221,200	200,000	225,720
Notes, 7.625%, due 2012	200,000	217,600	200,000	222,040
8% Series, due 2026	75,000	88,748	75,000	90,525
Medium-term notes, 6.89% series, due 2007	17,500	17,654	17,500	17,971
Medium-term notes, 6.27% series, due 2008	25,000	25,263	25,000	25,600
Medium-term notes, 7.59% series, due 2017	25,000	28,155	25,000	28,573
Medium-term notes, 7.78% series, due 2022	25,000	28,645	25,000	29,088
Medium-term notes, 7.92% series, due 2027	25,000	29,398	25,000	30,000
Medium-term notes, 6.76% series, due 2027	7,500	7,832	7,500	7,976
Unamortized discount	(4,021)	—	(4,657)	—
	595,979		670,343	
Revolving credit facility and commercial paper	147,000	147,000	150,000	150,000
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	50,000	50,000
2003 Series B, due 2038	50,000	50,000	50,000	50,000
Fixed-rate bonds:				
6.10% 1999 Series A, due 2038	12,410	13,093	12,410	13,068
5.95% 1999 Series C, due 2038	14,320	15,136	14,320	15,057
5.55% 1999 Series D, due 2038	8,270	8,696	8,270	8,593
5.45% 2003 Series C, due 2038	30,000	30,705	30,000	30,264
5.25% 2003 Series D, due 2038	20,000	20,836	20,000	20,400
5.80% 2003 Series E, due 2038	15,000	15,629	15,000	15,218
5.25% 2004 Series A, due 2034	65,000	67,210	65,000	65,878
5.00% 2004 Series B, due 2033	75,000	76,688	75,000	75,000
4.85% 2005 Series A, due 2035 net of $24.6 million held in trust in 2005	100,000	101,050	75,366	73,030
4.75% 2006 Series A, due 2036	56,000	56,213	—	—
Unamortized discount	(4,697)	—	(4,159)	—
	541,303		461,207	
Other	29,617	—	26,563	—
	1,313,899		1,308,113	
Less: current maturities	(27,545)		(83,215)	
Long-term debt, less current maturities	$1,286,354		$1,224,898	

Note 6 Long-Term Debt (Continued)

In April 2006, the Company amended its $300 million credit facility. The facility was originally scheduled to expire in April 2010 and was extended to April 2011. The Company will continue to use $150 million of the $300 million as long-term debt and the remaining $150 million for working capital purposes. Interest rates for the facility are calculated at either the London Interbank Offering Rate plus an applicable margin, or the greater of the prime rate or one-half of one percent plus the Federal Funds rate. The applicable margin, unused commitment fee, and utilization fee associated with the amended credit facility are lower than those of the previous facility. At December 31, 2006, no borrowings were outstanding on the short-term portion of the credit facility and $147 million was outstanding on the long-term portion.

In September 2006, the Company issued $56 million in Clark County, Nevada 4.75% industrial development revenue bonds ("IDRBs") Series 2006A pursuant to a financing agreement and indenture. The IDRBs were issued at a discount of 0.625% and are due September 1, 2036. The proceeds from the IDRBs were used by Southwest to expand and upgrade facilities in Clark County, Nevada.

The Company's Revolving Credit Facility, letters of credit, and certain bond insurance policies contain financial covenants, the most restrictive of which require a maximum leverage ratio of 70 percent (debt to capitalization as defined) and a minimum net worth calculation of $475 million adjusted for equity issuances after May 10, 2002. If the Company was 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, 2006, the Company was in compliance with the applicable covenants.

The effective interest rates on the 2003 Series A and B variable-rate IDRBs were 5.14 percent and 4.09 percent, respectively, at December 31, 2006 and 4.64 percent and 3.84 percent, respectively, at December 31, 2005. The effective interest rates on the tax-exempt Series A variable-rate IDRBs were 5.03 percent and 4.55 percent at December 31, 2006 and 2005, respectively.

The fair value of the revolving credit facility and the variable-rate IDRBs approximates carrying value. Market values for the debentures and fixed-rate IDRBs were determined based on dealer quotes using trading records for December 31, 2006 and 2005, as applicable, and other secondary sources which are customarily consulted for data of this kind.

Estimated maturities of long-term debt for the next five years are $27.5 million, $34.1 million, $6.6 million, $1.4 million, and $347 million, respectively.

The $7.5 million medium-term notes, 6.76% series, due 2027 contain 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 mature in 2027. If the bondholder exercises the put, the maturities of long-term debt for 2007 will total $35 million.

Note 7 Short-Term Debt

As discussed in Note 6, Southwest has a $300 million five-year credit facility, effective April 2006, of which $150 million has been designated by management for working capital purposes (and related outstanding amounts are designated as short-term debt). No short-term borrowings were outstanding on the credit facility at December 31, 2006. Short-term borrowings on the credit facility were $24 million at December 31, 2005. The weighted-average interest rate on these borrowings was 5.08 percent at December 31, 2005.

Note 8 Commitments and Contingencies

Legal and Regulatory Proceedings. The Company maintains liability insurance for various risks associated with the operation of its natural gas pipelines and facilities. In May 2005, a leaking natural gas line was involved in a fire that severely injured an individual. By December 2005, the Company had recorded a total liability related to this incident equal to the Company's maximum self-insured retention level for the policy year August 2004 to July 2005 of $11 million. In the fourth quarter of 2006, the case was settled. The amount of the settlement that exceeded $11 million was covered by insurance. The Company's current insurance contracts limit the self-insured retention to $1 million per incident plus payment of the first $5 million in aggregate claims above $1 million.

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 Pension and Other Postretirement Benefits

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

In September 2006, the FASB issued SFAS No. 158, which requires employers to recognize the overfunded or underfunded positions of defined benefit postretirement plans, including pension plans, in their balance sheets. Under SFAS No. 158, any actuarial gains and losses, prior service costs and transition assets or obligations that were not recognized under previous accounting standards must be recognized in accumulated other comprehensive income under stockholders' equity, net of tax, until they are amortized as a component of net periodic benefit cost. SFAS No. 158 does not change how net periodic pension and postretirement costs are accounted for and reported in the income statement. The Company adopted the provisions of SFAS No. 158 effective December 31, 2006.

In accordance with SFAS No. 71, the Company has established a regulatory asset for the portion of the total amounts otherwise chargeable to accumulated other comprehensive income that are expected to be recovered through rates in future periods. The changes in actuarial gains and losses, prior service costs and transition assets or obligations pertaining to the regulatory asset will be recognized as an adjustment to the regulatory asset account as these amounts are recognized as components of net periodic pension costs each year. The following table discloses the incremental effect of applying the provisions of SFAS No. 158 (and SFAS No. 71) to individual line items in the balance sheet as of December 31, 2006.

(Thousands of dollars)	Before Application of SFAS No. 158 *	SFAS No. 158 Adjustments	SFAS No. 71 Regulatory Adjustments	Adjusted Balance **
Assets				
Deferred charges and other assets	$ 101,712	$ —	$77,283	$ 178,995
Total assets	3,407,682	—	77,283	3,484,965
Capitalization and Liabilities				
Accumulated other comprehensive income (loss), net	(8,598)	(52,983)	47,915	(13,666)
Total equity	906,493	(52,983)	47,915	901,425
Total capitalization	2,292,847	(52,983)	47,915	2,287,779
Current liabilities:				
Deferred income taxes	16,383	(912)	—	15,471
Other current liabilities	53,501	2,400	—	55,901
Total current liabilities	494,576	1,488	—	496,064
Deferred income taxes and other credits:				
Deferred income taxes and investment tax credits	310,686	(31,561)	29,368	308,493
Other deferred credits	178,622	83,056	—	261,678
Total deferred income taxes and other credits	620,259	51,495	29,368	701,122
Total capitalization and liabilities	$3,407,682	$ —	$77,283	$3,484,965

* Balances before application of SFAS No. 158 include the effects of 2006 plan experience and changes in actuarial assumptions on the additional minimum liability, coupled with the regulatory impacts of SFAS No. 71.

** At December 31, 2006, the combined net funded status of the three plans reflected a liability of $155 million. Of this amount, approximately $101 million was offset with a regulatory asset.

The table below discloses net amounts recognized in accumulated other comprehensive income as a result of adopting the provisions of SFAS No. 158 (as impacted by SFAS No. 71) as of December 31, 2006. Tax amounts are calculated using a 38 percent rate.

(Thousands of dollars)	Total	Qualified Retirement Plan	SERP	PBOP
Adjustments to adopt SFAS No. 158:				
Net actuarial loss, net of $44.9 million of tax	$(73,323)	$(62,464)	$(8,045)	$(2,814)
Net transition obligation, net of $2 million of tax	(3,225)	—	—	(3,225)
Prior service credit, net of $9,000 of tax	14	14	—	—
Reversal of additional minimum pension liability, net of $14.4 million of tax	23,551	16,432	7,119	—
Estimated amounts recoverable through rates, net of $29.4 million of tax	47,915	41,876	—	6,039
Total amounts recognized in accumulated other comprehensive income	$ (5,068)	$ (4,142)	$ (926)	$ —

Note 9 Pension and Other Postretirement Benefits (Continued)

Investment objectives and strategies for the qualified 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 qualified 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	58 to 70
Debt securities	32 to 38
Other	up to 5

The Company's pension costs for these plans are affected by the amount of cash contributions to the plans, the return on plan assets, discount rates, and by employee demographics, including age, compensation, and length of service. Changes made to the provisions of the plans may also impact current and future pension costs. Actuarial formulas are used in the determination of pension costs and are affected by actual plan experience and assumptions about future experience. Key actuarial assumptions include the expected return on plan assets, the discount rate used in determining the projected benefit obligation and pension costs, and the assumed rate of increase in employee compensation. Relatively small changes in these assumptions, particularly the discount rate, may significantly affect pension costs and plan obligations for the qualified retirement plan.

SFAS No. 87 *Employer's Accounting for Pensions* states that the assumed discount rate should reflect the rate at which the pension benefits could be effectively settled. In making this estimate, in addition to rates implicit in current prices of annuity contracts that could be used to settle the liabilities, employers may look to rates of return on high-quality fixed-income investments currently available and expected to be available during the period to maturity of the pension benefits. In determining the discount rate, the Company matches the plan's projected cash flows to a spot-rate yield curve based on highly rated corporate bonds. The resulting rate is then rounded to the nearest 25 basis points.

Due to an increase in market interest rates for high-quality fixed-income investments, the Company raised the discount rate to 6.00% at December 31, 2006 from 5.75% at December 31, 2005. The weighted-average rate of compensation increase was raised to 3.75% from 3.30%. The Company maintained its asset return assumption for 2007 at 8.50%. These offsetting changes will not result in a significant change in pension expense for 2007.

Note 9 Pension and Other Postretirement Benefits (Continued)

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

	2006		
(Thousands of dollars)	Qualified Retirement Plan	SERP	PBOP
Change in benefit obligations			
Benefit obligation for service rendered to date at beginning of year (PBO/PBO/APBO)	$ 473,418	$ 34,123	$ 37,553
Service cost	16,284	211	854
Interest cost	26,805	1,893	2,118
Actuarial loss (gain)	(4,806)	(207)	(297)
Benefits paid	(15,898)	(2,363)	(1,121)
Benefit obligation at end of year (PBO/PBO/APBO)	495,803	33,657	39,107
Change in plan assets			
Market value of plan assets at beginning of year	338,618	—	20,979
Actual return on plan assets	42,733	—	2,742
Employer contributions	23,253	2,363	1,107
Benefits paid	(15,898)	(2,363)	—
Market value of plan assets at end of year	388,706	—	24,828
Funded status at year end	$(107,097)	$(33,657)	$(14,279)
Weighted-average assumptions (benefit obligation)			
Discount rate	6.00%	6.00%	6.00%
Weighted-average rate of compensation increase	3.75%	3.75%	3.75%
Asset Allocation			
Equity securities	63%		77%
Debt securities	32%		16%
Other	5%		7%
Total	100%	N/A	100%

Note 9 Pension and Other Postretirement Benefits (Continued)

(Thousands of dollars)	2005 Qualified Retirement Plan	2005 SERP	2005 PBOP
Change in benefit obligations			
Benefit obligation for service rendered to date at beginning of year (PBO/PBO/APBO)	$ 428,116	$ 31,385	$ 35,988
Service cost	15,787	223	837
Interest cost	25,327	1,811	2,115
Actuarial loss (gain)	17,842	2,963	103
Benefits paid	(13,654)	(2,259)	(1,490)
Benefit obligation at end of year (PBO/PBO/APBO)	473,418	34,123	37,553
Change in plan assets			
Market value of plan assets at beginning of year	318,664	—	18,750
Actual return on plan assets	15,988	—	1,102
Employer contributions	17,620	2,259	1,127
Benefits paid	(13,654)	(2,259)	—
Market value of plan assets at end of year	338,618	—	20,979
Funded status	(134,800)	(34,123)	(16,574)
Unrecognized net actuarial loss (gain)	123,028	14,428	5,954
Unrecognized transition obligation (2012)	—	—	6,069
Unrecognized prior service cost	(34)	9	—
Prepaid (accrued) benefit cost	$ (11,806)	$(19,686)	$ (4,551)
Accrued benefit liability	$ (66,082)	$(32,580)	$ (4,551)
Additional minimum pension liability adjustment	54,276	12,894	—
	$ (11,806)	$(19,686)	$ (4,551)
Weighted-average assumptions (benefit obligation)			
Discount rate	5.75%	5.75%	5.75%
Weighted-average rate of compensation increase	3.30%	3.30%	3.30%
Asset Allocation			
Equity securities	61%		71%
Debt securities	30%		15%
Other	9%		14%
Total	100%	N/A	100%

Estimated funding for the plans above during calendar year 2007 is approximately $24 million. The accumulated benefit obligation for the retirement plan was $422 million and $405 million, and for the SERP was $32.2 million and $32.6 million at December 31, 2006 and 2005, respectively.

Pension benefits expected to be paid for each of the next five years beginning with 2007 are the following: $16.8 million, $18 million, $19.2 million, $20.6 million, and $22.2 million. Pension benefits expected to be paid during 2012 to 2016 total $138 million. Retiree welfare benefits expected to be paid for each of the next five years beginning with 2007 are the following: $1.4 million, $1.5 million, $1.6 million, $1.7 million, and $1.8 million. Retiree welfare benefits expected to be paid during 2012 to 2016 total $10.5 million. SERP benefits expected to be paid for each of the next five years beginning with 2007 are the following: $2.4 million, $2.5 million, $2.5 million, $2.5 million, and $2.5 million. SERP benefits expected to be paid during 2012 to 2016 total $12.6 million. No assurance can be made that actual funding and benefits paid will match our estimates.

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.

Note 9 Pension and Other Postretirement Benefits (Continued)

Components of net periodic benefit cost:

	Qualified Retirement Plan			SERP			PBOP		
	2006	2005	2004	2006	2005	2004	2006	2005	2004
(Thousands of dollars)									
Service cost	$ 16,284	$ 15,787	$ 13,790	$ 211	$ 223	$ 211	$ 854	$ 837	$ 722
Interest cost	26,805	25,327	23,659	1,893	1,811	1,745	2,118	2,115	2,180
Expected return on plan assets	(30,608)	(29,553)	(28,067)	—	—	—	(1,817)	(1,675)	(1,426)
Amortization of prior service costs (credits)	(11)	(11)	54	9	116	140	—	—	—
Amortization of transition obligation	—	—	—	—	—	—	867	867	867
Amortization of net loss	5,352	2,453	—	1,244	912	639	168	136	213
Net periodic benefit cost	$ 17,822	$ 14,003	$ 9,436	$3,357	$3,062	$2,735	$ 2,190	$ 2,280	$ 2,556
Weighted-average assumptions (net benefit cost)									
Discount rate	5.75%	6.00%	6.50%	5.75%	6.00%	6.50%	5.75%	6.00%	6.50%
Expected return on plan assets	8.50%	8.75%	8.75%	8.50%	8.75%	8.75%	8.50%	8.75%	8.75%
Weighted-average rate of compensation increase	3.30%	4.00%	4.25%	3.30%	4.00%	4.25%	3.30%	4.00%	4.25%

The estimated net loss that will be amortized from accumulated other comprehensive income or regulatory assets into net periodic benefit cost over the next year is $5 million for the qualified retirement plan and $1.1 million for the SERP. The estimated transition obligation for the PBOP that will be amortized from regulatory assets into net periodic benefit cost over the next year is $870,000. The estimated prior service costs (credits) for the qualified retirement plan and SERP and the estimated net loss for the PBOP that will be amortized over the next year are not significant.

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 up to one-half of amounts deferred. The maximum matching contribution is three percent of an employee's annual compensation. The cost of the plan was $3.6 million in 2006, $3.5 million in 2005, and $3.5 million in 2004. 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 base salary. Upon retirement, 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.

Note 10 Stock-Based Compensation

At December 31, 2006, the Company had two stock-based compensation plans: a stock option plan and a performance share stock plan. Prior to January 1, 2006, these plans were accounted for in accordance with APB Opinion No. 25, "Accounting for Stock Issued to Employees" and related interpretations. Effective January 1, 2006, the Company adopted SFAS No. 123 (revised 2004) "Share-Based Payment", using the modified prospective transition method. Accordingly, financial information for prior periods has not been restated. The adoption of SFAS No. 123 (revised 2004) did not have a material impact on the Company's financial condition, results of operations, or cash flows. Under the modified prospective transition method, expense is recognized for any new awards granted after the effective date and for the unvested portion of awards granted prior to the effective date.

Under the option plan, the Company may grant options to purchase shares of common stock to key employees and outside directors. The option grants in 2006 consumed the remaining options that could be issued under the option plan and no future grants are anticipated. 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 Black-Scholes option pricing model in 2006 and 2005 and the extended binomial option pricing model in 2004. The following assumptions were used in the valuation calculation:

	2006	2005	2004
Dividend yield	2.48 to 2.82%	3.14 to 3.28%	3.50%
Risk-free interest rate range	4.91 to 5.06%	3.88 to 4.09%	1.66 to 3.23%
Expected volatility range	15%	18%	13 to 20%
Expected life	6 years	6 years	1 to 3 years

The following tables summarize Company stock option plan activity and related information (thousands of options):

	2006		2005		2004	
	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	1,475	$23.70	1,646	$22.46	1,502	$21.83
Granted during the year	252	32.60	347	26.00	403	23.36
Exercised during the year	(749)	23.30	(510)	21.28	(254)	20.21
Forfeited during the year	(6)	26.81	(8)	22.41	(5)	21.83
Expired during the year	(15)	28.09	—	—	—	—
Outstanding at year end	957	$26.26	1,475	$23.70	1,646	$22.46
Exercisable at year end	413	$23.31	813	$23.06	1,010	$22.36

Note 10 Stock-Based Compensation (Continued)

The intrinsic value of a stock option is the amount by which the market value of the underlying stock exceeds the exercise price of the option. The aggregate intrinsic value of outstanding options was $11.6 million, $4.3 million, and $5.3 million at December 31, 2006, December 31, 2005, and December 31, 2004, respectively. The aggregate intrinsic value of exercisable options was $6.2 million, $3 million, and $3.6 million at December 31, 2006, December 31, 2005, and December 31, 2004, respectively. The aggregate intrinsic value of exercised options was $11.3 million, $2.6 million, and $1.3 million during 2006, 2005, and 2004, respectively. The market value of Southwest Gas stock was $38.37, $26.40, and $25.40 at December 31, 2006, December 31, 2005, and December 31, 2004, respectively.

The weighted-average remaining contractual life for outstanding options was 7.7 years for 2006. The weighted-average remaining contractual life for exercisable options was 6.4 years for 2006. The weighted-average grant-date fair value of options granted was $5.92 for 2006, $4.18 for 2005, and $1.65 for 2004. The following table summarizes information about stock options outstanding at December 31, 2006 (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	26	2.7 Years	$18.13	26	$18.13
$20.49 to $26.10	664	7.4 Years	$24.12	368	$23.36
$28.75 to $33.07	267	9.0 Years	$32.38	19	$29.14

As of December 31, 2006, there was $1.5 million of total unrecognized compensation cost related to nonvested stock options. That cost is expected to be recognized over a period of 3 years. The total fair value of options vested was $1 million, $609,000, and $917,000 during 2006, 2005, and 2004, respectively. The Company received $17.5 million in cash from the exercise of options during 2006 and a corresponding tax benefit of $2.6 million which was recorded in additional paid-in capital. The following table summarizes the status of the Company's nonvested options as of December 31, 2006 (thousands of options):

	Number of options	Weighted-average grant date fair value
Nonvested at the beginning of the year	662	$3.00
Granted	252	$5.92
Vested	(364)	$2.80
Forfeited	(6)	$4.15
Nonvested at December 31, 2006	544	$4.47

In addition to the option plan, the Company may issue 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 three years after grant (and are subject to a final adjustment as determined by the Board of Directors) and are then issued as common stock. The following table summarizes the activity of this plan (thousands of shares):

Year Ended December 31,	2006	2005	2004
Nonvested performance shares at beginning of year	357	316	381
Performance shares granted (including dividends)	95	143	156
Performance shares forfeited	—	(6)	—
Shares vested and issued*	(133)	(96)	(221)
Nonvested performance shares at end of year	319	357	316
Average grant date fair value of awards granted this year	$26.97	$24.71	$22.70

* Includes shares converted for taxes and retiree payouts.

Note 11 Income Taxes

Income tax expense (benefit) consists of the following (thousands of dollars):

Year Ended December 31,	2006	2005	2004
Current:			
Federal	$29,916	$ 553	$ (225)
State	4,830	2,218	(1,186)
	34,746	2,771	(1,411)
Deferred:			
Federal	9,385	21,301	28,607
State	366	540	3,041
	9,751	21,841	31,648
Total income tax expense	$44,497	$24,612	$30,237

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

Year Ended December 31,	2006	2005	2004
Deferred federal and state:			
Property-related items	$ 28,372	$ (3,143)	$ (3,165)
Purchased gas cost adjustments	(22,188)	28,094	34,923
Employee benefits	(3,223)	2,232	240
Injuries and damages reserves	4,543	(4,072)	190
All other deferred	3,115	(402)	328
Total deferred federal and state	10,619	22,709	32,516
Deferred ITC, net	(868)	(868)	(868)
Total deferred income tax expense	$ 9,751	$21,841	$31,648

The consolidated effective income tax rate for the period ended December 31, 2006 and the two prior periods differ 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,	2006	2005	2004
Federal statutory income tax rate	35.0%	35.0%	35.0%
Net state taxes	2.5	2.7	2.8
Property-related items	0.6	1.1	0.8
Effect of closed tax years and resolved issues	(1.3)	—	(1.8)
Tax credits	(0.7)	(1.3)	(1.0)
Corporate owned life insurance	(0.9)	(1.6)	(0.7)
All other differences	(0.5)	0.1	(0.3)
Consolidated effective income tax rate	34.7%	36.0%	34.8%

Note 11 Income Taxes (Continued)

Deferred tax assets and liabilities consist of the following (thousands of dollars):

December 31,	2006	2005
Deferred tax assets:		
Deferred income taxes for future amortization of ITC	$ 6,427	$ 6,964
Employee benefits	36,542	50,468
Alternative minimum tax	36,820	28,903
Net operating losses & credits	—	37,976
Other	4,549	10,510
Valuation allowance	—	—
	84,338	134,821
Deferred tax liabilities:		
Property-related items, including accelerated depreciation	330,308	337,234
Regulatory balancing accounts	46,207	68,395
Property-related items previously flowed through	8,272	9,411
Unamortized ITC	10,330	11,198
Debt-related costs	5,681	6,292
Other	7,504	5,196
	408,302	437,726
Net deferred tax liabilities	$323,964	$302,905
Current	$ 15,471	$ 68,166
Noncurrent	308,493	234,739
Net deferred tax liabilities	$323,964	$302,905

Note 12 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, 2006 and 2005, accounts receivable for these services totaled $9.2 million and $8.2 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, 2006 is as follows (thousands of dollars):

2006	Gas Operations	Construction Services	Adjustments (a)	Total
Revenues from unaffiliated customers	$1,727,394	$216,753		$1,944,147
Intersegment sales	—	80,611		80,611
Total	$1,727,394	$297,364		$2,024,758
Interest expense	$ 93,291	$ 1,686		$ 94,977
Depreciation and amortization	$ 146,654	$ 22,310		$ 168,964
Income tax expense	$ 36,240	$ 8,257		$ 44,497
Segment income	$ 71,473	$ 12,387		$ 83,860
Segment assets	$3,352,074	$136,654	$(3,763)	$3,484,965
Capital expenditures	$ 305,914	$ 39,411		$ 345,325

2005	Gas Operations	Construction Services	Adjustments (a)	Total
Revenues from unaffiliated customers	$1,455,257	$187,249		$1,642,506
Intersegment sales	—	71,777		71,777
Total	$1,455,257	$259,026		$1,714,283
Interest expense	$ 89,318	$ 1,009		$ 90,327
Depreciation and amortization	$ 137,981	$ 18,272		$ 156,253
Income tax expense	$ 17,767	$ 6,845		$ 24,612
Segment income	$ 33,670	$ 10,153		$ 43,823
Segment assets	$3,103,804	$128,181	$(3,559)	$3,228,426
Capital expenditures	$ 258,547	$ 35,822		$ 294,369

2004	Gas Operations	Construction Services	Adjustments (a)	Total
Revenues from unaffiliated customers	$1,262,052	$153,392		$1,415,444
Intersegment sales	—	61,616		61,616
Total	$1,262,052	$215,008		$1,477,060
Interest expense	$ 85,861	$ 645		$ 86,506
Depreciation and amortization	$ 130,515	$ 15,503		$ 146,018
Income tax expense	$ 24,698	$ 5,539		$ 30,237
Segment income	$ 48,354	$ 8,421		$ 56,775
Segment assets	$2,843,199	$ 99,120	$(4,203)	$2,938,116
Capital expenditures	$ 274,748	$ 27,940		$ 302,688

(a) Construction services segment assets include deferred tax assets of $3 million and income taxes payable of $758,000 in 2006, which were netted against gas operations segment deferred tax liabilities and income taxes receivable, net during consolidation and deferred tax assets of $3.6 million and $4.2 million in 2005 and 2004, respectively, which were netted against gas operations segment deferred tax liabilities during consolidation.

Note 13 Quarterly Financial Data (Unaudited)

(Thousands of dollars, except per share amounts)	Quarter Ended March 31	June 30	September 30	December 31
2006				
Operating revenues	$676,941	$430,902	$351,800	$565,115
Operating income (loss)	89,325	25,236	3,197	91,424
Net income (loss)	44,180	3,709	(10,736)	46,707
Basic earnings (loss) per common share*	1.12	0.09	(0.26)	1.12
Diluted earnings (loss) per common share*	1.11	0.09	(0.26)	1.11
2005				
Operating revenues	$542,880	$361,130	$313,278	$496,995
Operating income (loss)	72,849	14,935	(5,459)	68,323
Net income (loss)	32,829	(2,817)	(16,444)	30,255
Basic earnings (loss) per common share*	0.88	(0.07)	(0.43)	0.77
Diluted earnings (loss) per common share*	0.88	(0.07)	(0.43)	0.76
2004				
Operating revenues	$473,400	$278,697	$264,467	$460,496
Operating income (loss)	85,802	5,954	(9,017)	87,028
Net income (loss)	41,044	(8,362)	(16,353)	40,446
Basic earnings (loss) per common share*	1.19	(0.24)	(0.46)	1.12
Diluted earnings (loss) per common share*	1.18	(0.24)	(0.46)	1.11

* 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.

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.

Management's Report on Internal Control Over Financial Reporting

Company management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined by Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. Under the supervision and with the participation of Company management, including the principal executive officer and principal financial officer, the Company conducted an evaluation of the effectiveness of internal control over financial reporting based on the *"Internal Control—Integrated Framework"* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based upon the Company's evaluation under such framework, Company management concluded that the internal control over financial reporting was effective as of December 31, 2006. Management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2006 has been audited by PricewaterhouseCoopers, LLP, an independent registered public accounting firm, as stated in their report which is included herein.

February 28, 2007

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Southwest Gas Corporation

We have completed integrated audits of Southwest Gas Corporation's consolidated financial statements and of its internal control over financial reporting as of December 31, 2006, in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, of cash flows and of stockholders' equity and comprehensive income present fairly, in all material respects, the financial position of Southwest Gas Corporation and its subsidiaries at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 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 audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (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 of financial statements 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.

As discussed in Note 1 and Note 9 to the consolidated financial statements, the Company changed the manner in which it accounts for share-based compensation and defined benefit postretirement plans in 2006.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, that the Company maintained effective internal control over financial reporting as of December 31, 2006 based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control—Integrated Framework issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PRICEWATERHOUSECOOPERS LLP

Los Angeles, California
February 28, 2007

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 3, 2007 at 10:00 a.m. at the Palms Casino Resort, 4321 West 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 purchasing the Company's common stock and investing cash dividends in additional shares 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 2006 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

Thomas E. Chestnut
Tucson, Arizona
Owner, President and Chief Executive Officer
Chestnut Construction Company

Stephen C. Comer
Las Vegas, Nevada
Retired Partner
Deloitte & Touche

Richard M. Gardner
Scottsdale, Arizona
Retired Partner
Deloitte & Touche

LeRoy C. Hanneman, Jr.
Phoenix, Arizona
Chairman and Chief Executive Officer
Element Homes, LLC
Chairman of the Board of Directors
Southwest Gas Corporation

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

Michael O. Maffie
Las Vegas, Nevada
Retired Chief Executive Officer
Southwest Gas Corporation

Anne L. Mariucci
Phoenix, Arizona
Private Investor

Michael J. Melarkey
Reno, Nevada
Partner
Avansino, Melarkey, Knobel & Mulligan

Jeffrey W. Shaw
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
Nevada Title Company

Officers

Jeffrey W. Shaw
Chief Executive Officer

James P. Kane
President

George C. Biehl
Executive Vice President/Chief Financial Officer and Corporate Secretary

John P. Hester
Senior Vice President/Regulatory Affairs and Energy Resources

Edward A. Janov
Senior Vice President/Finance

Christina A. Palacios
Senior Vice President/
Central Arizona Division

Thomas R. Sheets
Senior Vice President/Legal Affairs and General Counsel

Dudley J. Sondeno
Senior Vice President/Chief Knowledge and Technology Officer

Roy R. Centrella
Vice President/Controller/Chief Accounting Officer

Garold L. Clark
Vice President/
Southern Arizona Division

Fred W. Cover
Vice President/Human Resources

Luis F. Frisby
Vice President/
Southern California Division

Kenneth J. Kenny
Vice President/Treasurer

Roger C. Montgomery
Vice President/Pricing

William N. Moody
Vice President/Gas Resources

Dennis Redmond
Vice President/
Northern Nevada Division

Anita M. Romero
Vice President/
Southern Nevada 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

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

Ninety-Third Revised A.C.C. Sheet No. 11
Canceling Ninety-Second Revised A.C.C. Sheet No. 11

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

Description	Delivery Charge	3/ Rate Adjustment	4/ Monthly Gas Cost	Currently Effective Tariff Rate
G-5 – Single-Family Residential Gas Service				
Basic Service Charge per Month	$ 9.70			$ 9.70
Commodity Charge per Therm:				
Summer (May–October):				
First 15 Therms	$ .54200	$ .01263	$ .95372	$ 1.50835
Over 15 Therms	.50100	.01263	.95372	1.46735
Winter (November–April):				
First 35 Therms	$ .54200	$ .01263	$ .95372	$ 1.50835
Over 35 Therms	.50100	.01263	.95372	1.46735
G-6 – Multi-Family Residential Gas Service				
Basic Service Charge per Month	$ 8.70			$ 8.70
Commodity Charge per Therm:				
Summer (May–October):				
First 7 Therms	$ .54200	$ .01263	$ .95372	$ 1.50835
Over 7 Therms	.50100	.01263	.95372	1.46735
Winter (November–April):				
First 18 Therms	$ .54200	$ .01263	$ .95372	$ 1.50835
Over 18 Therms	.50100	.01263	.95372	1.46735
G-10 – Single-Family Low Income Residential Gas Service				
Basic Service Charge per Month	$ 7.00			$ 7.00
Commodity Charge per Therm:				
Summer (May–October):				
First 15 Therms	$ .54200	$ .00322	$ .84372	$ 1.38894
Over 15 Therms	.50100	.00322	.84372	1.34794
Winter (November–April):				
First 35 Therms	$ .26421	$ .00322	$ .84372	$ 1.11115
Next 115 Therms	.23141	.00322	.84372	1.07835
Over 150 Therms	.50100	.00322	.84372	1.34794
G-11 – Multi-Family Low Income Residential Gas Service				
Basic Service Charge per Month	$ 7.00			$ 7.00
Commodity Charge per Therm:				
Summer (May–October):				
First 7 Therms	$ .54200	$ .00322	$ .84372	$ 1.38894
Over 7 Therms	.50100	.00322	.84372	1.34794
Winter (November–April):				
First 18 Therms	$ .26421	$ .00322	$ .84372	$ 1.11115
Next 132 Therms	.23141	.00322	.84372	1.07835
Over 150 Therms	.50100	.00322	.84372	1.34794
G-15 – Special Residential Gas Service for Air Conditioning				
Basic Service Charge per Month	$ 9.70			$ 9.70
Commodity Charge per Therm:				
Summer (May–October):				
First 15 Therms	$ .54200	$ .00322	$ .95372	$ 1.49894
Over 15 Therms	.28200	.00322	.95372	1.23894
Winter (November–April):				
First 35 Therms	$ .54200	$ .00322	$ .95372	$ 1.49894
Over 35 Therms	.50100	.00322	.95372	1.45794

Issued On July 24, 2007
Docket No. G-00000C-98-0568

Issued by
John P. Hester
Senior Vice President

Effective July 31, 2007
Decision No. 62994

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

Ninety-Sixth Revised A.C.C. Sheet No. 12
Canceling Ninety-Fifth Revised A.C.C. Sheet No. 12

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

Description	Delivery Charge	3/ Rate Adjustment	4/ Monthly Gas Cost	Currently Effective Tariff Rate
G-20 – Master-Metered Mobile Home Park Gas Service				
Basic Service Charge per Month	$ 60.00			$ 60.00
Commodity Charge per Therm:				
All Usage	$ .38400	$ .01263	$ .95372	$ 1.35035
G-25 – General Gas Service				
Basic Service Charge per Month:				
Small	$ 25.00			$ 25.00
Medium	33.00			33.00
Large	145.00			145.00
Transportation Eligible	720.00			720.00
Commodity Charge per Therm:				
Small, All Usage	$ .56217	$ .00322	$ .95372	$ 1.51911
Medium, All Usage	.39349	.00322	.95372	1.35043
Large, All Usage	.27211	.00322	.95372	1.22905
Transportation Eligible	.08953	.00322	.95372	1.04647
Demand Charge per Month– Transportation Eligible:				
Demand Charge 5/	$ .06234			$ 0.06234
G-30 – Optional Gas Service				
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-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	$ .09900	$ .00322	$ .95372	$ 1.05594
G-45 – Street Lighting Gas Service				
Commodity Charge per Therm of Rated Capacity:				
All Usage	$ .54600	$ .00322	$ .95372	$ 1.50294
G-55 – Gas Service for Compression on Customer's Premises 6/				
Basic Service Charge per Month:				
Small	$ 25.00			$ 25.00
Large	190.00			190.00
Residential	9.70			9.70
Commodity Charge per Therm:				
All Usage	$ .17000	$ .00322	$ .95372	$ 1.12694
G-60 – Electric Generation Gas Service				
Basic Service Charge per Month	As specified on A.C.C. Sheet No. 40.			
Commodity Charge per Therm:				
All Usage	$ .11400	$ .00322	$ .95372	$ 1.07094
G-75 – Small Essential Agricultural User Gas Service				
Basic Service Charge per Month	$ 90.00			$ 90.00
Commodity Charge per Therm:				
All Usage	$ .22300	$ .00322	$ .95372	$ 1.17994

Issued On July 24, 2007
Docket No. G-00000C-98-0568

Issued by
John P. Hester
Senior Vice President

Effective July 31, 2007
Decision No. 62994

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

Thirtieth Revised A.C.C. Sheet No. 13
Canceling Twenty-Ninth Revised A.C.C. Sheet No. 13

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

Description	Delivery Charge	3/ Rate Adjustment	4/ Monthly Gas Cost	Currently Effective Tariff Rate
G-80 – Natural Gas Engine 7/ Gas Service				
Basic Service Charge per Month:				
Off-Peak Season (October–March)	$ 0.00			$ 0.00
Peak Season (April–September)	$ 95.00			$ 95.00
Commodity Charge per Therm:				
All Usage	$ .17700	$ .00322	$ .73057	$ 0.91079

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 Commodity Charge per Therm less the Monthly Gas Cost, and Demand Charge, if applicable, of the Currently Effective Tariff Rate for each meter included in the transportation service agreement, plus an amount of $.00806 per therm for distribution 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.

3/ (a) For Schedule Nos. G-5, G-6 and G-20, the Rate Adjustment includes $.00941 per therm to recover LIRA program costs. This charge shall be updated annually effective May 1.

(b) For all rate schedules except for Schedule Nos. G-30 and B-1, the Rate Adjustment includes $0.00176 per therm to fund DSM Program costs. This charge shall be updated annually effective the first billing cycle in April.

(c) For all rate schedules, except for Schedule Nos. G-30 and B-1, the Rate Adjustment includes $.00074 per therm for the Gas Research Fund. This charge shall be updated annually effective May 1.

(d) For all rate schedules, the Rate Adjustment includes $.00072 per therm for the Department of Transportation (DOT) Safety Program costs. This charge shall be updated annually effective May 1 and will expire on February 28, 2009.

4/ Except for Schedule Nos. G-10, G-11, G-30 and G-80, the Monthly Gas Cost includes $.11000 per therm to reduce the unrecovered balance in the Gas Cost Balancing Account.

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

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

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

Issued On April 23, 2007
Docket No. G-01551A-01-0060/ G-01551A-04-0876

Issued by
John P. Hester
Senior Vice President

Effective May 1, 2007
Decision No. 63598/68649

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

SOUTHWEST GAS CORPORATION
PROPOSED ARIZONA TARIFF REVISIONS

DESCRIPTION	PROPOSED CHANGE
Table of Contents	Reflect proposed changes to Special Supplementary Tariff Provisions.
Statement of Rates	Change rates to reflect Southwest's proposed rate design changes and revenue requirement. Include footnote on Sheet No. 13 describing rate adjustments for Revenue Decoupling Adjustment Provision.
Special Supplementary Tariff	Eliminate Title Assignment Service. Implement new tariff provisions for the Company's proposed Weather Normalization Adjustment Provision and Revenue Decoupling Adjustment Provision.

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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

A.C.C. Sheet No. 11
Canceling _____ A.C.C. Sheet No. _____

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

Description	Delivery Charge	3/ Rate Adjustment	4/ Monthly Gas Cost	Currently Effective Tariff Rate	
G-5 – Single-Family Residential Gas Service					
Basic Service Charge per Month	$ 12.80			$ 12.80	I
Commodity Charge per Therm:					
Summer (May–October):					
First 15 Therms	$ .88069	$ .01263	$ .59733	$ 1.49065	I
Over 15 Therms	.00000	.01263	1.47802	1.49065	I
Winter (November–April):					
First 35 Therms	$ .88069	$ .01263	$ .59733	$ 1.49065	I
Over 35 Therms	.00000	.01263	1.47802	1.49065	I
G-6 – Multi-Family Residential Gas Service					
Basic Service Charge per Month	$ 8.70			$ 8.70	I
Commodity Charge per Therm:					
Summer (May–October):					
First 7 Therms	$ .88069	$ .01263	$ .59733	$ 1.49065	I
Over 7 Therms	.00000	.01263	1.47802	1.49065	I
Winter (November–April):					
First 18 Therms	$ .88069	$ .01263	$ .59733	$ 1.49065	I
Over 18 Therms	.00000	.01263	1.47802	1.49065	I
G-10 – Single-Family Low Income Residential Gas Service					
Basic Service Charge per Month	$ 7.50			$ 7.50	I
Commodity Charge per Therm:					
Summer (May–October):					
First 15 Therms	$ .88069	$ .00322	$ .48733	$ 1.37124	I
Over 15 Therms	.00000	.00322	1.36802	1.37124	I
Winter (November–April):					
First 35 Therms	$ .60644	$ .00322	$ .48733	$ 1.09699	I
Next 115 Therms	(.27425)	.00322	1.36802	1.09699	I
Over 150 Therms	.00000	.00322	1.36802	1.37124	I
G-11 – Multi-Family Low Income Residential Gas Service					
Basic Service Charge per Month	$ 7.50			$ 7.50	I
Commodity Charge per Therm:					
Summer (May–October):					
First 7 Therms	$ .88069	$ .00322	$ .48733	$ 1.37124	I
Over 7 Therms	.00000	.00322	1.36802	1.37124	I
Winter (November–April):					
First 18 Therms	$ .60644	$ .00322	$ .48733	$ 1.09699	I
Next 132 Therms	(.27425)	.00322	1.36802	1.09699	I
Over 150 Therms	.00000	.00322	1.36802	1.37124	I
G-15 – Special Residential Gas Service for Air Conditioning					
Basic Service Charge per Month	$ 12.80			$ 12.80	I
Commodity Charge per Therm:					
Summer (May–October):					
First 15 Therms	$ .88069	$ .00322	$ .59733	$ 1.48124	I
Over 15 Therms	.00000	.00322	1.47802	1.48124	I
Winter (November–April):					
First 35 Therms	$ .88069	$ .00322	$ .59733	$ 1.48124	I
Over 35 Therms	.00000	.00322	1.47802	1.48124	I

Issued On August 31, 2007
Docket No. _____

Issued by
John P. Hester
Senior Vice President

Effective _____
Decision No. _____

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

Description	Delivery Charge	3/ Rate Adjustment	4/ Monthly Gas Cost	Currently Effective Tariff Rate	
G-20 – Master-Metered Mobile Home Park Gas Service					
Basic Service Charge per Month	$ 60.00			$ 60.00	
Commodity Charge per Therm:					
All Usage	$ .41531	$ .01263	$ .92426	$ 1.35220	I
G-25 – General Gas Service					
Basic Service Charge per Month:					
Small	$ 25.00			$ 25.00	I
Medium	43.50			43.50	I
Large	160.00			160.00	I
Transportation Eligible	950.00			950.00	I
Commodity Charge per Therm:					
Small, All Usage	$ .75852	$ .00322	$ .92426	$ 1.68600	I
Medium, All Usage	.40988	.00322	.92426	1.33736	I
Large, All Usage	.28843	.00322	.92426	1.21591	I
Transportation Eligible	.09902	.00322	.92426	1.02650	I
Demand Charge per Month– Transportation Eligible:					
Demand Charge 5/	$ .064142			$ 0.064142	I
G-30 – Optional Gas Service					
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-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	$ .09513	$ .00322	$ .92426	$ 1.02261	I
G-45 – Street Lighting Gas Service					
Commodity Charge per Therm of Rated Capacity:					
All Usage	$ .69899	$ .00322	$ .92426	$ 1.62647	I
G-55 – Gas Service for Compression on Customer's Premises 6/					
Basic Service Charge per Month:					
Small	$ 25.00			$ 25.00	I
Large	250.00			250.00	I
Residential	12.80			12.80	I
Commodity Charge per Therm:					
All Usage	$ .17535	$ .00322	$ .92426	$ 1.10283	I
G-60 – Electric Generation Gas Service					
Basic Service Charge per Month	As specified on A.C.C. Sheet No. 40.				
Commodity Charge per Therm:					
All Usage	$ .12363	$ .00322	$ .92426	$ 1.05111	I
G-75 – Small Essential Agricultural User Gas Service					
Basic Service Charge per Month	$120.00			$120.00	I
Commodity Charge per Therm:					
All Usage	$ .23335	$ .00322	$ .92426	$ 1.16083	I

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

Description	Delivery Charge	3/ Rate Adjustment	4/ Monthly Gas Cost	Currently Effective Tariff Rate	
G-80 – Natural Gas Engine 7/ Gas Service					
Basic Service Charge per Month:					
Off-Peak Season (October–March)	$ 0.00			$ 0.00	
Peak Season (April–September)	$125.00			$125.00	I
Commodity Charge per Therm:					
All Usage	$ .18746	$ .00322	$ .73057	$ 0.92125	I

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 Commodity Charge per Therm less the Monthly Gas Cost, and Demand Charge, if applicable, of the Currently Effective Tariff Rate for each meter included in the transportation service agreement, plus an amount of $.00806 per therm for distribution 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.

3/ (a) For Schedule Nos. G-5, G-6 and G-20, the Rate Adjustment includes $.00941 per therm to recover LIRA program costs. This charge shall be updated annually effective May 1.

(b) For all rate schedules except for Schedule Nos. G-30 and B-1, the Rate Adjustment includes $0.00176 per therm to fund DSM Program costs. This charge shall be updated annually effective the first billing cycle in April.

(c) For all rate schedules, except for Schedule Nos. G-30 and B-1, the Rate Adjustment includes $.00074 per therm for the Gas Research Fund. This charge shall be updated annually effective May 1.

(d) For all rate schedules, the Rate Adjustment includes $.00072 per therm for the Department of Transportation (DOT) Safety Program costs. This charge shall be updated annually effective May 1 and will expire on February 28, 2009.

(e) For rate Schedule Nos. G-5, G-6, G-10, G-11, G-25(S), G-25(M), and G-25(L), the Rate Adjustment includes an amount to recover/return RDAP under- or over-collections. The Rate Adjustment includes the following amounts: G-5 $.00000, G-6 $.00000, G-10 $.00000, G-11 $.00000, G-25(S) $.00000, G-25(M) $.00000, and G-25(L) $.00000. N N

4/ Except for Schedule Nos. G-10, G-11, G-30 and G-80, the Monthly Gas Cost includes $.11000 per therm to reduce the unrecovered balance in the Gas Cost Balancing Account.

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

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

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

SPECIAL SUPPLEMENTARY TARIFF
INTERSTATE PIPELINE CAPACITY RELEASE SERVICE PROVISION

T

D/L

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).

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).

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

B. RATES AND BIDDING PROCEDURES *(Continued)* D/L

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.

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. L

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

T

B. RATES AND BIDDING PROCEDURES *(Continued)*

D/L

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.

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.

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

D. RECALL OF RELEASED CAPACITY L

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. L

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SPECIAL SUPPLEMENTARY TARIFF
REVENUE DECOUPLING ADJUSTMENT PROVISION

APPLICABILITY

The Revenue Decoupling Adjustment Provision (RDAP) applies to residential Rate Schedule Nos. G-5, G-6, G-10 and G-11 and to General Service Schedule Nos. G-25(S), G-25(M) and G-25(L) included in this Arizona Gas Tariff. The RDAP specifies the accounting procedures and rate setting adjustments necessary to assure the Utility neither over-recovers, nor under-recovers, the margins-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 utility's last general rate case and the margin billed pursuant to the Utility's Weather Normalization Adjustment Provision during the Test Period. The Rate Adjustment revisions will be accomplished by increasing or decreasing the Revenue Decoupling Adjustment Provision Balancing Account (RDAPBA) Adjustment. The RDAPBA Adjustment will be calculated by dividing the RDAPBA at the end of the Test Period by the volume of natural gas expected to be delivered to customers over the following 12-month period for each customer class included in the RDAP.

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SPECIAL SUPPLEMENTARY TARIFF
REVENUE DECOUPLING ADJUSTMENT PROVISION
(Continued)

REVENUE DECOUPLING ADJUSTMENT PROVISION BALANCING ACCOUNT

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

1. A debit or credit entry equal to 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 below and the actual number of customers during the month.

Average Margin per Customer per Month

	G-5	G-6	G-15	G-25(S)	G-25(M)	G-25(L)
January	$ 39.77	$ 22.07	$ 42.00	$ 73.41	$ 205.14	$ 895.49
February	39.25	21.94	41.90	67.29	192.91	859.48
March	37.52	21.47	40.47	53.70	174.57	824.22
April	31.36	19.99	35.57	40.39	140.00	694.07
May	23.38	14.11	24.08	36.09	120.32	593.59
June	21.32	13.82	23.36	32.11	107.38	527.83
July	20.33	13.62	23.47	31.26	100.66	486.63
August	19.98	13.52	22.95	31.30	98.38	478.09
September	20.44	13.62	23.65	31.52	103.48	498.95
October	21.06	13.76	23.69	32.24	108.79	535.04
November	27.47	18.91	33.49	36.21	135.30	682.07
December	37.68	21.70	40.83	56.93	187.13	881.07

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 RDAPBA Adjustment.

TIMING AND MANNER OF FILING

The Utility shall file its RDAP Rate Adjustment revisions annually with the Commission in accordance with all statutory and regulatory requirements.

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D/N

SPECIAL SUPPLEMENTARY TARIFF
WEATHER NORMALIZATION ADJUSTMENT PROVISION

APPLICABILITY

The Weather Normalization Adjustment Provision (WNAP) applies to the heat-sensitive portion of residential Rate Schedule Nos. G-5, G-6, G-10, and G-11, and General Service Schedule Nos. G-25(S), G-25(M), and G-25(L). The WNAP specifies the procedures used to adjust the monthly bill for each customer served under these rate schedules to account for variations in non-gas revenues which are due to differences between the actual temperatures and normal temperatures for the days in the customer's billing cycle. The WNAP will apply to bills during the winter season months of November through April.

WNAP PROCESS

A "WNAP Volume Adjustment" will be calculated for each customer for each winter billing cycle to reflect the difference between the customer's actual use and usage assuming normal weather. The WNAP Volume Adjustment will then be used to calculate a "WNAP Dollar Adjustment" which will be added to each customer's non-gas revenue calculated on actual metered volumes. The process is set forth below.

WNAP CYCLE HEATING DEGREE DAY (HDD) VARIANCE

HDDs will be calculated for each billing cycle and for each operating district of the Company's Arizona service area. Normal HDDs are calculated as the ten-year average HDDs for each day during the winter season months. Actual HDDs are calculated as the number of degrees Fahrenheit that any winter season day's average of high and low temperature is below 65 degrees. The degree day calculation formulas are as follows:

Normal Cycle HDD	=	Ten-year average HDDs for each day in the billing cycle
Actual Cycle HDD	=	The number of degrees that any day's average temperature is less than 65 degrees Fahrenheit for each day in the billing cycle
Cycle HDD Variance	=	The sum of Normal Cycle HDDs for each day in the billing cycle less the sum of Actual Cycle HDDs for each day in the billing cycle

N

D/N

SPECIAL SUPPLEMENTARY TARIFF
WEATHER NORMALIZATION ADJUSTMENT PROVISION
(Continued)

NON-TEMPERATURE SENSITIVE BASE LOAD VOLUME PER DAY

A Base Load Volume will be calculated for each customer to estimate the customer's monthly non-temperature sensitive usage. The Base Load Volume per Day will be calculated by determining the customer's lowest average daily use for the summer, May through October billing periods. Average daily use is the customer's total monthly use divided by the number of days in the billing cycle. For new customers, Base Load Volume per Day will be estimated based upon the average Base Load Volume for other customers in the operating district. If necessary, Company personnel will adjust customers' Base Load Volume per Day to reflect a more representative amount.

CYCLE USAGE PER HDD

A cycle usage per HDD will be calculated for each customer. Cycle Usage per HDD will be calculated by subtracting the customer's Base Load Volume (Base Load Volume = Base Load Volume per Day multiplied by the number of days in billing cycle) from actual usage and provided the difference is greater than zero, dividing the difference by the Actual Cycle HDDs. If the actual usage is less than the customer's Base Load Volume no weather adjustment will be made to the customer's bill.

WNAP VOLUME ADJUSTMENT

A WNAP Volume Adjustment will be calculated for each customer. The WNAP Volume Adjustment will be calculated by multiplying the customer's Cycle Usage per HDD by the Cycle HDD Variance.

WNAP DOLLAR ADJUSTMENT

A WNAP Dollar Adjustment will be calculated for each customer. The WNAP Dollar Adjustment will be calculated by multiplying the WNAP Volume Adjustment by Southwest's non-gas delivery charge rates including the affect of any "blocks" in Southwest's rate design. The WNAP Dollar Adjustment will be added to the customer's non-gas revenue calculated on actual metered volumes for billing purposes.

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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

A.C.C. Sheet No. 99-103
Canceling _____
A.C.C. Sheet No. _____

HELD FOR FUTURE USE

D/N

Issued On August 31, 2007
Docket No. _____

Issued by
John P. Hester
Senior Vice President

Effective _____ T
Decision No. _____

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ADMITTED

SOUTHWEST GAS CORPORATION

Docket No. G-01551A-07-____

2007
ARIZONA
GENERAL RATE CASE

Volume II
SUPPORTING SCHEDULES

August 31, 2007

SOUTHWEST GAS CORPORATION
ARIZONA
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ARIZONA
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SOUTHWEST GAS CORPORATION
ARIZONA
INCREASE IN GROSS REVENUE REQUIREMENT
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

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	$ 1,094,790,046	$ 1,843,481,069	$ 1,469,135,558	1
2	Adjusted Operating Income	C-1	$ 73,180,098	$ 73,180,098	$ 73,180,098	2
3	Current Rate of Return		6.68%	3.97%	4.98%	3
4	Required Operating Income		$ 103,457,659	$ 103,457,659	$ 103,457,659	4
5	Required Rate of Return	D-1	9.45%	5.61%	7.04%	5
6	Operating Income Deficiency (Ln 4 - Ln 2)				$ 30,277,561	6
7	Gross Revenue Conversion Factor	C-3			1.6586	7
8	Increase in Gross Revenue Requirements				$ 50,219,828	8

SCHEDULE A-1
Sheet 1 of 3

SOUTHWEST GAS CORPORATION
ARIZONA
SUMMARY OF THE OVERALL RESULTS OF OPERATIONS
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Recorded at 04/30/07	Adjustments	Adjusted Amounts	Deficiency	Adjusted for Deficiency	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
1	Operating Revenue	$ 996,389,570	$ (597,154,892)	$ 399,234,678	$ 50,219,828	$ 449,454,506	1
2	Gas Cost	593,424,664	(593,424,664)	0	0	0	2
3	Operating Margin	$ 402,964,907	$ (3,730,229)	$ 399,234,678	$ 50,219,828	$ 449,454,506	3
	Operating Expenses						
4	Other Gas Supply	$ 685,079	$ 16,522	$ 701,601	$ 0	$ 701,601	4
5	Distribution	87,644,582	1,883,873	89,528,455	0	89,528,455	5
6	Customer Accounts	37,800,950	929,959	38,730,909	150,107	38,881,016	6
7	Customer Service & Information	1,320,355	(193,559)	1,126,796	0	1,126,796	7
8	Sales	230,155	(230,155)	0	0	0	8
	Administrative and General						
9	Direct	4,018,714	(9,175)	4,009,539	0	4,009,539	9
10	System Allocable	49,951,482	2,985,674	52,937,155	0	52,937,155	10
	Depreciation and Amortization						
11	Direct	77,709,373	3,246,873	80,956,247	0	80,956,247	11
12	System Allocable	6,721,772	(74,834)	6,646,938	0	6,646,938	12
13	Regulatory Amortizations	2,234,576	(1,950,048)	284,528	0	284,528	13
14	Taxes Other Than Income	28,912,193	4,212,687	33,124,880	0	33,124,880	14
15	Interest on Customer Deposits	1,856,153	59,161	1,915,314	0	1,915,314	15
16	Income Taxes	21,941,766	(5,849,548)	16,092,218	19,792,160	35,884,378	16
17	Total Operating Expenses	$ 321,027,150	$ 5,027,430	$ 326,054,580	$ 19,942,267	$ 345,996,847	17
18	Net Operating Income	$ 81,937,757	$ (8,757,659)	$ 73,180,098	$ 30,277,561	$ 103,457,659	18
	Rate Base						
	Gas Plant in Service						
19	Direct	$ 1,956,244,952	$ 2,976,115	$ 1,959,221,067		$ 1,959,221,067	19
20	System Allocable	93,253,492	1,373,330	94,626,822		94,626,822	20
21	Total Gross Plant	$ 2,049,498,445	$ 4,349,445	$ 2,053,847,890		$ 2,053,847,890	21
	Accumulated Provision for Depreciation and Amortization						
22	Direct	$ 692,096,947	$ 0	$ 692,096,947		$ 692,096,947	22
23	System Allocable	60,178,616	0	60,178,616		60,178,616	23
24	Total Accumulated Provision for Depreciation and Amortization	$ 752,275,563	$ 0	$ 752,275,563		$ 752,275,563	24
25	Net Plant in Service	$ 1,297,222,881	$ 4,349,445	$ 1,301,572,326		$ 1,301,572,326	25
	Other Rate Base Items						
26	Working Capital	$ 5,681,932	$ 0	$ 5,681,932		$ 5,681,932	26
27	Customer Advances	(37,910,017)	0	(37,910,017)		(37,910,017)	27
28	Customer Deposits	(31,921,898)	0	(31,921,898)		(31,921,898)	28
29	Deferred Taxes	(142,632,297)	0	(142,632,297)		(142,632,297)	29
30	Total Other Rate Base Items	$ (206,782,280)	$ 0	$ (206,782,280)		$ (206,782,280)	30
31	Total Rate Base	$ 1,090,440,601	$ 4,349,445	$ 1,094,790,046		$ 1,094,790,046	31
32	Rate of Return	7.51%		6.68%		9.45%	32

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SPREAD OF REVENUE INCREASE BY CUSTOMER CLASS
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Proposed Schedule Number	Increase/(Decrease) [1] Dollars	Increase/(Decrease) [1] Percent	Line No.
	(a)	(b)	(e)	(f)	
	Sales Service				
1	Residential Gas Service	G-5	$ 39,934,556	15.84%	1
2	Multi-Family Residential Gas Service	G-6	(172,559)	-2.60%	2
3	Low Income Residential Gas Service	G-10	628,374	9.31%	3
4	Low Income Multi-Family Residential	G-11	(21,515)	-4.48%	4
5	Special Residential Gas Service	G-15	(29,730)	-42.30%	5
6	Master Metered Mobile Home Park Gas Service	G-20	69,634	7.16%	6
	General Gas Service	G-25			
7	Small		985,825	12.53%	7
8	Medium		2,781,036	11.44%	8
9	Large		3,717,967	7.01%	9
10	Transporation Eligible		1,732,413	8.62%	10
11	Optional Gas Service	G-30	0	0.00%	11
12	Air Conditioning Gas Service	G-40	6,712	5.43%	12
13	Street Lighting Gas Service	G-45	15,649	28.02%	13
	Gas Service for Compression on Customer's Premises	G-55			
14	Small		950	2.60%	14
15	Large		28,302	6.99%	15
16	Residential		4,358	17.10%	16
17	Electric Generation Gas Service	G-60	148,774	5.88%	17
18	Small Essential Agriculture User Gas Service	G-75	175,508	5.65%	18
19	Natural Gas Engine Gas Service	G-80	214,392	8.38%	19
20	Total Sales and Full Margin Transportation		$ 50,220,646	13.06%	20
21	Special Contract Service	B-1	0	0.00%	21
22	Other Operating Revenue		0	0.00%	22
23	Total Arizona Revenue		$ 50,220,646	12.58%	23

[1] Schedule H-1, Sheet 1.

SOUTHWEST GAS CORPORATION
ARIZONA
SUMMARY OF RESULTS OF OPERATIONS

Line No.	Description	Prior Years Year Ending 2005 [1]	Prior Years Year Ending 2006 [1]	Test Year Actual 4/30/07 [2]	Test Year Adjusted 4/30/07 [2]	Projected Year Present Rates 4/30/08 [3]	Projected Year Proposed Rates 4/30/08 [3]	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
1	Operating Revenues	$ 748,627,816	$ 895,549,006	$ 402,964,907	$ 399,234,678	$ 406,994,556	$ 453,949,051	1
2	Operating Expenses and Taxes	708,138,708	827,185,527	321,027,150	326,054,580	334,116,215	352,676,952	2
3	Net Operating Income	$ 40,489,108	$ 68,363,479	$ 81,937,757	$ 73,180,098	$ 72,878,341	$ 101,272,100	3
4	Other Income and Deductions	0	0	0	0	0	0	4
5	Interest Expense	45,778,673	47,089,555	47,844,172	48,035,008	48,035,008	48,035,008	5
6	Net Income	$ (5,289,565)	$ 21,273,925	$ 34,093,585	$ 25,145,090	$ 24,843,333	$ 53,237,092	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).

SCHEDULE A-2
Sheet 1 of 2

SOUTHWEST GAS CORPORATION
TOTAL SYSTEM
SUMMARY RESULTS OF OPERATIONS [1]

Line No.	Description	Prior Years Year Ended 2005	Prior Years Year Ended 2006	Test Year 12 Months Ended 4/30/2007	Line No.
	(a)	(b)	(c)	(d)	
1	Gross Revenues	$ 1,444,439,794	$ 1,714,338,144	$ 1,819,838,987	1
2	Revenue Deductions & Operating Expenses	1,331,337,384	1,564,262,733	1,663,045,445	2
3	Operating Income	$ 113,102,410	$ 150,075,411	$ 156,793,542	3
4	Other Income and (Deductions)	20,022,734	27,086,512	23,197,938	4
5	Income Before Interest Deductions	$ 133,125,144	$ 177,161,923	$ 179,991,480	5
6	Interest Expense	$ 90,348,303	$ 94,658,870	$ 94,386,778	6
7	Allowance for Debt Funds Used During Construction	1,046,495	1,356,704	1,340,971	7
8	Net Interest Expense	$ 89,301,808	$ 93,302,166	$ 93,045,807	8
9	Net Income	$ 43,823,336	$ 83,859,757	$ 86,945,673	9
10	Preferred and Preference Dividend Requirements	-	-	-	10
11	Net Income Applicable to Common Stock	$ 43,823,336	$ 83,859,757	$ 86,945,673	11
12	Weighted Average Shares of Common Stock Outstanding	38,131,533	40,565,773	42,015,865	
13	Earnings per Common Share	$ 1.15	$ 2.07	$ 2.07	13
14	Dividends paid per Common Share	$ 0.82	$ 0.82	$ 0.86	14
15	Dividend Pay-out Ratio	71%	40%	42%	15
16	Return on Average Invested Capital	5.81%	9.82%	9.22%	16
17	Return on Year End Invested Capital	5.53%	9.16%	8.96%	17
18	Return on Average Common Equity	5.81%	9.82%	9.22%	18
19	Return on year End Common Equity	5.53%	9.16%	8.96%	19
20	Times Bond Interest Earned- Before Income Taxes	1.75	2.41	2.54	20
21	Times Total Interest and Preferred Dividend Earned - After Income Taxes	1.49	1.90	1.93	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 Year Ended 2005	Prior Years Year Ended 2006	Test Year Ended 4/30/07	Projected Year 4/30/08 [2]	Line No.
	(a)	(b)	(c)	(d)	(e)	
	Net Capital Amounts					
1	Short-Term Debt	$ 24,000,000	-	-	-	1
2	Long-Term Debt	1,281,549,896	1,284,281,898	1,191,537,443	1,232,254,958	2
3	Total Debt	$ 1,305,549,896	1,284,281,898	1,191,537,443	1,232,254,958	3
4	Preferred Equity	$ 100,000,000	100,000,000	100,000,000	100,000,000	4
5	Common Equity	792,779,873	915,091,067	970,385,472	1,063,024,645	5
6	Total Capital	$ 2,198,329,769	2,299,372,965	2,261,922,915	2,395,279,603	6
	Capitalization Ratios					
7	Short-Term Debt	1.09%	0.00%	0.00%	0.00%	7
8	Long-Term Debt	58.30%	55.85%	52.68%	51.45%	8
9	Total Debt					9
10	Preferred Equity	4.55%	4.35%	4.42%	4.17%	10
11	Common Equity	36.06%	39.80%	42.90%	44.38%	11
12	Total	100.00%	100.00%	100.00%	100.00%	12
	Weighted Cost of Capital					
13	Short-Term Debt	0.08%	0.00%	0.00%	0.00%	13
14	Long-Term Debt	4.01%	3.81%	3.63%	3.54%	14
15	Preferred Equity	0.37%	0.36%	0.36%	0.34%	15
16	Common Equity	3.97%	3.78%	4.83%	4.99%	16
17	Total Weighted Cost of Capital	8.43%	7.95%	8.82%	8.88%	17

[1] Based on the equity method of accounting
[2] Estimated

SCHEDULE A-3
Sheet 1 of 1

SOUTHWEST GAS CORPORATION
ARIZONA
CONSTRUCTION EXPENDITURES, PLANT PLACED IN SERVICE, AND GROSS PLANT
FOR THE YEARS ENDED DECEMBER 31, 2005 AND 2006,
THE TEST YEAR ENDED APRIL 30, 2007
AND PROJECTED YEARS ENDING APRIL 30, 2008, 2009 AND 2010

Line No.	Description	Actual			Projected			Line No.
		Year Ended 2005	Year Ended 2006	Test Year Ended 4/30/07	Year Ending 4/30/08	Year Ending 4/30/09	Year Ending 4/30/10	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
	Construction Expenditures							
1	Arizona Direct	$ 138,867,871	$ 160,629,695	$ 186,420,582	$ 152,957,589	$ 127,213,460	$ 110,084,317	1
2	System Allocable [1]	4,895,032	4,439,341	5,276,742	12,249,310	12,976,995	10,829,825	2
3	Total Construction Expenditures	$ 143,762,903	$ 165,069,036	$ 191,697,324	$ 165,206,899	$ 140,190,455	$ 120,914,142	3
	Net Plant Placed in Service							
4	Arizona Direct	$ 104,459,744	$ 138,976,231	$ 174,818,211	$ 135,957,589	$ 110,213,460	$ 93,084,317	4
5	System Allocable [1]	3,290,925	2,359,381	1,960,813	5,244,359	5,656,956	4,439,511	5
6	Total Net Plant Placed in Service	$ 107,750,669	$ 141,335,612	$ 176,779,024	$ 141,201,948	$ 115,870,416	$ 97,523,828	6
	Gross Utility Plant in Service							
7	Arizona Direct	$ 1,743,005,275	$ 1,881,981,506	$ 1,956,244,952	$ 2,092,202,541	$ 2,202,416,001	$ 2,295,500,318	7
8	System Allocable [1]	89,522,472	91,881,853	93,253,492	98,497,851	104,154,807	108,594,318	8
9	Total Gross Utility Plant in Service	$ 1,832,527,747	$ 1,973,863,359	$ 2,049,498,444	$ 2,190,700,392	$ 2,306,570,808	$ 2,404,094,636	9

[1] Allocation based on the 4-Factor (56.70%), Sch C-1, Sh 17

SCHEDULE A-4
Sheet 1 of 1

SOUTHWEST GAS CORPORATION
TOTAL SYSTEM
SUMMARY STATEMENT OF CASH FLOWS

Line No.	Description	Prior Years[1] Year Ended 2005	Prior Years[1] Year Ended 2006	Test Year[1] 12 Months Ended 4/30/07	Projected Year[2] At Present Rates Year Ended 12/31/08	Projected Year[2] At Proposed Rates Year Ended 12/31/08	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
1	Cash Flows from Operating Activities	$ 211,703,533	$ 243,754,915	$ 289,529,579	$ 283,865,452	$ 314,143,013	1
2	Cash Flows from Investing Activities	(249,118,733)	(269,365,111)	(296,242,426)	(268,973,585)	(268,973,585)	2
3	Cash Flows from Financing Activities	55,163,406	16,900,448	(52,156,413)	(22,212,501)	(22,212,501)	3
4	Increase (Decrease) in Cash and Cash Equivalents	$ 17,748,206	$ (8,709,748)	$ (58,869,260)	$ (7,320,634)	$ 22,956,927	4

[1] Supporting Schedule E-3
[2] Supporting Schedule F-2

SCHEDULE A-5
Sheet 1 of 1

SOUTHWEST GAS CORPORATION
ARIZONA
ADJUSTED ORIGINAL COST AND RCND RATE BASE
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Schedule Reference	Adjusted Original Cost Rate Base	Adjusted RCND	Fair Value [1]	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	Gas Plant in Service	B-2 & B-3	$ 2,053,847,890	$ 3,224,193,614	$ 2,639,020,752	1
2	Accumulated Depreciation and Amortization	B-2 & B-3	752,275,563	1,173,930,265	963,102,914	2
3	Net Gas Plant in Service		$ 1,301,572,326	$ 2,050,263,349	$ 1,675,917,838	3
	Additions					
4	Working Capital	B-5	$ 5,681,932	$ 5,681,932	$ 5,681,932	4
5	Total Additions		$ 5,681,932	$ 5,681,932	$ 5,681,932	5
	Deductions					
6	Customer Advances for Construction	B-6	$ (37,910,017)	$ (37,910,017)	$ (37,910,017)	6
7	Customer Deposits	B-6	(31,921,898)	(31,921,898)	(31,921,898)	7
8	Deferred Income Taxes	B-6	(142,632,297)	(142,632,297)	(142,632,297)	8
9	Total Deductions		$ (212,464,212)	$ (212,464,212)	$ (212,464,212)	9
10	Total Rate Base		$ 1,094,790,046	$ 1,843,481,069	$ 1,469,135,558	10

[1] 50/50 weighting of Original Cost and Reconstructed Cost.

SOUTHWEST GAS CORPORATION
ARIZONA
RECORDED RATE BASE, AS ADJUSTED
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description (a)	Recorded at 04/30/07 (b)	Adjustments (c)	Adjusted at 04/30/07 (d)	Line No.
	Rate Base				
	Gas Plant in Service				
1	Direct	$ 1,956,244,952	$ 2,976,115	$ 1,959,221,067	1
2	System Allocable	93,253,492	1,373,330	94,626,822	2
3	Total Gross Plant	$ 2,049,498,445	$ 4,349,445	$ 2,053,847,890	3
	Accumulated Provision for Depreciation and Amortization				
4	Direct	$ 692,096,947	$ 0	$ 692,096,947	4
5	System Allocable	60,178,616	0	60,178,616	5
6	Total Accumulated Provision for Depreciation and Amortization	$ 752,275,563	$ 0	$ 752,275,563	6
7	Net Plant in Service [1]	$ 1,297,222,881	$ 4,349,445	$ 1,301,572,326	7
	Other Rate Base Items				
8	Working Capital [2]	$ 5,681,932	$ 0	$ 5,681,932	8
9	Customer Advances [3]	(37,910,017)	0	(37,910,017)	9
10	Customer Deposits [3]	(31,921,898)	0	(31,921,898)	10
11	Deferred Taxes [3]	(142,632,297)	0	(142,632,297)	11
12	Total Other Rate Base Items	$ (206,782,280)	$ 0	$ (206,782,280)	12
13	Total Rate Base	$ 1,090,440,601	$ 4,349,445	$ 1,094,790,046	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 APRIL 30, 2007

Line No.	Description	Account Number	Balance at 04/30/07	Adjustments	Adjusted Balance	Allocation Of System Allocable Amounts [1]	Test Year Balance As Allocated at 04/30/07	Line No.
	(a)	(b)	(c) WP B-2	(d) WP B-2	(e) WP B-2	(f)	(g)	
	Direct Gas Plant in Service							
1	Intangible Plant		$ 3,877,710	$ 0	$ 3,877,710	$ 64,301,246	$ 68,178,956	1
2	Distribution Plant		1,857,071,868	2,705,995	1,859,777,863	0	1,859,777,863	2
3	General Plant		95,295,374	270,120	95,565,494	30,325,576	125,891,071	3
4	Total Gas Plant in Service	101	$ 1,956,244,952	$ 2,976,115	$ 1,959,221,067	$ 94,626,822	$ 2,053,847,890	4
	Accumulated Provision for Depreciation and Amortization							
5	Intangible Plant		$ 2,614,115	$ 0	$ 2,614,115	$ 45,888,295	$ 48,502,410	5
6	Distribution Plant		677,637,884	0	677,637,884	0	677,637,884	6
7	General Plant		11,844,949	0	11,844,949	14,290,321	26,135,269	7
8	Total Accumulated Depreciation and Amortization	108 & 111	$ 692,096,947	$ 0	$ 692,096,947	$ 60,178,616	$ 752,275,563	8
9	Total Net Gas Plant In Service		$ 1,264,148,005	$ 2,976,115	$ 1,267,124,120	$ 34,448,206	$ 1,301,572,326	9
	System Allocable Gas Plant in Service							
10	Intangible Plant		$ 111,710,077	$ 1,696,000	$ 113,406,077			10
11	General Plant		52,758,163	726,099	53,484,262			11
12	Total System Allocable Gas Plant	101	$ 164,468,240	$ 2,422,099	$ 166,890,339			12
	Accumulated Provision For Depreciation and Amortization							
13	Intangible Plant		$ 80,931,738	$ 0	$ 80,931,738			13
14	General Plant		25,203,388	0	25,203,388			14
15	Total System Allocable Accumulated Depreciation and Amortization	108 & 111	$ 106,135,125	$ 0	$ 106,135,125			15
16	System Allocable Net Gas Plant In Service		$ 58,333,115	$ 2,422,099	$ 60,755,214			16

[1] Allocated based on the 4-Factor. Supporting Schedule C-1, Sh 17

SCHEDULE B-2
Sheet 1 of 3

SOUTHWEST GAS CORPORATION
ARIZONA
COMPLETED CONSTRUCTION NOT CLASSIFIED
ADJUSTMENT NO. 17

Line No.	Description (a)	Account Number (b)		Completed Cost of Plant [1] (c)	Line No.
	Distribution Plant				
1	Land and Land Rights	374.0	$	733,126	1
2	Mains	376.0		1,530,064	2
3	Regulator Station	378.0		325,675	3
4	Industrial Measuring & Regulating Station	385.0		117,130	4
5	Total Distribution Plant		$	2,705,995	5
	General Plant				
6	Structures and Improvements	390.1	$	27,443	6
7	Office Furniture and Equipment	391.0		215,492	7
8	Transportation Equipment	392.1		27,184	8
9	Total General Plant		$	270,120	9
10	Total Arizona		$	2,976,115	10

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. 17

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
COMPLETED CONSTRUCTION NOT CLASSIFIED
ADJUSTMENT NO. 17

Line No.	Description	Account Number	Completed Cost of Plant [1]	Line No.
	(a)	(b)	(c)	
	Intangible Plant			
1	Miscellaneous Intangible [1]	303.0	$ 1,696,000	1
2	Total Intangible Plant		$ 1,696,000	2
	General Plant [2]			
3	Structures and Improvements	390.1	$ 265,254	3
4	Office Furniture & Equipment	391.0	28,258	4
5	Computer Equipment	391.1	432,587	5
6	Total General Plant		$ 726,099	6
7	Total System Allocable		$ 2,422,099	7
8	Arizona 4-Factor [3]		56.70%	8
9	Amount Allocated to Arizona		$ 1,373,330	9

Explanation
To record System Allocable plant completed but not yet classified to plant-in-service accounts and adjust Miscellaneous Intangible consistent with prior Commission decisions.

[1] Adjustment to Miscellaneous Intangible Plant detailed on WP B-2, Adj. 17
[2] Supporting Workpapers B-2, Adj. 17
[3] Supporting Schedule C-1, Sh 17

SOUTHWEST GAS CORPORATION
ARIZONA
RCND GAS PLANT IN SERVICE
AT APRIL 30, 2007

Line No.	Description	Reference	Balance at 04/30/07	Adjustments [1]	Adjusted Balance	Allocation Of System Allocable Amounts [2]	Test Year Balance As Allocated at 04/30/07	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	
	Gas Plant in Service							
1	Intangible Plant	B-2, Sh 1	$ 3,877,710	$ 0	$ 3,877,710	$ 64,301,246	$ 68,178,956	1
2	Distribution Plant	B-4	2,993,874,268	2,705,995	2,996,580,263	0	2,996,580,263	2
3	General Plant	B-4	121,281,531	270,120	121,551,651	37,882,745	159,434,396	3
4	Total Gas Plant in Service		$ 3,119,033,509	$ 2,976,115	$ 3,122,009,624	$ 102,183,990	$ 3,224,193,614	4
	Accumulated Provision for Depreciation and Amortization							
5	Intangible Plant	B-2, Sh 1	$ 2,614,115	$ 0	$ 2,614,115	$ 45,888,295	$ 48,502,410	5
6	Distribution Plant	[3]	1,092,452,403	0	1,092,452,403	0	1,092,452,403	6
7	General Plant	[3]	15,074,955	0	15,074,955	17,900,496	32,975,451	7
8	Total Accumulated Depreciation and Amortization		$ 1,110,141,473	$ 0	$ 1,110,141,473	$ 63,788,792	$ 1,173,930,265	8
9	Total Net Gas Plant In Service		$ 2,008,892,036	$ 2,976,115	$ 2,011,868,151	$ 38,395,198	$ 2,050,263,349	9
	System Allocable Gas Plant in Service							
10	Intangible Plant	B-2, Sh 1	$ 111,710,077	$ 1,696,000	$ 113,406,077			10
11	General Plant	B-4	66,086,502	726,099	66,812,601			11
12	Total System Allocable Gas Plant		$ 177,796,579	$ 2,422,099	$ 180,218,678			12
	Accumulated Provision For Depreciation and Amortization							
13	Intangible Plant	B-2, Sh 1	$ 80,931,738	$ 0	$ 80,931,738			13
14	General Plant	[3]	31,570,540	0	31,570,540			14
15	Total System Allocable Accumulated Depreciation and Amortization		$ 112,502,278	$ 0	$ 112,502,278			15
16	System Allocable Net Gas Plant In Service		$ 65,294,301	$ 2,422,099	$ 67,716,400			16

[1] Adjustments are calculated in Schedule B-2, and are identical to the adjustments presented in Schedule B-3.
[2] Amounts are allocated to Arizona using the 4-Factor of 56.70% as calculated in Sch C-1, Sh 17.
[3] 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.

SCHEDULE B-3
Sheet 1 of 1

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

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	12,148	1	1.00	12,148	74
75	2004	104,102	1	1.00	104,102	75
76	2005	78,132	1	1.00	78,132	76
77	2006	270,953	1	1.00	270,953	77
78	2007	0	1	1.00	0	78
79	Total	$ 1,415,749			$ 1,415,749	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 375 - Structures and Improvements

Line No.	Year Installed	Original Cost Total Arizona	H - W Index	Ratio To Current Index	RCN Total Arizona	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	19	19.42	$ 0	1
2	1931	0	17	21.71	0	2
3	1932	0	16	23.06	0	3
4	1933	0	17	21.71	0	4
5	1934	0	19	19.42	0	5
6	1935	0	18	20.50	0	6
7	1936	0	19	19.42	0	7
8	1937	196	20	18.45	3,616	8
9	1938	94	20	18.45	1,734	9
10	1939	1,659	20	18.45	30,609	10
11	1940	373	20	18.45	6,882	11
12	1941	2,797	22	16.77	46,906	12
13	1942	0	23	16.04	0	13
14	1943	0	23	16.04	0	14
15	1944	0	24	15.38	0	15
16	1945	5,437	24	15.38	83,621	16
17	1946	2,032	27	13.67	27,777	17
18	1947	895	32	11.53	10,319	18
19	1948	4,989	36	10.25	51,137	19
20	1949	6,441	37	9.97	64,217	20
21	1950	8,724	39	9.46	82,529	21
22	1951	21,212	42	8.79	186,453	22
23	1952	1,568	44	8.39	13,156	23
24	1953	4,318	44	8.39	36,228	24
25	1954	2,625	46	8.02	21,053	25
26	1955	959	48	7.69	7,375	26
27	1956	4,816	52	7.10	34,194	27
28	1957	0	55	6.71	0	28
29	1958	0	57	6.47	0	29
30	1959	0	58	6.36	0	30
31	1960	0	59	6.25	0	31
32	1961	0	58	6.36	0	32
33	1962	0	59	6.25	0	33
34	1963	0	60	6.15	0	34
35	1964	0	61	6.05	0	35
36	1965	394	64	5.77	2,273	36
37	1966	0	65	5.68	0	37
38	1967	0	67	5.51	0	38
39	1968	0	71	5.20	0	39
40	1969	0	75	4.92	0	40
41	1970	0	79	4.67	0	41
42	1971	0	87	4.24	0	42
43	1972	0	93	3.97	0	43
44	1973	23,733	100	3.69	87,575	44
45	1974	8,122	118	3.13	25,422	45
46	1975	0	133	2.77	0	46
47	1976	0	138	2.67	0	47
48	1977	437	148	2.49	1,088	48
49	1978	674	161	2.29	1,543	49
50	1979	0	177	2.08	0	50
51	1980	0	194	1.90	0	51
52	1981	0	204	1.81	0	52
53	1982	0	207	1.78	0	53
54	1983	0	215	1.72	0	54
55	1984	0	224	1.65	0	55
56	1985	0	226	1.63	0	56
57	1986	0	231	1.60	0	57
58	1987	0	232	1.59	0	58
59	1988	0	233	1.58	0	59
60	1989	0	232	1.59	0	60
61	1990	2,068	237	1.56	3,227	61
62	1991	2,033	233	1.58	3,212	62
63	1992	0	238	1.55	0	63
64	1993	0	250	1.48	0	64
65	1994	0	261	1.41	0	65
66	1995	3,960	265	1.39	5,504	66
67	1996	0	176	2.10	0	67
68	1997	0	282	1.31	0	68
69	1998	0	285	1.29	0	69
70	1999	0	287	1.29	0	70
71	2000	0	295	1.25	0	71
72	2001	0	303	1.22	0	72
73	2002	0	310	1.19	0	73
74	2003	0	320	1.15	0	74
75	2004	0	342	1.08	0	75
76	2005	0	355	1.04	0	76
77	2006	0	364	1.01	0	77
78	2007	0	369	1.00	0	78
79	Total	$ 110,556			$ 837,650	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 376 - Mains - Steel

Line No.	Year Installed	Original Cost Total Arizona	H - W Index	Ratio To Current Index	RCN Total Arizona	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 110,287	19	29.21	$ 3,221,483	1
2	1931	2,569	18	30.83	79,202	2
3	1932	0	18	30.83	0	3
4	1933	0	17	32.65	0	4
5	1934	2,743	18	30.83	84,567	5
6	1935	8,484	19	29.21	247,818	6
7	1936	25	18	30.83	771	7
8	1937	18,672	20	27.75	518,148	8
9	1938	21,117	20	27.75	585,997	9
10	1939	255	20	27.75	7,076	10
11	1940	248	20	27.75	6,882	11
12	1941	50,081	20	27.75	1,389,748	12
13	1942	28,746	21	26.43	759,757	13
14	1943	36,902	21	26.43	975,320	14
15	1944	19,749	21	26.43	521,966	15
16	1945	74,752	22	25.23	1,885,993	16
17	1946	1,842	24	23.13	42,605	17
18	1947	340,177	27	20.56	6,994,039	18
19	1948	892,864	31	17.90	15,982,266	19
20	1949	593,535	33	16.82	9,983,259	20
21	1950	887,648	35	15.86	14,078,097	21
22	1951	775,075	37	15.00	11,626,125	22
23	1952	785,337	39	14.23	11,175,346	23
24	1953	572,737	41	13.54	7,754,859	24
25	1954	714,888	44	12.61	9,014,738	25
26	1955	2,960,952	46	12.07	35,738,691	26
27	1956	1,298,571	48	11.56	15,011,481	27
28	1957	1,337,661	52	10.67	14,272,843	28
29	1958	2,201,021	54	10.28	22,626,496	29
30	1959	2,323,128	57	9.74	22,627,267	30
31	1960	2,013,690	58	9.57	19,271,013	31
32	1961	2,066,692	61	9.10	18,806,897	32
33	1962	2,012,622	63	8.81	17,731,200	33
34	1963	1,636,906	64	8.67	14,191,975	34
35	1964	2,076,922	66	8.41	17,466,914	35
36	1965	2,042,130	68	8.16	16,663,781	36
37	1966	1,740,646	69	8.04	13,994,794	37
38	1967	1,154,873	73	7.60	8,777,035	38
39	1968	805,513	75	7.40	5,960,796	39
40	1969	1,645,787	80	6.94	11,421,762	40
41	1970	1,038,468	84	6.61	6,864,273	41
42	1971	2,068,456	90	6.17	12,762,374	42
43	1972	3,400,169	96	5.78	19,652,977	43
44	1973	2,689,968	100	5.55	14,929,322	44
45	1974	3,010,081	117	4.74	14,267,784	45
46	1975	1,357,176	133	4.17	5,659,424	46
47	1976	706,819	142	3.91	2,763,662	47
48	1977	1,255,176	155	3.58	4,493,530	48
49	1978	1,332,530	171	3.25	4,330,723	49
50	1979	1,174,106	187	2.97	3,487,095	50
51	1980	1,585,387	200	2.78	4,407,376	51
52	1981	3,146,219	219	2.53	7,959,934	52
53	1982	1,678,376	239	2.32	3,893,832	53
54	1983	2,498,554	246	2.26	5,646,732	54
55	1984	3,647,489	251	2.21	8,060,951	55
56	1985	2,176,976	245	2.27	4,941,736	56
57	1986	2,955,225	233	2.38	7,033,436	57
58	1987	3,391,604	241	2.30	7,800,689	58
59	1988	2,383,093	258	2.15	5,123,650	59
60	1989	3,717,875	270	2.06	7,658,823	60
61	1990	3,308,320	276	2.01	6,649,723	61
62	1991	4,659,996	283	1.96	9,133,592	62
63	1992	5,778,074	286	1.94	11,209,464	63
64	1993	5,226,581	294	1.89	9,878,238	64
65	1994	6,761,555	315	1.76	11,900,337	65
66	1995	8,725,101	317	1.75	15,268,927	66
67	1996	7,138,415	319	1.74	12,420,842	67
68	1997	7,144,441	327	1.70	12,145,550	68
69	1998	7,074,377	330	1.68	11,884,953	69
70	1999	7,096,919	341	1.63	11,567,978	70
71	2000	9,767,186	356	1.56	15,236,810	71
72	2001	12,970,719	362	1.53	19,845,200	72
73	2002	14,391,437	367	1.51	21,731,070	73
74	2003	13,625,719	385	1.44	19,621,035	74
75	2004	24,561,057	470	1.18	28,982,047	75
76	2005	27,276,025	568	0.98	26,730,505	76
77	2006	23,737,792	580	0.96	22,788,280	77
78	2007	13,791,193	555	1.00	13,791,193	78
79	Total	$ 281,504,501			$ 784,023,074	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 376 - Mains - Plastic

Line No.	Year Installed	Original Cost Total Arizona	H - W Index	Ratio To Current Index	RCN Total Arizona	Line No.
	(a)	(b)	(c)	(d)	(e)	
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	0	0	0.00	0	26
27	1956	0	0	0.00	0	27
28	1957	0	0	0.00	0	28
29	1958	0	0	0.00	0	29
30	1959	0	0	0.00	0	30
31	1960	0	0	0.00	0	31
32	1961	0	0	0.00	0	32
33	1962	748,193	71	5.99	4,481,676	33
34	1963	428,972	72	5.90	2,530,935	34
35	1964	475,983	73	5.82	2,770,221	35
36	1965	307,898	74	5.74	1,767,335	36
37	1966	905,696	76	5.59	5,062,841	37
38	1967	1,064,717	79	5.38	5,728,177	38
39	1968	627,957	81	5.25	3,296,774	39
40	1969	1,230,749	84	5.06	6,227,590	40
41	1970	665,960	87	4.89	3,256,544	41
42	1971	1,443,059	92	4.62	6,666,933	42
43	1972	2,050,016	96	4.43	9,081,571	43
44	1973	1,941,493	100	4.25	8,251,345	44
45	1974	2,050,661	112	3.79	7,772,005	45
46	1975	1,578,398	130	3.27	5,161,361	46
47	1976	536,310	137	3.10	1,662,561	47
48	1977	1,089,575	147	2.89	3,148,872	48
49	1978	592,055	158	2.69	1,592,628	49
50	1979	2,381,840	174	2.44	5,811,690	50
51	1980	3,284,873	193	2.20	7,226,721	51
52	1981	4,119,248	209	2.03	8,362,073	52
53	1982	2,666,401	224	1.90	5,066,162	53
54	1983	4,331,689	232	1.83	7,926,991	54
55	1984	6,449,088	236	1.80	11,608,358	55
56	1985	5,345,843	235	1.81	9,675,976	56
57	1986	16,844,922	238	1.79	30,152,410	57
58	1987	18,046,412	245	1.73	31,220,293	58
59	1988	20,871,124	256	1.66	34,646,066	59
60	1989	16,391,542	273	1.56	25,570,806	60
61	1990	21,710,416	281	1.51	32,782,728	61
62	1991	6,734,079	288	1.48	9,966,437	62
63	1992	9,637,063	290	1.47	14,166,483	63
64	1993	22,121,139	297	1.43	31,633,229	64
65	1994	26,500,967	302	1.41	37,366,363	65
66	1995	33,530,317	305	1.39	46,607,141	66
67	1996	32,013,365	313	1.36	43,538,176	67
68	1997	28,045,133	319	1.33	37,300,027	68
69	1998	31,758,246	324	1.31	41,603,302	69
70	1999	41,479,609	329	1.29	53,508,696	70
71	2000	42,957,950	336	1.26	54,127,017	71
72	2001	44,929,064	344	1.24	55,712,039	72
73	2002	48,155,194	350	1.21	58,267,785	73
74	2003	39,882,777	356	1.19	47,460,505	74
75	2004	48,178,101	368	1.15	55,404,816	75
76	2005	35,969,957	391	1.09	39,207,253	76
77	2006	44,084,470	411	1.03	45,407,004	77
78	2007	25,612,217	425	1.00	25,612,217	78
79	Total	$ 701,770,738			$ 985,398,133	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

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	20.58	$ 0	1
2	1931	0	24	20.58	0	2
3	1932	0	23	21.48	0	3
4	1933	0	22	22.45	0	4
5	1934	0	22	22.45	0	5
6	1935	0	22	22.45	0	6
7	1936	9	22	22.45	204	7
8	1937	0	24	20.58	0	8
9	1938	0	24	20.58	0	9
10	1939	0	24	20.58	0	10
11	1940	0	26	19.00	0	11
12	1941	0	26	19.00	0	12
13	1942	0	26	19.00	0	13
14	1943	0	26	19.00	0	14
15	1944	0	26	19.00	0	15
16	1945	0	26	19.00	0	16
17	1946	257	29	17.03	4,383	17
18	1947	0	34	14.53	0	18
19	1948	0	37	13.35	0	19
20	1949	0	39	12.67	0	20
21	1950	0	40	12.35	0	21
22	1951	0	44	11.23	0	22
23	1952	0	45	10.98	0	23
24	1953	0	46	10.74	0	24
25	1954	0	47	10.51	0	25
26	1955	0	49	10.08	0	26
27	1956	1,909	54	9.15	17,467	27
28	1957	862	57	8.67	7,474	28
29	1958	4,597	60	8.23	37,833	29
30	1959	9,479	62	7.97	75,548	30
31	1960	990	64	7.72	7,643	31
32	1961	2,924	64	7.72	22,573	32
33	1962	2,126	66	7.48	15,902	33
34	1963	1,761	67	7.37	12,979	34
35	1964	3,436	68	7.26	24,945	35
36	1965	10,337	68	7.26	75,047	36
37	1966	18,044	70	7.06	127,391	37
38	1967	1,213	72	6.86	8,321	38
39	1968	6,213	73	6.77	42,062	39
40	1969	9,130	76	6.50	59,345	40
41	1970	6,758	83	5.95	40,210	41
42	1971	26,432	90	5.49	145,112	42
43	1972	121,838	97	5.09	620,155	43
44	1973	7,125	100	4.94	35,198	44
45	1974	25,965	116	4.26	110,611	45
46	1975	8,724	135	3.66	31,930	46
47	1976	5,089	148	3.34	16,997	47
48	1977	51,116	158	3.13	159,993	48
49	1978	48,042	173	2.86	137,400	49
50	1979	19,178	187	2.64	50,630	50
51	1980	38,905	203	2.43	94,539	51
52	1981	14,510	224	2.21	32,067	52
53	1982	111,363	246	2.01	223,840	53
54	1983	195,817	246	2.01	393,592	54
55	1984	223,722	248	1.99	445,207	55
56	1985	36,610	243	2.03	74,318	56
57	1986	245,515	243	2.03	498,395	57
58	1987	85,410	250	1.98	169,112	58
59	1988	159,597	267	1.85	295,254	59
60	1989	82,821	278	1.78	147,421	60
61	1990	167,420	276	1.79	299,682	61
62	1991	138,093	279	1.77	244,425	62
63	1992	681,920	288	1.72	1,172,902	63
64	1993	746,297	298	1.66	1,238,853	64
65	1994	1,155,389	310	1.59	1,837,069	65
66	1995	1,541,035	313	1.58	2,434,835	66
67	1996	1,310,502	323	1.53	2,005,068	67
68	1997	768,309	332	1.49	1,144,780	68
69	1998	2,070,724	335	1.47	3,043,964	69
70	1999	4,464,002	342	1.44	6,428,163	70
71	2000	999,272	352	1.40	1,398,981	71
72	2001	2,013,010	358	1.38	2,777,954	72
73	2002	3,115,187	363	1.36	4,236,654	73
74	2003	1,848,155	365	1.35	2,495,009	74
75	2004	2,731,884	422	1.17	3,196,304	75
76	2005	2,108,698	480	1.03	2,171,959	76
77	2006	2,029,761	494	1.00	2,029,761	77
78	2007	2,950,936	494	1.00	2,950,936	78
79	Total	$ 32,428,418			$ 45,368,397	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 380 - Services - Steel

Line No.	Year Installed	Original Cost Total Arizona	H - W Index	Ratio To Current Index	RCN Total Arizona	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 7,968	16	26.88	$ 214,180	1
2	1931	0	15	28.67	0	2
3	1932	89	15	28.67	2,552	3
4	1933	0	14	30.71	0	4
5	1934	18	15	28.67	516	5
6	1935	0	15	28.67	0	6
7	1936	27	16	26.88	726	7
8	1937	0	17	25.29	0	8
9	1938	57	17	25.29	1,442	9
10	1939	2,685	17	25.29	67,904	10
11	1940	90	18	23.89	2,150	11
12	1941	5,351	18	23.89	127,835	12
13	1942	13,586	19	22.63	307,451	13
14	1943	854	19	22.63	19,326	14
15	1944	18,288	19	22.63	413,857	15
16	1945	41,233	19	22.63	933,103	16
17	1946	95,483	22	19.55	1,866,693	17
18	1947	160,197	25	17.20	2,755,388	18
19	1948	273,184	28	15.36	4,196,106	19
20	1949	174,401	30	14.33	2,499,166	20
21	1950	360,219	32	13.44	4,841,343	21
22	1951	460,792	33	13.03	6,004,120	22
23	1952	536,295	35	12.29	6,591,066	23
24	1953	431,133	37	11.62	5,009,765	24
25	1954	407,929	39	11.03	4,499,457	25
26	1955	1,057,831	41	10.49	11,096,647	26
27	1956	640,051	45	9.56	6,118,888	27
28	1957	689,534	48	8.96	6,178,225	28
29	1958	700,970	50	8.60	6,028,342	29
30	1959	347,311	53	8.11	2,816,692	30
31	1960	34,061	54	7.96	271,126	31
32	1961	50,735	58	7.41	375,946	32
33	1962	30,786	60	7.17	220,736	33
34	1963	32,890	60	7.17	235,821	34
35	1964	8,473	63	6.83	57,871	35
36	1965	50,907	64	6.72	342,095	36
37	1966	27,286	66	6.52	177,905	37
38	1967	19,573	69	6.23	121,940	38
39	1968	6,249	72	5.97	37,307	39
40	1969	1,610	77	5.58	8,984	40
41	1970	8,413	84	5.12	43,075	41
42	1971	17,239	90	4.78	82,402	42
43	1972	54,231	95	4.53	245,666	43
44	1973	45,257	100	4.30	194,605	44
45	1974	85,242	113	3.81	324,772	45
46	1975	17,598	129	3.33	58,601	46
47	1976	25,345	138	3.12	79,076	47
48	1977	21,208	149	2.89	61,291	48
49	1978	3,548	161	2.67	9,473	49
50	1979	141,078	176	2.44	344,230	50
51	1980	272,137	192	2.24	609,587	51
52	1981	270,738	208	2.07	560,428	52
53	1982	28,363	226	1.90	53,890	53
54	1983	466,371	232	1.85	862,786	54
55	1984	233,187	237	1.81	422,068	55
56	1985	42,502	234	1.84	78,204	56
57	1986	31,816	233	1.85	58,860	57
58	1987	14,688	241	1.78	26,145	58
59	1988	26,998	246	1.75	47,247	59
60	1989	15,753	251	1.71	26,938	60
61	1990	141,536	262	1.64	232,119	61
62	1991	122,859	272	1.58	194,117	62
63	1992	274,772	278	1.55	425,897	63
64	1993	1,189,070	285	1.51	1,795,496	64
65	1994	572,577	293	1.47	841,688	65
66	1995	850,702	292	1.47	1,250,532	66
67	1996	483,798	296	1.45	701,507	67
68	1997	580,186	301	1.43	829,666	68
69	1998	686,681	306	1.41	968,220	69
70	1999	425,847	313	1.37	583,410	70
71	2000	403,721	323	1.33	536,949	71
72	2001	411,556	331	1.30	535,023	72
73	2002	432,844	338	1.27	549,712	73
74	2003	389,176	347	1.24	482,578	74
75	2004	464,438	382	1.13	524,815	75
76	2005	268,769	426	1.01	271,457	76
77	2006	466,936	436	0.99	462,267	77
78	2007	144,339	430	1.00	144,339	78
79	Total	$ 16,819,665			$ 89,961,807	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 380 - Services - Plastic

Line No.	Year Installed	Original Cost Total Arizona	H - W Index	Ratio To Current Index	RCN Total Arizona	Line No.
	(a)	(b)	(c)	(d)	(e)	
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	10,524	45	8.58	90,296	24
25	1954	20,492	46	8.39	171,928	25
26	1955	89,224	47	8.21	732,529	26
27	1956	67,961	49	7.88	535,533	27
28	1957	142,579	52	7.42	1,057,936	28
29	1958	180,891	54	7.15	1,293,371	29
30	1959	429,116	56	6.89	2,956,609	30
31	1960	167,121	57	6.77	1,131,409	31
32	1961	213,075	59	6.54	1,393,511	32
33	1962	379,364	61	6.33	2,401,374	33
34	1963	401,788	62	6.23	2,503,139	34
35	1964	343,634	64	6.03	2,072,113	35
36	1965	371,547	65	5.94	2,206,989	36
37	1966	288,639	68	5.68	1,639,470	37
38	1967	324,970	71	5.44	1,767,837	38
39	1968	218,855	74	5.22	1,142,423	39
40	1969	3,871	78	4.95	19,161	40
41	1970	62,485	84	4.60	287,431	41
42	1971	115,755	89	4.34	502,377	42
43	1972	321,912	95	4.06	1,306,963	43
44	1973	191,634	100	3.86	739,707	44
45	1974	805,654	111	3.48	2,803,676	45
46	1975	201,283	127	3.04	611,900	46
47	1976	199,709	134	2.88	575,162	47
48	1977	283,669	144	2.68	760,233	48
49	1978	137,791	155	2.49	343,100	49
50	1979	1,215,235	170	2.27	2,758,583	50
51	1980	1,632,379	184	2.10	3,427,996	51
52	1981	1,930,226	197	1.96	3,783,243	52
53	1982	2,481,893	218	1.77	4,392,951	53
54	1983	17,999,839	227	1.70	30,599,726	54
55	1984	20,143,737	230	1.68	33,841,478	55
56	1985	12,910,774	226	1.71	22,077,424	56
57	1986	20,755,210	230	1.68	34,868,753	57
58	1987	18,437,590	236	1.64	30,237,648	58
59	1988	18,135,471	240	1.61	29,198,108	59
60	1989	12,999,818	247	1.56	20,279,716	60
61	1990	16,593,624	256	1.51	25,056,372	61
62	1991	7,709,642	265	1.46	11,256,077	62
63	1992	12,845,145	269	1.43	18,368,557	63
64	1993	15,838,556	277	1.39	22,015,593	64
65	1994	22,614,705	281	1.37	30,982,146	65
66	1995	25,690,373	279	1.38	35,452,715	66
67	1996	30,339,320	287	1.34	40,654,689	67
68	1997	26,934,376	292	1.32	35,553,376	68
69	1998	27,410,423	297	1.30	35,633,550	69
70	1999	33,943,021	304	1.27	43,107,637	70
71	2000	30,039,853	312	1.24	37,249,418	71
72	2001	31,512,238	323	1.20	37,814,686	72
73	2002	31,740,729	333	1.16	36,819,246	73
74	2003	30,777,545	339	1.14	35,086,401	74
75	2004	30,761,193	348	1.11	34,144,924	75
76	2005	28,751,552	364	1.06	30,476,645	76
77	2006	38,644,406	377	1.02	39,417,294	77
78	2007	11,683,913	386	1.00	11,683,913	78
79	Total	$ 588,446,329			$ 807,285,042	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

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	$ 66,335	27	7.67	$ 508,789	1
2	1931	4,694	26	7.96	37,364	2
3	1932	2,225	25	8.28	18,423	3
4	1933	1,940	25	8.28	16,063	4
5	1934	11,552	25	8.28	95,651	5
6	1935	14,275	25	8.28	118,197	6
7	1936	17,283	25	8.28	143,103	7
8	1937	35,418	26	7.96	281,927	8
9	1938	20,040	26	7.96	159,518	9
10	1939	14,175	26	7.96	112,833	10
11	1940	20,448	26	7.96	162,766	11
12	1941	32,988	26	7.96	262,584	12
13	1942	26,062	26	7.96	207,454	13
14	1943	17,148	26	7.96	136,498	14
15	1944	15,493	26	7.96	123,324	15
16	1945	18,994	26	7.96	151,192	16
17	1946	49,872	33	6.27	312,697	17
18	1947	130,316	41	5.05	658,096	18
19	1948	208,674	42	4.93	1,028,763	19
20	1949	188,559	45	4.60	867,371	20
21	1950	160,885	48	4.31	693,414	21
22	1951	206,128	55	3.76	775,041	22
23	1952	196,035	55	3.76	737,092	23
24	1953	240,519	55	3.76	904,351	24
25	1954	147,460	55	3.76	554,450	25
26	1955	550,773	56	3.70	2,037,860	26
27	1956	257,251	63	3.29	846,356	27
28	1957	151,675	66	3.14	476,260	28
29	1958	535,560	71	2.92	1,563,835	29
30	1959	187,001	71	2.92	546,043	30
31	1960	743,022	71	2.92	2,169,624	31
32	1961	288,444	73	2.84	819,181	32
33	1962	535,657	79	2.62	1,403,421	33
34	1963	483,084	79	2.62	1,265,680	34
35	1964	112,953	79	2.62	295,937	35
36	1965	313,021	79	2.62	820,115	36
37	1966	146,307	86	2.41	352,600	37
38	1967	90,075	88	2.35	211,676	38
39	1968	106,468	88	2.35	250,200	39
40	1969	122,731	89	2.33	285,963	40
41	1970	248,264	94	2.20	546,181	41
42	1971	463,749	100	2.07	959,960	42
43	1972	680,916	100	2.07	1,409,496	43
44	1973	714,375	100	2.07	1,478,756	44
45	1974	849,428	111	1.86	1,579,936	45
46	1975	320,571	128	1.62	519,325	46
47	1976	378,527	131	1.58	598,073	47
48	1977	454,756	136	1.52	691,229	48
49	1978	210,584	139	1.49	313,770	49
50	1979	825,508	143	1.45	1,196,987	50
51	1980	1,444,227	149	1.39	2,007,476	51
52	1981	1,311,743	158	1.31	1,718,383	52
53	1982	1,434,834	158	1.31	1,879,633	53
54	1983	3,944,172	146	1.42	5,600,724	54
55	1984	2,763,584	147	1.41	3,896,653	55
56	1985	3,596,759	158	1.31	4,711,754	56
57	1986	1,759,158	166	1.25	2,198,948	57
58	1987	1,909,784	165	1.25	2,387,230	58
59	1988	3,943,060	170	1.22	4,810,533	59
60	1989	4,217,411	177	1.17	4,934,371	60
61	1990	3,392,259	185	1.12	3,799,330	61
62	1991	4,270,504	190	1.09	4,654,849	62
63	1992	2,596,384	192	1.08	2,804,095	63
64	1993	307,772	191	1.08	332,394	64
65	1994	8,240,560	189	1.10	9,064,616	65
66	1995	6,217,363	190	1.09	6,776,926	66
67	1996	5,994,503	192	1.08	6,474,063	67
68	1997	5,877,396	196	1.06	6,230,040	68
69	1998	6,495,044	196	1.06	6,884,747	69
70	1999	10,060,249	193	1.07	10,764,466	70
71	2000	8,828,259	202	1.02	9,004,824	71
72	2001	10,103,988	209	0.99	10,002,948	72
73	2002	11,723,077	203	1.02	11,957,539	73
74	2003	13,152,999	191	1.08	14,205,239	74
75	2004	17,175,222	183	1.13	19,408,001	75
76	2005	16,109,089	186	1.11	17,881,089	76
77	2006	38,344,542	197	1.05	40,261,769	77
78	2007	19,831,069	207	1.00	19,831,069	78
79	Total	$ 226,663,229			$ 266,189,134	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 385 - Measuring and Regulating Equipment - Ind.

Line No.	Year Installed	Original Cost Total Arizona	H - W Index	Ratio To Current Index	RCN Total Arizona	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	24	20.58	$ 0	1
2	1931	0	24	20.58	0	2
3	1932	0	23	21.48	0	3
4	1933	0	22	22.45	0	4
5	1934	0	22	22.45	0	5
6	1935	0	22	22.45	0	6
7	1936	0	22	22.45	0	7
8	1937	0	24	20.58	0	8
9	1938	0	24	20.58	0	9
10	1939	0	24	20.58	0	10
11	1940	0	26	19.00	0	11
12	1941	0	26	19.00	0	12
13	1942	0	26	19.00	0	13
14	1943	0	26	19.00	0	14
15	1944	0	26	19.00	0	15
16	1945	0	26	19.00	0	16
17	1946	0	29	17.03	0	17
18	1947	0	34	14.53	0	18
19	1948	0	37	13.35	0	19
20	1949	0	39	12.67	0	20
21	1950	0	40	12.35	0	21
22	1951	0	44	11.23	0	22
23	1952	0	45	10.98	0	23
24	1953	0	46	10.74	0	24
25	1954	0	47	10.51	0	25
26	1955	0	49	10.08	0	26
27	1956	0	54	9.15	0	27
28	1957	0	57	8.67	0	28
29	1958	0	60	8.23	0	29
30	1959	0	62	7.97	0	30
31	1960	0	64	7.72	0	31
32	1961	0	64	7.72	0	32
33	1962	0	66	7.48	0	33
34	1963	0	67	7.37	0	34
35	1964	0	68	7.26	0	35
36	1965	0	68	7.26	0	36
37	1966	0	70	7.06	0	37
38	1967	0	72	6.86	0	38
39	1968	59,173	73	6.77	400,601	39
40	1969	0	76	6.50	0	40
41	1970	0	83	5.95	0	41
42	1971	0	90	5.49	0	42
43	1972	21,891	97	5.09	111,425	43
44	1973	32,288	100	4.94	159,503	44
45	1974	103,218	116	4.26	439,709	45
46	1975	76,790	135	3.66	281,051	46
47	1976	45,302	148	3.34	151,309	47
48	1977	16,356	158	3.13	51,194	48
49	1978	17,162	173	2.86	49,083	49
50	1979	31,941	187	2.64	84,324	50
51	1980	125,610	203	2.43	305,232	51
52	1981	102,045	224	2.21	225,519	52
53	1982	140,659	246	2.01	282,725	53
54	1983	172,078	246	2.01	345,877	54
55	1984	365,456	248	1.99	727,257	55
56	1985	62,688	243	2.03	127,257	56
57	1986	156,319	243	2.03	317,328	57
58	1987	14,460	250	1.98	28,631	58
59	1988	164,131	267	1.85	303,642	59
60	1989	90,436	278	1.78	160,976	60
61	1990	52,403	276	1.79	93,801	61
62	1991	61,230	279	1.77	108,377	62
63	1992	35,239	288	1.72	60,611	63
64	1993	141,754	298	1.66	235,312	64
65	1994	246,541	310	1.59	392,000	65
66	1995	329,429	313	1.58	520,498	66
67	1996	486,187	323	1.53	743,866	67
68	1997	622,531	332	1.49	927,571	68
69	1998	686,294	335	1.47	1,008,852	69
70	1999	521,190	342	1.44	750,514	70
71	2000	202,831	352	1.40	283,963	71
72	2001	314,785	358	1.38	434,403	72
73	2002	362,293	363	1.36	492,718	73
74	2003	416,339	365	1.35	562,058	74
75	2004	333,516	422	1.17	390,214	75
76	2005	381,770	480	1.03	393,223	76
77	2006	350,639	494	1.00	350,639	77
78	2007	106,977	494	1.00	106,977	78
79	Total	$ 7,449,951			$ 12,408,240	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 387 - Other Distribution Equipment

Line No.	Year Installed	Original Cost Total Arizona	H - W Index	Ratio To Current Index	RCN Total Arizona	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	24	20.58	$ 0	1
2	1931	0	24	20.58	0	2
3	1932	0	23	21.48	0	3
4	1933	0	22	22.45	0	4
5	1934	0	22	22.45	0	5
6	1935	0	22	22.45	0	6
7	1936	0	22	22.45	0	7
8	1937	0	24	20.58	0	8
9	1938	0	24	20.58	0	9
10	1939	0	24	20.58	0	10
11	1940	0	26	19.00	0	11
12	1941	0	26	19.00	0	12
13	1942	0	26	19.00	0	13
14	1943	0	26	19.00	0	14
15	1944	0	26	19.00	0	15
16	1945	0	26	19.00	0	16
17	1946	0	29	17.03	0	17
18	1947	0	34	14.53	0	18
19	1948	0	37	13.35	0	19
20	1949	0	39	12.67	0	20
21	1950	0	40	12.35	0	21
22	1951	0	44	11.23	0	22
23	1952	0	45	10.98	0	23
24	1953	0	46	10.74	0	24
25	1954	0	47	10.51	0	25
26	1955	0	49	10.08	0	26
27	1956	0	54	9.15	0	27
28	1957	0	57	8.67	0	28
29	1958	0	60	8.23	0	29
30	1959	0	62	7.97	0	30
31	1960	0	64	7.72	0	31
32	1961	0	64	7.72	0	32
33	1962	0	66	7.48	0	33
34	1963	0	67	7.37	0	34
35	1964	0	68	7.26	0	35
36	1965	0	68	7.26	0	36
37	1966	0	70	7.06	0	37
38	1967	0	72	6.86	0	38
39	1968	0	73	6.77	0	39
40	1969	0	76	6.50	0	40
41	1970	0	83	5.95	0	41
42	1971	0	90	5.49	0	42
43	1972	0	97	5.09	0	43
44	1973	0	100	4.94	0	44
45	1974	0	116	4.26	0	45
46	1975	2,618	135	3.66	9,582	46
47	1976	0	148	3.34	0	47
48	1977	0	158	3.13	0	48
49	1978	0	173	2.86	0	49
50	1979	35,268	187	2.64	93,108	50
51	1980	34,199	203	2.43	83,104	51
52	1981	88,691	224	2.21	196,007	52
53	1982	254,179	246	2.01	510,900	53
54	1983	0	246	2.01	0	54
55	1984	12,674	248	1.99	25,221	55
56	1985	45	243	2.03	91	56
57	1986	29,911	243	2.03	60,719	57
58	1987	1,134	250	1.98	2,245	58
59	1988	0	267	1.85	0	59
60	1989	0	278	1.78	0	60
61	1990	0	276	1.79	0	61
62	1991	193	279	1.77	342	62
63	1992	541	288	1.72	931	63
64	1993	0	298	1.66	0	64
65	1994	0	310	1.59	0	65
66	1995	245	313	1.58	387	66
67	1996	0	323	1.53	0	67
68	1997	2,006	332	1.49	2,989	68
69	1998	0	335	1.47	0	69
70	1999	0	342	1.44	0	70
71	2000	0	352	1.40	0	71
72	2001	1,026	358	1.38	1,416	72
73	2002	0	363	1.36	0	73
74	2003	0	365	1.35	0	74
75	2004	0	422	1.17	0	75
76	2005	0	480	1.03	0	76
77	2006	0	494	1.00	0	77
78	2007	0	494	1.00	0	78
79	Total	$ 462,730			$ 987,042	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

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	2005	0	1	1.00	0	76
77	2006	0	1	1.00	0	77
78	2007	1,963,827	1	1.00	1,963,827	78
79	Total	$ 8,418,416			$ 8,418,416	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

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	19.42	$ 0	1
2	1931	0	17	21.71	0	2
3	1932	0	16	23.06	0	3
4	1933	0	17	21.71	0	4
5	1934	0	19	19.42	0	5
6	1935	0	18	20.50	0	6
7	1936	0	19	19.42	0	7
8	1937	0	20	18.45	0	8
9	1938	0	20	18.45	0	9
10	1939	0	20	18.45	0	10
11	1940	0	20	18.45	0	11
12	1941	0	22	16.77	0	12
13	1942	0	23	16.04	0	13
14	1943	0	23	16.04	0	14
15	1944	0	24	15.38	0	15
16	1945	0	24	15.38	0	16
17	1946	0	27	13.67	0	17
18	1947	0	32	11.53	0	18
19	1948	0	36	10.25	0	19
20	1949	0	37	9.97	0	20
21	1950	0	39	9.46	0	21
22	1951	0	42	8.79	0	22
23	1952	0	44	8.39	0	23
24	1953	0	44	8.39	0	24
25	1954	0	46	8.02	0	25
26	1955	0	48	7.69	0	26
27	1956	0	52	7.10	0	27
28	1957	0	55	6.71	0	28
29	1958	0	57	6.47	0	29
30	1959	0	58	6.36	0	30
31	1960	0	59	6.25	0	31
32	1961	0	58	6.36	0	32
33	1962	0	59	6.25	0	33
34	1963	0	60	6.15	0	34
35	1964	0	61	6.05	0	35
36	1965	0	64	5.77	0	36
37	1966	0	65	5.68	0	37
38	1967	0	67	5.51	0	38
39	1968	0	71	5.20	0	39
40	1969	0	75	4.92	0	40
41	1970	0	79	4.67	0	41
42	1971	0	87	4.24	0	42
43	1972	15,408	93	3.97	61,170	43
44	1973	2,858	100	3.69	10,546	44
45	1974	5,984	118	3.13	18,730	45
46	1975	28,410	133	2.77	78,696	46
47	1976	0	138	2.67	0	47
48	1977	333,672	148	2.49	830,843	48
49	1978	2,837	161	2.29	6,497	49
50	1979	0	177	2.08	0	50
51	1980	5,244,133	194	1.90	9,963,853	51
52	1981	38,653	204	1.81	69,962	52
53	1982	0	207	1.78	0	53
54	1983	0	215	1.72	0	54
55	1984	2,441,523	224	1.65	4,028,513	55
56	1985	1,687,626	226	1.63	2,750,830	56
57	1986	1,023,067	231	1.60	1,636,907	57
58	1987	67,606	232	1.59	107,494	58
59	1988	5,267,716	233	1.58	8,322,991	59
60	1989	3,221,887	232	1.59	5,122,800	60
61	1990	168,754	237	1.56	263,256	61
62	1991	838,588	233	1.58	1,324,969	62
63	1992	193,045	238	1.55	299,220	63
64	1993	98,925	250	1.48	146,409	64
65	1994	255,760	261	1.41	360,622	65
66	1995	481,215	265	1.39	668,889	66
67	1996	189,940	176	2.10	398,874	67
68	1997	353,457	282	1.31	463,029	68
69	1998	478,732	285	1.29	617,564	69
70	1999	1,090,608	287	1.29	1,406,884	70
71	2000	779,977	295	1.25	974,971	71
72	2001	177,401	303	1.22	216,429	72
73	2002	336,702	310	1.19	400,675	73
74	2003	262,206	320	1.15	301,537	74
75	2004	452,406	342	1.08	488,598	75
76	2005	72,343	355	1.04	75,237	76
77	2006	139,383	364	1.01	140,777	77
78	2007	314,145	369	1.00	314,145	78
79	Total	$ 26,064,967			$ 41,871,917	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

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	19.42	$ 0	1
2	1931	0	17	21.71	0	2
3	1932	0	16	23.06	0	3
4	1933	0	17	21.71	0	4
5	1934	0	19	19.42	0	5
6	1935	0	18	20.50	0	6
7	1936	0	19	19.42	0	7
8	1937	0	20	18.45	0	8
9	1938	0	20	18.45	0	9
10	1939	0	20	18.45	0	10
11	1940	0	20	18.45	0	11
12	1941	0	22	16.77	0	12
13	1942	0	23	16.04	0	13
14	1943	0	23	16.04	0	14
15	1944	0	24	15.38	0	15
16	1945	0	24	15.38	0	16
17	1946	0	27	13.67	0	17
18	1947	0	32	11.53	0	18
19	1948	0	36	10.25	0	19
20	1949	0	37	9.97	0	20
21	1950	0	39	9.46	0	21
22	1951	0	42	8.79	0	22
23	1952	0	44	8.39	0	23
24	1953	0	44	8.39	0	24
25	1954	0	46	8.02	0	25
26	1955	0	48	7.69	0	26
27	1956	0	52	7.10	0	27
28	1957	0	55	6.71	0	28
29	1958	0	57	6.47	0	29
30	1959	0	58	6.36	0	30
31	1960	0	59	6.25	0	31
32	1961	0	58	6.36	0	32
33	1962	0	59	6.25	0	33
34	1963	0	60	6.15	0	34
35	1964	0	61	6.05	0	35
36	1965	0	64	5.77	0	36
37	1966	0	65	5.68	0	37
38	1967	0	67	5.51	0	38
39	1968	0	71	5.20	0	39
40	1969	0	75	4.92	0	40
41	1970	0	79	4.67	0	41
42	1971	0	87	4.24	0	42
43	1972	0	93	3.97	0	43
44	1973	0	100	3.69	0	44
45	1974	0	118	3.13	0	45
46	1975	0	133	2.77	0	46
47	1976	0	138	2.67	0	47
48	1977	0	148	2.49	0	48
49	1978	0	161	2.29	0	49
50	1979	19,087	177	2.08	39,701	50
51	1980	7,025	194	1.90	13,348	51
52	1981	0	204	1.81	0	52
53	1982	0	207	1.78	0	53
54	1983	0	215	1.72	0	54
55	1984	68,562	224	1.65	113,127	55
56	1985	27,722	226	1.63	45,187	56
57	1986	30,477	231	1.60	48,763	57
58	1987	0	232	1.59	0	58
59	1988	87,786	233	1.58	138,702	59
60	1989	119,619	232	1.59	190,194	60
61	1990	0	237	1.56	0	61
62	1991	0	233	1.58	0	62
63	1992	0	238	1.55	0	63
64	1993	89,014	250	1.48	131,741	64
65	1994	10,978	261	1.41	15,479	65
66	1995	0	265	1.39	0	66
67	1996	6,416	176	2.10	13,474	67
68	1997	9,418	282	1.31	12,338	68
69	1998	121,696	285	1.29	156,988	69
70	1999	55,047	287	1.29	71,011	70
71	2000	14,670	295	1.25	18,338	71
72	2001	235,573	303	1.22	287,399	72
73	2002	60,614	310	1.19	72,131	73
74	2003	5,638	320	1.15	6,484	74
75	2004	10,805	342	1.08	11,669	75
76	2005	2,005	355	1.04	2,085	76
77	2006	4,067	364	1.01	4,108	77
78	2007	0	369	1.00	0	78
79	Total	$ 986,219			$ 1,392,267	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 391 - Office Furniture and Equipment

Line No.	Year Installed	Original Cost Total Arizona	H - W Index	Ratio To Current Index	RCN Total Arizona	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	11	28.18	$ 0	1
2	1931	0	11	28.18	0	2
3	1932	0	11	28.18	0	3
4	1933	0	11	28.18	0	4
5	1934	0	11	28.18	0	5
6	1935	0	11	28.18	0	6
7	1936	0	12	25.83	0	7
8	1937	0	13	23.85	0	8
9	1938	0	13	23.85	0	9
10	1939	0	13	23.85	0	10
11	1940	0	13	23.85	0	11
12	1941	0	13	23.85	0	12
13	1942	0	15	20.67	0	13
14	1943	0	15	20.67	0	14
15	1944	0	15	20.67	0	15
16	1945	0	16	19.38	0	16
17	1946	0	20	15.50	0	17
18	1947	0	23	13.48	0	18
19	1948	0	26	11.92	0	19
20	1949	0	26	11.92	0	20
21	1950	0	27	11.48	0	21
22	1951	0	29	10.69	0	22
23	1952	0	31	10.00	0	23
24	1953	0	33	9.39	0	24
25	1954	0	34	9.12	0	25
26	1955	0	36	8.61	0	26
27	1956	0	39	7.95	0	27
28	1957	0	41	7.56	0	28
29	1958	0	42	7.38	0	29
30	1959	0	45	6.89	0	30
31	1960	0	46	6.74	0	31
32	1961	0	51	6.08	0	32
33	1962	0	53	5.85	0	33
34	1963	0	55	5.64	0	34
35	1964	0	57	5.44	0	35
36	1965	2,051	60	5.17	10,604	36
37	1966	3,149	62	5.00	15,745	37
38	1967	0	66	4.70	0	38
39	1968	0	70	4.43	0	39
40	1969	1,554	74	4.19	6,511	40
41	1970	0	81	3.83	0	41
42	1971	0	87	3.56	0	42
43	1972	0	94	3.30	0	43
44	1973	0	100	3.10	0	44
45	1974	0	109	2.84	0	45
46	1975	0	123	2.52	0	46
47	1976	0	130	2.38	0	47
48	1977	3,374	141	2.20	7,423	48
49	1978	0	151	2.05	0	49
50	1979	0	164	1.89	0	50
51	1980	244,314	178	1.74	425,106	51
52	1981	1,097	186	1.67	1,832	52
53	1982	0	203	1.53	0	53
54	1983	9,167	209	1.48	13,567	54
55	1984	49,377	212	1.46	72,090	55
56	1985	1,031,674	211	1.47	1,516,561	56
57	1986	365,471	218	1.42	518,969	57
58	1987	52,450	226	1.37	71,857	58
59	1988	515,269	219	1.42	731,682	59
60	1989	114,045	213	1.46	166,506	60
61	1990	6,328	228	1.36	8,606	61
62	1991	14,321	242	1.28	18,331	62
63	1992	29,616	249	1.24	36,724	63
64	1993	29,863	260	1.19	35,537	64
65	1994	69,698	257	1.21	84,335	65
66	1995	93,459	246	1.26	117,758	66
67	1996	48,437	250	1.24	60,062	67
68	1997	92,529	251	1.24	114,736	68
69	1998	82,590	254	1.22	100,760	69
70	1999	461,041	261	1.19	548,639	70
71	2000	660,913	268	1.16	766,659	71
72	2001	42,515	280	1.11	47,192	72
73	2002	532,749	289	1.07	570,041	73
74	2003	25,848	293	1.06	27,399	74
75	2004	192,535	298	1.04	200,236	75
76	2005	8,828	303	1.02	9,005	76
77	2006	94,985	305	1.02	96,885	77
78	2007	560,912	310	1.00	560,912	78
79	Total	$ 5,440,159			$ 6,962,270	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

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	28.18	$ 0	1
2	1931	0	11	28.18	0	2
3	1932	0	11	28.18	0	3
4	1933	0	11	28.18	0	4
5	1934	0	11	28.18	0	5
6	1935	0	11	28.18	0	6
7	1936	0	12	25.83	0	7
8	1937	0	13	23.85	0	8
9	1938	0	13	23.85	0	9
10	1939	0	13	23.85	0	10
11	1940	0	13	23.85	0	11
12	1941	0	13	23.85	0	12
13	1942	0	15	20.67	0	13
14	1943	0	15	20.67	0	14
15	1944	0	15	20.67	0	15
16	1945	0	16	19.38	0	16
17	1946	0	20	15.50	0	17
18	1947	0	23	13.48	0	18
19	1948	0	26	11.92	0	19
20	1949	0	26	11.92	0	20
21	1950	0	27	11.48	0	21
22	1951	0	29	10.69	0	22
23	1952	0	31	10.00	0	23
24	1953	0	33	9.39	0	24
25	1954	0	34	9.12	0	25
26	1955	0	36	8.61	0	26
27	1956	0	39	7.95	0	27
28	1957	0	41	7.56	0	28
29	1958	0	42	7.38	0	29
30	1959	0	45	6.89	0	30
31	1960	0	46	6.74	0	31
32	1961	0	51	6.08	0	32
33	1962	0	53	5.85	0	33
34	1963	0	55	5.64	0	34
35	1964	0	57	5.44	0	35
36	1965	0	60	5.17	0	36
37	1966	0	62	5.00	0	37
38	1967	0	66	4.70	0	38
39	1968	0	70	4.43	0	39
40	1969	0	74	4.19	0	40
41	1970	0	81	3.83	0	41
42	1971	0	87	3.56	0	42
43	1972	0	94	3.30	0	43
44	1973	0	100	3.10	0	44
45	1974	0	109	2.84	0	45
46	1975	0	123	2.52	0	46
47	1976	0	130	2.38	0	47
48	1977	0	141	2.20	0	48
49	1978	0	151	2.05	0	49
50	1979	0	164	1.89	0	50
51	1980	0	178	1.74	0	51
52	1981	0	186	1.67	0	52
53	1982	0	203	1.53	0	53
54	1983	0	209	1.48	0	54
55	1984	0	212	1.46	0	55
56	1985	0	211	1.47	0	56
57	1986	0	218	1.42	0	57
58	1987	0	226	1.37	0	58
59	1988	0	219	1.42	0	59
60	1989	0	213	1.46	0	60
61	1990	0	228	1.36	0	61
62	1991	0	242	1.28	0	62
63	1992	0	249	1.24	0	63
64	1993	18,529	260	1.19	22,050	64
65	1994	15,506	257	1.21	18,762	65
66	1995	37,950	246	1.26	47,817	66
67	1996	7,201	250	1.24	8,929	67
68	1997	26,325	251	1.24	32,643	68
69	1998	16,218	254	1.22	19,786	69
70	1999	33,827	261	1.19	40,254	70
71	2000	126,939	268	1.16	147,249	71
72	2001	385,839	280	1.11	428,281	72
73	2002	187,887	289	1.07	201,039	73
74	2003	933,310	293	1.06	989,309	74
75	2004	869,595	298	1.04	904,379	75
76	2005	3,109,193	303	1.02	3,171,377	76
77	2006	2,278,230	305	1.02	2,323,795	77
78	2007	516,819	310	1.00	516,819	78
79	Total	$ 8,563,368			$ 8,872,489	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 392.1 - Transportation Equipment

Line No.	Year Installed	Original Cost Total Arizona	H - W Index	Ratio To Current Index	RCN Total Arizona	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	22	21.05	$ 0	1
2	1931	0	20	23.15	0	2
3	1932	0	19	24.37	0	3
4	1933	0	19	24.37	0	4
5	1934	0	20	23.15	0	5
6	1935	0	21	22.05	0	6
7	1936	0	21	22.05	0	7
8	1937	0	23	20.13	0	8
9	1938	0	23	20.13	0	9
10	1939	0	23	20.13	0	10
11	1940	0	24	19.29	0	11
12	1941	0	25	18.52	0	12
13	1942	0	28	16.54	0	13
14	1943	0	29	15.97	0	14
15	1944	0	29	15.97	0	15
16	1945	0	29	15.97	0	16
17	1946	0	34	13.62	0	17
18	1947	0	37	12.51	0	18
19	1948	0	39	11.87	0	19
20	1949	0	40	11.58	0	20
21	1950	0	42	11.02	0	21
22	1951	0	45	10.29	0	22
23	1952	0	46	10.07	0	23
24	1953	0	49	9.45	0	24
25	1954	0	49	9.45	0	25
26	1955	0	51	9.08	0	26
27	1956	0	55	8.42	0	27
28	1957	0	59	7.85	0	28
29	1958	0	62	7.47	0	29
30	1959	0	64	7.23	0	30
31	1960	0	65	7.12	0	31
32	1961	0	67	6.91	0	32
33	1962	0	67	6.91	0	33
34	1963	0	68	6.81	0	34
35	1964	0	70	6.61	0	35
36	1965	0	71	6.52	0	36
37	1966	0	73	6.34	0	37
38	1967	0	76	6.09	0	38
39	1968	0	80	5.79	0	39
40	1969	0	84	5.51	0	40
41	1970	0	88	5.26	0	41
42	1971	0	93	4.98	0	42
43	1972	0	95	4.87	0	43
44	1973	0	100	4.63	0	44
45	1974	0	117	3.96	0	45
46	1975	0	141	3.28	0	46
47	1976	0	153	3.03	0	47
48	1977	0	164	2.82	0	48
49	1978	0	178	2.60	0	49
50	1979	3,530	197	2.35	8,296	50
51	1980	24,702	222	2.09	51,627	51
52	1981	0	246	1.88	0	52
53	1982	0	263	1.76	0	53
54	1983	1,020	269	1.72	1,754	54
55	1984	4,311	273	1.70	7,329	55
56	1985	19,935	276	1.68	33,491	56
57	1986	15,181	280	1.65	25,049	57
58	1987	26,797	286	1.62	43,411	58
59	1988	18,237	295	1.57	28,632	59
60	1989	10,678	281	1.65	17,619	60
61	1990	21,628	298	1.55	33,523	61
62	1991	15,983	320	1.45	23,175	62
63	1992	46,577	316	1.47	68,468	63
64	1993	81,449	324	1.43	116,472	64
65	1994	99,120	331	1.40	138,768	65
66	1995	690,587	333	1.39	959,916	66
67	1996	56,193	336	1.38	77,546	67
68	1997	415,661	351	1.32	548,673	68
69	1998	1,695,088	380	1.22	2,068,007	69
70	1999	1,427,295	385	1.20	1,712,754	70
71	2000	3,067,572	389	1.19	3,650,411	71
72	2001	5,426,548	390	1.19	6,457,592	72
73	2002	3,974,869	395	1.17	4,650,597	73
74	2003	1,229,586	401	1.15	1,414,024	74
75	2004	2,855,228	414	1.12	3,197,855	75
76	2005	3,033,617	439	1.05	3,185,298	76
77	2006	4,950,008	457	1.01	4,999,508	77
78	2007	1,914,959	463	1.00	1,914,959	78
79	Total	$ 31,126,359			$ 35,434,754	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

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	21.05	$ 0	1
2	1931	0	20	23.15	0	2
3	1932	0	19	24.37	0	3
4	1933	0	19	24.37	0	4
5	1934	0	20	23.15	0	5
6	1935	0	21	22.05	0	6
7	1936	0	21	22.05	0	7
8	1937	0	23	20.13	0	8
9	1938	0	23	20.13	0	9
10	1939	0	23	20.13	0	10
11	1940	0	24	19.29	0	11
12	1941	0	25	18.52	0	12
13	1942	0	28	16.54	0	13
14	1943	0	29	15.97	0	14
15	1944	0	29	15.97	0	15
16	1945	0	29	15.97	0	16
17	1946	0	34	13.62	0	17
18	1947	0	37	12.51	0	18
19	1948	0	39	11.87	0	19
20	1949	0	40	11.58	0	20
21	1950	0	42	11.02	0	21
22	1951	0	45	10.29	0	22
23	1952	0	46	10.07	0	23
24	1953	0	49	9.45	0	24
25	1954	0	49	9.45	0	25
26	1955	0	51	9.08	0	26
27	1956	0	55	8.42	0	27
28	1957	0	59	7.85	0	28
29	1958	0	62	7.47	0	29
30	1959	0	64	7.23	0	30
31	1960	0	65	7.12	0	31
32	1961	0	67	6.91	0	32
33	1962	0	67	6.91	0	33
34	1963	0	68	6.81	0	34
35	1964	0	70	6.61	0	35
36	1965	0	71	6.52	0	36
37	1966	0	73	6.34	0	37
38	1967	0	76	6.09	0	38
39	1968	0	80	5.79	0	39
40	1969	0	84	5.51	0	40
41	1970	0	88	5.26	0	41
42	1971	0	93	4.98	0	42
43	1972	0	95	4.87	0	43
44	1973	0	100	4.63	0	44
45	1974	0	117	3.96	0	45
46	1975	0	141	3.28	0	46
47	1976	0	153	3.03	0	47
48	1977	0	164	2.82	0	48
49	1978	0	178	2.60	0	49
50	1979	0	197	2.35	0	50
51	1980	31,662	222	2.09	66,174	51
52	1981	0	246	1.88	0	52
53	1982	0	263	1.76	0	53
54	1983	2,855	269	1.72	4,911	54
55	1984	0	273	1.70	0	55
56	1985	62,611	276	1.68	105,186	56
57	1986	30,615	280	1.65	50,515	57
58	1987	17,738	286	1.62	28,736	58
59	1988	36,482	295	1.57	57,277	59
60	1989	1,293	281	1.65	2,133	60
61	1990	0	298	1.55	0	61
62	1991	0	320	1.45	0	62
63	1992	0	316	1.47	0	63
64	1993	9,251	324	1.43	13,229	64
65	1994	52,958	331	1.40	74,141	65
66	1995	0	333	1.39	0	66
67	1996	0	336	1.38	0	67
68	1997	41,958	351	1.32	55,385	68
69	1998	5,158	380	1.22	6,293	69
70	1999	50,326	385	1.20	60,391	70
71	2000	19,100	389	1.19	22,729	71
72	2001	4,375	390	1.19	5,206	72
73	2002	73,301	395	1.17	85,762	73
74	2003	0	401	1.15	0	74
75	2004	26,256	414	1.12	29,407	75
76	2005	64,821	439	1.05	68,062	76
77	2006	11,760	457	1.01	11,878	77
78	2007	0	463	1.00	0	78
79	Total	$ 542,520			$ 747,415	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 394 - Tools, Shop and Garage Equipment

Line No.	Year Installed	Original Cost Total Arizona	H - W Index	Ratio To Current Index	RCN Total Arizona	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	22	21.05	$ 0	1
2	1931	0	20	23.15	0	2
3	1932	0	19	24.37	0	3
4	1933	0	19	24.37	0	4
5	1934	0	20	23.15	0	5
6	1935	0	21	22.05	0	6
7	1936	0	21	22.05	0	7
8	1937	0	23	20.13	0	8
9	1938	0	23	20.13	0	9
10	1939	0	23	20.13	0	10
11	1940	0	24	19.29	0	11
12	1941	0	25	18.52	0	12
13	1942	0	28	16.54	0	13
14	1943	0	29	15.97	0	14
15	1944	0	29	15.97	0	15
16	1945	0	29	15.97	0	16
17	1946	0	34	13.62	0	17
18	1947	0	37	12.51	0	18
19	1948	0	39	11.87	0	19
20	1949	0	40	11.58	0	20
21	1950	0	42	11.02	0	21
22	1951	0	45	10.29	0	22
23	1952	0	46	10.07	0	23
24	1953	0	49	9.45	0	24
25	1954	0	49	9.45	0	25
26	1955	0	51	9.08	0	26
27	1956	0	55	8.42	0	27
28	1957	0	59	7.85	0	28
29	1958	0	62	7.47	0	29
30	1959	0	64	7.23	0	30
31	1960	0	65	7.12	0	31
32	1961	0	67	6.91	0	32
33	1962	0	67	6.91	0	33
34	1963	0	68	6.81	0	34
35	1964	0	70	6.61	0	35
36	1965	0	71	6.52	0	36
37	1966	0	73	6.34	0	37
38	1967	0	76	6.09	0	38
39	1968	0	80	5.79	0	39
40	1969	0	84	5.51	0	40
41	1970	0	88	5.26	0	41
42	1971	0	93	4.98	0	42
43	1972	0	95	4.87	0	43
44	1973	0	100	4.63	0	44
45	1974	0	117	3.96	0	45
46	1975	0	141	3.28	0	46
47	1976	0	153	3.03	0	47
48	1977	0	164	2.82	0	48
49	1978	0	178	2.60	0	49
50	1979	0	197	2.35	0	50
51	1980	55,189	222	2.09	115,345	51
52	1981	23,738	246	1.88	44,627	52
53	1982	34,866	263	1.76	61,364	53
54	1983	2,424	269	1.72	4,169	54
55	1984	22,791	273	1.70	38,745	55
56	1985	17,010	276	1.68	28,577	56
57	1986	269,928	280	1.65	445,381	57
58	1987	30,450	286	1.62	49,329	58
59	1988	77,470	295	1.57	121,628	59
60	1989	226,378	281	1.65	373,524	60
61	1990	17,527	298	1.55	27,167	61
62	1991	25,031	320	1.45	36,295	62
63	1992	71,553	316	1.47	105,183	63
64	1993	87,860	324	1.43	125,640	64
65	1994	71,131	331	1.40	99,583	65
66	1995	342,679	333	1.39	476,324	66
67	1996	46,697	336	1.38	64,442	67
68	1997	79,347	351	1.32	104,738	68
69	1998	489,352	380	1.22	597,009	69
70	1999	269,676	385	1.20	323,611	70
71	2000	358,741	389	1.19	426,902	71
72	2001	242,895	390	1.19	289,045	72
73	2002	380,357	395	1.17	445,018	73
74	2003	134,426	401	1.15	154,590	74
75	2004	504,361	414	1.12	564,884	75
76	2005	662,868	439	1.05	696,011	76
77	2006	496,552	457	1.01	501,518	77
78	2007	183,727	463	1.00	183,727	78
79	Total	$ 5,225,024			$ 6,504,376	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 395 - Laboratory Equipment

Line No.	Year Installed	Original Cost Total Arizona	H - W Index	Ratio To Current Index	RCN Total Arizona	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	11	28.18	$ 0	1
2	1931	0	11	28.18	0	2
3	1932	0	11	28.18	0	3
4	1933	0	11	28.18	0	4
5	1934	0	11	28.18	0	5
6	1935	0	11	28.18	0	6
7	1936	0	12	25.83	0	7
8	1937	0	13	23.85	0	8
9	1938	0	13	23.85	0	9
10	1939	0	13	23.85	0	10
11	1940	0	13	23.85	0	11
12	1941	0	13	23.85	0	12
13	1942	0	15	20.67	0	13
14	1943	0	15	20.67	0	14
15	1944	0	15	20.67	0	15
16	1945	0	16	19.38	0	16
17	1946	0	20	15.50	0	17
18	1947	0	23	13.48	0	18
19	1948	0	26	11.92	0	19
20	1949	0	26	11.92	0	20
21	1950	0	27	11.48	0	21
22	1951	0	29	10.69	0	22
23	1952	0	31	10.00	0	23
24	1953	0	33	9.39	0	24
25	1954	0	34	9.12	0	25
26	1955	0	36	8.61	0	26
27	1956	0	39	7.95	0	27
28	1957	0	41	7.56	0	28
29	1958	0	42	7.38	0	29
30	1959	0	45	6.89	0	30
31	1960	0	46	6.74	0	31
32	1961	0	51	6.08	0	32
33	1962	0	53	5.85	0	33
34	1963	0	55	5.64	0	34
35	1964	0	57	5.44	0	35
36	1965	0	60	5.17	0	36
37	1966	0	62	5.00	0	37
38	1967	0	66	4.70	0	38
39	1968	0	70	4.43	0	39
40	1969	0	74	4.19	0	40
41	1970	0	81	3.83	0	41
42	1971	0	87	3.56	0	42
43	1972	0	94	3.30	0	43
44	1973	0	100	3.10	0	44
45	1974	0	109	2.84	0	45
46	1975	0	123	2.52	0	46
47	1976	0	130	2.38	0	47
48	1977	0	141	2.20	0	48
49	1978	0	151	2.05	0	49
50	1979	0	164	1.89	0	50
51	1980	0	178	1.74	0	51
52	1981	0	186	1.67	0	52
53	1982	0	203	1.53	0	53
54	1983	0	209	1.48	0	54
55	1984	0	212	1.46	0	55
56	1985	0	211	1.47	0	56
57	1986	0	218	1.42	0	57
58	1987	0	226	1.37	0	58
59	1988	0	219	1.42	0	59
60	1989	0	213	1.46	0	60
61	1990	2,960	228	1.36	4,026	61
62	1991	0	242	1.28	0	62
63	1992	0	249	1.24	0	63
64	1993	1,176	260	1.19	1,399	64
65	1994	35,045	257	1.21	42,404	65
66	1995	11,623	246	1.26	14,645	66
67	1996	10,818	250	1.24	13,414	67
68	1997	0	251	1.24	0	68
69	1998	3,633	254	1.22	4,432	69
70	1999	145,052	261	1.19	172,612	70
71	2000	0	268	1.16	0	71
72	2001	0	280	1.11	0	72
73	2002	59,897	289	1.07	64,090	73
74	2003	1,553	293	1.06	1,646	74
75	2004	4,842	298	1.04	5,036	75
76	2005	0	303	1.02	0	76
77	2006	2,466	305	1.02	2,515	77
78	2007	0	310	1.00	0	78
79	Total	$ 279,065			$ 326,219	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 396 - Power Operated Equipment

Line No.	Year Installed	Original Cost Total Arizona	H - W Index	Ratio To Current Index	RCN Total Arizona	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	22	21.05	$ 0	1
2	1931	0	20	23.15	0	2
3	1932	0	19	24.37	0	3
4	1933	0	19	24.37	0	4
5	1934	0	20	23.15	0	5
6	1935	0	21	22.05	0	6
7	1936	0	21	22.05	0	7
8	1937	0	23	20.13	0	8
9	1938	0	23	20.13	0	9
10	1939	0	23	20.13	0	10
11	1940	0	24	19.29	0	11
12	1941	0	25	18.52	0	12
13	1942	0	28	16.54	0	13
14	1943	0	29	15.97	0	14
15	1944	0	29	15.97	0	15
16	1945	0	29	15.97	0	16
17	1946	0	34	13.62	0	17
18	1947	0	37	12.51	0	18
19	1948	0	39	11.87	0	19
20	1949	0	40	11.58	0	20
21	1950	0	42	11.02	0	21
22	1951	0	45	10.29	0	22
23	1952	0	46	10.07	0	23
24	1953	0	49	9.45	0	24
25	1954	0	49	9.45	0	25
26	1955	0	51	9.08	0	26
27	1956	0	55	8.42	0	27
28	1957	0	59	7.85	0	28
29	1958	0	62	7.47	0	29
30	1959	0	64	7.23	0	30
31	1960	0	65	7.12	0	31
32	1961	0	67	6.91	0	32
33	1962	0	67	6.91	0	33
34	1963	0	68	6.81	0	34
35	1964	0	70	6.61	0	35
36	1965	0	71	6.52	0	36
37	1966	0	73	6.34	0	37
38	1967	0	76	6.09	0	38
39	1968	0	80	5.79	0	39
40	1969	0	84	5.51	0	40
41	1970	0	88	5.26	0	41
42	1971	0	93	4.98	0	42
43	1972	0	95	4.87	0	43
44	1973	0	100	4.63	0	44
45	1974	0	117	3.96	0	45
46	1975	0	141	3.28	0	46
47	1976	0	153	3.03	0	47
48	1977	0	164	2.82	0	48
49	1978	0	178	2.60	0	49
50	1979	8,127	197	2.35	19,098	50
51	1980	2,846	222	2.09	5,948	51
52	1981	0	246	1.88	0	52
53	1982	0	263	1.76	0	53
54	1983	842	269	1.72	1,448	54
55	1984	65,772	273	1.70	111,812	55
56	1985	3,072	276	1.68	5,161	56
57	1986	32,514	280	1.65	53,648	57
58	1987	10,232	286	1.62	16,576	58
59	1988	10,046	295	1.57	15,772	59
60	1989	28,315	281	1.65	46,720	60
61	1990	0	298	1.55	0	61
62	1991	81,471	320	1.45	118,133	62
63	1992	9,053	316	1.47	13,308	63
64	1993	52,469	324	1.43	75,031	64
65	1994	908,327	331	1.40	1,271,658	65
66	1995	106,996	333	1.39	148,724	66
67	1996	99,210	336	1.38	136,910	67
68	1997	25,800	351	1.32	34,056	68
69	1998	286,456	380	1.22	349,476	69
70	1999	160,970	385	1.20	193,164	70
71	2000	194,797	389	1.19	231,808	71
72	2001	298,640	390	1.19	355,382	72
73	2002	145,971	395	1.17	170,786	73
74	2003	91,305	401	1.15	105,001	74
75	2004	291,462	414	1.12	326,437	75
76	2005	455,586	439	1.05	478,365	76
77	2006	542,423	457	1.01	547,847	77
78	2007	396,593	463	1.00	396,593	78
79	Total	$ 4,309,295			$ 5,228,862	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

Account 397.1 - Communication Equipment

Line No.	Year Installed	Original Cost Total Arizona	H - W Index	Ratio To Current Index	RCN Total Arizona	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	15	23.33	$ 0	1
2	1931	0	15	23.33	0	2
3	1932	0	15	23.33	0	3
4	1933	0	15	23.33	0	4
5	1934	0	15	23.33	0	5
6	1935	0	15	23.33	0	6
7	1936	0	15	23.33	0	7
8	1937	0	17	20.59	0	8
9	1938	0	17	20.59	0	9
10	1939	0	17	20.59	0	10
11	1940	0	17	20.59	0	11
12	1941	0	18	19.44	0	12
13	1942	0	19	18.42	0	13
14	1943	0	19	18.42	0	14
15	1944	0	19	18.42	0	15
16	1945	0	19	18.42	0	16
17	1946	0	21	16.67	0	17
18	1947	0	24	14.58	0	18
19	1948	0	26	13.46	0	19
20	1949	0	28	12.50	0	20
21	1950	0	30	11.67	0	21
22	1951	0	31	11.29	0	22
23	1952	0	33	10.61	0	23
24	1953	0	34	10.29	0	24
25	1954	0	36	9.72	0	25
26	1955	0	37	9.46	0	26
27	1956	0	39	8.97	0	27
28	1957	0	41	8.54	0	28
29	1958	0	42	8.33	0	29
30	1959	0	45	7.78	0	30
31	1960	0	46	7.61	0	31
32	1961	0	49	7.14	0	32
33	1962	0	51	6.86	0	33
34	1963	0	52	6.73	0	34
35	1964	0	54	6.48	0	35
36	1965	0	57	6.14	0	36
37	1966	0	58	6.03	0	37
38	1967	0	62	5.65	0	38
39	1968	0	64	5.47	0	39
40	1969	0	69	5.07	0	40
41	1970	1,328	78	4.49	5,963	41
42	1971	0	88	3.98	0	42
43	1972	0	95	3.68	0	43
44	1973	3,598	100	3.50	12,593	44
45	1974	0	109	3.21	0	45
46	1975	0	122	2.87	0	46
47	1976	0	131	2.67	0	47
48	1977	0	142	2.46	0	48
49	1978	0	151	2.32	0	49
50	1979	0	160	2.19	0	50
51	1980	0	170	2.06	0	51
52	1981	0	185	1.89	0	52
53	1982	0	206	1.70	0	53
54	1983	6,506	218	1.61	10,475	54
55	1984	0	220	1.59	0	55
56	1985	267,138	214	1.64	438,106	56
57	1986	50,148	215	1.63	81,741	57
58	1987	62,216	216	1.62	100,790	58
59	1988	21,920	215	1.63	35,730	59
60	1989	39,104	214	1.64	64,131	60
61	1990	0	220	1.59	0	61
62	1991	2,143	225	1.56	3,343	62
63	1992	7,069	232	1.51	10,674	63
64	1993	36,691	236	1.48	54,303	64
65	1994	246,135	239	1.46	359,357	65
66	1995	104,819	247	1.42	148,843	66
67	1996	28,698	254	1.38	39,603	67
68	1997	250,043	257	1.36	340,058	68
69	1998	204,183	265	1.32	269,522	69
70	1999	490,884	275	1.27	623,423	70
71	2000	115,485	285	1.23	142,047	71
72	2001	10,168	299	1.17	11,897	72
73	2002	0	309	1.13	0	73
74	2003	32,490	318	1.10	35,739	74
75	2004	79,112	327	1.07	84,650	75
76	2005	25,766	337	1.04	26,797	76
77	2006	57,712	345	1.01	58,289	77
78	2007	514,903	350	1.00	514,903	78
79	Total	$ 2,658,259			$ 3,472,977	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

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	23.33	$ 0	1
2	1931	0	15	23.33	0	2
3	1932	0	15	23.33	0	3
4	1933	0	15	23.33	0	4
5	1934	0	15	23.33	0	5
6	1935	0	15	23.33	0	6
7	1936	0	15	23.33	0	7
8	1937	0	17	20.59	0	8
9	1938	0	17	20.59	0	9
10	1939	0	17	20.59	0	10
11	1940	0	17	20.59	0	11
12	1941	0	18	19.44	0	12
13	1942	0	19	18.42	0	13
14	1943	0	19	18.42	0	14
15	1944	0	19	18.42	0	15
16	1945	0	19	18.42	0	16
17	1946	0	21	16.67	0	17
18	1947	0	24	14.58	0	18
19	1948	0	26	13.46	0	19
20	1949	0	28	12.50	0	20
21	1950	0	30	11.67	0	21
22	1951	0	31	11.29	0	22
23	1952	0	33	10.61	0	23
24	1953	0	34	10.29	0	24
25	1954	0	36	9.72	0	25
26	1955	0	37	9.46	0	26
27	1956	0	39	8.97	0	27
28	1957	0	41	8.54	0	28
29	1958	0	42	8.33	0	29
30	1959	0	45	7.78	0	30
31	1960	0	46	7.61	0	31
32	1961	0	49	7.14	0	32
33	1962	0	51	6.86	0	33
34	1963	0	52	6.73	0	34
35	1964	0	54	6.48	0	35
36	1965	0	57	6.14	0	36
37	1966	0	58	6.03	0	37
38	1967	0	62	5.65	0	38
39	1968	0	64	5.47	0	39
40	1969	0	69	5.07	0	40
41	1970	0	78	4.49	0	41
42	1971	0	88	3.98	0	42
43	1972	0	95	3.68	0	43
44	1973	0	100	3.50	0	44
45	1974	0	109	3.21	0	45
46	1975	0	122	2.87	0	46
47	1976	0	131	2.67	0	47
48	1977	0	142	2.46	0	48
49	1978	0	151	2.32	0	49
50	1979	0	160	2.19	0	50
51	1980	0	170	2.06	0	51
52	1981	0	185	1.89	0	52
53	1982	0	206	1.70	0	53
54	1983	0	218	1.61	0	54
55	1984	0	220	1.59	0	55
56	1985	0	214	1.64	0	56
57	1986	0	215	1.63	0	57
58	1987	0	216	1.62	0	58
59	1988	19,285	215	1.63	31,435	59
60	1989	0	214	1.64	0	60
61	1990	0	220	1.59	0	61
62	1991	0	225	1.56	0	62
63	1992	5,275	232	1.51	7,965	63
64	1993	3,280	236	1.48	4,854	64
65	1994	27,121	239	1.46	39,597	65
66	1995	130,115	247	1.42	184,763	66
67	1996	16,779	254	1.38	23,155	67
68	1997	0	257	1.36	0	68
69	1998	0	265	1.32	0	69
70	1999	9,867	275	1.27	12,531	70
71	2000	36,919	285	1.23	45,410	71
72	2001	0	299	1.17	0	72
73	2002	0	309	1.13	0	73
74	2003	0	318	1.10	0	74
75	2004	5,834	327	1.07	6,242	75
76	2005	534,901	337	1.04	556,297	76
77	2006	0	345	1.01	0	77
78	2007	0	350	1.00	0	78
79	Total	$ 789,376			$ 912,249	79

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
RCN COST OF GAS PLANT IN SERVICE AS OF APRIL 30, 2007

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	23.33	$ 0	1
2	1931	0	15	23.33	0	2
3	1932	0	15	23.33	0	3
4	1933	0	15	23.33	0	4
5	1934	0	15	23.33	0	5
6	1935	0	15	23.33	0	6
7	1936	0	15	23.33	0	7
8	1937	0	17	20.59	0	8
9	1938	0	17	20.59	0	9
10	1939	0	17	20.59	0	10
11	1940	0	17	20.59	0	11
12	1941	0	18	19.44	0	12
13	1942	0	19	18.42	0	13
14	1943	0	19	18.42	0	14
15	1944	0	19	18.42	0	15
16	1945	0	19	18.42	0	16
17	1946	0	21	16.67	0	17
18	1947	0	24	14.58	0	18
19	1948	0	26	13.46	0	19
20	1949	0	28	12.50	0	20
21	1950	0	30	11.67	0	21
22	1951	0	31	11.29	0	22
23	1952	0	33	10.61	0	23
24	1953	0	34	10.29	0	24
25	1954	0	36	9.72	0	25
26	1955	0	37	9.46	0	26
27	1956	0	39	8.97	0	27
28	1957	0	41	8.54	0	28
29	1958	0	42	8.33	0	29
30	1959	0	45	7.78	0	30
31	1960	0	46	7.61	0	31
32	1961	0	49	7.14	0	32
33	1962	0	51	6.86	0	33
34	1963	0	52	6.73	0	34
35	1964	0	54	6.48	0	35
36	1965	0	57	6.14	0	36
37	1966	0	58	6.03	0	37
38	1967	0	62	5.65	0	38
39	1968	0	64	5.47	0	39
40	1969	0	69	5.07	0	40
41	1970	0	78	4.49	0	41
42	1971	0	88	3.98	0	42
43	1972	0	95	3.68	0	43
44	1973	0	100	3.50	0	44
45	1974	1,816	109	3.21	5,829	45
46	1975	0	122	2.87	0	46
47	1976	0	131	2.67	0	47
48	1977	4,754	142	2.46	11,695	48
49	1978	0	151	2.32	0	49
50	1979	3,438	160	2.19	7,529	50
51	1980	32,264	170	2.06	66,464	51
52	1981	5,188	185	1.89	9,805	52
53	1982	0	206	1.70	0	53
54	1983	0	218	1.61	0	54
55	1984	1,062	220	1.59	1,689	55
56	1985	5,617	214	1.64	9,212	56
57	1986	37,656	215	1.63	61,379	57
58	1987	7,287	216	1.62	11,805	58
59	1988	3,370	215	1.63	5,493	59
60	1989	3,341	214	1.64	5,479	60
61	1990	13,839	220	1.59	22,004	61
62	1991	5,291	225	1.56	8,254	62
63	1992	0	232	1.51	0	63
64	1993	17,590	236	1.48	26,033	64
65	1994	24,420	239	1.46	35,653	65
66	1995	12,023	247	1.42	17,073	66
67	1996	9,106	254	1.38	12,566	67
68	1997	8,397	257	1.36	11,420	68
69	1998	15,676	265	1.32	20,692	69
70	1999	21,553	275	1.27	27,372	70
71	2000	345,507	285	1.23	424,974	71
72	2001	39,231	299	1.17	45,900	72
73	2002	59,479	309	1.13	67,211	73
74	2003	11,761	318	1.10	12,937	74
75	2004	29,579	327	1.07	31,650	75
76	2005	92,304	337	1.04	95,996	76
77	2006	40,749	345	1.01	41,156	77
78	2007	40,050	350	1.00	40,050	78
79	Total	$ 892,348			$ 1,137,320	79

Southwest Gas Corporation
System Allocable Plant
RCND Cost of Gas Plant in Service at April 30, 2007

Account 389 - Land and Land Rights

Line No.	Year Installed	Original Cost	H - W Index	Ratio To Current Index	RCN Cost	Line No.
	(a)	(b)	(c)	(d)	(e)	
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	0	1	1.00	0	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	0	1	1.00	0	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	0	1	1.00	0	55
56	1985	0	1	1.00	0	56
57	1986	0	1	1.00	0	57
58	1987	0	1	1.00	0	58
59	1988	0	1	1.00	0	59
60	1989	248,909	1	1.00	248,909	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	142,398	1	1.00	142,398	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	0	1	1.00	0	68
69	1998	0	1	1.00	0	69
70	1999	0	1	1.00	0	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	2005	0	1	1.00	0	76
77	2006	0	1	1.00	0	77
78	2007	0	1	1.00	0	78
79	Total	$ 391,307			$ 391,307	79

Southwest Gas Corporation
System Allocable Plant
RCND Cost of Gas Plant in Service at April 30, 2007

Account 390 - General Plant Structures

Line No.	Year Installed	Original Cost	H - W Index	Ratio To Current Index	RCN Cost	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	19	19.42	$ 0	1
2	1931	0	17	21.71	0	2
3	1932	0	16	23.06	0	3
4	1933	0	17	21.71	0	4
5	1934	0	19	19.42	0	5
6	1935	0	18	20.50	0	6
7	1936	0	19	19.42	0	7
8	1937	0	20	18.45	0	8
9	1938	0	20	18.45	0	9
10	1939	0	20	18.45	0	10
11	1940	0	20	18.45	0	11
12	1941	0	22	16.77	0	12
13	1942	0	23	16.04	0	13
14	1943	0	23	16.04	0	14
15	1944	0	24	15.38	0	15
16	1945	0	24	15.38	0	16
17	1946	0	27	13.67	0	17
18	1947	0	32	11.53	0	18
19	1948	0	36	10.25	0	19
20	1949	0	37	9.97	0	20
21	1950	0	39	9.46	0	21
22	1951	0	42	8.79	0	22
23	1952	0	44	8.39	0	23
24	1953	0	44	8.39	0	24
25	1954	0	46	8.02	0	25
26	1955	0	48	7.69	0	26
27	1956	0	52	7.10	0	27
28	1957	0	55	6.71	0	28
29	1958	0	57	6.47	0	29
30	1959	0	58	6.36	0	30
31	1960	0	59	6.25	0	31
32	1961	0	58	6.36	0	32
33	1962	0	59	6.25	0	33
34	1963	0	60	6.15	0	34
35	1964	0	61	6.05	0	35
36	1965	0	64	5.77	0	36
37	1966	0	65	5.68	0	37
38	1967	0	67	5.51	0	38
39	1968	0	71	5.20	0	39
40	1969	0	75	4.92	0	40
41	1970	0	79	4.67	0	41
42	1971	0	87	4.24	0	42
43	1972	0	93	3.97	0	43
44	1973	0	100	3.69	0	44
45	1974	0	118	3.13	0	45
46	1975	0	133	2.77	0	46
47	1976	0	138	2.67	0	47
48	1977	0	148	2.49	0	48
49	1978	0	161	2.29	0	49
50	1979	0	177	2.08	0	50
51	1980	0	194	1.90	0	51
52	1981	0	204	1.81	0	52
53	1982	2,627	207	1.78	4,676	53
54	1983	115,704	215	1.72	199,011	54
55	1984	428,836	224	1.65	707,579	55
56	1985	116,407	226	1.63	189,743	56
57	1986	31,084	231	1.60	49,734	57
58	1987	581,609	232	1.59	924,758	58
59	1988	1,012,423	233	1.58	1,599,628	59
60	1989	10,112,249	232	1.59	16,078,476	60
61	1990	66,563	237	1.56	103,838	61
62	1991	59,392	233	1.58	93,839	62
63	1992	15,661	238	1.55	24,275	63
64	1993	225,214	250	1.48	333,317	64
65	1994	43,645	261	1.41	61,539	65
66	1995	32,181	265	1.39	44,732	66
67	1996	78,025	176	2.10	163,853	67
68	1997	50,000	282	1.31	65,500	68
69	1998	257,451	285	1.29	332,112	69
70	1999	127,886	287	1.29	164,973	70
71	2000	364,071	295	1.25	455,089	71
72	2001	133,508	303	1.22	162,880	72
73	2002	69,752	310	1.19	83,005	73
74	2003	190,103	320	1.15	218,618	74
75	2004	757,550	342	1.08	818,154	75
76	2005	2,466,847	355	1.04	2,565,521	76
77	2006	259,307	364	1.01	261,900	77
78	2007	330,840	369	1.00	330,840	78
79	Total	$ 17,928,935			$ 26,037,590	79

Southwest Gas Corporation
System Allocable Plant
RCND Cost of Gas Plant in Service at April 30, 2007

Account 391 - Office Furniture and Equipment

Line No.	Year Installed	Original Cost	H - W Index	Ratio To Current Index	RCN Cost	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	11	28.18	$ 0	1
2	1931	0	11	28.18	0	2
3	1932	0	11	28.18	0	3
4	1933	0	11	28.18	0	4
5	1934	0	11	28.18	0	5
6	1935	0	11	28.18	0	6
7	1936	0	12	25.83	0	7
8	1937	0	13	23.85	0	8
9	1938	0	13	23.85	0	9
10	1939	0	13	23.85	0	10
11	1940	0	13	23.85	0	11
12	1941	0	13	23.85	0	12
13	1942	0	15	20.67	0	13
14	1943	0	15	20.67	0	14
15	1944	0	15	20.67	0	15
16	1945	0	16	19.38	0	16
17	1946	0	20	15.50	0	17
18	1947	0	23	13.48	0	18
19	1948	0	26	11.92	0	19
20	1949	0	26	11.92	0	20
21	1950	0	27	11.48	0	21
22	1951	0	29	10.69	0	22
23	1952	0	31	10.00	0	23
24	1953	0	33	9.39	0	24
25	1954	0	34	9.12	0	25
26	1955	0	36	8.61	0	26
27	1956	0	39	7.95	0	27
28	1957	0	41	7.56	0	28
29	1958	0	42	7.38	0	29
30	1959	0	45	6.89	0	30
31	1960	0	46	6.74	0	31
32	1961	0	51	6.08	0	32
33	1962	0	53	5.85	0	33
34	1963	0	55	5.64	0	34
35	1964	0	57	5.44	0	35
36	1965	0	60	5.17	0	36
37	1966	0	62	5.00	0	37
38	1967	0	66	4.70	0	38
39	1968	0	70	4.43	0	39
40	1969	0	74	4.19	0	40
41	1970	0	81	3.83	0	41
42	1971	0	87	3.56	0	42
43	1972	0	94	3.30	0	43
44	1973	0	100	3.10	0	44
45	1974	0	109	2.84	0	45
46	1975	1,110	123	2.52	2,797	46
47	1976	0	130	2.38	0	47
48	1977	1,109	141	2.20	2,440	48
49	1978	0	151	2.05	0	49
50	1979	21,369	164	1.89	40,387	50
51	1980	3,560	178	1.74	6,194	51
52	1981	42,149	186	1.67	70,389	52
53	1982	111,131	203	1.53	170,030	53
54	1983	9,269	209	1.48	13,718	54
55	1984	239,609	212	1.46	349,829	55
56	1985	226,356	211	1.47	332,743	56
57	1986	109,935	218	1.42	156,108	57
58	1987	139,348	226	1.37	190,907	58
59	1988	32,514	219	1.42	46,170	59
60	1989	94,482	213	1.46	137,944	60
61	1990	52,047	228	1.36	70,784	61
62	1991	94,774	242	1.28	121,311	62
63	1992	60,430	249	1.24	74,933	63
64	1993	793,678	260	1.19	944,477	64
65	1994	180,094	257	1.21	217,914	65
66	1995	273,368	246	1.26	344,444	66
67	1996	32,878	250	1.24	40,769	67
68	1997	317,421	251	1.24	393,602	68
69	1998	530,680	254	1.22	647,430	69
70	1999	187,692	261	1.19	223,353	70
71	2000	157,430	268	1.16	182,619	71
72	2001	254,358	280	1.11	282,337	72
73	2002	792,328	289	1.07	847,791	73
74	2003	417,820	293	1.06	442,889	74
75	2004	223,117	298	1.04	232,042	75
76	2005	149,523	303	1.02	152,513	76
77	2006	1,385,103	305	1.02	1,412,805	77
78	2007	2,478,907	310	1.00	2,478,907	78
79	Total	$ 9,413,589			$ 10,630,576	79

Southwest Gas Corporation
System Allocable Plant
RCND Cost of Gas Plant In Service at April 30, 2007

Account 391.1 - Computer Equipment

Line No.	Year Installed	Original Cost	H - W Index	Ratio To Current Index	RCN Cost	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	11	28.18	$ 0	1
2	1931	0	11	28.18	0	2
3	1932	0	11	28.18	0	3
4	1933	0	11	28.18	0	4
5	1934	0	11	28.18	0	5
6	1935	0	11	28.18	0	6
7	1936	0	12	25.83	0	7
8	1937	0	13	23.85	0	8
9	1938	0	13	23.85	0	9
10	1939	0	13	23.85	0	10
11	1940	0	13	23.85	0	11
12	1941	0	13	23.85	0	12
13	1942	0	15	20.67	0	13
14	1943	0	15	20.67	0	14
15	1944	0	15	20.67	0	15
16	1945	0	16	19.38	0	16
17	1946	0	20	15.50	0	17
18	1947	0	23	13.48	0	18
19	1948	0	26	11.92	0	19
20	1949	0	26	11.92	0	20
21	1950	0	27	11.48	0	21
22	1951	0	29	10.69	0	22
23	1952	0	31	10.00	0	23
24	1953	0	33	9.39	0	24
25	1954	0	34	9.12	0	25
26	1955	0	36	8.61	0	26
27	1956	0	39	7.95	0	27
28	1957	0	41	7.56	0	28
29	1958	0	42	7.38	0	29
30	1959	0	45	6.89	0	30
31	1960	0	46	6.74	0	31
32	1961	0	51	6.08	0	32
33	1962	0	53	5.85	0	33
34	1963	0	55	5.64	0	34
35	1964	0	57	5.44	0	35
36	1965	0	60	5.17	0	36
37	1966	0	62	5.00	0	37
38	1967	0	66	4.70	0	38
39	1968	0	70	4.43	0	39
40	1969	0	74	4.19	0	40
41	1970	0	81	3.83	0	41
42	1971	0	87	3.56	0	42
43	1972	0	94	3.30	0	43
44	1973	0	100	3.10	0	44
45	1974	0	109	2.84	0	45
46	1975	0	123	2.52	0	46
47	1976	0	130	2.38	0	47
48	1977	0	141	2.20	0	48
49	1978	0	151	2.05	0	49
50	1979	0	164	1.89	0	50
51	1980	0	178	1.74	0	51
52	1981	0	186	1.67	0	52
53	1982	0	203	1.53	0	53
54	1983	0	209	1.48	0	54
55	1984	0	212	1.46	0	55
56	1985	0	211	1.47	0	56
57	1986	0	218	1.42	0	57
58	1987	15,509	226	1.37	21,247	58
59	1988	20,788	219	1.42	29,519	59
60	1989	0	213	1.46	0	60
61	1990	13,289	228	1.36	18,073	61
62	1991	0	242	1.28	0	62
63	1992	4,711	249	1.24	5,842	63
64	1993	142,408	260	1.19	169,466	64
65	1994	8,266	257	1.21	10,002	65
66	1995	1,557,156	246	1.26	1,962,017	66
67	1996	970,663	250	1.24	1,203,622	67
68	1997	656,937	251	1.24	814,602	68
69	1998	238,253	254	1.22	290,669	69
70	1999	1,704,416	261	1.19	2,028,255	70
71	2000	420,553	268	1.16	487,841	71
72	2001	926,702	280	1.11	1,028,639	72
73	2002	1,669,071	289	1.07	1,785,906	73
74	2003	991,003	293	1.06	1,050,463	74
75	2004	496,647	298	1.04	516,513	75
76	2005	1,942,958	303	1.02	1,981,817	76
77	2006	2,424,573	305	1.02	2,473,064	77
78	2007	154,932	310	1.00	154,932	78
79	Total	14,358,835			$ 16,032,489	79

Southwest Gas Corporation
System Allocable Plant
RCND Cost of Gas Plant in Service at April 30, 2007

Account 392.11 - Transportation Equip. - Light Vehicles

Line No.	Year Installed	Original Cost	H - W Index	Ratio To Current Index	RCN Cost	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	22	21.05	$ 0	1
2	1931	0	20	23.15	0	2
3	1932	0	19	24.37	0	3
4	1933	0	19	24.37	0	4
5	1934	0	20	23.15	0	5
6	1935	0	21	22.05	0	6
7	1936	0	21	22.05	0	7
8	1937	0	23	20.13	0	8
9	1938	0	23	20.13	0	9
10	1939	0	23	20.13	0	10
11	1940	0	24	19.29	0	11
12	1941	0	25	18.52	0	12
13	1942	0	28	16.54	0	13
14	1943	0	29	15.97	0	14
15	1944	0	29	15.97	0	15
16	1945	0	29	15.97	0	16
17	1946	0	34	13.62	0	17
18	1947	0	37	12.51	0	18
19	1948	0	39	11.87	0	19
20	1949	0	40	11.58	0	20
21	1950	0	42	11.02	0	21
22	1951	0	45	10.29	0	22
23	1952	0	46	10.07	0	23
24	1953	0	49	9.45	0	24
25	1954	0	49	9.45	0	25
26	1955	0	51	9.08	0	26
27	1956	0	55	8.42	0	27
28	1957	0	59	7.85	0	28
29	1958	0	62	7.47	0	29
30	1959	0	64	7.23	0	30
31	1960	0	65	7.12	0	31
32	1961	0	67	6.91	0	32
33	1962	0	67	6.91	0	33
34	1963	0	68	6.81	0	34
35	1964	0	70	6.61	0	35
36	1965	0	71	6.52	0	36
37	1966	0	73	6.34	0	37
38	1967	0	76	6.09	0	38
39	1968	0	80	5.79	0	39
40	1969	0	84	5.51	0	40
41	1970	0	88	5.26	0	41
42	1971	0	93	4.98	0	42
43	1972	0	95	4.87	0	43
44	1973	0	100	4.63	0	44
45	1974	0	117	3.96	0	45
46	1975	0	141	3.28	0	46
47	1976	0	153	3.03	0	47
48	1977	0	164	2.82	0	48
49	1978	0	178	2.60	0	49
50	1979	0	197	2.35	0	50
51	1980	0	222	2.09	0	51
52	1981	0	246	1.88	0	52
53	1982	0	263	1.76	0	53
54	1983	0	269	1.72	0	54
55	1984	0	273	1.70	0	55
56	1985	0	276	1.68	0	56
57	1986	0	280	1.65	0	57
58	1987	0	286	1.62	0	58
59	1988	0	295	1.57	0	59
60	1989	0	281	1.65	0	60
61	1990	0	298	1.55	0	61
62	1991	0	320	1.45	0	62
63	1992	0	316	1.47	0	63
64	1993	0	324	1.43	0	64
65	1994	0	331	1.40	0	65
66	1995	76,379	333	1.39	106,167	66
67	1996	37,111	336	1.38	51,213	67
68	1997	60,586	351	1.32	79,974	68
69	1998	134,635	380	1.22	164,255	69
70	1999	97,475	385	1.20	116,970	70
71	2000	176,541	389	1.19	210,084	71
72	2001	477,300	390	1.19	567,987	72
73	2002	177,063	395	1.17	207,164	73
74	2003	317,824	401	1.15	365,498	74
75	2004	701,089	414	1.12	785,220	75
76	2005	520,369	439	1.05	546,387	76
77	2006	548,895	457	1.01	554,384	77
78	2007	170,559	463	1.00	170,559	78
79	Total	$ 3,495,826			$ 3,925,862	79

Southwest Gas Corporation
System Allocable Plant
RCND Cost of Gas Plant In Service at April 30, 2007

Account 392.12 - Transportation Equip - Heavy Vehicles

Line No.	Year Installed	Original Cost	H - W Index	Ratio To Current Index	RCN Cost	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	22	21.05	$ 0	1
2	1931	0	20	23.15	0	2
3	1932	0	19	24.37	0	3
4	1933	0	19	24.37	0	4
5	1934	0	20	23.15	0	5
6	1935	0	21	22.05	0	6
7	1936	0	21	22.05	0	7
8	1937	0	23	20.13	0	8
9	1938	0	23	20.13	0	9
10	1939	0	23	20.13	0	10
11	1940	0	24	19.29	0	11
12	1941	0	25	18.52	0	12
13	1942	0	28	16.54	0	13
14	1943	0	29	15.97	0	14
15	1944	0	29	15.97	0	15
16	1945	0	29	15.97	0	16
17	1946	0	34	13.62	0	17
18	1947	0	37	12.51	0	18
19	1948	0	39	11.87	0	19
20	1949	0	40	11.58	0	20
21	1950	0	42	11.02	0	21
22	1951	0	45	10.29	0	22
23	1952	0	46	10.07	0	23
24	1953	0	49	9.45	0	24
25	1954	0	49	9.45	0	25
26	1955	0	51	9.08	0	26
27	1956	0	55	8.42	0	27
28	1957	0	59	7.85	0	28
29	1958	0	62	7.47	0	29
30	1959	0	64	7.23	0	30
31	1960	0	65	7.12	0	31
32	1961	0	67	6.91	0	32
33	1962	0	67	6.91	0	33
34	1963	0	68	6.81	0	34
35	1964	0	70	6.61	0	35
36	1965	0	71	6.52	0	36
37	1966	0	73	6.34	0	37
38	1967	0	76	6.09	0	38
39	1968	0	80	5.79	0	39
40	1969	0	84	5.51	0	40
41	1970	0	88	5.26	0	41
42	1971	0	93	4.98	0	42
43	1972	0	95	4.87	0	43
44	1973	0	100	4.63	0	44
45	1974	0	117	3.96	0	45
46	1975	0	141	3.28	0	46
47	1976	0	153	3.03	0	47
48	1977	0	164	2.82	0	48
49	1978	0	178	2.60	0	49
50	1979	0	197	2.35	0	50
51	1980	0	222	2.09	0	51
52	1981	0	246	1.88	0	52
53	1982	0	263	1.76	0	53
54	1983	0	269	1.72	0	54
55	1984	0	273	1.70	0	55
56	1985	0	276	1.68	0	56
57	1986	0	280	1.65	0	57
58	1987	0	286	1.62	0	58
59	1988	0	295	1.57	0	59
60	1989	0	281	1.65	0	60
61	1990	0	298	1.55	0	61
62	1991	0	320	1.45	0	62
63	1992	0	316	1.47	0	63
64	1993	0	324	1.43	0	64
65	1994	0	331	1.40	0	65
66	1995	0	333	1.39	0	66
67	1996	0	336	1.38	0	67
68	1997	0	351	1.32	0	68
69	1998	0	380	1.22	0	69
70	1999	0	385	1.20	0	70
71	2000	37,640	389	1.19	44,792	71
72	2001	48,663	390	1.19	57,909	72
73	2002	0	395	1.17	0	73
74	2003	0	401	1.15	0	74
75	2004	0	414	1.12	0	75
76	2005	0	439	1.05	0	76
77	2006	0	457	1.01	0	77
78	2007	0	463	1.00	0	78
79	Total	$ 86,303			$ 102,701	79

Southwest Gas Corporation
System Allocable Plant
RCND Cost of Gas Plant in Service at April 30, 2007

Account 393 - Stores Equipment

Line No.	Year Installed	Original Cost	H - W Index	Ratio To Current Index	RCN Cost	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	22	21.05	$ 0	1
2	1931	0	20	23.15	0	2
3	1932	0	19	24.37	0	3
4	1933	0	19	24.37	0	4
5	1934	0	20	23.15	0	5
6	1935	0	21	22.05	0	6
7	1936	0	21	22.05	0	7
8	1937	0	23	20.13	0	8
9	1938	0	23	20.13	0	9
10	1939	0	23	20.13	0	10
11	1940	0	24	19.29	0	11
12	1941	0	25	18.52	0	12
13	1942	0	28	16.54	0	13
14	1943	0	29	15.97	0	14
15	1944	0	29	15.97	0	15
16	1945	0	29	15.97	0	16
17	1946	0	34	13.62	0	17
18	1947	0	37	12.51	0	18
19	1948	0	39	11.87	0	19
20	1949	0	40	11.58	0	20
21	1950	0	42	11.02	0	21
22	1951	0	45	10.29	0	22
23	1952	0	46	10.07	0	23
24	1953	0	49	9.45	0	24
25	1954	0	49	9.45	0	25
26	1955	0	51	9.08	0	26
27	1956	0	55	8.42	0	27
28	1957	0	59	7.85	0	28
29	1958	0	62	7.47	0	29
30	1959	0	64	7.23	0	30
31	1960	0	65	7.12	0	31
32	1961	0	67	6.91	0	32
33	1962	0	67	6.91	0	33
34	1963	0	68	6.81	0	34
35	1964	0	70	6.61	0	35
36	1965	0	71	6.52	0	36
37	1966	0	73	6.34	0	37
38	1967	0	76	6.09	0	38
39	1968	0	80	5.79	0	39
40	1969	0	84	5.51	0	40
41	1970	0	88	5.26	0	41
42	1971	0	93	4.98	0	42
43	1972	0	95	4.87	0	43
44	1973	0	100	4.63	0	44
45	1974	0	117	3.96	0	45
46	1975	0	141	3.28	0	46
47	1976	0	153	3.03	0	47
48	1977	0	164	2.82	0	48
49	1978	0	178	2.60	0	49
50	1979	0	197	2.35	0	50
51	1980	0	222	2.09	0	51
52	1981	0	246	1.88	0	52
53	1982	0	263	1.76	0	53
54	1983	0	269	1.72	0	54
55	1984	0	273	1.70	0	55
56	1985	9,972	276	1.68	16,753	56
57	1986	0	280	1.65	0	57
58	1987	0	286	1.62	0	58
59	1988	5,765	295	1.57	9,051	59
60	1989	0	281	1.65	0	60
61	1990	0	298	1.55	0	61
62	1991	0	320	1.45	0	62
63	1992	0	316	1.47	0	63
64	1993	4,370	324	1.43	6,249	64
65	1994	0	331	1.40	0	65
66	1995	0	333	1.39	0	66
67	1996	0	336	1.38	0	67
68	1997	0	351	1.32	0	68
69	1998	0	380	1.22	0	69
70	1999	0	385	1.20	0	70
71	2000	0	389	1.19	0	71
72	2001	0	390	1.19	0	72
73	2002	3,999	395	1.17	4,679	73
74	2003	0	401	1.15	0	74
75	2004	0	414	1.12	0	75
76	2005	0	439	1.05	0	76
77	2006	0	457	1.01	0	77
78	2007	0	463	1.00	0	78
79	Total	$ 24,106			$ 36,732	79

Southwest Gas Corporation
System Allocable Plant
RCND Cost of Gas Plant in Service at April 30, 2007

Account 394 - Tools, Shop, and Garage Equipment

Line No.	Year Installed	Original Cost	H - W Index	Ratio To Current Index	RCN Cost	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	22	21.05	$ 0	1
2	1931	0	20	23.15	0	2
3	1932	0	19	24.37	0	3
4	1933	0	19	24.37	0	4
5	1934	0	20	23.15	0	5
6	1935	0	21	22.05	0	6
7	1936	0	21	22.05	0	7
8	1937	0	23	20.13	0	8
9	1938	0	23	20.13	0	9
10	1939	0	23	20.13	0	10
11	1940	0	24	19.29	0	11
12	1941	0	25	18.52	0	12
13	1942	0	28	16.54	0	13
14	1943	0	29	15.97	0	14
15	1944	0	29	15.97	0	15
16	1945	0	29	15.97	0	16
17	1946	0	34	13.62	0	17
18	1947	0	37	12.51	0	18
19	1948	0	39	11.87	0	19
20	1949	0	40	11.58	0	20
21	1950	0	42	11.02	0	21
22	1951	0	45	10.29	0	22
23	1952	0	46	10.07	0	23
24	1953	0	49	9.45	0	24
25	1954	0	49	9.45	0	25
26	1955	0	51	9.08	0	26
27	1956	0	55	8.42	0	27
28	1957	0	59	7.85	0	28
29	1958	0	62	7.47	0	29
30	1959	0	64	7.23	0	30
31	1960	0	65	7.12	0	31
32	1961	0	67	6.91	0	32
33	1962	0	67	6.91	0	33
34	1963	0	68	6.81	0	34
35	1964	0	70	6.61	0	35
36	1965	0	71	6.52	0	36
37	1966	0	73	6.34	0	37
38	1967	0	76	6.09	0	38
39	1968	0	80	5.79	0	39
40	1969	0	84	5.51	0	40
41	1970	0	88	5.26	0	41
42	1971	0	93	4.98	0	42
43	1972	0	95	4.87	0	43
44	1973	0	100	4.63	0	44
45	1974	0	117	3.96	0	45
46	1975	0	141	3.28	0	46
47	1976	0	153	3.03	0	47
48	1977	0	164	2.82	0	48
49	1978	0	178	2.60	0	49
50	1979	0	197	2.35	0	50
51	1980	0	222	2.09	0	51
52	1981	0	246	1.88	0	52
53	1982	0	263	1.76	0	53
54	1983	0	269	1.72	0	54
55	1984	0	273	1.70	0	55
56	1985	0	276	1.68	0	56
57	1986	0	280	1.65	0	57
58	1987	3,127	286	1.62	5,066	58
59	1988	0	295	1.57	0	59
60	1989	1,667	281	1.65	2,751	60
61	1990	0	298	1.55	0	61
62	1991	0	320	1.45	0	62
63	1992	18,955	316	1.47	27,864	63
64	1993	10,828	324	1.43	15,484	64
65	1994	21,272	331	1.40	29,781	65
66	1995	6,222	333	1.39	8,649	66
67	1996	7,203	336	1.38	9,940	67
68	1997	0	351	1.32	0	68
69	1998	0	380	1.22	0	69
70	1999	21,393	385	1.20	25,672	70
71	2000	16,336	389	1.19	19,440	71
72	2001	36,762	390	1.19	43,747	72
73	2002	3,117	395	1.17	3,647	73
74	2003	19,712	401	1.15	22,669	74
75	2004	33,759	414	1.12	37,810	75
76	2005	26,730	439	1.05	28,067	76
77	2006	5,013	457	1.01	5,063	77
78	2007	0	463	1.00	0	78
79	Total	$ 232,096			$ 285,650	79

Southwest Gas Corporation
System Allocable Plant
RCND Cost of Gas Plant in Service at April 30, 2007

Account 395 - Laboratory Equipment

Line No.	Year Installed	Original Cost	H - W Index	Ratio To Current Index	RCN Cost	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	11	28.18	$ 0	1
2	1931	0	11	28.18	0	2
3	1932	0	11	28.18	0	3
4	1933	0	11	28.18	0	4
5	1934	0	11	28.18	0	5
6	1935	0	11	28.18	0	6
7	1936	0	12	25.83	0	7
8	1937	0	13	23.85	0	8
9	1938	0	13	23.85	0	9
10	1939	0	13	23.85	0	10
11	1940	0	13	23.85	0	11
12	1941	0	13	23.85	0	12
13	1942	0	15	20.67	0	13
14	1943	0	15	20.67	0	14
15	1944	0	15	20.67	0	15
16	1945	0	16	19.38	0	16
17	1946	0	20	15.50	0	17
18	1947	0	23	13.48	0	18
19	1948	0	26	11.92	0	19
20	1949	0	26	11.92	0	20
21	1950	0	27	11.48	0	21
22	1951	0	29	10.69	0	22
23	1952	0	31	10.00	0	23
24	1953	0	33	9.39	0	24
25	1954	0	34	9.12	0	25
26	1955	0	36	8.61	0	26
27	1956	0	39	7.95	0	27
28	1957	0	41	7.56	0	28
29	1958	0	42	7.38	0	29
30	1959	0	45	6.89	0	30
31	1960	0	46	6.74	0	31
32	1961	0	51	6.08	0	32
33	1962	0	53	5.85	0	33
34	1963	0	55	5.64	0	34
35	1964	0	57	5.44	0	35
36	1965	0	60	5.17	0	36
37	1966	0	62	5.00	0	37
38	1967	0	66	4.70	0	38
39	1968	0	70	4.43	0	39
40	1969	0	74	4.19	0	40
41	1970	0	81	3.83	0	41
42	1971	0	87	3.56	0	42
43	1972	0	94	3.30	0	43
44	1973	0	100	3.10	0	44
45	1974	0	109	2.84	0	45
46	1975	0	123	2.52	0	46
47	1976	0	130	2.38	0	47
48	1977	0	141	2.20	0	48
49	1978	0	151	2.05	0	49
50	1979	0	164	1.89	0	50
51	1980	0	178	1.74	0	51
52	1981	0	186	1.67	0	52
53	1982	0	203	1.53	0	53
54	1983	15,956	209	1.48	23,615	54
55	1984	0	212	1.46	0	55
56	1985	0	211	1.47	0	56
57	1986	0	218	1.42	0	57
58	1987	2,948	226	1.37	4,039	58
59	1988	0	219	1.42	0	59
60	1989	53,551	213	1.46	78,184	60
61	1990	11,519	228	1.36	15,666	61
62	1991	51,141	242	1.28	65,460	62
63	1992	1,364	249	1.24	1,691	63
64	1993	16,254	260	1.19	19,342	64
65	1994	2,387	257	1.21	2,888	65
66	1995	6,021	246	1.26	7,586	66
67	1996	2,723	250	1.24	3,377	67
68	1997	0	251	1.24	0	68
69	1998	0	254	1.22	0	69
70	1999	0	261	1.19	0	70
71	2000	0	268	1.16	0	71
72	2001	0	280	1.11	0	72
73	2002	46,969	289	1.07	50,257	73
74	2003	0	293	1.06	0	74
75	2004	15,738	298	1.04	16,368	75
76	2005	44,639	303	1.02	45,532	76
77	2006	0	305	1.02	0	77
78	2007	9,868	310	1.00	9,868	78
79	Total	$ 281,078			$ 343,873	79

Southwest Gas Corporation
System Allocable Plant
RCND Cost of Gas Plant in Service at April 30, 2007

Account 397 - Communication Equipment

Line No.	Year Installed	Original Cost	H - W Index	Ratio To Current Index	RCN Cost	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	15	23.33	$ 0	1
2	1931	0	15	23.33	0	2
3	1932	0	15	23.33	0	3
4	1933	0	15	23.33	0	4
5	1934	0	15	23.33	0	5
6	1935	0	15	23.33	0	6
7	1936	0	15	23.33	0	7
8	1937	0	17	20.59	0	8
9	1938	0	17	20.59	0	9
10	1939	0	17	20.59	0	10
11	1940	0	17	20.59	0	11
12	1941	0	18	19.44	0	12
13	1942	0	19	18.42	0	13
14	1943	0	19	18.42	0	14
15	1944	0	19	18.42	0	15
16	1945	0	19	18.42	0	16
17	1946	0	21	16.67	0	17
18	1947	0	24	14.58	0	18
19	1948	0	26	13.46	0	19
20	1949	0	28	12.50	0	20
21	1950	0	30	11.67	0	21
22	1951	0	31	11.29	0	22
23	1952	0	33	10.61	0	23
24	1953	0	34	10.29	0	24
25	1954	0	36	9.72	0	25
26	1955	0	37	9.46	0	26
27	1956	0	39	8.97	0	27
28	1957	0	41	8.54	0	28
29	1958	0	42	8.33	0	29
30	1959	0	45	7.78	0	30
31	1960	0	46	7.61	0	31
32	1961	0	49	7.14	0	32
33	1962	0	51	6.86	0	33
34	1963	0	52	6.73	0	34
35	1964	0	54	6.48	0	35
36	1965	0	57	6.14	0	36
37	1966	0	58	6.03	0	37
38	1967	0	62	5.65	0	38
39	1968	0	64	5.47	0	39
40	1969	0	69	5.07	0	40
41	1970	0	78	4.49	0	41
42	1971	0	88	3.98	0	42
43	1972	0	95	3.68	0	43
44	1973	0	100	3.50	0	44
45	1974	0	109	3.21	0	45
46	1975	0	122	2.87	0	46
47	1976	0	131	2.67	0	47
48	1977	0	142	2.46	0	48
49	1978	0	151	2.32	0	49
50	1979	0	160	2.19	0	50
51	1980	0	170	2.06	0	51
52	1981	0	185	1.89	0	52
53	1982	0	206	1.70	0	53
54	1983	0	218	1.61	0	54
55	1984	0	220	1.59	0	55
56	1985	2,036	214	1.64	3,339	56
57	1986	0	215	1.63	0	57
58	1987	0	216	1.62	0	58
59	1988	108,194	215	1.63	176,356	59
60	1989	0	214	1.64	0	60
61	1990	0	220	1.59	0	61
62	1991	0	225	1.56	0	62
63	1992	0	232	1.51	0	63
64	1993	10,150	236	1.48	15,022	64
65	1994	503,169	239	1.46	734,627	65
66	1995	107,946	247	1.42	153,283	66
67	1996	1,840,500	254	1.38	2,539,890	67
68	1997	230,627	257	1.36	313,653	68
69	1998	502,642	265	1.32	663,487	69
70	1999	61,658	275	1.27	78,306	70
71	2000	450,007	285	1.23	553,509	71
72	2001	113,486	299	1.17	132,779	72
73	2002	594,260	309	1.13	671,514	73
74	2003	287,842	318	1.10	316,626	74
75	2004	57,462	327	1.07	61,484	75
76	2005	439,560	337	1.04	457,142	76
77	2006	41,782	345	1.01	42,200	77
78	2007	312,512	350	1.00	312,512	78
79	Total	$ 5,663,833			$ 7,225,729	79

Southwest Gas Corporation
System Allocable Plant
RCND Cost of Gas Plant in Service at April 30, 2007

Account 398 - Miscellaneous Equipment

Line No.	Year Installed	Original Cost	H - W Index	Ratio To Current Index	RCN Cost	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	1930	$ 0	15	23.33	$ 0	1
2	1931	0	15	23.33	0	2
3	1932	0	15	23.33	0	3
4	1933	0	15	23.33	0	4
5	1934	0	15	23.33	0	5
6	1935	0	15	23.33	0	6
7	1936	0	15	23.33	0	7
8	1937	0	17	20.59	0	8
9	1938	0	17	20.59	0	9
10	1939	0	17	20.59	0	10
11	1940	0	17	20.59	0	11
12	1941	0	18	19.44	0	12
13	1942	0	19	18.42	0	13
14	1943	0	19	18.42	0	14
15	1944	0	19	18.42	0	15
16	1945	0	19	18.42	0	16
17	1946	0	21	16.67	0	17
18	1947	0	24	14.58	0	18
19	1948	0	26	13.46	0	19
20	1949	0	28	12.50	0	20
21	1950	0	30	11.67	0	21
22	1951	0	31	11.29	0	22
23	1952	0	33	10.61	0	23
24	1953	0	34	10.29	0	24
25	1954	0	36	9.72	0	25
26	1955	0	37	9.46	0	26
27	1956	0	39	8.97	0	27
28	1957	0	41	8.54	0	28
29	1958	0	42	8.33	0	29
30	1959	0	45	7.78	0	30
31	1960	0	46	7.61	0	31
32	1961	0	49	7.14	0	32
33	1962	0	51	6.86	0	33
34	1963	0	52	6.73	0	34
35	1964	0	54	6.48	0	35
36	1965	0	57	6.14	0	36
37	1966	0	58	6.03	0	37
38	1967	0	62	5.65	0	38
39	1968	0	64	5.47	0	39
40	1969	0	69	5.07	0	40
41	1970	0	78	4.49	0	41
42	1971	0	88	3.98	0	42
43	1972	0	95	3.68	0	43
44	1973	0	100	3.50	0	44
45	1974	0	109	3.21	0	45
46	1975	0	122	2.87	0	46
47	1976	0	131	2.67	0	47
48	1977	0	142	2.46	0	48
49	1978	0	151	2.32	0	49
50	1979	2,094	160	2.19	4,586	50
51	1980	14,327	170	2.06	29,514	51
52	1981	0	185	1.89	0	52
53	1982	6,931	206	1.70	11,783	53
54	1983	28,541	218	1.61	45,951	54
55	1984	0	220	1.59	0	55
56	1985	13,167	214	1.64	21,594	56
57	1986	2,224	215	1.63	3,625	57
58	1987	32,389	216	1.62	52,470	58
59	1988	17,166	215	1.63	27,981	59
60	1989	6,073	214	1.64	9,960	60
61	1990	5,679	220	1.59	9,030	61
62	1991	0	225	1.56	0	62
63	1992	0	232	1.51	0	63
64	1993	5,876	236	1.48	8,696	64
65	1994	4,570	239	1.46	6,672	65
66	1995	9,222	247	1.42	13,095	66
67	1996	21,868	254	1.38	30,178	67
68	1997	0	257	1.36	0	68
69	1998	16,533	265	1.32	21,824	69
70	1999	78,187	275	1.27	99,297	70
71	2000	21,260	285	1.23	26,150	71
72	2001	59,053	299	1.17	69,092	72
73	2002	130,344	309	1.13	147,289	73
74	2003	235,306	318	1.10	258,837	74
75	2004	33,110	327	1.07	35,428	75
76	2005	40,768	337	1.04	42,399	76
77	2006	97,566	345	1.01	98,542	77
78	2007	0	350	1.00	0	78
79	Total	$ 882,254			$ 1,073,993	79

SOUTHWEST GAS CORPORATION
ARIZONA
SUMMARY OF WORKING CAPITAL ALLOWANCE
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description (a)	Reference (b)	Balance (c)	Line No.
1	Cash Working Capital	B-5, Sh 2	$ (10,379,937)	1
2	Materials and Supplies	B-5, Sh 3	12,389,898	2
3	Prepayments	B-5, Sh 4	3,671,971	3
4	Total Working Capital		$ 5,681,932	4
			B-1, Sh 1	

SOUTHWEST GAS CORPORATION
ARIZONA
LEAD-LAG STUDY
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description [1] (a)	Cost (b)	Lag Days (c)	Dollar Days (d)	Line No.
1	Cost of Gas [2]	$ 540,064,385	42.30	22,842,405,297	1
2	Labor Cost	117,038,570	12.33	1,443,650,156	2
3	Provision for Uncollected Accounts	2,977,729	120.00	357,327,523	3
4	Other O & M Expenses	54,826,860	8.40	460,689,209	4
5	Total O & M Expenses	$ 714,907,545	35.12	25,104,072,186	5
6	Interest	48,035,008	84.65	4,066,302,142	6
7	Taxes Other Than Income Taxes	33,124,880	185.34	6,139,365,177	7
8	Income Taxes-Current	21,699,571	37.00	802,884,115	8
9	Total Operating Expenses	$ 817,767,003	44.16	36,112,623,619	9
10	Number of Days in Test Period	365			10
11	Average Daily Operating Expense	$ 2,240,458			11
12	Lag in Receipt of Revenue		39.53		12
13	Net Difference Revenue-Expense Lag	(4.63)			13
14	Cash Working Capital	$ (10,379,937)			14
		B-5, Sh 1			

[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 APRIL 30, 2007

Line No.	Description	Account Number [1] 154	155	163	System Allocable	Total Materials and Supplies	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
1	April 2006	$ 10,597,125	$ 32,492	$ 279,910	$ (15,105)	$ 10,894,422	1
2	May	11,983,908	33,770	271,892	(15,266)	12,274,304	2
3	June	11,689,534	34,098	182,004	(15,364)	11,890,271	3
4	July	11,770,954	36,340	170,741	(15,553)	11,962,482	4
5	August	11,445,271	39,575	292,884	(15,638)	11,762,092	5
6	September	11,495,118	36,003	546,932	(15,730)	12,062,323	6
7	October	12,297,156	37,707	712,071	(15,751)	13,031,182	7
8	November	12,188,899	34,120	828,671	(13,992)	13,037,698	8
9	December	11,943,342	32,556	1,063,757	(14,070)	13,025,585	9
10	January 2007	11,734,137	33,185	914,604	(15,954)	12,665,971	10
11	February	10,991,050	34,695	1,082,310	(16,071)	12,091,985	11
12	March	12,320,228	32,740	1,363,463	(16,207)	13,700,223	12
13	April	11,644,649	32,332	1,009,492	(16,343)	12,670,131	13
14	Thirteen Month Total	$ 152,101,370	$ 449,613	$ 8,718,730	$ (201,044)	$ 161,068,668	14
15	Thirteen Month Average	$ 11,700,105	$ 34,586	$ 670,672	$ (15,465)	$ 12,389,898	15

B-5, Sh 1

Note:
System Allocable includes common inventory accounts for 154, 155 and 163 after 4-Factor allocation on Supporting Schedule C-1, Sh 17 of 56.70%.

[1] Source: Company Records

SOUTHWEST GAS CORPORATION
ARIZONA
PREPAYMENTS
FOR THE THIRTEEN MONTHS ENDED APRIL 30, 2007

Line No.	Description	Balance [1]	4-Factor [2]	Allocation	Line No.
	(a)	(b)	(c)	(d)	
1	April 2006	$ 5,367,019			1
2	May	4,571,452			2
3	June	3,756,402			3
4	July	5,219,958			4
5	August	9,299,535			5
6	September	8,623,454			6
7	October	7,836,438			7
8	November	6,430,014			8
9	December	9,144,710			9
10	January 2007	8,343,687			10
11	February	7,723,320			11
12	March	6,044,664			12
13	April	5,600,962			13
14	Thirteen Month Total	$ 87,961,615			14
15	13 Month Average	$ 6,766,278			15
16	Deferred Taxes	(290,138)			16
17	Net of Deferred Tax	$ 6,476,140	56.70%	$ 3,671,971	17
				B-5, Sh 1	

[1] Eligible Prepayments - Account 165. Supporting Workpapers B-5
[2] Supporting Schedule C-1, Sh 17

SOUTHWEST GAS CORPORATION
ARIZONA
CUSTOMER ADVANCES FOR CONSTRUCTION
FOR THE THIRTEEN MONTHS ENDED APRIL 30, 2007

Line No.	Description (a)	Balance [1] (b)	Line No.
1	April 2006	$ 25,965,152	1
2	May	27,771,678	2
3	June	30,949,084	3
4	July	32,596,096	4
5	August	35,041,274	5
6	September	36,572,843	6
7	October	38,058,790	7
8	November	38,732,669	8
9	December	41,078,966	9
10	January 2007	43,365,612	10
11	February	45,355,426	11
12	March	48,147,845	12
13	April	49,194,789	13
14	Thirteen Month Total	$ 492,830,224	14
15	Thirteen Month Average	$ 37,910,017	15
		B-1, Sh 1	

[1] Source: Company Records, Account 252

SOUTHWEST GAS CORPORATION
ARIZONA
CUSTOMER DEPOSITS
FOR THE THIRTEEN MONTHS ENDED APRIL 30, 2007

Line No.	Description (a)	Balance [1] (b)	Line No.
1	April 2006	$ 29,940,533	1
2	May	30,244,307	2
3	June	30,534,168	3
4	July	30,907,667	4
5	August	31,068,422	5
6	September	31,294,649	6
7	October	31,925,334	7
8	November	32,387,660	8
9	December	32,677,847	9
10	January 2007	32,866,855	10
11	February	33,171,595	11
12	March	33,562,862	12
13	April	34,402,771	13
14	Thirteen Month Total	$ 414,984,669	14
15	Thirteen Month Average	$ 31,921,898	15
		B-1, Sh 1	

[1] Source: Company Records, Account 235
(excludes 235.0 1330)

SOUTHWEST GAS CORPORATION
DEFERRED TAXES
AT APRIL 30, 2007

Line No.	Description [1] (a)	Arizona (b)	System Allocable Allocation (c)	Recorded Deferred Tax (d)	Line No.
1	Account 282\Deferred Tax Liability	$ 154,353,059	$ 9,156,387	$ 163,509,446	1
2	Account 190\Deferred Tax Asset	0	(20,877,149)	(20,877,149)	2
3	Total	$ 154,353,059	$ (11,720,762)	$ 142,632,297	3
				B-1, Sh 1	

Deferred Tax Detail
Arizona

	Description	Federal	State	Total Recorded	
4	Account 282\Deferred Tax Liability	$ 138,065,125	$ 16,287,934	$ 154,353,059	4
5	Account 190\Deferred Tax Asset	0	0	0	5
6	Total	$ 138,065,125	$ 16,287,934	$ 154,353,059	6

System Allocable

	Description [1]	Recorded		
7	Account 282\Deferred Tax Liability	$ 16,148,831		7
8	4-Factor [2]	56.70%		8
9	Arizona Allocation	$ 9,156,387		9
10	Account 190\Deferred Tax Asset	$ (36,820,369)		10
11	4-Factor [2]	56.70%		11
12	Arizona Allocation	$ (20,877,149)		12
		Ln 2, Col (c)		

[1] Source: Company Records
[2] Supporting Schedule C-1, Sh 17

SCHEDULE B-6
Sheet 3 of 3

SOUTHWEST GAS CORPORATION
ARIZONA
ADJUSTED TEST YEAR INCOME STATEMENT
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Reference Sch C-1, Sheet	Recorded at 04/30/07	Adjustments	Adjusted at 04/30/07	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	Revenues	2	$ 996,389,570	$ (597,154,892)	$ 399,234,678	1
2	Gas Cost	C-2, Adj 2	593,424,664	(593,424,664)	0	2
3	Total Margin		$ 402,964,907	$ (3,730,229)	$ 399,234,678	3
	Expenses					
4	Other Gas Supply	3	$ 685,079	$ 16,522	$ 701,601	4
5	Distribution	3	87,644,582	1,883,873	89,528,455	5
6	Customer Accounts	3	37,800,950	929,959	38,730,909	6
7	Customer Information	4	1,320,355	(193,559)	1,126,796	7
8	Sales	4	230,155	(230,155)	0	8
	Administrative & General					
9	Direct	9, 10, 13	4,018,714	(9,175)	4,009,539	9
10	System Allocable	9, 12, 13	49,951,482	2,985,673	52,937,155	10
	Depreciation & Amortization					
11	Direct	14, Ln 1 + 2	77,709,373	3,246,873	80,956,247	11
12	System Allocable	14, Ln 10	6,721,772	(74,834)	6,646,938	12
13	Regulatory Amortizations	14, Ln 3 + 4	2,234,576	(1,950,048)	284,528	13
14	Other Taxes	15	28,912,193	4,212,687	33,124,880	14
15	Interest On Customer Deposits	C-2, Adj 16	1,856,153	59,161	1,915,314	15
16	Income Taxes	16	21,941,766	(5,849,548)	16,092,218	16
17	Total Expenses		$ 321,027,150	$ 5,027,429	$ 326,054,579	17
18	Net Income		$ 81,937,757	$ (8,757,658)	$ 73,180,099	18

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
ADJUSTED SALES AND REVENUES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Recorded At 4/30/2007	Adjustment No. 1	Test Period Balance As Adjusted	Line No.
	(a)	(b)	(c)	(d)	
1	Sales Quantity (therms)	699,988,330	(35,386,981)	664,601,349	1
2	Revenue	$ 996,389,570	$(597,154,892)	$ 399,234,678	2
3	Total Revenue Adjustment		$(597,154,892)		3

SOUTHWEST GAS CORPORATION
ARIZONA
OPERATION AND MAINTENANCE EXPENSES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007
AS ADJUSTED FOR THE TEST YEAR

Line No.	Description (a)	Account Number (b)	Recorded at 04/30/07 (c)	Adjustments (d)	Adjusted at 04/30/07 (e)	Line No.
	Gas Supply Expenses					
1	Natural Gas Transmission Line Purchases	803	$ 497,594,745	$ (497,594,745)	$ 0	1
2	Purchased Gas Cost Adjustments	805.1	35,473,742	(35,473,742)	0	2
3	Gas Used for Compressor Station Fuel	810	0	0	0	3
4	Other Gas Supply Expenses	813	685,079	16,522	701,601	4
5	Total Other Gas Supply Expenses		$ 533,753,566	$ (533,051,965)	$ 701,601	5
	Transmission Expenses					
6	Trans. and Compression of Gas by Others	858	$ 60,356,176	$ (60,356,176)	$ 0	6
	Distribution Expenses					
7	Operation Supervision and Engineering	870	$ 10,284,450	$ 164,824	$ 10,449,274	7
8	Distribution Load Dispatching	871	365,012	6,776	371,788	8
9	Mains and Services Expenses	874	11,538,999	160,370	11,699,369	9
10	Measuring and Regulating Expenses - General	875	2,508,768	48,137	2,556,906	10
11	Meter and House Regulator Expenses	878	7,953,431	179,386	8,132,818	11
12	Customer Installation Expenses	879	9,368,426	209,595	9,578,022	12
13	Other Expenses	880	11,077,820	1,252	11,079,072	13
14	Rents	881	2,250,258	0	2,250,258	14
15	Maintenance Supervision and Engineering	885	3,063,149	72,731	3,135,880	15
16	Maintenance of Structures and Improvements	886	106,729	698	107,427	16
17	Maintenance of Mains	887	14,780,019	763,708	15,543,726	17
18	Maintenance of Meas. and Reg. Sta. Equip.	889	2,003,667	38,126	2,041,794	18
19	Maintenance of Services	892	9,932,954	199,704	10,132,658	19
20	Maintenance of Meters and House Regulators	893	2,029,799	33,418	2,063,217	20
21	Maintenance of Other Equipment	894	381,100	5,147	386,247	21
22	Total Distribution Expenses		$ 87,644,582	$ 1,883,873	$ 89,528,455	22
	Customer Accounts Expenses					
23	Supervision	901	$ 4,262,958	$ 106,518	$ 4,369,476	23
24	Meter Reading	902	6,927,716	126,770	7,054,485	24
25	Customer Records and Collection Expenses	903	23,221,791	686,168	23,907,959	25
26	Uncollectible Accounts	904	2,977,729	0	2,977,729	26
27	Miscellaneous Customer Accounts Expenses	905	410,756	10,504	421,260	27
28	Total Customer Accounts Expenses		$ 37,800,950	$ 929,959	$ 38,730,909	28

Supporting Schedules C-1, Sh 5-7

SOUTHWEST GAS CORPORATION
ARIZONA
OPERATION AND MAINTENANCE EXPENSES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007
AS ADJUSTED FOR THE TEST YEAR

Line No.	Description (a)	Account Number (b)	Recorded at 04/30/07 (c)	Adjustments (d)	Adjusted at 04/30/07 (e)	Line No.
	Customer Service and Informational Expenses					
1	Customer Assistance Expenses	908	$ 1,217,452	$ (137,759)	$ 1,079,693	1
2	Inform. and Instruc. Advertising Expenses	909	35,525	(10,400)	25,125	2
3	Misc. Customer Service and Inform. Expenses	910	67,377	(45,400)	21,977	3
4	Total Customer Service and Informational Expenses		$ 1,320,355	$ (193,559)	$ 1,126,796	4
	Sales Expenses					
5	Supervision	911	$ 0	$ 0	$ 0	5
6	Demonstrating and Selling Expenses	912	0	0	0	6
7	Advertising Expenses	913	230,155	(230,155)	0	7
8	Total Sales Expenses		$ 230,155	$ (230,155)	$ 0	8
9	Total Operation and Maintenance Expenses		$ 721,105,785	$ (591,018,024)	$ 130,087,761	9
	Administrative and General Expenses					
10	Administrative and General Salaries	920	$ 32,197,506	$ 570,687	$ 32,768,193	10
11	Office Supplies and Expenses	921	5,852,900	(5,657)	5,847,243	11
12	Admin. and Gen. Exp. Transferred - Credit	922	(5,306,010)	(93,963)	(5,399,973)	12
13	Outside Services Employed	923	5,826,032	7,789	5,833,821	13
14	Property Insurance	924	205,169	(3,563)	201,606	14
15	Injuries and Damages	925	5,678,766	2,490,088	8,168,854	15
16	Employee Pension and Benefits	926	53,270	0	53,270	16
17	Regulatory Commission Expenses	928	125,693	(33,693)	92,000	17
18	Miscellaneous General Expenses	930	3,704,733	9,716	3,714,448	18
19	Rents	931	2,525,009	4,443	2,529,452	19
20	Maintenance of General Plant	935	3,107,127	30,652	3,137,779	20
21	Total Administrative and General Expenses		$ 53,970,196	$ 2,976,498	$ 56,946,694	21
22	Total Operation, Maintenance and Administrative General Expenses		$ 775,075,980	$ (588,041,525)	$ 187,034,455	22

Supporting Schedules C-1, Sh 8-13

SOUTHWEST GAS CORPORATION
ARIZONA
OPERATION AND MAINTENANCE EXPENSES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Account Number	Recorded at 04/30/07	Purchased Gas Cost Adj. No. 2	Labor/Loading Annualization Adj. No. 3	Customer Billing Annualization Adj. No. 4	Miscellaneous Adjustments Adj. No. 5	Vehicle Compensation Adj. No. 6	Out-of-Period Expenses Adj. No. 7	Leak Survey and Repair Adj. No. 8	Surcharge Adjustment Adj. No. 9	Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
	Gas Supply Expenses												
1	Natural Gas Transmission Line Purchases	803	$ 497,594,745	$ (497,594,745)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	1
2	Purchased Gas Cost Adjustments	805.1	35,473,742	(35,473,742)	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	3
4	Total Gas Supply Expenses		$ 533,068,487	$ (533,068,487)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	4
	Other Gas Costs												
	Other Gas Supply Expenses	813											
5	Labor		$ 395,051	$ 0	$ 16,354	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 411,405	5
6	Labor Loadings		230,046	0	168	0	0	0	0	0	0	230,214	6
7	Materials and Expenses		59,983	0	0	0	0	0	0	0	0	59,983	7
8	Total		$ 685,079	$ 0	$ 16,522	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 701,601	8
	Transmission Expenses												
	Transmission and Compression of Gas	858											
9	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	9
10	Labor Loadings		0	0	0	0	0	0	0	0	0	0	10
11	Materials and Expenses		60,356,176	(60,356,176)	0	0	0	0	0	0	0	0	11
12	Total		$ 60,356,176	$ (60,356,176)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	12
	Distribution Expenses												
	Operation												
	Operation Supervision and Engineering	870											
13	Labor		$ 5,432,837	$ 0	$ 269,456	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 5,702,293	13
14	Labor Loadings		3,324,229	0	(35,615)	0	0	0	0	0	0	3,288,613	14
15	Materials and Expenses		1,527,384	0	0	0	(13,837)	(55,179)	0	0	0	1,458,368	15
16	Total		$ 10,284,450	$ 0	$ 233,841	$ 0	$ (13,837)	$ (55,179)	$ 0	$ 0	$ 0	$ 10,449,274	16
	Distribution Load Dispatching	871											
17	Labor		$ 157,302	$ 0	$ 6,786	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 164,089	17
18	Labor Loadings		94,460	0	(10)	0	0	0	0	0	0	94,450	18
19	Materials and Expenses		113,250	0	0	0	0	0	0	0	0	113,250	19
20	Total		$ 365,012	$ 0	$ 6,776	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 371,788	20
	Mains and Services Expenses	874											
21	Labor		$ 3,721,975	$ 0	$ 185,450	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 3,907,425	21
22	Labor Loadings		2,276,795	0	(25,080)	0	0	0	0	0	0	2,251,715	22
23	Materials and Expenses		5,540,228	0	0	0	0	0	0	0	0	5,540,228	23
24	Total		$ 11,538,999	$ 0	$ 160,370	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 11,699,369	24
	Measuring and Regulating Station Expenses	875											
25	Labor		$ 1,123,829	$ 0	$ 55,995	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1,179,824	25
26	Labor Loadings		687,366	0	(7,571)	0	0	0	0	0	0	679,795	26
27	Materials and Expenses		697,574	0	0	0	(286)	0	0	0		697,287	27
28	Total		$ 2,508,768	$ 0	$ 48,424	$ 0	$ (286)	$ 0	$ 0	$ 0	$ 0	$ 2,556,906	28
	Meter and House Regulator Expenses	878											
29	Labor		$ 4,168,770	$ 0	$ 207,711	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 4,376,482	29
30	Labor Loadings		2,571,424	0	(28,325)	0	0	0	0	0	0	2,543,099	30
31	Materials and Expenses		1,213,237	0	0	0	0	0	0	0	0	1,213,237	31
32	Total		$ 7,953,431	$ 0	$ 179,386	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 8,132,818	32
	Customer Installation Expenses	879											
33	Labor		$ 4,871,260	$ 0	$ 242,713	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 5,113,973	33
34	Labor Loadings		3,006,582	0	(33,118)	0	0	0	0	0	0	2,973,464	34
35	Materials and Expenses		1,490,584	0	0	0	0	0	0	0	0	1,490,584	35
36	Total		$ 9,368,426	$ 0	$ 209,595	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 9,578,022	36

SCHEDULE C-1
Sheet 5 of 18

SOUTHWEST GAS CORPORATION
ARIZONA
OPERATION AND MAINTENANCE EXPENSES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Account Number	Recorded at 04/30/07	Purchased Gas Cost Adj. No. 2	Labor/Loading Annualization Adj. No. 3	Customer Billing Annualization Adj. No. 4	Miscellaneous Adjustments Adj. No. 5	Vehicle Compensation Adj. No. 6	Out-of-Period Expenses Adj. No. 7	Leak Survey and Repair Adj. No. 8	Surcharge Adjustment Adj. No. 9	Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
	Other Expenses	880											
1	Labor		$ 3,961,678	$ 0	$ 194,282	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 4,155,960	1
2	Labor Loadings		2,411,926	0	(24,052)	0	0	0	0	0	0	2,387,874	2
3	Materials and Expenses		4,704,216	0	0	0	(168,977)	0	0	0	0	4,535,239	3
4	Total		$ 11,077,820	$ 0	$ 170,230	$ 0	$ (168,977)	$ 0	$ 0	$ 0	$ 0	$ 11,079,072	4
	Rents	881											
5	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	5
6	Labor Loadings		0	0	0	0	0	0	0	0	0	0	6
7	Materials and Expenses		2,250,258	0	0	0	0	0	0	0	0	2,250,258	7
8	Total		$ 2,250,258	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 2,250,258	8
	Maintenance												
	Maintenance Supervision and Engineering	885											
9	Labor		$ 1,690,204	$ 0	$ 83,771	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1,773,975	9
10	Labor Loadings		1,034,883	0	(11,040)	0	0	0	0	0	0	1,023,843	10
11	Materials and Expenses		338,062	0	0	0	0	0	0	0	0	338,062	11
12	Total		$ 3,063,149	$ 0	$ 72,731	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 3,135,880	12
	Maintenance of Structures and Improvements	886											
13	Labor		$ 16,168	$ 0	$ 806	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 16,974	13
14	Labor Loadings		9,808	0	(108)	0	0	0	0	0	0	9,700	14
15	Materials and Expenses		80,753	0	0	0	0	0	0	0	0	80,753	15
16	Total		$ 106,729	$ 0	$ 698	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 107,427	16
	Maintenance of Mains	887											
17	Labor		$ 5,132,018	$ 0	$ 255,705	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 5,387,723	17
18	Labor Loadings		3,146,953	0	(34,664)	0	0	0	0	0	0	3,112,289	18
19	Materials and Expenses		6,501,048	0	0	0	0	0	113,670	(143,226)	572,224	7,043,715	19
20	Total		$ 14,780,019	$ 0	$ 221,041	$ 0	$ 0	$ 0	$ 113,670	$ (143,226)	$ 572,224	$ 15,543,726	20
	Maint. of Meas. & Reg. Station Equipment	889											
21	Labor		$ 884,322	$ 0	$ 44,062	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 928,384	21
22	Labor Loadings		538,866	0	(5,936)	0	0	0	0	0	0	532,930	22
23	Materials and Expenses		580,480	0	0	0	0	0	0	0	0	580,480	23
24	Total		$ 2,003,667	$ 0	$ 38,126	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 2,041,794	24
	Maintenance of Services	892											
25	Labor		$ 3,713,870	$ 0	$ 185,045	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 3,898,915	25
26	Labor Loadings		2,285,768	0	(25,178)	0	0	0	0	0	0	2,260,590	26
27	Materials and Expenses		3,933,316	0	0	0	0	0	113,670	(73,832)	0	3,973,153	27
28	Total		$ 9,932,954	$ 0	$ 159,866	$ 0	$ 0	$ 0	$ 113,670	$ (73,832)	$ 0	$ 10,132,658	28
	Maintenance of Meters and House Regulators	893											
29	Labor		$ 775,241	$ 0	$ 38,627	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 813,868	29
30	Labor Loadings		472,875	0	(5,209)	0	0	0	0	0	0	467,666	30
31	Materials and Expenses		781,684	0	0	0	0	0	0	0	0	781,684	31
32	Total		$ 2,029,799	$ 0	$ 33,418	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 2,063,217	32
	Maintenance of Other Equipment	894											
33	Labor		$ 119,238	$ 0	$ 5,941	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 125,180	33
34	Labor Loadings		72,151	0	(795)	0	0	0	0	0	0	71,356	34
35	Materials and Expenses		189,711	0	0	0	0	0	0	0	0	189,711	35
36	Total		$ 381,100	$ 0	$ 5,147	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 386,247	36
	Total Distribution Expenses												
37	Labor		$ 35,768,714	$ 0	$ 1,776,349	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 37,545,063	37
38	Labor Loadings		21,934,085	0	(236,701)	0	0	0	0	0	0	21,697,383	38
39	Materials and Expenses		29,941,784	0	0	0	(183,101)	(55,179)	227,339	(217,058)	572,224	30,286,009	39
40	Total		$ 87,644,582	$ 0	$ 1,539,648	$ 0	$ (183,101)	$ (55,179)	$ 227,339	$ (217,058)	$ 572,224	$ 89,528,455	40

SCHEDULE C-1
Sheet 6 of 18

SOUTHWEST GAS CORPORATION
ARIZONA
OPERATION AND MAINTENANCE EXPENSES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Account Number	Recorded at 04/30/07	Purchased Gas Cost Adj. No. 2	Labor/Loading Annualization Adj. No. 3	Customer Billing Annualization Adj. No. 4	Miscellaneous Adjustments Adj. No. 5	Vehicle Compensation Adj. No. 6	Out-of-Period Expenses Adj. No. 7	Leak Survey and Repair Adj. No. 8	Surcharge Adjustment Adj. No. 9	Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
	Customer Accounts Expenses												
	Operation												
	Supervision	901											
1	Labor		$ 2,472,697	$ 0	$ 123,203	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 2,595,900	1
2	Labor Loadings		1,514,764	0	(16,686)	0	0	0	0	0	0	1,498,079	2
3	Materials and Expenses		275,497	0	0	0	0	0	0	0	0	275,497	3
4	Total		$ 4,262,958	$ 0	$ 106,518	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 4,369,476	4
	Meter Reading Expenses	902											
5	Labor		$ 2,940,669	$ 0	$ 146,520	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 3,087,190	5
6	Labor Loadings		1,793,044	0	(19,751)	0	0	0	0	0	0	1,773,293	6
7	Materials and Expenses		2,194,002	0	0	0	0	0	0	0	0	2,194,002	7
8	Total		$ 6,927,716	$ 0	$ 126,770	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 7,054,485	8
	Customer Records and Collections - Division	903											
9	Labor		$ 9,707,531	$ 0	$ 508,848	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 10,216,379	9
10	Labor Loadings		5,903,813	0	(57,725)	0	0	0	0	0	0	5,846,088	10
11	Materials and Expenses		6,969,822	0	0	285,239	(48,126)	0	0	0	0	7,206,935	11
12	Total		$ 22,581,166	$ 0	$ 451,123	$ 285,239	$ (48,126)	$ 0	$ 0	$ 0	$ 0	$ 23,269,402	12
	Customer Records and Collections - Allocation	903											
13	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	13
14	Labor Loadings		0	0	0	0	0	0	0	0	0	0	14
15	Materials and Expenses		640,625	0	0	0	(2,068)	0	0	0	0	638,557	15
16	Total		$ 640,625	$ 0	$ 0	$ 0	$ (2,068)	$ 0	$ 0	$ 0	$ 0	$ 638,557	16
	Uncollectible Accounts Expenses	904											
17	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	17
18	Labor Loadings		0	0	0	0	0	0	0	0	0	0	18
19	Materials and Expenses		2,977,729	0	0	0	0	0	0	0	0	2,977,729	19
20	Total		$ 2,977,729	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 2,977,729	20
	Miscellaneous Customer Accounts Expenses	905											
21	Labor		$ 243,969	$ 0	$ 12,156	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 256,125	21
22	Labor Loadings		149,992	0	(1,652)	0	0	0	0	0	0	148,340	22
23	Materials and Expenses		16,795	0	0	0	0	0	0	0	0	16,795	23
24	Total		$ 410,756	$ 0	$ 10,504	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 421,260	24
	Total Customer Accounts Expenses												
25	Labor		$ 15,364,865	$ 0	$ 790,727	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 16,155,593	25
26	Labor Loadings		9,361,613	0	(95,813)	0	0	0	0	0	0	9,265,800	26
27	Materials and Expenses		13,074,471	0	0	285,239	(50,194)	0	0	0	0	13,309,516	27
28	Total		$ 37,800,950	$ 0	$ 694,914	$ 285,239	$ (50,194)	$ 0	$ 0	$ 0	$ 0	$ 38,730,909	28

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SOUTHWEST GAS CORPORATION
ARIZONA
OPERATION AND MAINTENANCE EXPENSES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Account Number	Recorded at 04/30/07	Purchased Gas Cost Adj. No. 2	Labor/Loading Annualization Adj. No. 3	Customer Billing Annualization Adj. No. 4	Miscellaneous Adjustments Adj. No. 5	Vehicle Compensation Adj. No. 6	Out-of-Period Expenses Adj. No. 7	Leak Survey and Repair Adj. No. 8	Surcharge Adjustment Adj. No. 9	Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
	Customer Service and Informational Expenses												
	Operation												
	Customer Assistance Expenses	908											
1	Labor		$ 311,697	$ 0	$ 14,712	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 326,410	1
2	Labor Loadings		189,887	0	(1,400)	0	0	0	0	0	0	188,487	2
3	Materials and Expenses		715,869	0	0	0	(151,072)	0	0	0	0	564,797	3
4	Total		$ 1,217,452	$ 0	$ 13,313	$ 0	$ (151,072)	$ 0	$ 0	$ 0	$ 0	$ 1,079,693	4
	Informational and Instructional Expenses	909											
5	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	5
6	Labor Loadings		0	0	0	0	0	0	0	0	0	0	6
7	Materials and Expenses		35,525	0	0	0	(10,400)	0	0	0	0	25,125	7
8	Total		$ 35,525	$ 0	$ 0	$ 0	$ (10,400)	$ 0	$ 0	$ 0	$ 0	$ 25,125	8
	Misc. Customer Service & Inform. Expense	910											
9	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	9
10	Labor Loadings		0	0	0	0	0	0	0	0	0	0	10
11	Materials and Expenses		67,377	0	0	0	(45,400)	0	0	0	0	21,977	11
12	Total		$ 67,377	$ 0	$ 0	$ 0	$ (45,400)	$ 0	$ 0	$ 0	$ 0	$ 21,977	12
	Total Customer Service & Info. Expense												
13	Labor		$ 311,697	$ 0	$ 14,712	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 326,410	13
14	Labor Loadings		189,887	0	(1,400)	0	0	0	0	0	0	188,487	14
15	Materials and Expenses		818,771	0	0	0	(206,872)	0	0	0	0	611,899	15
16	Total		$ 1,320,355	$ 0	$ 13,313	$ 0	$ (206,872)	$ 0	$ 0	$ 0	$ 0	$ 1,126,796	16
	Sales Expenses												
	Supervision	911											
17	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	17
18	Labor Loadings		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	19
20	Total		$ 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	21
22	Labor Loadings		0	0	0	0	0	0	0	0	0	0	22
23	Materials and Expenses		0	0	0	0	0	0	0	0	0	0	23
24	Total		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	24
	Advertising Expenses	913											
25	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	25
26	Labor Loadings		0	0	0	0	0	0	0	0	0	0	26
27	Materials and Expenses		230,155	0	0	0	(230,155)	0	0	0	0	0	27
28	Total		$ 230,155	$ 0	$ 0	$ 0	$ (230,155)	$ 0	$ 0	$ 0	$ 0	$ 0	28
	Total Sales Expenses												
29	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	29
30	Labor Loadings		0	0	0	0	0	0	0	0	0	0	30
31	Materials and Expenses		230,155	0	0	0	(230,155)	0	0	0	0	0	31
32	Total		$ 230,155	$ 0	$ 0	$ 0	$ (230,155)	$ 0	$ 0	$ 0	$ 0	$ 0	32
	Total Rate Jurisdiction												
33	Labor		$ 51,840,327	$ 0	$ 2,598,143	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 54,438,470	33
34	Labor Loadings		31,715,630	0	(333,746)	0	0	0	0	0	0	31,381,884	34
35	Materials and Expenses		637,549,827	(593,424,664)	0	285,239	(670,322)	(55,179)	227,339	(217,058)	572,224	44,267,406	35
36	Total		$ 721,105,785	$ (593,424,664)	$ 2,264,397	$ 285,239	$ (670,322)	$ (55,179)	$ 227,339	$ (217,058)	$ 572,224	$ 130,087,761	36

SOUTHWEST GAS CORPORATION
ARIZONA
ALLOCATION OF RECORDED ADMINISTRATIVE AND GENERAL EXPENSES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Account Number	Total Company	Direct Charges: Total Arizona	Direct Charges: Other Jurisdictions	To Be Allocated	Allocation Factor [1]: 4-Factor	Factor II	Factor III	A&G Allocation	Total Allocation	Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f) (c-d-e)	(g)	(h)	(i)	(j)	(k)	(l) (d) + (k)	
	Administrative and General Salaries	920											
1	Labor		$ 39,960,366	$ 0	$ 0	$ 39,960,366	$ 22,657,527	$ 0	$ 0	$ 0	$ 22,657,527	$ 22,657,527	1
2	Labor Loadings		18,893,123	0	0	18,893,123	10,712,401	0	0	0	10,712,401	10,712,401	2
3	Materials and Expense		(2,067,764)	0	0	(2,067,764)	(1,172,422)	0	0	0	(1,172,422)	(1,172,422)	3
4	Total Administrative and General Salaries		$ 56,785,724	$ 0	$ 0	$ 56,785,724	$ 32,197,506	$ 0	$ 0	$ 0	$ 32,197,506	$ 32,197,506	4
5	Office Supplies	921	$ 10,322,576	$ 0	$ 0	$ 10,322,576	$ 5,852,900	$ 0	$ 0	$ 0	$ 5,852,900	$ 5,852,900	5
6	Administrative Expenses Transferred - Credit	922	$ (8,953,780)	$ 0	$ 0	$ (8,953,780)	$ 0	$ 0	$ 0	$ (5,306,010)	$ (5,306,010)	$ (5,306,010)	6
7	Outside Services Employed	923	$ 10,109,664	$ 768,490	$ 421,346	$ 8,919,827	$ 5,057,542	$ 0	$ 0	$ 0	$ 5,057,542	$ 5,826,032	7
8	Property Insurance	924	$ 373,578	$ 0	$ 0	$ 373,578	$ 0	$ 205,169	$ 0	$ 0	$ 205,169	$ 205,169	8
9	Injuries and Damages	925	$ 10,468,287	$ 406,029	$ 762,898	$ 9,299,361	$ 5,272,737	$ 0	$ 0	$ 0	$ 5,272,737	$ 5,678,766	9
10	Employee Pensions and Benefits	926	$ 0	$ 179,818	$ 32,821	$ (212,639)	$ 0	$ 0	$ (126,547)	$ 0	$ (126,547)	$ 53,270	10
11	Regulatory Commission Expenses	928	$ 349,604	$ 125,693	$ 223,911	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 125,693	11
	Miscellaneous General Expenses	930											
12	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	12
13	Labor Loadings		0	0	0	0	0	0	0	0	0	0	13
14	Materials and Expense		6,599,734	471,259	425,699	5,702,776	3,233,474	0	0	0	3,233,474	3,704,733	14
15	Total Miscellaneous General Expenses		$ 6,599,734	$ 471,259	$ 425,699	$ 5,702,776	$ 3,233,474	$ 0	$ 0	$ 0	$ 3,233,474	$ 3,704,733	15
16	Rents	931	$ 4,453,278	$ 0	$ 0	$ 4,453,278	$ 2,525,009	$ 0	$ 0	$ 0	$ 2,525,009	$ 2,525,009	16
	Maintenance of General Plant	935											
17	Labor		$ 820,763	$ 569,163	$ 32,834	$ 218,766	$ 124,040	$ 0	$ 0	$ 0	$ 124,040	$ 693,203	17
18	Labor Loadings		496,745	348,660	19,929	128,156	72,665	0	0	0	72,665	421,325	18
19	Materials and Expense		2,995,721	1,149,602	359,351	1,486,767	842,997	0	0	0	842,997	1,992,599	19
20	Total Maintenance of General Plant		$ 4,313,229	$ 2,067,425	$ 412,115	$ 1,833,689	$ 1,039,702	$ 0	$ 0	$ 0	$ 1,039,702	$ 3,107,127	20
	Total Administrative and General Expenses												
21	Labor		$ 40,781,129	$ 569,163	$ 32,834	$ 40,179,132	$ 22,781,568	$ 0	$ 0	$ 0	$ 22,781,568	$ 23,350,731	21
22	Labor Loadings		19,389,868	348,660	19,929	19,021,279	10,785,065	0	0	0	10,785,065	11,133,725	22
23	Materials and Expense		34,650,897	3,100,891	2,226,027	29,323,980	21,612,237	205,169	(126,547)	(5,306,010)	16,384,849	19,485,739	23
24	Total Administrative and General Expenses		$ 94,821,894	$ 4,018,714	$ 2,278,790	$ 88,524,391	$ 55,178,870	$ 205,169	$ (126,547)	$ (5,306,010)	$ 49,951,482	$ 53,970,196	24
				C-1, Sh 1							C-1, Sh 1		

[1] Schedule C-1, Sh 17

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SOUTHWEST GAS CORPORATION
ARIZONA
DIRECT ADJUSTMENTS TO ADMINISTRATIVE AND GENERAL EXPENSE
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Account Number	Labor/Loading Annualization Adj. No. 3	Rate Case Expense Adj. No. 13	Total Adjustments	Line No.
	(a)	(b)	(c)	(d)	(e)	
	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	$ (33,693)	$ (33,693)	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		$ 28,359	$ 0	$ 28,359	17
18	Labor Loadings		(3,841)	0	(3,841)	18
19	Materials and Expenses		0	0	0	19
20	Total Maintenance of General Plant		$ 24,518	$ 0	$ 24,518	20
	Total Administrative and General					
21	Labor		$ 28,359	$ 0	$ 28,359	21
22	Labor Loadings		(3,841)	0	(3,841)	22
23	Materials and Expenses		0	(33,693)	(33,693)	23
24	Total Administrative and General Expense		$ 24,518	$ (33,693)	$ (9,175)	24
					C-1, Sh 1	

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SOUTHWEST GAS CORPORATION
ARIZONA
SYSTEM ALLOCABLE ADJUSTMENTS TO ADMINISTRATIVE AND GENERAL EXPENSE
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Account Number	Labor/Loading Annualization Adj. No. 3	Miscellaneous Adjustments Adj. No. 5	Vehicle Compensation Adj. No. 6	Out-of-Period Expenses Adj. No. 7	Injuries and Damages Adj. No. 10	AGA Dues Adj. No. 11	Paiute/SGTC Annualization Adj. No. 12	Total Adjustments	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	
	Administrative and General Salaries	920									
1	Labor		$ 1,167,758	0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1,167,758	1
2	Labor Loadings		10,876	0	0	0	0	0	0	10,876	2
3	Materials and Expenses		0	0	(251,850)	0	0	0	79,720	(172,130)	3
4	Total Administrative and General Salaries		$ 1,178,634	0	$ (251,850)	$ 0	$ 0	$ 0	$ 79,720	$ 1,006,503	4
5	Office Supplies and Expense	921	$ 0	(26,128)	$ 0	0	$ 0	$ 0	$ 16,150	$ (9,977)	5
6	Administrative Expenses Transferred - Credit	922	$ (158,561)	0	$ 0	0	$ 0	$ 0	$ 0	$ (158,561)	6
7	Outside Services Employed	923	$ 0	0	$ 0	0	$ 0	$ 0	$ 13,738	$ 13,738	7
8	Property Insurance	924	$ 0	0	$ 0	0	$ 0	$ 0	$ (6,487)	$ (6,487)	8
9	Injuries and Damages	925	$ 0	0	$ 0	446,779	$ 3,930,256	$	$ 14,654	$ 4,391,689	9
10	Employee Pensions and Benefits	926	$ 0	0	$ 0	0	$ 0	$ 0	$ 0	$ 0	10
11	Regulatory Commission Expense	928	$ 0	0	$ 0	0	$ 0	$ 0	$ 0	$ 0	11
	Miscellaneous General Expense	930									
12	Labor		$ 0	0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	12
13	Labor Loadings		0	0	0	0	0	0	0	0	13
14	Materials and Expenses		0	(19,810)	0	0	0	(13,087)	50,032	17,135	14
15	Total Miscellaneous General Expense		$ 0	(19,810)	$ 0	$ 0	$ 0	$ (13,087)	$ 50,032	$ 17,135	15
16	Rents	931	$ 0	0	$ 0	0	$	$ 0	$ 7,836	$ 7,836	16
	Maintenance of General Plant	935									
17	Labor		$ 7,889	0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 7,889	17
18	Labor Loadings		74	0	0	0	0	0	0	74	18
19	Materials and Expenses		0	0	0	0	0	0	2,855	2,855	19
20	Total Maintenance of General Plant		$ 7,963	0	$ 0	$ 0	$ 0	$ 0	$ 2,855	$ 10,818	20
	Total Administrative and General										
21	Labor		$ 1,175,647	0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1,175,647	21
22	Labor Loadings		10,950	0	0	0	0	0	0	10,950	22
23	Materials and Expenses		(158,561)	(45,937)	(251,850)	446,779	3,930,256	(13,087)	178,498	4,086,097	23
24	Total Administrative and General Expense		$ 1,028,035	(45,937)	$ (251,850)	$ 446,779	$ 3,930,256	$ (13,087)	$ 178,498	$ 5,272,694	24
										C-1, Sh 12	

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Sheet 11 of 18

SOUTHWEST GAS CORPORATION
ARIZONA
ALLOCATION OF ADMINISTRATIVE AND GENERAL EXPENSE ADJUSTMENTS
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Account Number	Total Company	Direct Charges		To Be Allocated [2]	Allocation Factor [3]					Adjustment Total	Line No.
				Arizona [1]	Other Jurisdictions		4-Factor	Factor II	Factor III	A&G Allocation	Total Allocation		
	(a)	(b)	(c) (d)+(e)+(f)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l) (d) + (k)	
	Administrative and General Salaries	920											
1	Labor		$ 1,167,758	$ 0	$ 0	$ 1,167,758	$ 662,119	$ 0	$ 0	$ 0	$ 662,119	$ 662,119	1
2	Labor Loadings		10,876	0	0	10,876	6,167	0	0	0	6,167	6,167	2
3	Materials and Expense		(172,130)	0	0	(172,130)	(97,598)	0	0	0	(97,598)	(97,598)	3
4	Total Administrative and General Salaries		$ 1,006,503	$ 0	$ 0	$ 1,006,503	$ 570,687	$ 0	$ 0	$ 0	$ 570,687	$ 570,687	4
5	Office Supplies	921	$ (9,977)	$ 0	$ 0	$ (9,977)	$ (5,657)	$ 0	$ 0	$ 0	$ (5,657)	$ (5,657)	5
6	Administrative Expenses Transferred - Credit	922	$ (158,561)	$ 0	$ 0	$ (158,561)	$ 0	$ 0	$ 0	$ (93,963)	$ (93,963)	$ (93,963)	6
7	Outside Services Employed	923	$ 13,738	$ 0	$ 0	$ 13,738	$ 7,789	$ 0	$ 0	$ 0	$ 7,789	$ 7,789	7
8	Property Insurance	924	$ (6,487)	$ 0	$ 0	$ (6,487)	$ 0	$ (3,563)	$ 0	$ 0	$ (3,563)	$ (3,563)	8
9	Injuries and Damages	925	$ 4,391,689	$ 0	$ 0	$ 4,391,689	$ 2,490,088	$ 0	$ 0	$ 0	$ 2,490,088	$ 2,490,088	9
10	Employee Pensions and Benefits	926	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	10
11	Regulatory Commission Expenses	928	$ (33,693)	$ (33,693)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ (33,693)	11
	Miscellaneous General Expenses	930											
12	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	12
13	Labor Loadings		0	0	0	0	0	0	0	0	0	0	13
14	Materials and Expense		17,135	0	0	17,135	9,716	0	0	0	9,716	9,716	14
15	Total Miscellaneous General Expenses		$ 17,135	$ 0	$ 0	$ 17,135	$ 9,716	$ 0	$ 0	$ 0	$ 9,716	$ 9,716	15
16	Rents	931	$ 7,836	$ 0	$ 0	$ 7,836	$ 4,443	$ 0	$ 0	$ 0	$ 4,443	$ 4,443	16
	Maintenance of General Plant	935											
17	Labor		$ 36,248	$ 28,359	$ 0	$ 7,889	$ 4,473	$ 0	$ 0	$ 0	$ 4,473	$ 32,832	17
18	Labor Loadings		(3,767)	(3,841)	0	74	42	0	0	0	42	(3,799)	18
19	Materials and Expenses		2,855	0	0	2,855	1,619	0	0	0	1,619	1,619	19
20	Total Maintenance of General Plant		$ 35,337	$ 24,518	$ 0	$ 10,818	$ 6,134	$ 0	$ 0	$ 0	$ 6,134	$ 30,652	20
	Total Administrative and General Expenses												
21	Labor		$ 1,204,006	$ 28,359	$ 0	$ 1,175,647	$ 666,592	$ 0	$ 0	$ 0	$ 666,592	$ 694,951	21
22	Labor Loadings		7,109	(3,841)	0	10,950	6,208	0	0	0	6,208	2,368	22
23	Materials and Expenses		4,052,404	(33,693)	0	4,086,097	2,410,400	(3,563)	0	(93,963)	2,312,873	2,279,180	23
24	Total Administrative and General Expenses		$ 5,263,519	$ (9,175)	$ 0	$ 5,272,694	$ 3,083,200	$ (3,563)	$ 0	$ (93,963)	$ 2,985,674	$ 2,976,499	24
											C-1, Sh 1		

[1] Schedule C-1, Sheet 10, Column e
[2] Schedule C-1, Sheet 11, Column j

SOUTHWEST GAS CORPORATION
ARIZONA
ALLOCATION OF ADJUSTED ADMINISTRATIVE AND GENERAL EXPENSES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Account Number	Total Company [1]	Direct Charges		To Be Allocated	Allocation Factor [4]					Total	Line No.
				Arizona [2]	Other Jurisdictions [3]		4-Factor	Factor II	Factor III	A&G Allocation	Total Allocation		
	(a)	(b)	(c)	(d)	(e)	(f) (c-d-e)	(g)	(h)	(i)	(j)	(k)	(l) (d) + (k)	
	Administrative and General Salaries	920											
1	Labor		$ 41,128,124	$ 0	$ 0	$ 41,128,124	$ 23,319,646	$ 0	$ 0	$ 0	$ 23,319,646	$ 23,319,646	1
2	Labor Loadings		18,903,999	0	0	18,903,999	10,718,567	0	0	0	10,718,567	10,718,567	2
3	Materials and Expense		(2,239,895)	0	0	(2,239,895)	(1,270,020)	0	0	0	(1,270,020)	(1,270,020)	3
4	Total Administrative and General Salaries		$ 57,792,228	$ 0	$ 0	$ 57,792,228	$ 32,768,193	$ 0	$ 0	$ 0	$ 32,768,193	$ 32,768,193	4
5	Office Supplies	921	$ 10,312,598	$ 0	$ 0	$ 10,312,598	$ 5,847,243	$ 0	$ 0	$ 0	$ 5,847,243	$ 5,847,243	5
6	Administrative Expenses Transferred - Credit	922	$ (9,112,341)	$ 0	$ 0	$ (9,112,341)	$ 0	$ 0	$ 0	$ (5,399,973)	$ (5,399,973)	$ (5,399,973)	6
7	Outside Services Employed	923	$ 10,123,402	$ 768,490	$ 421,346	$ 8,933,565	$ 5,065,331	$ 0	$ 0	$ 0	$ 5,065,331	$ 5,833,821	7
8	Property Insurance	924	$ 367,090	$ 0	$ 0	$ 367,090	$ 0	$ 201,606	$ 0	$ 0	$ 201,606	$ 201,606	8
9	Injuries and Damages	925	$ 14,859,976	$ 406,029	$ 762,898	$ 13,691,049	$ 7,762,825	$ 0	$ 0	$ 0	$ 7,762,825	$ 8,168,854	9
10	Employee Pensions and Benefits	926	$ 0	$ 179,818	$ 32,821	$ (212,639)	$ 0	$ 0	$ (126,547)	$ 0	$ (126,547)	$ 53,270	10
11	Regulatory Commission Expenses	928	$ 315,911	$ 92,000	$ 223,911	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 92,000	11
	Miscellaneous General Expenses	930											
12	Labor		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	12
13	Labor Loadings		0	0	0	0	0	0	0	0	0	0	13
14	Materials and Expense		6,616,869	471,259	425,699	5,719,911	3,243,190	0	0	0	3,243,190	3,714,448	14
15	Total Miscellaneous General Expenses		$ 6,616,869	$ 471,259	$ 425,699	$ 5,719,911	$ 3,243,190	$ 0	$ 0	$ 0	$ 3,243,190	$ 3,714,448	15
16	Rents	931	$ 4,461,114	$ 0	$ 0	$ 4,461,114	$ 2,529,452	$ 0	$ 0	$ 0	$ 2,529,452	$ 2,529,452	16
	Maintenance of General Plant	935											
17	Labor		$ 857,011	$ 597,522	$ 32,834	$ 226,655	$ 128,513	$ 0	$ 0	$ 0	$ 128,513	$ 726,035	17
18	Labor Loadings		492,978	344,820	19,929	128,230	72,706	0	0	0	72,706	417,526	18
19	Materials and Expense		2,998,576	1,149,602	359,351	1,489,622	844,616	0	0	0	844,616	1,994,218	19
20	Total Maintenance of General Plant		$ 4,348,565	$ 2,091,943	$ 412,115	$ 1,844,507	$ 1,045,836	$ 0	$ 0	$ 0	$ 1,045,836	$ 3,137,779	20
	Total Administrative and General Expenses												
21	Labor		$ 41,985,135	$ 597,522	$ 32,834	$ 41,354,778	$ 23,448,159	$ 0	$ 0	$ 0	$ 23,448,159	$ 24,045,681	21
22	Labor Loadings		19,396,977	344,820	19,929	19,032,229	10,791,274	0	0	0	10,791,274	11,136,093	22
23	Materials and Expense		38,703,301	3,067,198	2,226,027	33,410,077	24,022,636	201,606	(126,547)	(5,399,973)	18,697,722	21,764,919	23
24	Total Administrative and General Expenses		$ 100,085,413	$ 4,009,539	$ 2,278,790	$ 93,797,084	$ 58,262,069	$ 201,606	$ (126,547)	$ (5,399,973)	$ 52,937,155	$ 56,946,694	24
				C-1, Sh 1							C-1, Sh 1		

[1] Schedule C-1, Sheet 9, Column (c) + Schedule C-1, Sheet 12, Column (c)
[2] Schedule C-1, Sheet 9, Column (d) + Schedule C-1, Sheet 12, Column (d)
[3] Schedule C-1, Sheet 9, Column (e) + Schedule C-1, Sheet 12, Column (e)
[4] Schedule C-1, Sheet 17

SCHEDULE C-1
Sheet 13 of 18

SOUTHWEST GAS CORPORATION
ARIZONA
DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description (a)	Account Number (b)	Recorded at 04/30/07 (c)	Adjustments (d)	Adjusted at 04/30/07 (e)	Line No.
	Arizona					
1	Depreciation [1]	403	$ 77,518,821	$ 3,310,495	$ 80,829,317	1
2	Amortization [1]	404.3	190,552	(63,622)	126,930	2
3	Amortization of Gas Plant Acquisition	406	(52,996)	0	(52,996)	3
4	Regulatory Amortizations [2]	407.3	2,287,572	(1,950,048)	337,524	4
5	Total Depreciation and Amortization Expense		$ 79,943,949	$ 1,296,825	$ 81,240,775	5
	System Allocable					
6	Depreciation [1]	403	$ 4,293,980	$ 186,182	$ 4,480,162	6
7	Amortization [1]	404.3	7,560,997	(318,164)	7,242,833	7
8	Total System Allocable Depreciation and Amortization		$ 11,854,978	$ (131,982)	$ 11,722,995	8
9	Arizona 4-Factor [3]		56.70%	56.70%	56.70%	9
10	Arizona Allocation		$ 6,721,772	$ (74,834)	$ 6,646,938	10
11	Total Depreciation and Amortization (Ln 5 + Ln 10)		$ 86,665,721	$ 1,221,991	$ 87,887,713	11

[1] Supporting Workpapers C-2, Adj. No. 14
[2] Supporting Workpapers C-2, Adj. No. 9
[3] Supporting Schedule C-1, Sheet 17

SOUTHWEST GAS CORPORATION
ARIZONA
SUMMARY OF OTHER TAXES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007
AS ADJUSTED FOR THE TEST YEAR

Line No.	Description	Account Number	Recorded at 04/30/07	Adjustment	Adjusted at 04/30/07	Line No.
	(a)	(b)	(c) [1]	(d) [2]	(e)	
1	Property Tax	408.1	$ 28,899,902	$ 4,212,687	$ 33,112,588	1
2	Miscellaneous	408.1	12,291	0	12,291	2
3	Total Other Taxes		$ 28,912,193	$ 4,212,687	$ 33,124,880	3
				C-1, Sh 1		

[1] Source: Company Records
[2] Supporting Schedule C-2, Adj. 15

SCHEDULE C-1
Sheet 15 of 18

SOUTHWEST GAS CORPORATION
ARIZONA
INCOME TAXES ON OPERATIONS
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007
AS ADJUSTED

Line No.	Description (a)	Recorded at 04/30/07 (b)	Adjusted at 4/30/07 (c)	After Rate Relief (d)	Line No.
	State Income Tax				
1	Margin	$ 402,964,907	$ 399,234,678	$ 449,454,506	1
2	Expenses	299,085,384	309,962,362	310,112,469	2
3	Taxable Income Before Interest	$ 103,879,523	$ 89,272,317	$ 139,342,038	3
4	Interest Expense (Ln 24)	47,844,172	48,035,008	48,035,008	4
5	State Taxable Income	$ 56,035,351	$ 41,237,308	$ 91,307,030	5
6	Effective State Income Tax Rate [2]	6.9680%	6.9680%	6.9680%	6
7	State Income Tax	$ 3,904,543	$ 2,873,416	$ 6,362,274	7
8	South Georgia Amortization	29,686	29,686	29,686	8
9	Investment Tax Credit	0	0	0	9
10	State Income Tax	$ 3,934,229	$ 2,903,102	$ 6,391,960	10
	Federal Income Tax				
11	Margin	$ 402,964,907	$ 399,234,678	$ 449,454,506	11
12	Expenses	299,085,384	309,962,362	310,112,469	12
13	Taxable Income Before Interest	$ 103,879,523	$ 89,272,317	$ 139,342,038	13
14	Interest Expense (Ln 24)	47,844,172	48,035,008	48,035,008	14
15	Federal Taxable Income	$ 56,035,351	$ 41,237,308	$ 91,307,030	15
16	Federal Income Tax Rate [2]	32.5612%	32.5612%	32.5612%	16
17	Federal Income Tax	$ 18,245,783	$ 13,427,362	$ 29,730,665	17
18	South Georgia Amortization	290,114	290,114	290,114	18
19	Investment Tax Credit	(528,360)	(528,360)	(528,360)	19
20	Federal Income Tax	$ 18,007,537	$ 13,189,116	$ 29,492,419	20
21	Total Federal and State Income Tax	$ 21,941,766	$ 16,092,218	$ 35,884,378	21
	Interest Calculation [1]				
22	Rate Base	$ 1,090,440,601	$ 1,094,790,046	$ 1,094,790,046	22
23	Weighted Cost of Debt	4.39%	4.39%	4.39%	23
24	Interest Expense	$ 47,844,172	$ 48,035,008	$ 48,035,008	24

[1] Supporting Schedule A-1, Sheet 2.
[2] Supporting Schedule C-3, Sheet 2.

SOUTHWEST GAS CORPORATION
COMPUTATION OF FOUR FACTOR ALLOCATION RATE
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description (a)	Arizona (b)	Northern California (d)	Southern California (e)	Northern Nevada (f)	Southern Nevada (g)	Total (h)	Line No.
1	Factor I Direct Operating Expenses	$ 128,081,480	$ 4,645,847	$ 17,949,491	$ 13,762,642	$ 54,937,257	$ 219,376,717	1
2	Percent of Total	58.38%	2.12%	8.18%	6.27%	25.04%	100.00%	2
3	Factor II Average Direct Gross Plant in Service	$ 1,864,610,670	$ 101,980,124	$ 247,575,806	$ 184,517,164	$ 996,926,187	$ 3,395,609,951	3
4	Percent of Total	54.92%	3.00%	7.29%	5.43%	29.36%	100.00%	4
5	Factor III Direct Labor	$ 52,409,490	$ 1,521,078	$ 7,754,523	$ 5,481,942	$ 20,897,037	$ 88,064,070	5
6	Percent of Total	59.51%	1.73%	8.81%	6.22%	23.73%	100.00%	6
7	Factor IV Average Number of Customers	$ 945,005	$ 42,464	$ 131,286	$ 88,459	$ 543,377	$ 1,750,591	7
8	Percent of Total	53.98%	2.43%	7.50%	5.05%	31.04%	100.00%	8
9	Total 4-Factor	226.80%	9.27%	31.78%	22.98%	109.17%	400.00%	9
10	4-Factor	56.70%	2.32%	7.94%	5.74%	27.29%	99.99%	10
11	A&G Transfer Rate A&G Overheads	$ 5,304,411	$ 154,515	$ 675,322	$ 329,935	$ 2,486,783	$ 8,950,966	11
12	Percent of Total	59.26%	1.73%	7.54%	3.69%	27.78%	100.00%	12

SOUTHWEST GAS CORPORATION
CALCULATION OF THE MODIFIED
MASSACHUSETTS FORMULA
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

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	$ 52,409,490	$ 1,521,078	$ 7,754,523	$ 5,481,942	$ 20,897,037	$ 2,841,146	$ 0	$ 90,905,216	1
2	Percent to Total	57.65%	1.67%	8.53%	6.03%	22.99%	3.13%	0.00%	100.00%	2
3	Margin	$ 402,964,907	$ 15,712,229	$ 46,127,511	$ 38,627,527	$ 173,896,582	$ 29,948,409	$ 461,150	$ 707,738,315	3
4	Percent to Total	56.94%	2.22%	6.52%	5.46%	24.57%	4.23%	0.07%	100.00%	4
5	Gross Plant	$ 1,956,244,952	$ 104,698,050	$ 257,583,088	$ 189,891,399	$ 1,031,916,426	$ 163,574,936	$ 1,794,544	$ 3,705,703,395	5
6	Percent to Total	52.79%	2.83%	6.95%	5.12%	27.85%	4.41%	0.05%	100.00%	6
7	Total (Ln 2 + Ln 4 + Ln 6)	167.38%	6.72%	22.00%	16.61%	75.41%	11.77%	0.11%	300.00%	7
8	Total Modified Mass Formula (Ln 7 / 3)	55.79%	2.24%	7.33%	5.54%	25.14%	3.92%	0.04%	100.00%	8

SCHEDULE C-1
Sheet 18 of 18

SOUTHWEST GAS CORPORATION
ARIZONA
SUMMARY OF ADJUSTMENTS
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Revenue Adj. No. 1	Purchased Gas Cost Adj. No. 2	Labor/Loading Annualization Adj. No. 3	Customer Billing Annualization Adj. No. 4	Miscellaneous Adjustments Adj. No. 5	Vehicle Compensation Adj. No. 6	Out-of-Period Expenses Adj. No. 7	Leak Survey and Repair Adj. No. 8	Surcharge Adjustment Adj. No. 9	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	
1	Operating Revenue	$ (597,154,892)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	1
2	Gas Cost	0	(593,424,664)	0	0	0	0	0	0	0	2
3	Operating Margin	$ (597,154,892)	$ 593,424,664	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	3
	Operating Expenses										
4	Other Gas Supply	$ 0	$ 0	$ 16,522	$ 0	$ 0	$ 0	$ 0	$ 0	0	4
5	Distribution	0	0	1,539,648	0	(183,101)	(55,179)	227,339	(217,058)	572,224	5
6	Customer Accounts	0	0	694,914	285,239	(50,194)	0	0	0	0	6
7	Customer Service & Information	0	0	13,313	0	(206,872)	0	0	0	0	7
8	Sales	0	0	0	0	(230,155)	0	0	0	0	8
	Administrative and General										
9	Direct	0	0	24,518	0	0	0	0	0	0	9
10	System Allocable	0	0	578,837	0	(26,046)	(142,799)	253,323	0	0	10
	Depreciation and Amortization										
11	Direct	0	0	0	0	0	0	0	0	0	11
12	System Allocable	0	0	0	0	0	0	0	0	0	12
13	Regulatory Amortizations	0	0	0	0	0	0	0	0	(1,950,048)	13
14	Taxes Other Than Income	0	0	0	0	0	0	0	0	0	14
15	Interest on Customer Deposits	0	0	0	0	0	0	0	0	0	15
16	Total Operating Expenses	$ 0	$ 0	$ 2,867,752	$ 285,239	$ (696,368)	$ (197,978)	$ 480,662	$ (217,058)	$ (1,377,824)	16
17	Net Operating Income	$ (597,154,892)	$ 593,424,664	$ (2,867,752)	$ (285,239)	$ 696,368	$ 197,978	$ (480,662)	$ 217,058	$ 1,377,824	17
	Rate Base										
	Gas Plant in Service										
18	Direct	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	18
19	System Allocable	0	0	0	0	0	0	0	0	0	19
20	Total Gross Plant	$ 0	$ 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	$ 0	21
22	System Allocable	0	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	$ 0	23
24	Net Plant in Service	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	24
	Other Rate Base Items										
25	Working Capital	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	25
26	Customer Advances	0	0	0	0	0	0	0	0	0	26
27	Customer Deposits	0	0	0	0	0	0	0	0	0	27
28	Deferred Taxes	0	0	0	0	0	0	0	0	0	28
29	Total Other Rate Base Items	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	29
30	Total Rate Base	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	30

SCHEDULE C-2
Sheet 1 of 2

SOUTHWEST GAS CORPORATION
ARIZONA
SUMMARY OF ADJUSTMENTS
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Injuries and Damages Adj. No. 10	AGA Dues Adj. No. 11	Paiute Alloc. Annualization Adj. No. 12	Rate Case Expense Adj. No. 13	Annualized Dep. & Amort. Adj. No. 14	Property Tax Annualization Adj. No. 15	Interest on Customer Dep. Adj. No. 16	CCNC Adj. No. 17	Total of Adjustments	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	
1	Operating Revenue	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$	$ 0	$ (597,154,892)	1
2	Gas Cost	0	0	0	0	0	0		0	(593,424,664)	2
3	Operating Margin	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$	$ 0	$ (3,730,229)	3
	Operating Expenses										
4	Other Gas Supply	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 16,522	4
5	Distribution	0	0	0	0	0	0	0	0	1,883,873	5
6	Customer Accounts	0	0	0	0	0	0	0	0	929,959	6
7	Customer Service & Information	0	0	0	0	0	0	0	0	(193,559)	7
8	Sales	0	0	0	0	0	0	0	0	(230,155)	8
	Administrative and General										
9	Direct	0	0	0	(33,693)	0	0	0	0	(9,175)	9
10	System Allocable	2,228,455	(7,420)	101,324						2,985,674	10
	Depreciation and Amortization										
11	Direct	0	0	0	0	3,246,873	0	0	0	3,246,873	11
12	System Allocable	0	0	0	0	(74,834)	0	0	0	(74,834)	12
13	Regulatory Amortizations	0	0	0	0	0	0	0	0	(1,950,048)	13
14	Taxes Other Than Income	0	0	0	0	0	4,212,687	0	0	4,212,687	14
15	Interest on Customer Deposits	0	0	0	0	0	0	59,161	0	59,161	15
16	Total Operating Expenses	$ 2,228,455	$ (7,420)	$ 101,324	$ (33,693)	$ 3,172,039	$ 4,212,687	$ 59,161	$ 0	$ 10,876,978	16
17	Net Operating Income	$ (2,228,455)	$ 7,420	$ (101,324)	$ 33,693	$ (3,172,039)	$ (4,212,687)	$ (59,161)	$ 0	$ (14,607,206)	17
	Rate Base										
	Gas Plant in Service										
18	Direct	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 2,976,115	$ 2,976,115	18
19	System Allocable	0	0	0	0	0	0	0	1,373,330	1,373,330	19
20	Total Gross Plant	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 4,349,445	$ 4,349,445	20
	Accumulated Provision for Depreciation and Amortization										
21	Direct	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	21
22	System Allocable	0	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	$ 0	23
24	Net Plant in Service	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 4,349,445	$ 4,349,445	24
	Other Rate Base Items										
25	Working Capital	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	25
26	Customer Advances	0	0	0	0	0	0	0	0	0	26
27	Customer Deposits	0	0	0	0	0	0	0	0	0	27
28	Deferred Taxes	0	0	0	0	0	0	0	0	0	28
29	Total Other Rate Base Items	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	29
30	Total Rate Base	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 4,349,445	$ 4,349,445	30

SCHEDULE C-2
Sheet 2 of 2

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SALES & TRANSPORTATION QUANTITY AND REVENUES
ADJUSTMENT NO.1
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Recorded At 4/30/2007	Adjustment No. 1	Test Period Balance As Adjusted	Line No.
	(a)	(b)	(c)	(d)	
1	Sales Quantity (therms)	699,988,330	(35,386,981)	664,601,349	1
2	Transportation Quantity (therms)	74,237,984	4,271,585	78,509,569	2
3	Total Quantity	774,226,314	(31,115,396)	743,110,918	3
4	Revenue	$ 996,389,570	$(597,154,892)	**$ 399,234,678**	4
5	Total Revenue Adjustment		$(597,154,892)		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 ($540,064,385) from the cost of service.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PURCHASED GAS COST
ADJUSTMENT NO. 2
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	FERC Account Number	Amount	Line No.
	(a)	(b)	(c)	
1	Operating Expenses	401	$(593,424,664)	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	(25,155,242)	3
4	Present Rate Adjustment	803	67,624,882	4
5	Proposed Rate Making Adjustment	803	(540,064,385)	5
6	Purchased Gas Cost Adjustments	805.1	(35,473,742)	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		$(533,068,487)	9
	Transmission Expenses			
	Transmission & Compression			
10	of Gas by Others	858	$(60,356,176)	10
11	Total Transmission Expenses		$(60,356,176)	11
12	Adjustment No. 2		$(593,424,664)	12

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
COST OF PURCHASED GAS - ACCOUNT NO. 803
ADJUSTED AT PRESENT RATES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Recorded Total	Volume Adjustment			Rate Adjustment			Adjusted Total	Line No.
			Sales	Seasonal	Optional	Sales	Seasonal	Optional		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
1	Sales Volumes - Therms	699,988,330	(15,556,599)	(213,516)	(19,616,866)	602,083,024	13,070,981	49,447,344	664,601,349	1
2	Recorded Average Cost of Purchased Gas - Account No. 803	$ 0.71086	$ 0.71086	$ 0.71086	$ 0.71086	$ 0.71086	$ 0.71086	$ 0.71086		2
3	Cost of Purchased Gas [1]					$ 0.81426	$ 0.73057	$ 0.81426		3
4	Change In Average Cost of Purchased Gas					$ 0.10340	$ 0.01971	$ 0.10340		4
5	Cost of Purchased Gas - Account No. 803	$ 497,594,745	$(11,058,587)	$(151,780)	$(13,944,875)	$ 62,254,490	$ 257,610	$ 5,112,782	$ 540,064,385	5

[1] Cost of gas effective May 1, 2007 excluding Account No. 191 surcharge.

SCHEDULE C-2
ADJUSTMENT NO. 2
Sheet 2 of 2

SOUTHWEST GAS CORPORATION
ARIZONA
LABOR AND LABOR LOADING ANNUALIZATION
ADJUSTMENT NO. 3

Line No.	Description (a)	Labor [1] (b)	Loading [1] (c)	Total (d) (b) + (c)	Line No.
	Operations				
1	Account 813	$ 16,354	$ 168	$ 16,522	1
2	Account 870	269,456	(35,615)	233,841	2
3	Account 871	6,786	(10)	6,776	3
4	Account 874	185,450	(25,080)	160,370	4
5	Account 875	55,995	(7,571)	48,424	5
6	Account 878	207,711	(28,325)	179,386	6
7	Account 879	242,713	(33,118)	209,595	7
8	Account 880	194,282	(24,052)	170,230	8
9	Account 901	123,203	(16,686)	106,518	9
10	Account 902	146,520	(19,751)	126,770	10
11	Account 903	508,848	(57,725)	451,123	11
12	Account 905	12,156	(1,652)	10,504	12
13	Account 908	14,712	(1,400)	13,313	13
14	Account 909	0	0	0	14
15	Account 910	0	0	0	15
16	Account 920	662,119	6,167	668,285	16
17	Account 922	(93,096)	(867)	(93,963)	17
18	Account 930	0	0	0	18
19	Total Operating Expense	$ 2,553,210	$ (245,517)	$ 2,307,693	19
	Maintenance				
20	Account 885	$ 83,771	$ (11,040)	$ 72,731	20
21	Account 886	806	(108)	698	21
22	Account 887	255,705	(34,664)	221,041	22
23	Account 889	44,062	(5,936)	38,126	23
24	Account 892	185,045	(25,178)	159,866	24
25	Account 893	38,627	(5,209)	33,418	25
26	Account 894	5,941	(795)	5,147	26
27	Account 935	32,832	(3,799)	29,033	27
28	Total Maintenance Expense	$ 646,788	$ (86,728)	$ 560,059	28
29	Total Operations and Maintenance	$ 3,199,998	$ (332,245)	$ 2,867,752	29
	Functionalization				
30	Other Gas Supply	$ 16,354	$ 168	$ 16,522	30
31	Distribution	1,776,349	(236,701)	1,539,648	31
32	Customer Accounts	790,727	(95,813)	694,914	32
33	Customer Service & Information	14,712	(1,400)	13,313	33
34	Sales	0	0	0	34
35	Administrative and General	601,854	1,501	603,355	35
36	Total	$ 3,199,998	$ (332,245)	$ 2,867,752	36

Explanation
To annualize labor and related loadings as of April 30, 2007, to reflect within-grade increases through April 2008, and a 6.09% compounded labor increase effective June 2007 and June 2008.

[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 APRIL 30, 2007
ADJUSTMENT NO. 4

Line No.	Description	Reference	Amount [1]	Line No.
	(a)	(b)	(c)	
	Bill Print Function			
	Hardware/Software Maintenance Fees & Supplies:	Company Records		
1	Variable Form Usage Fee from IBM		$ 41,110	1
2	Equipment Supplies (toner, developer & fuser)		32,100	2
3	Bill Stock (regular, disconnect & final)		327,070	3
4	Subtotal - Bill Print Function		$ 400,280	4
	Bill Insert Function			
	Hardware/Software Supplies:	Company Records		
5	Supplies (B&H, strapping & tags)		$ 14,353	5
6	Envelopes (mailing & remittance)		472,983	6
7	Subtotal - Bill Insert Function		$ 487,336	7
	Postage			
8	Postage for Bills Only	Company Records	$ 6,280,154	8
9	Subtotal - Postage		$ 6,280,154	9
10	Total Annual Variable Costs Related to Customer Billing	Ln 4 + Ln 7 + Ln 9	$ 7,167,770	10
11	Annual Number of Bills - Total Company	Company Records	21,145,300	11
12	Incremental Cost per Customer Bill	Ln 10 / Ln 11	$ 0.34	12
13	Annual Number of Bills in Test Year - Arizona	Company Records	11,340,054	13
14	Annual Number of Bills in Test Year As Adjusted - Arizona	Company Records	11,502,844	14
15	Increase in Annual Number of Arizona Bills	Ln 14 - Ln 13	162,790	15
16	Adjustment to Recognize Incremental Billing Costs for Annualized Customers	Ln 12 * Ln 15	$ 55,182	16
17	Postage Increase [2]		$ 0.02	17
18	Postage Adjustment	Ln 14 * Ln 17	$ 230,057	18
19	Total Adjustment (Account 903)	Ln 16 + Ln 18	$ 285,239	19

Explanation
To recognize the incremental costs of billing for additional customer bills and postage added to the Test Year based on annualized customer levels.

[1] Supporting Workpapers C-2, Adj. 4

SOUTHWEST GAS CORPORATION
ARIZONA
MISCELLANEOUS ADJUSTMENTS
ADJUSTMENT NO. 5

Line No.	Account Number (a)	Reference (b)	Amount (c)	Paiute & SGTC Allocation [1] 3.96% (d)	Net of Paiute (e) (c) + (d)	Allocation Factor [2] (f)	Total (g) (e) * (f)	Line No.
	Arizona							
1	870	WP C-2, Adj. 5	$ 13,837				$ 13,837	1
2	875	WP C-2, Adj. 5	286				286	2
3	880	WP C-2, Adj. 5	168,977				168,977	3
4	Subtotal Distribution	Ln 1 to Ln 3	$ 183,101				$ 183,101	4
5	903	WP C-2, Adj. 5	$ 48,126				$ 48,126	5
6	Subtotal Customer Accounts	Ln 5	$ 48,126				$ 48,126	6
7	908	WP C-2, Adj. 5	$ 148,422				$ 148,422	7
8	909	WP C-2, Adj. 5	10,400				10,400	8
9	910	WP C-2, Adj. 5	45,400				45,400	9
10	Subtotal Customer Service & Information	Ln 7 to Ln 9	$ 204,222				$ 204,222	10
11	913		$ 230,155				$ 230,155	11
12	Subtotal Sales	Ln 11	$ 230,155				$ 230,155	12
13	Subtotal Arizona	Ln 4 + Ln 6 + Ln 10 + Ln 12	$ 665,604				$ 665,604	13
	System Allocable							
14	903	WP C-2, Adj. 5	$ 3,831	N/A	$ 3,831	53.98%	$ 2,068	14
15	Subtotal Customer Accounts	Ln 14	$ 3,831		$ 3,831		$ 2,068	15
16	908		$ 4,673	N/A	$ 4,673	56.70%	$ 2,650	16
17	Subtotal Customer Service & Information	Ln 16	$ 4,673		$ 4,673		$ 2,650	17
18	921	WP C-2, Adj. 5	$ 27,205	$ 1,078	$ 26,128	56.70%	$ 14,814	18
19	930.2		20,627	817	19,810	56.70%	11,232	19
20	Subtotal Administrative and General	Ln 18 to Ln 19	$ 47,832	$ 1,895	$ 45,937		$ 26,046	20
21	Subtotal System Allocable	Ln 15 + Ln 17 + Ln 20	$ 56,336	$ 1,895	$ 54,441		$ 30,764	21
22	Total Adjustment	Ln 13 + Ln 21					$ 696,368	22

Explanation
To remove various expenditures from the cost of service.

[1] Supporting Schedule C-1, Sh 18.
[2] Allocation factors calculated in C-1, Sh 17. Accounts 813, 921, 930.2, and 935 are allocated using the 4-Factor and ccount 903 is allocated based on Factor IV.

SCHEDULE C-2
ADJUSTMENT NO. 5
Sheet 1 of 1

SOUTHWEST GAS CORPORATION
ARIZONA
EMPLOYEE VEHICLE COMPENSATION
ADJUSTMENT NO. 6

Line No.	Description (a)	Reference (b)	Account Number (c)	Amount (d)	Line No.
1	Arizona	Company Records	870	$ 55,179	1
2	System Allocable	Company Records		$ 262,239	2
3	Less: Paiute & SGTC Allocation at 3.96%	C-1, Sh 18		10,389	3
4	Adjustment Before 4-Factor Allocation	Ln 2 - Ln 3		$ 251,850	4
5	Arizona 4-Factor Allocation	C-1, Sh 17		56.70%	5
6	Adjustment Allocated to Arizona	Ln 4 * Ln 5	920	$ 142,799	6
7	Total Adjustment	Ln 1 + Ln 6		$ 197,978	7

Explanation
To remove imputed earnings associated with an 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. 7

Line No.	Description (a)	Reference (b)	Account Number (c)		Total (d)	Line No.
	Arizona					
1	J/E 335 [1]	Company Records	887	$	113,670	1
2	J/E 335 [1]	Company Records	892		113,670	2
3	Subtotal	Ln 1 + Ln 2		$	227,339	3
	System Allocable					
4	70898270	Company Records	925	$	101,747	4
5	70898393				180,883	5
6	70898275				182,578	6
7	Subtotal	Ln 4 + Ln 5 + Ln 6		$	465,208	7
8	Less: Paiute & SGTC Allocation at 3.96%	C-1, Sh 18			3.96%	8
9	Amount to be Allocated	Ln 7 * Ln 8		$	446,779	9
10	Arizona 4-Factor	C-1, Sh 17			56.70%	10
11	Net System Allocable to Arizona	Ln 9 * Ln 10		$	253,323	11
12	Total Adjustment	Ln 3 + Ln 11		$	480,662	12

[1] To include Arizona expenses charged to Southern Nevada erroneously during the test year (April 2007).
[2] To remove reclassification booked during the test year (May 2006) of three payments made prior to the test year year (April 2006).

SOUTHWEST GAS CORPORATION
ARIZONA
LEAK SURVEY AND REPAIR
ADJUSTMENT NO. 8

Line No.	Description	Account Number	Leak Repair [1]	Accelerated Leak Survey [1]	Total Adjustment	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	Maintenance of Mains	887	$ (71,515)	$ (71,712)	$ (143,226)	1
2	Maintenance of Services	892	(20,865)	(52,967)	(73,832)	2
3	Total Adjustment [2]		$ (92,379)	$ (124,679)	$ (217,058)	3

[1] Supporting Workpapers C-2, Adj. 8

SOUTHWEST GAS CORPORATION
ARIZONA
SURCHARGE ADJUSTMENTS
ADJUSTMENT NO. 9

Line No.	Description	Account Number	Amount [1]	Line No.
	(a)	(b)	(c)	
1	Recorded Regulatory Amortization	407.3	$ 2,287,572	1
	Adjustments: [2]			
2	R&D		$ (755,950)	2
3	TRIMP		(551,530)	3
4	Demand Side Management (DSM)		(642,568)	4
5	Total Adjustments (Ln 2 + Ln 3 + Ln 4)		$ (1,950,048)	5
6	Annualized Regulatory Amortization (Ln 1 + Ln 5)	407.3	$ 337,524	6
7	Test Year TRIMP Costs [3]	182.3	$ 920,914	7
8	TRIMP written off [4]	887	(348,690)	8
9	O&M Expense Adjustment [5] (Ln 7 + Ln 8)	887	$ 572,224	9
10	Total Revenue Requirement Impact (Ln 5 + Ln 9)		$ (1,377,824)	10

[1] Source: Company Records
[2] R&D, TRIMP, and DSM costs are recovered through a surcharge. Since the Company is not including the offsetting revenue in revenue at present rates, the expense is being removed with this adjustment.
[3] TRIMP costs were deferred to Account 182.3, and 50% of these costs were recovered through a surcharge per Decision No. 68487.
[4] Disallowed TRIMP costs were written off to Account 887. There is a one month lag between the transaction posting date and the write-off date.
[5] Southwest is requesting to recover its ongoing non-capital related incremental TRIMP costs in base rates, based on test year expenditures, and to discontinue the TRIMP surcharge.

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)	10-Year Total (e)	Total Arizona Accrual (f)	Line No.
	Claims Paid	WP C-2, Adj. 10					
1	< $1,000,000				$ 7,698,138		1
2	At $1,000,000				8,000,000		2
3	$1,000,000 < $10,000,000				16,963,879		3
4	Total Claims Paid				$ 32,662,017		4
5	10 Year Average					$ 3,266,202	5
6	Less FERC Allocation @ 3.96%	C-1, Sh 18	3.96%			(129,342)	6
7	Net System Allocable					$ 3,136,860	7
8	Arizona 4-Factor	C-1, Sh 17	56.70%			$ 1,778,600	8
9	Recorded Amounts [2]			$ 200,000			9
10	Less FERC Allocation @ 3.96%	C-1, Sh 18	3.96%	(7,920)			10
11	Net System Allocable			$ 192,080			11
12	Arizona 4-Factor	C-1, Sh 17	56.70%			$ 108,909	12
13	Arizona Direct [2]		100.00%			(558,765)	13
14	Total Recorded Arizona					$ (449,856)	14
15	Total Adjustment (Ln 8 - Ln 14)					$ 2,228,455	15

[1] Supporting Workpapers C-2, Adj. 10
[2] Source: Company Records

SOUTHWEST GAS CORPORATION
ARIZONA
AMERICAN GAS ASSOCIATION (AGA) DUES
ADJUSTMENT NO. 11

Line No.	Description	Reference	Account Number	Amounts	Line No.
	(a)	(b)	(c)	(d)	
1	2007 AGA Dues	Company Records	930.2	$ 401,975	1
2	Marketing & Lobbying Percentage	WP C-2, Adj. 11		3.39%	2
3	Marketing & Lobbying Amount of Dues	Ln 1 * Ln 2		$ (13,627)	3
4	Less: Paiute & SGTC Allocation at 3.96%	C-1, Sh 18		540	4
5	Adjustment to AGA Dues Before 4-Factor	Ln 3 + Ln 4		$ (13,087)	5
6	Arizona 4-Factor Allocation	C-1, Sh 17		56.70%	6
7	Adjustment to Arizona for Removal of Marketing & Lobbying from AGA Dues	Ln 5 * Ln 6		$ (7,420)	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
SYSTEM ALLOCABLE
ADMINISTRATIVE AND GENERAL EXPENSES
ANNUALIZED PAIUTE ALLOCATION
ADJUSTMENT NO. 12

Line No.	Description	FERC Account Number	12 Months Ended 04/30/07 Net Recorded [1]	Charged to Paiute [2]	Gross Recorded	MMF Allocation Paiute [3]	Paiute Annualized	Reduction to Paiute's A&G Expenses	Amount Allocated to Arizona [4]	Line No.
	(a)	(b)	(c)	(d)	(e) (c) + (d)	(f)	(g)	(h) (d) - (g)	(i)	
1	Administrative and General Salaries	920	$ 56,785,724	$ 2,402,071	$ 59,187,796	3.92%	$ 2,322,351	$ 79,720	$ 45,201	1
2	Office Supplies	921	10,322,576	438,378	10,760,953	3.92%	422,227	16,150	9,157	2
3	Outside Services Employed	923	8,919,827	378,579	9,298,407	3.92%	364,842	13,738	7,789	3
4	Property Insurance	924	373,578	91,630	465,208	21.09%	98,118	(6,487)	(3,563)	4
5	Injuries and Damages	925	9,299,361	395,033	9,694,393	3.92%	380,379	14,654	8,309	5
6	Miscellaneous General Expenses	930.2	4,453,278	233,944	4,687,222	3.92%	183,913	50,032	28,368	6
7	Rents	931	4,453,278	190,026	4,643,304	3.92%	182,189	7,836	4,443	7
8	Maintenance of General Plant	935	1,833,689	77,859	1,911,548	3.92%	75,003	2,855	1,619	8
9	Total		$ 96,441,311	$ 4,207,520	$ 100,648,831		$ 4,029,022	$ 178,498	$ 101,324	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 April 30, 2007.

Note:
Account 493, Rent from Gas Property, changed by -$63,304 due to annualizing the Paiute rental charge at April 30, 2007. Supporting Workpaper C-2, Adj. 12.

[1] Supporting Schedule C-1, Sh 9
[2] Source: Company Records
[3] Modified Massachusetts Formula as calculated in Sch C-1, Sh 18, Col (g); 21.09% based on insurable property. Supporting Workpaper C-2, Adj. 12.
[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 17.

SCHEDULE C-2
ADJUSTMENT NO. 12
Sheet 1 of 1

SOUTHWEST GAS CORPORATION
ARIZONA
SCHEDULE OF ESTIMATED INCREMENTAL RATE CASE EXPENSE
ADJUSTMENT NO. 13

Line No.	Description (a)	Account Number (b)	Estimated Amounts (c)	Line No.
	2007 Arizona Rate Case			
1	Printing/Copying/Postage/Freight		$ 55,000	1
2	Professional Services		120,000	2
3	Notice/Publication		10,000	3
4	Court Reporting		16,000	4
5	Travel/Transportation		75,000	5
6	Total Arizona Rate Case Expense		$ 276,000	6
7	Amortization Period (In Years) [1]		3	7
8	Annual Arizona Rate Case Expense (Ln 6 / Ln 7)	928	$ 92,000	8
9	Rate Case Expense Recorded in Test Year	928	125,693	9
10	Adjustment to Test Year Expense (Ln 8 - Ln 9)		$ (33,693)	10

Source: Company Records

[1] The Company proposes to amortize its incremental rate case expense over three years, which is the estimated length of its Arizona rate case cycle.

SOUTHWEST GAS CORPORATION
ARIZONA
DEPRECIATION AND AMORTIZATION EXPENSE ANNUALIZATION
ADJUSTMENT NO. 14

Line No.	Description	Recorded at 04/30/07	Annualization Adjustment	Adjusted at 04/30/07	Line No.
	(a)	(b)	(c)	(d)	
	Arizona [1]				
1	Depreciation Expense	$ 77,518,821	$ 3,310,495	$ 80,829,317	1
2	Amortization Expense	2,425,128	(63,622)	2,361,506	2
3	Total	$ 79,943,949	$ 3,246,873	$ 83,190,823	3
	System Allocable [1]				
4	Depreciation Expense	$ 4,293,980	$ 186,182	$ 4,480,162	4
5	Amortization Expense	7,560,997	(318,164)	7,242,833	5
6	Total	$ 11,854,978	$ (131,982)	$ 11,722,995	6
7	Arizona 4-Factor [2]	56.70%	56.70%	56.70%	7
8	Amount Allocated to Arizona	$ 6,721,772	(74,834)	6,646,938	8
9	Total (Ln 3 + Ln 8)	$ 86,665,721	$ 3,172,039	$ 89,837,761	9

Explanation:
This adjustment annualizes depreciation and amortization expense as of April 30, 2007.

[1] Supporting Workpapers C-2, Adj. 14
[2] Supporting Schedule C-1, Sh 17

SCHEDULE C-2
ADJUSTMENT NO. 14
Sheet 1 of 1

SOUTHWEST GAS CORPORATION
ARIZONA
PROPERTY TAX
ADJUSTMENT NO. 15

Line No.	Description	Reference		Arizona	Line No.
	(a)	(b)		(c)	
1	Adjusted Net Plant in Service	B-2, Sh 1	$	1,267,124,120	1
	Add:				
2	Materials and Supplies	B-5, Sh 3		12,389,898	2
	Less:				
3	Transportation Equipment	[1]		(27,969,828)	3
4	Land Rights	[2]		(1,823,920)	4
5	Estimated Full Cash Value	Ln 1 to Ln 4	$	1,249,720,269	5
6	2008 Assessment Rate			23.00%	6
7	Assessed Value	Ln 5 * Ln 6	$	287,435,662	7
8	Property Tax Rate			11.52%	8
9	Annualized Property Tax Expense	Ln 7 * Ln 8	$	33,112,588	9
10	Recorded Property Tax Expense	C-1, Sh 16		28,899,902	10
11	Total Adjustment	Ln 9 - Ln 10	$	4,212,687	11

Explanation:
To annualize Property Tax Expense to reflect adjusted investment at 04/30/07 based on estimated 2007 property tax rates and the statutory 2008 assessment ratio.

[1] Adjusted balance net of accumulated depreciation. Supporting Workpapers B-2
[2] Balance as recorded at 04/30/07. Supporting Workpapers B-2

SOUTHWEST GAS CORPORATION
ARIZONA
INTEREST ON CUSTOMER DEPOSITS
ADJUSTMENT NO. 16

Line No.	Description	Account Number	Recorded at 04/30/07 [1]	Adjustment	Adjusted at 04/30/07	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	Interest Expense	431	$ 1,856,153	$ 59,161	$ 1,915,314	1
	Customer Deposits	235				
2	April 2006				$ 29,940,533	2
3	May				30,244,307	3
4	June				30,534,168	4
5	July				30,907,667	5
6	August				31,068,422	6
7	September				31,294,649	7
8	October				31,925,334	8
9	November				32,387,660	9
10	December				32,677,847	10
11	January 2007				32,866,855	11
12	February				33,171,595	12
13	March				33,562,862	13
14	April				34,402,771	14
15	Thirteen Month Total				$ 414,984,669	15
16	Thirteen Month Average				$ 31,921,898	16
17	Interest Rate				6.00%	17
18	Adjusted Interest Expense				$ 1,915,314	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. 16

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	0.2989%	2.99	2
3	Subtotal			$ 997.01	3
4	Less: State Income Tax [2]	$ 997.01	6.9680%	69.47	4
5	Subtotal			$ 927.54	5
6	Less: Federal Income Tax [2]	$ 997.01	32.5612%	324.64	6
7	Total			$ 602.90	7
8	Gross Revenue Conversion Factor (Ln 1 / Ln 7)			1.6586	8
				A-1, Sh 1	

[1] Uncollectibles divided by Test Year Recorded Revenue
[2] Supporting Schedule C-3, Sh 2

SOUTHWEST GAS CORPORATION
ARIZONA
COMPUTATION OF STATE AND FEDERAL TAX RATES
AS OF APRIL 30, 2007

Line No.	Description	Rate	Rate	Line No.
	(a)	(b)	(c)	
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
			C-1, Sh 16	

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
COST OF CAPITAL AT APRIL 30, 2007

Line No.	Description	Capital Ratio	Capital Cost	Weighted Cost of Capital	Line No.
	(a)	(b)	(c)	(d)	
1	Long-Term Debt	51.00%	7.96% [1]	4.06%	1
2	Preferred Equity	4.00%	8.20% [2]	0.33%	2
3	Common Equity	45.00%	11.25% [3]	5.06%	3
4	Total	100.00%		9.45%	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 APRIL 30, 2007

Line No.	Description	Net System Balance at 4/30/2007	Adjustments[1]	Pro Forma Net Capital Amounts	Capital Ratio	Line No.
	(a)	(b)	(c)	(d)	(e)	
	Debt					
	Long-Term Debt:					
1	Debentures	$ 466,044,469	$ -	$ 466,044,469	27.19%	1
2	Medium-Term Notes	124,418,910	-	124,418,910	7.26%	2
3	Term Facilities	53,169,199	-	53,169,199	3.10%	3
4	Clark County IDRB's	470,604,484	(470,604,484)	-	0.00%	4
5	Big Bear IDRB's	49,268,815	(49,268,815)	-	0.00%	5
6	Total Long-Term Debt	$ 1,163,505,877	$ (519,873,299)	$ 643,632,578	37.55%	6
	Equity					
7	Preferred Equity	$ 100,000,000	-	$ 100,000,000	5.83%	7
8	Common Equity	970,385,472	-	970,385,472	56.61%	8
9	Total Equity	$ 1,070,385,472	$ -	$ 1,070,385,472	62.45%	9
10	Total Capital	$ 2,233,891,349	$ (519,873,299)	$ 1,714,018,050	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.

SCHEDULE D-1
Sheet 2 of 2

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
COST OF DEBT AT APRIL 30, 2007

Line No.	Description	Net Principal Amount Outstanding	Interest Rate	Cost of Debt	Line No.
	(a)	(b)	(c)	(d)	
1	Fixed Rate Debt [1]	$ 590,463,379	8.11%	$ 47,871,327	1
2	Variable Rate Debt [2]	53,169,199	6.27%	3,332,516	2
3	Total Long-Term Debt	$ 643,632,578	7.96%	$ 51,203,843	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 APRIL 30, 2007

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	8.0% Debenture, Due 2026	75,000,000	6,089,371	68,910,629	8.89%	6,126,155	1
2	8.375% Note, Due 2011	200,000,000	1,485,867	198,514,133	8.61%	17,091,670	2
3	7.625% Note, Due 2012	200,000,000	1,380,294	198,619,706	7.79%	15,472,475	3
4	Total Debentures	$ 475,000,000	$ 8,955,531	$ 466,044,469	8.30%	$ 38,690,300	4
	Medium Term Notes						
5	7.59% MTN, Due 2017	$ 25,000,000	$ 147,215	$ 24,852,785	7.68%	$ 1,908,694	5
6	7.78% MTN, Due 2022	25,000,000	175,679	24,824,321	7.86%	1,951,192	6
7	7.92% MTN, Due 2027	25,000,000	204,455	24,795,545	8.00%	1,983,644	7
8	6.89% MTN, Due 2007	17,500,000	7,731	17,492,269	7.00%	1,224,459	8
9	6.76% MTN, Due 2027	7,500,000	3,458	7,496,542	6.88%	515,762	9
10	6.27% MTN, Due 2008	25,000,000	42,553	24,957,447	6.40%	1,597,277	10
11	Total Medium Term Notes	$ 125,000,000	$ 581,090	$ 124,418,910	7.38%	$ 9,181,027	11
12	Total Debentures and MTNs	$ 600,000,000	$ 9,536,621	$ 590,463,379	8.11%	$ 47,871,327	12
					Sch D-2, Sheet 1		
	Tax Exempt Clark County						
15	1999 Series A, Due 2038	12,410,000	588,249	11,821,751	6.56%	775,635	15
16	1999 Series C, Due 2038	14,320,000	802,862	13,517,138	6.49%	877,460	16
17	1999 Series D, Due 2038	8,270,000	463,307	7,806,693	6.07%	473,654	17
18	2003 Series C, Due 2038	30,000,000	1,449,535	28,550,465	5.89%	1,682,012	18
19	2003 Series D, Due 2038	20,000,000	1,805,668	18,194,332	6.09%	1,108,562	19
20	2003 Series E, Due 2038	15,000,000	190,744	14,809,256	5.92%	876,186	20
21	2004 Series A, Due 2034	65,000,000	3,164,929	61,835,071	5.99%	3,706,076	21
22	2004 Series B, Due 2033	75,000,000	5,031,036	69,968,964	5.91%	4,133,791	22
23	2005 Series A, Due 2034	100,000,000	3,609,886	96,390,114	5.34%	5,143,154	23
24	2006 Series B, Due 2033	56,000,000	1,410,826	54,589,174	5.08%	2,774,192	24
25	Total Tax Exempt	$ 396,000,000	$ 18,517,043	$ 377,482,957	5.71%	$ 21,550,723	25
26	Total Fixed-Rate Debt	$ 996,000,000	$ 28,053,664	$ 967,946,336	7.17%	$ 69,422,049	26

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
VARIABLE RATE DEBT COST OF DEBT
AT APRIL 30, 2007

Line No.	Description (a)	Net Proceeds (b)	Interest Rate (c)	Cost of Debt (d)	Line No.
1	Term Facility[1]	$ 53,169,199	6.27%	$ 3,332,516	1
			Sch D-2, Sheet 1		
2	Big Bear 1993 Series A IDRB [2]	$ 49,268,815	5.33%	$ 2,624,876	2
3	Clark Co.2003 Series A & B IDRB [3]	93,121,527	5.18%	$ 4,821,469	3

[1] Based on $150 million designated long-term of the $300 million Bank Facility less $842 thousand of unamortized expense.
[2] The net amount represents $50 million face value less $ $731 thousand of unamortized balances.
[3] The net amount represents $100 million face value less $6.88 million of unamortized balances.

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
COST OF LONG-TERM DEBT
ORIGINAL NET PROCEEDS OF ISSUES OUTSTANDING [1]

Line No.	Description	Origination Date	Maturity Date	Coupon Rate	Offered	Gross Proceeds	Underwriter's Commission and Discounts Amount	Underwriter's Commission and Discounts Percent of Gross Proceeds	Debt and Issuance Expense Amount	Debt and Issuance Expense Percent of Gross Proceeds	Net Proceeds Amount	Net Proceeds Per $100 Unit	Cost of Money [2]	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	
	Debentures													
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				$ 475,000,000	$ 475,000,000	$ 5,764,750	1.21%	$ 6,607,231	1.39%	$ 462,628,019	97.40		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 [3]	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
13	Total Medium Term Notes				$ 125,000,000	$ 125,000,000	$ 867,950	0.69%	$ 249,917	0.20%	$ 123,882,133	99.11		13
	Tax Exempt Clark County													
14	1999 Series A, Due 2038 [3]	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	6.64%	14
15	1999 Series C, Due 2038 [3]	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	6.45%	15
16	1999 Series D, Due 2038 [3]	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	6.13%	16
17	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	17
18	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	18
19	2003 Series C, Due 2038 [3]	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	5.93%	19
20	2003 Series D, Due 2038 [3]	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	3.70%	20
21	2003 Series E, Due 2038 [3]	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	5.93%	21
22	2004 Series A, Due 2034 [3]	07/16/04	07/01/34	5.25%	65,000,000	65,000,000	1,081,500	1.66%	2,915,229	4.48%	61,003,271	93.85	6.07%	22
23	2004 Series B, Due 2033 [3]	10/16/04	12/01/33	5.00%	75,000,000	75,000,000	956,250	1.28%	5,034,263	6.71%	69,009,487	92.01	5.99%	23
22	2005 Series A, Due 2035 [3]	10/01/05	10/01/35	4.85%	100,000,000	100,000,000	1,350,000	1.35%	2,724,048	2.72%	95,925,952	95.93	5.36%	22
23	2006 Series B, Due 2036 [3]	09/01/06	09/01/36	4.75%	56,000,000	56,000,000	686,000	1.23%	791,438	1.41%	54,522,562	97.36	5.09%	23
24	Total Tax Exempt Clark County				$ 496,000,000	$ 496,000,000	$ 4,878,114	0.98%	$ 22,316,049	4.50%	$ 468,805,837	94.52		24
	Tax Exempt Big Bear													
25	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	25
26	Term Facility [4]	04/20/06	04/19/11	Var	$ 150,000,000	$ 150,000,000	$ -	0.00%	$ 711,178	0.47%	$ 149,288,822	99.53	Var	26
27	Total Debt Capital				$ 1,296,000,000	$ 1,296,000,000	$ 11,685,814	0.90%	$ 30,541,139	2.36%	$ 1,253,773,047	96.74		27

[1] Based on Company records.
[2] Based on the Net Proceeds method.
[3] Effective rate at issuance.
[4] A commercial paper program was initiated in October 2002 and is backed by $50 million of the term facility.

SCHEDULE D-2
Sheet 4 of 4

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
COST OF PREFERRED SECURITIES
AT APRIL 30, 2007

Line No.	Description	Net Proceeds Per Security	Number of Securities	Net Proceeds	Effective Cost	Annual Cost	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
1	Trust Originated Preferred Securities Liquidation Amount $25[1]	$ 23.52	4,000,000	$ 94,172,446	8.20% Sch D-1, sh 1	$ 7,722,141	1

[1] 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.

SCHEDULE D-3
Sheet 1 of 2

SOUTHWEST GAS CORPORATION
COST OF PREFERRED SECURITIES
ORIGINAL NET PROCEEDS OF ISSUES OUTSTANDING AT APRIL 30, 2007

Line No.	Description	Annual Dividend Rate/Share	Total Issued		Underwriter's Commission		Reacquired Debt Expense		Issuance Expense		Net Proceeds		Line No.
			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%	$ 547,324	0.547%	$ 94,081,227	$ 23.52	1

[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.
1	A cost of common equity of 11.25 percent is recommended by Southwest Gas Corporation as more fully explained and supported in the direct testimony of Mr. Frank J. Hanley.	1

SOUTHWEST GAS CORPORATION
COMPARATIVE BALANCE SHEETS

Line No.	Description	Balance at 4/30/07 Arizona	Balance at 4/30/07 Other	Balance at 4/30/07 Total	Balance at 12/31/06 Arizona	Balance at 12/31/06 Other	Balance at 12/31/06 Total	Balance at 12/31/05 Arizona	Balance at 12/31/05 Other	Balance at 12/31/05 Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	
	Assets and Other Debits										
	Utility Plant										
1	Utility Plant (101, 105, 114, 118)	$ 1,955,564,837	$ 1,755,558,061	$ 3,711,122,898	$ 1,881,283,726	$ 1,713,418,973	$ 3,594,702,699	$ 1,742,254,499	$ 1,607,809,819	$ 3,350,064,318	1
2	Construction Work in Progress (107)	11,303,613	38,662,980	49,966,593	30,910,335	43,313,114	74,223,449	28,781,731	24,212,307	52,994,038	2
3	Total Utility Plant	$ 1,966,868,450	$ 1,794,221,041	$ 3,761,089,491	$ 1,912,194,061	$ 1,756,732,087	$ 3,668,926,148	$ 1,771,036,230	$ 1,632,022,126	$ 3,403,058,356	3
4	Less: Accumulated Provision for Depreciation and Amortization (108, 111, 119)	688,698,569	582,306,358	1,271,004,927	674,414,547	560,886,077	1,235,300,624	614,949,046	514,204,471	1,129,153,517	4
5	Net Utility Plant	$ 1,278,169,881	$ 1,211,914,683	$ 2,490,084,564	$ 1,237,779,514	$ 1,195,846,010	$ 2,433,625,524	$ 1,156,087,184	$ 1,117,817,655	$ 2,273,904,839	5
	Other Property and Investments										
6	Northern California Surcharge (120)	$ -	$ 5,547,483	$ 5,547,483	$ -	$ 5,859,991	$ 5,859,991	$ -	$ 6,735,698	$ 6,735,698	6
7	Non-Utility Property (121)	-	80,017	80,017	-	80,017	80,017	-	80,017	80,017	7
8	Non-Utility Accumulated Depreciation (122)	-	-	-	-	-	-	-	-	-	8
9	Investment in Subsidiary and Associated Companies (123, 123.1)	-	135,594,132	135,594,132	-	131,063,571	131,063,571	-	115,110,620	115,110,620	9
10	Other Investments (124)	-	-	-	-	-	-	-	-	-	10
11	Special Funds (125, 128)	-	55,174,633	55,174,633	-	52,868,271	52,868,271	-	50,122,378	50,122,378	11
12	Total Other Property and Investments	$ -	$ 196,396,265	$ 196,396,265	$ -	$ 189,871,850	$ 189,871,850	$ -	$ 172,048,713	$ 172,048,713	12
	Current and Accrued Assets										
13	Cash (131)	$ -	$ (28,267,866)	$ (28,267,866)	$ -	$ (9,643,554)	$ (9,643,554)	$ -	$ (4,853,506)	$ (4,853,506)	13
14	Working Funds (135)	-	1,108,034	1,108,034	-	947,094	947,094	-	725,769	725,769	14
15	Temporary Cash Investments (136)	-	1,980,928	1,980,928	-	8,470,545	8,470,545	-	42,046,806	42,046,806	15
16	Notes and Accounts Receivables Less Accumulated Provision for Uncollectible Accounts (141 - 144)	7,297,701	127,184,206	134,481,907	14,498,307	171,761,870	186,260,177	18,577,422	137,417,311	155,994,733	16
17	Receivables from Associated Companies (145-146)	-	19,921,310	19,921,310	-	23,248,322	23,248,322	-	32,029,585	32,029,585	17
18	Materials and Supplies (151, 154, 155, 163)	12,900,762	9,981,939	22,882,701	13,255,070	10,247,461	23,502,531	11,563,091	10,362,693	21,925,784	18
19	Liquefied Natural Gas Stored (164.1, 164.2)	-	8,951,081	8,951,081	-	14,005,846	14,005,846	-	13,047,683	13,047,683	19
20	Prepayments (165)	-	5,941,216	5,941,216	-	9,658,139	9,658,139	-	9,510,702	9,510,702	20
21	Interest and Dividends Receivable (171)	-	-	-	-	-	-	-	-	-	21
22	Accrued Utility Revenue (173)	-	40,300,000	40,300,000	-	73,300,000	73,300,000	-	68,400,000	68,400,000	22
23	Miscellaneous Current and Accrued Assets (174)	-	(7,293,006)	(7,293,006)	-	3,300,749	3,300,749	-	2,915,682	2,915,682	23
24	Total Current and Accrued Assets	$ 20,198,463	$ 179,807,842	$ 200,006,305	$ 27,753,377	$ 305,296,472	$ 333,049,849	$ 30,140,513	$ 311,602,725	$ 341,743,238	24
	Deferred Debits										
25	Unamortized Debt Discount and Expenses (181)	$ -	$ 18,877,479	$ 18,877,479	$ -	$ 19,334,215	$ 19,334,215	$ -	$ 20,132,394	$ 20,132,394	25
26	Other Regulatory Assets (182)	4,807,329	31,954,790	36,762,119	4,985,215	70,719,430	75,704,645	5,219,715	101,984,008	107,203,723	26
27	Preliminary Survey and Investigation Charges (183)	-	(741,889)	(741,889)	-	(141,888)	(141,888)	-	(330,051)	(330,051)	27
28	Clearing Accounts (184)	(146,740)	280,916	134,176	(98,085)	155,105	57,020	(113,083)	286,332	173,249	28
29	Miscellaneous Deferred Debits (186)	5,515,015	4,973,380	10,488,395	5,781,981	5,255,832	11,037,813	5,748,523	5,348,064	11,096,587	29
30	Research & Development (188)	-	-	-	-	223,939	223,939	-	243,559	243,559	30
31	Loss on Reacquired Debt (189)	-	17,448,187	17,448,187	-	17,676,072	17,676,072	-	18,386,157	18,386,157	31
32	Accumulated Deferred Income Taxes (190)	-	36,820,369	36,820,369	-	36,820,369	36,820,369	-	28,902,829	28,902,829	32
33	Unrecovered Purchased Gas Costs (191)	63,014,918	(20,111,034)	42,903,884	67,851,766	9,154,811	77,006,577	46,447,057	62,967,432	109,414,489	33
34	Total Deferred Debits	$ 73,190,522	$ 89,502,198	$ 162,692,720	$ 78,520,877	$ 159,197,885	$ 237,718,762	$ 57,302,212	$ 237,920,724	$ 295,222,936	34
35	Total Assets and Other Debits	$ 1,371,558,866	$ 1,677,620,988	$ 3,049,179,854	$ 1,344,053,768	$ 1,850,212,217	$ 3,194,265,985	$ 1,243,529,909	$ 1,839,389,817	$ 3,082,919,726	35

NOTE: The Arizona columns above reflect only those amounts separately identified in the Southwest Gas general ledger as pertaining solely to Arizona. Allocations are not included, thus the debits and credits in the Arizona columns do not balance. The financial statements appearing herein are unaudited, and were prepared solely for the purposes of complying with the filing requirements for this general rate case.

SCHEDULE E-1
Sheet 1 of 2

SOUTHWEST GAS CORPORATION
COMPARATIVE BALANCE SHEETS

Line No.	Description	Balance at 4/30/07 Arizona	Balance at 4/30/07 Other	Balance at 4/30/07 Total	Balance at 12/31/06 Arizona	Balance at 12/31/06 Other	Balance at 12/31/06 Total	Balance at 12/31/05 Arizona	Balance at 12/31/05 Other	Balance at 12/31/05 Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	
	Liabilities and Other Credits										
	Proprietary Capital										
1	Common Stock Issued (201)	$ -	$ 43,781,138	$ 43,781,138	$ -	$ 43,400,167	$ 43,400,167	$ -	$ 40,958,167	$ 40,958,167	1
2	Preferred Stock Issued (204)	-	-	-	-	-	-	-	-	-	2
3	Premium on Capital Stock (207)	-	719,685,842	719,685,842	-	708,795,500	708,795,500	-	638,211,780	638,211,780	3
4	Other Paid in Capital (208-211)	-	-	-	-	-	-	-	-	-	4
5	Reacquired Capital Stock (217)	-	-	-	-	-	-	-	-	-	5
6	Capital Stock Expense (214)	-	(10,537,842)	(10,537,842)	-	(10,537,842)	(10,537,842)	-	(9,964,407)	(9,964,407)	6
7	Retained Earnings (216)	-	217,456,334	217,456,334	-	173,433,242	173,433,242	-	123,574,333	123,574,333	7
8	Total Proprietary Capital	$ -	$ 970,385,472	$ 970,385,472	$ -	$ 915,091,067	$ 915,091,067	$ -	$ 792,779,873	$ 792,779,873	8
	Long-Term Debt										
9	Bonds (221, 222)	$ -	$ 1,146,000,000	$ 1,146,000,000	$ -	$ 1,146,000,000	$ 1,146,000,000	$ -	$ 1,165,000,000	$ 1,165,000,000	9
10	Other Long-Term Debt (224, 226)	-	45,537,442	45,537,442	-	138,281,898	138,281,898	-	141,184,296	141,184,296	10
11	Other - Preferred Securities (224.1)	-	100,000,000	100,000,000	-	100,000,000	100,000,000	-	100,000,000	100,000,000	11
12	Total Long-Term Debt	$ -	$ 1,291,537,442	$ 1,291,537,442	$ -	$ 1,384,281,898	$ 1,384,281,898	$ -	$ 1,406,184,296	$ 1,406,184,296	12
	Current and Accured Liabilities										
13	Notes Payable (231)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24,000,000	$ 24,000,000	13
14	Accounts Payable (232)	-	95,913,923	95,913,923	-	239,350,227	239,350,227	-	234,527,974	234,527,974	14
15	Payables to Associated Companies (233,234)	-	7,190,228	7,190,228	-	7,644,900	7,644,900	-	8,449,664	8,449,664	15
16	Customer Deposits (235)	34,911,701	32,449,462	67,361,163	32,944,994	31,205,607	64,150,601	29,349,616	28,202,220	57,551,836	16
17	Taxes Accrued (236)	13,259,372	45,344,420	58,603,792	12,379,928	7,155,100	19,535,028	15,188,196	7,386,794	22,574,990	17
18	Interest Accrued (237)	1,050,806	19,145,588	20,196,394	981,687	20,380,198	21,361,885	884,009	21,588,003	22,472,012	18
19	Dividends Declared (238)	-	9,062,521	9,062,521	-	8,562,910	8,562,910	-	8,062,300	8,062,300	19
20	Tax Collections Payable (241)	11,486,764	8,711,728	20,198,492	12,711,816	14,536,249	27,248,065	12,620,095	10,037,720	22,657,815	20
21	Miscellaneous Current and Accrued Liabilities (242)	6,223,324	53,752,965	59,976,289	3,027,404	51,709,315	54,736,719	2,342,302	56,131,024	58,473,326	21
22	Total Current and Accrued Liabilities	$ 66,931,967	$ 271,570,835	$ 338,502,802	$ 62,045,829	$ 380,544,506	$ 442,590,335	$ 60,384,218	$ 398,385,699	$ 458,769,917	22
	Deferred Credits										
23	Customer Advances for Construction (252)	$ 49,277,781	$ 22,242,084	$ 71,519,865	$ 41,078,966	$ 20,741,161	$ 61,820,127	$ 19,563,413	$ 14,268,786	$ 33,832,199	23
24	Other Deferred Credits (253)	26,392	36,940,611	36,967,003	26,392	35,739,640	35,766,032	26,392	34,574,926	34,601,318	24
25	Other Regulatory Liabilities (254)	13,778	7,056,731	7,070,509	15,500	7,256,383	7,271,883	17,222	7,470,217	7,487,439	25
26	Accumulated Deferred Investment Tax Credit (255)	6,251,910	3,789,207	10,041,117	6,428,030	3,902,279	10,330,309	6,956,390	4,241,495	11,197,885	26
27	Accumulated Deferred Income Taxes (282, 283)	202,414,610	118,764,163	321,178,773	178,076,468	157,186,936	335,263,404	175,200,549	148,819,491	324,020,040	27
28	Total Deferred Credits	$ 257,984,471	$ 188,792,796	$ 446,777,267	$ 225,625,356	$ 224,826,399	$ 450,451,755	$ 201,763,966	$ 209,374,915	$ 411,138,881	28
	Other Long-Term Liabilities										
29	Injuries and Damages Reserve (228)	$ -	$ 1,976,871	$ 1,976,871	$ -	$ 1,850,930	$ 1,850,930	$ -	$ 14,046,759	$ 14,046,759	29
30	Provision for Rate Refunds (229)	-	-	-	-	-	-	-	-	-	30
31	Total Other Long-Term Liabilities	$ -	$ 1,976,871	$ 1,976,871	$ -	$ 1,850,930	$ 1,850,930	$ -	$ 14,046,759	$ 14,046,759	31
32	Total Liabilities and Other Credits	$ 324,916,438	$ 2,724,263,416	$ 3,049,179,854	$ 287,671,185	$ 2,906,594,800	$ 3,194,265,985	$ 262,148,184	$ 2,820,771,542	$ 3,082,919,726	32

NOTE: The Arizona columns above reflect only those amounts separately identified in the Southwest Gas general ledger as pertaining solely to Arizona. Allocations are not included, thus the debits and credits in the Arizona columns do not balance. The financial statements appearing herein are unaudited, and were prepared solely for the purposes of complying with the filing requirements for this general rate case.

SCHEDULE E-1
Sheet 2 of 2

SOUTHWEST GAS CORPORATION
ARIZONA
COMPARATIVE INCOME STATEMENTS

Line No.	Description	For the Test Year Ended 4/30/07	For the Year Ended 12/31/06	For the Year Ended 12/31/05	Line No.
	(a)	(b)	(c)	(d)	
1	Operating Revenue	$ 996,389,571	$ 895,549,006	$ 748,627,816	1
2	Operating Expenses and Taxes	914,451,814	827,185,527	708,138,708	2
3	Operating Income	$ 81,937,757	$ 68,363,479	$ 40,489,108	3
4	Other Income and Deductions	0	0	0	4
5	Income Before Interest Deductions	$ 81,937,757	$ 68,363,479	$ 40,489,108	5
6	Net Interest Deductions	47,844,172	47,089,555	45,778,673	6
7	Net Income	$ 34,093,586	$ 21,273,925	$ (5,289,565)	7

SOUTHWEST GAS CORPORATION
STATEMENTS OF INCOME

Line No.	Description	Year Ended 4/30/07	Year Ended 12/31/06	Year Ended 12/31/05	Line No.
	(a)	(b)	(c)	(d)	
	Utility Operating Income				
1	Operating Revenues (400)	$ 1,819,838,987	$ 1,714,338,144	$ 1,444,439,794	1
	Operating Expenses:				
2	Operation Expense (401)	$ 1,384,748,289	$ 1,301,656,495	$ 1,094,523,587	2
3	Maintenance Expense (402)	59,699,065	57,731,331	52,482,297	3
4	Depreciation Expense (403)	135,124,525	131,614,569	123,211,463	4
5	Amortization of Other Limited Term Gas Plant (404.3)	7,814,947	8,241,888	8,213,311	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)	2,287,572	1,425,096	1,307,538	8
9	Taxes Other than Income Taxes (408.1)	37,842,709	34,166,679	38,082,464	9
10	Income Taxes - Federal (409.1)	59,947,616	19,186,368	(1,488,394)	10
11	Income Taxes - Other (409.1)	7,045,314	3,395,307	921,895	11
12	Provision for Deferred Income Taxes (410.1)	52,267,390	101,021,935	99,662,898	12
13	Provision for Deferred Income Taxes - Credit (411.1)	(83,018,417)	(93,463,370)	(84,866,110)	13
14	Investment Tax Credit Adjustment - Net (411.4)	(867,576)	(867,576)	(867,576)	14
15	Total Utility Operating Expenses	$ 1,663,045,445	$ 1,564,262,733	$ 1,331,337,384	15
16	Net Utility Operating Income	$ 156,793,542	$ 150,075,411	$ 113,102,410	16
	Other Income and Deductions				
	Other Income:				
17	Non-Utility Operating Income (415-418)	$ -	$ -	$ -	17
18	Equity in Earnings of Subsidiary Companies (418.1)	17,690,170	19,446,160	14,479,596	18
19	Interest and Dividend Income (419)	7,303,140	9,389,622	7,226,036	19
20	Allowance for Equity Funds Used During Construction (419.1)	1,424,293	1,372,036	966,689	20
21	Amortization of Investment Tax Credits (420)	-	-	-	21
22	Miscellaneous Non-Operating Income (421)	91,439	779	295,573	22
23	Total Other Income	$ 26,509,042	$ 30,208,597	$ 22,967,894	23
	Other (Income) Deductions:				
24	Miscellaneous Amortization (425)	$ 26,358	$ 26,358	$ 26,358	24
25	Miscellaneous (Income) Deductions (426)	1,044,907	169,178	1,074,955	25
26	Total (Income) Deductions	$ 1,071,265	$ 195,536	$ 1,101,313	26
	Taxes Applicable to Other Income and Deductions				
27	Taxes Other than Income Taxes (408.2)	$ 4,421	$ 4,421	$ 11,760	27
28	Income Taxes - (409.2)	977,586	1,536,215	2,181,392	28
29	Provision for Deferred Income Taxes (410.2,411.2)	1,257,832	1,385,913	(349,305)	29
30	Investment Tax Credit Adjustment - Net (411.5)	-	-	-	30
31	Total Taxes Applicable to Other Income and Deductions	$ 2,239,839	$ 2,926,549	$ 1,843,847	31
32	Net Other Income and (Deductions)	$ 23,197,938	$ 27,086,512	$ 20,022,734	32
	Interest Charges				
33	Interest on Long-Term Debt (427)	$ 79,350,696	$ 80,043,345	$ 76,055,512	33
34	Amortization of Debt Discount and Expense (428)	3,952,146	3,466,931	3,699,622	34
35	Other Interest Expense (430-431)	11,083,936	11,148,594	10,593,169	35
36	Total Interest Charges	$ 94,386,778	$ 94,658,870	$ 90,348,303	36
37	Allowance for Borrowed Funds Used During Construction (432)	1,340,971	1,356,704	1,046,495	37
38	Net Interest Charges	$ 93,045,807	$ 93,302,166	$ 89,301,808	38
39	Net Income	$ 86,945,673	$ 83,859,757	$ 43,823,336	39

SOUTHWEST GAS CORPORATION
TOTAL SYSTEM
COMPARATIVE STATEMENT OF CASH FLOWS

Line No.	Description	Test Year Ended 4/30/07	Year Ended 12/31/06	Year Ended 12/31/05	Line No.
	(a)	(b)	(c)	(d)	
	CASH FLOWS FROM OPERATING ACTIVITIES:				
1	Net Income	$ 87,821,323	$ 83,859,756	$ 43,823,336	1
	Adjustments to reconcile net income to net cash provided by operating activities:				
2	Depreciation and amortization	145,381,056	141,435,564	132,886,324	2
3	Deferred income taxes	(30,177,984)	2,458,247	14,465,375	3
	Changes in current assets and liabilities:				
4	Accounts receivable	18,866,845	(31,320,586)	(7,597,731)	4
5	Accrued utility revenue	(3,400,000)	(4,900,000)	(200,000)	5
6	Unrecovered purchased gas costs	88,264,127	32,407,911	(27,338,920)	6
7	Accounts payable	(46,758,655)	14,230,885	114,196,255	7
8	Accrued taxes	42,498,069	1,550,287	6,284,511	8
9	Other current assets and liabilities	-	-	-	9
10	Other	(12,965,202)	4,032,851	(64,815,617)	10
11	Net cash provided by operating activities	$ 289,529,579	$ 243,754,915	$ 211,703,533	11
	CASH FLOWS FROM INVESTING ACTIVITIES:				
12	Construction expenditures	$ (327,268,841)	$ (300,932,762)	$ (256,350,020)	12
13	Other	31,026,415	31,567,651	7,231,287	13
14	Net cash used in investing activities	$ (296,242,426)	$ (269,365,111)	$ (249,118,733)	14
	CASH FLOWS FROM FINANCING ACTIVITIES:				
15	Issuance of common stock	$ 65,896,688	$ 72,452,285	$ 64,135,240	15
16	Issuance of preferred securities, net	-	-	-	16
17	Retirement of preferred securities	-	-	-	17
18	Dividends paid	(34,012,501)	(33,500,237)	(31,227,582)	18
19	Issuance of long-term debt, net	55,948,400	79,948,400	123,255,748	19
20	Retirement of long-term debt	(139,989,000)	(78,000,000)	(25,000,000)	20
21	Issuance (repayment) of short-term debt	-	(24,000,000)	(76,000,000)	21
22	Net cash provided by (used in) financing activitie	$ (52,156,413)	$ 16,900,448	$ 55,163,406	22
23	Change in cash and temporary cash investments	$ (58,869,260)	$ (8,709,748)	$ 17,748,206	23
24	Cash at beginning of period	69,544,757	26,460,546	8,712,340	24
25	Cash at end of period	$ 10,675,497	$ 17,750,798	$ 26,460,546	25

SOUTHWEST GAS CORPORATION
TOTAL SYSTEM
STATEMENT OF CHANGES IN STOCKHOLDERS' EQUITY AND PREFERRED SECURITIES

Line No.	Description	Preferred Securities (1)		Common		Additional Paid-In Capital	Retained Earnings	Capital Stock Expense	Line No.
		Shares/Units	Amount	Shares	Amount				
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	
1	Balance December 31, 2004	-	$ -	36,794,343	$ 38,424,219	$576,298,008	$111,498,039	$ (9,651,927)	1
2	Net Earnings	-	-	-	-	-	43,823,336	-	2
3	Cash Dividends Declared-Common	-	-	-	-	-	(31,747,042)	-	3
4	Common Stock Issue	-	-	2,533,948	2,533,948	61,913,772	-	(312,480)	4
5	Balance December 31, 2005	-	$ -	39,328,291	$ 40,958,167	$638,211,780	$123,574,333	$ (9,964,407)	5
6	Redemption	-	-					-	6
7	Net Earnings	-	-	-	-	-	83,859,756	-	7
8	Cash Dividends Declared-Common	-	-	-	-	-	(34,000,847)	-	8
9	Common Stock Issue	-	-	2,442,000	2,442,000	70,583,720	-	(573,435)	9
10	Balance December 31, 2006	-	$ -	41,770,291	$ 43,400,167	$708,795,500	$173,433,242	$(10,537,842)	10
11	Net Earnings	-	-	-	-	-	53,132,100	-	11
12	Cash Dividends Declared-Common	-	-	-	-	-	(9,109,008)	-	12
13	Common Stock Issue	-	-	380,971	380,971	10,890,342	-	-	13
14	Balance April 30, 2007	-	$ -	42,151,262	$ 43,781,138	$719,685,842	$217,456,334	$(10,537,842)	14

SCHEDULE E-4
Sheet 1 of 1

SOUTHWEST GAS CORPORATION
ARIZONA
DETAIL OF UTILITY PLANT - NET ADDITIONS
FOR THE YEAR ENDED APRIL 30, 2007

Line No.	Description (a)	Account Number (b)	Balance at 30-Apr-07 (c)	Net Plant Additions (Deletions) (d)	Balance at 31-Dec-06 (e)	Line No.
	Intangible					
1	Organizational Costs	301	$ 42,653	$ 0	$ 42,653	1
2	Franchise and Consents	302	1,877,392	(10,601)	1,887,993	2
3	Miscellaneous Intangible	303	1,957,665	0	1,957,665	3
4	Total Intangible		$ 3,877,710	$ (10,601)	$ 3,888,311	4
	Distribution					
5	Land and Land Rights	374.1	$ 351,685	$ 0	$ 351,685	5
6	Rights of Way	374.2	1,064,064	0	1,064,064	6
7	Structures	375	110,557	0	110,557	7
8	Mains	376	983,275,239	39,661,687	943,613,552	8
9	Measuring and Regulating Station	378	32,428,418	1,327,647	31,100,771	9
10	Services	380	605,265,994	9,829,741	595,436,253	10
11	Meters	381	226,663,229	18,298,523	208,364,706	11
12	Industrial Measuring and Reg. Station	385	7,449,951	137,686	7,312,265	12
13	Other Equipment	387	462,730	0	462,730	13
14	Total Distribution		$ 1,857,071,867	$ 69,255,284	$ 1,787,816,583	14
	General					
15	Land and Land Rights	389	$ 8,418,416	$ 1,963,827	$ 6,454,589	15
16	Structures & Improvements - General	390.1	26,064,967	314,145	25,750,822	16
17	Structures and Improve. - Leasehold	390.2	986,219	0	986,219	17
18	Office Furniture and Equipment	391	5,440,159	560,913	4,879,246	18
19	Computer Equipment	391.1	8,563,368	516,820	8,046,548	19
20	Transportation Equipment	392.1	31,126,359	704,486	30,421,873	20
21	Stores Equipment	393	542,520	0	542,520	21
22	Tools, Shop, Garage Equipment	394	5,225,024	182,670	5,042,354	22
23	Laboratory Equipment	395	279,065	0	279,065	23
24	Power Operated Equipment	396	4,309,295	203,746	4,105,549	24
25	Communication Equipment - General	397	2,658,259	514,902	2,143,357	25
26	Telemetering Equipment	397.2	789,376	17,205	772,171	26
27	Miscellaneous Equipment	398	892,348	40,049	852,299	27
28	Total General		$ 95,295,375	$ 5,018,763	$ 90,276,612	28
29	Total Plant in Service		$ 1,956,244,952	$ 74,263,446	$ 1,881,981,506	29
30	Construction Work in Progress		14,716,205	(15,874,556)	30,590,761	30
31	Less: Accumulated Depreciation/Amort.		692,030,569	20,111,974	671,918,595	31
32	Total Net Plant		$ 1,278,930,588	$ 38,276,916	$ 1,240,653,672	32

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE PLANT
DETAIL OF UTILITY PLANT - NET ADDITIONS
FOR THE YEAR ENDED APRIL 30, 2007

Line No.	Description (a)	Account Number (b)	Balance at 30-Apr-07 (c)	Net Plant Additions (Deletions) (d)	Balance at 31-Dec-06 (e)	Line No.
	Intangible					
1	Organizational Costs	301	$ 61,816	$ 0	$ 61,816	1
2	Miscellaneous Intangible	303	111,648,261	1,375,104	110,273,157	2
3	Total Intangible		$ 111,710,077	$ 1,375,104	$ 110,334,973	3
	General					
4	Land and Land Rights	389	$ 391,307	$ 0	$ 391,307	4
5	Structures and Improvements - Gen	390.1	13,696,291	127,552	13,568,739	5
6	Structure and Improve. - Leasehold	390.2	4,232,645	115,411	4,117,234	6
7	Office Furniture and Equipment	391	9,413,589	410,465	9,003,124	7
8	Computer Equipment	391.1	14,358,835	29,491	14,329,344	8
9	Transportation Equipment - Light	392.11	3,495,826	38,713	3,457,113	9
10	Transportation Equipment - Heavy	392.12	86,303	0	86,303	10
11	Stores Equipment	393	24,106	0	24,106	11
12	Tools, Shop, Garage Equipment	394	232,096	0	232,096	12
13	Laboratory Equipment	395	281,078	9,868	271,210	13
14	Communication Equipment	397.1	5,376,875	305,579	5,071,296	14
15	Telemetering Equipment	397.2	286,958	6,933	280,025	15
16	Miscellaneous Equipment	398	882,254	0	882,254	16
17	Total General		$ 52,758,163	$ 1,044,012	$ 51,714,151	17
18	Total Systems - Plant in Service		$ 164,468,240	$ 2,419,116	$ 162,049,124	18
19	Construction Work in Progress		3,707,879	(1,254,849)	4,962,728	19
20	Less: Accumulated Depreciation/Amort.		106,157,029	1,513,306	104,643,723	20
21	Total Net Plant		$ 62,019,090	$ (349,039)	$ 62,368,129	21

SOUTHWEST GAS CORPORATION
ARIZONA
COMPARATIVE DEPARTMENTAL OPERATING INCOME STATEMENTS

Line No.	Description	For the TestYear Ended 4/30/07	For the Year Ended 12/31/06	For the Year Ended 12/31/05	Line No.
	(a)	(b)	(c)	(d)	
	Revenues				
1	Residential	$ 534,629,012	$ 459,375,848	$ 377,481,564	1
2	Small Commercial	242,901,625	223,648,183	177,615,441	2
3	Large Commercial	62,979,199	55,965,426	35,133,244	3
4	Small Industrial	45,642,205	45,890,749	32,947,420	4
5	Commercial-Compressed Nat. Gas	2,493,836	2,522,813	2,002,307	5
6	Irrigation/Water Pumping	12,830,537	13,109,820	13,103,224	6
7	Industrial-Essential Agriculture	23,610,155	20,104,961	8,084,740	7
8	Procurement Sales	44,370,052	48,895,478	82,336,266	8
9	Other Gas Sales	173,495	160,790	175,973	9
10	Transportation of Gas for Others	11,659,328	10,513,078	9,058,071	10
11	Rent from Gas Property	512,498	517,160	614,217	11
12	Other Gas Revenues	0	0	0	12
13	Miscellaneous Service Revenue	11,749,308	11,227,851	10,002,293	13
14	LIRA Program Recovery	868,933	584,995	(38,475)	14
15	Accrued Unbilled Revenues	1,969,388	3,031,854	111,531	15
16	Total Revenues	$ 996,389,571	$ 895,549,006	$ 748,627,816	16
	Operating Expenses				
17	Other Gas Supply and Gas Cost	$ 594,109,743	$ 525,175,154	$ 425,287,419	17
18	Transmission	0	(0)	12,556	18
19	Distribution	87,644,582	85,228,447	81,675,844	19
20	Customer Accounts	37,800,950	37,261,156	35,037,768	20
21	Customer Service & Information	1,320,355	889,541	674,654	21
22	Sales	230,155	250,732	105,813	22
23	Administrative and General	53,970,196	53,266,327	57,242,109	23
24	Depreciation and Amortization	86,665,721	83,858,314	79,019,889	24
25	Interest on Customer Deposits	1,856,153	1,876,829	1,705,847	25
26	Taxes Other Than Income	28,912,193	25,391,691	30,021,921	26
27	Income Taxes - Federal	18,007,537	11,455,272	(2,245,297)	27
28	Income Taxes - State	3,934,229	2,532,064	(399,817)	28
29	Total Expenses	$ 914,451,814	$ 827,185,527	$ 708,138,708	29
30	Operating Income	$ 81,937,757	$ 68,363,479	$ 40,489,108	30

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
OPERATING STATISTICS
FOR THE TEST YEAR ENDED APRIL 30, 2007

Line No.	Description	Schedule No.	Average Customers	Sales (Therms)	Average per Customer	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	Residential Gas Service	G-5	844,801	287,627,196	340	1
2	Multi-Family Residential Gas Service	G-6	30,690	6,507,195	212	2
3	Low Income Residential Gas Service	G-10	25,929	8,687,972	335	3
4	Multi-Family Low Income Residential Gas Service	G-11	2,193	538,091	245	4
5	Special Residential Gas Service for A/C	G-15	108	143,315	1,327	5
6	Special Residential Gas Service for Electric Generation	G-16	0	0	-	6
7	Master Metered Mobile Home Park Gas Service	G-20	164	2,214,306	13,502	7
	General Gas Service	G-25				
8	Small		16,961	5,112,687	301	8
9	Medium		16,047	45,322,582	2,824	9
10	Large		6,977	145,251,712	20,817	10
11	Transportation Eligible		145	81,978,961	565,372	11
12	Optional Gas Service	G-30	1	34,477,100	34,477,100	12
13	Gas Service to Armed Forces	G-35	0	0	-	13
14	Air Conditioning Gas Service	G-40	25	744,265	30,378	14
15	Street Lighting Gas Service	G-45	27	102,289	3,788	15
	Gas Service for Compression on Customer's Premises	G-55				
16	Small		21	177,495	8,452	16
17	Large		24	2,060,152	85,840	17
18	Residential		106	77,361	730	18
19	Cogeneration Gas Service	G-60	21	21,521,946	1,024,855	19
20	Small Essential Agriculture User Gas Service	G-75	87	7,214,684	82,611	20
21	Natural Gas Engine Gas Service	G-80	425	13,070,981	30,725	21
22	Total Gas Sales		944,753	662,830,290	702	22
23	Transportation Service Including Special Contract	T-1/B-1	247	113,414,439	458,549	23
24	Total Arizona		945,001	776,244,729	821	24

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
OPERATING STATISTICS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2006

Line No.	Description	Schedule No.	Average Customers	Sales (Therms)	Average per Customer	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	Residential Gas Service	G-5	810,250	257,670,165	318	1
2	Multi-Family Residential Gas Service	G-6	28,272	5,445,774	193	2
3	Low Income Residential Gas Service	G-10	24,343	7,865,249	323	3
4	Multi-Family Low Income Residential Gas Service	G-11	1,983	430,457	217	4
5	Special Residential Gas Service for A/C	G-15	114	142,235	1,248	5
6	Special Residential Gas Service for Electric Generation	G-16	0	0	-	6
7	Master Metered Mobile Home Park Gas Service	G-20	175	2,124,139	12,126	7
	General Gas Service	G-25				
8	Small		14,215	2,718,743	191	8
9	Medium		18,777	44,692,733	2,380	9
10	Large		6,938	146,196,011	21,071	10
11	Transportation Eligible		138	79,244,698	574,931	11
12	Optional Gas Service	G-30	5	73,283,590	14,416,444	12
13	Gas Service to Armed Forces	G-35	6	1,967,601	310,674	13
14	Air Conditioning Gas Service	G-40	27	782,191	29,332	14
15	Street Lighting Gas Service	G-45	26	101,268	3,907	15
	Gas Service for Compression on Customer's Premises	G-55				
16	Small		23	191,705	8,187	16
17	Large		25	2,220,080	90,003	17
18	Residential		105	74,348	711	18
19	Cogeneration Gas Service	G-60	22	18,701,265	866,468	19
20	Small Essential Agriculture User Gas Service	G-75	96	8,778,744	91,445	20
21	Natural Gas Engine Gas Service	G-80	471	13,755,821	29,190	21
22	Total Gas Sales		906,011	666,386,817	736	22
23	Transportation Service Including Special Contract	T-1/B-1	219	71,031,432	324,715	23
24	Total Arizona		906,230	737,418,249	814	24

SOUTHWEST GAS CORPORTATION
ARIZONA DIVISION
OPERATING STATISTICS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2005

Line No.	Description	Schedule No.	Average Customers	Sales (Therms)	Average per Customer	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	Residential Gas Service	G-5	823,164	258,307,113	314	1
2	Multti-Family Residential Gas Service	G-6	29,850	6,289,177	211	2
3	Low Income Residential Gas Service	G-10	26,177	8,995,604	344	3
4	Multi-Family Low Income Residential Gas Service	G-11	3,657	543,874	149	4
5	Special Residential Gas Service for A/C	G-15	126	181,622	1,437	5
6	Special Residential Gas Service for Electric Generation	G-16	0	29	174	6
7	Master Metered Mobile Home Park Gas Service	G-20	181	2,221,960	12,276	7
	General Gas Service	G-25				
8	Small		32,724	46,258,768	1,414	8
9	Medium		6,998	142,391,261	20,347	9
10	Large		115	51,837,818	449,461	10
11	Optional Gas Service	G-30	42	103,976,689	2,475,635	11
12	Gas Service to Armed Forces	G-35	11	3,153,221	286,656	12
13	Air Conditioning Gas Service	G-40	34	760,755	22,709	13
14	Street Lighting Gas Service	G-45	27	100,928	3,797	14
	Gas Service for Compression on Customer's Premises	G-55				
15	Small		23	204,582	8,831	15
16	Large		26	2,283,894	88,695	16
17	Residential		101	69,155	684	17
18	Cogeneration Gas Service	G-60	23	15,355,050	677,429	18
19	Small Essential Agriculture User Gas Service	G-75	99	8,670,397	87,580	19
20	Natural Gas Engine Gas Service	G-80	523	14,021,900	26,836	20
21	Total Gas Sales		923,899	665,623,797	720	21
22	Transportation Service Including Special Contract	T-1/B-1	218	67,162,701	308,204	22
23	Total Arizona		924,117	732,786,498	793	23

732,786,498
0

SOUTHWEST GAS CORPORATION
ARIZONA
TAXES CHARGED TO OPERATIONS
AS RECORDED AT APRIL 30, 2007

Line No.	Description	For the Test Year Ended 4/30/07	For the Year Ended 12/31/06	For the Year Ended 12/31/05	Line No.
	(a)	(b)	(c)	(d)	
	Federal Taxes				
1	Federal Income Tax	$ 18,007,537	$ 11,455,272	$ (2,245,297)	1
	State Taxes				
2	State Income Tax	$ 3,934,229	$ 2,532,064	$ (399,817)	2
	Local Taxes				
3	Property and Miscellaneous	$ 28,912,193	$ 25,391,691	$ 30,021,921	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 used in 2006 was 8.96% and is estimated to be 8.75% for 2007.

4. Additional information concerning these statements is contained in Southwest's 2006 Annual Report which is included in the instant application.

SOUTHWEST GAS CORPORATION
ARIZONA
PROJECTED INCOME STATEMENTS - PRESENT AND PROPOSED RATES

Line No.	Description	Test Year Ended 4/30/2007	Projected Year Present Rates 4/30/2008	Projected Year Proposed Rates 4/30/2008	Line No.
	(a)	(b)	(c)	(d)	
1	Operating Margin	$ 402,964,907	$ 406,994,556	$ 453,949,051	1
	Operating Expenses				
2	Other Gas Supply Expenses	$ 685,079	$ 701,601	$ 701,601	2
3	Distribution Expenses	87,644,582	89,521,943	89,521,943	3
4	Customer Accounts Expenses	37,800,950	38,730,909	38,730,909	4
5	Customer Service and Info. Expenses	1,320,355	1,126,796	1,126,796	5
6	Sales Expenses	230,155	0	0	6
7	Administrative and General Expenses	53,970,196	57,280,777	57,280,777	7
8	Depreciation and Amortization Expenses	86,665,721	95,152,859	95,152,859	8
9	Taxes Other than Income	21,941,766	34,118,626	34,118,626	9
10	Interest on Customer Deposits	1,856,153	1,915,314	1,915,314	10
11	Federal Income Taxes	18,007,537	12,919,971	28,208,918	11
12	State Income Taxes	3,934,229	2,845,505	6,117,294	12
13	Total Operating Expenses	$ 314,056,723	$ 334,314,300	$ 352,875,036	13
14	Operating Income	$ 88,908,184	$ 72,680,256	$ 101,074,015	14
15	Less: Interest Expense	47,844,172	48,035,008	48,035,008	15
16	Net Income	$ 41,064,012	$ 24,645,248	$ 53,039,007	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
TOTAL SYSTEM
COMPARATIVE STATEMENT OF CASH FLOWS

Line No.	Description	Test Year[1] Ended 4/30/07	Projected Year[2] At Present Rates Year Ended 12/31/08	Projected Year[2] At Proposed Rates Year Ended 12/31/08	Line No.
	(a)	(b)	(c)	(d)	
	CASH FLOWS FROM OPERATING ACTIVITIES:				
1	Net Income	$ 87,821,323	$ 87,821,323	$ 118,098,884	1
	Adjustments to reconcile net income to net cash provided by operating activities:				
2	Depreciation and amortization	145,381,056	154,381,056	154,381,056	2
3	Deferred income taxes	(30,177,984)	(30,177,984)	(30,177,984)	3
4	Changes in current assets and liabilities:		-	-	4
5	Accounts receivable	18,866,845	18,866,845	18,866,845	5
6	Accrued utility revenue	(3,400,000)	(3,400,000)	(3,400,000)	6
7	Unrecovered purchased gas costs	88,264,127	73,600,000	73,600,000	7
8	Accounts payable	(46,758,655)	(46,758,655)	(46,758,655)	8
9	Accrued taxes	42,498,069	42,498,069	42,498,069	9
10	Other	(12,965,202)	(12,965,202)	(12,965,202)	10
11	Net cash provided by operating activities	$289,529,579	$283,865,452	$314,143,013	11
	CASH FLOWS FROM INVESTING ACTIVITIES:				
12	Construction expenditures	(327,268,841)	(300,000,000)	(300,000,000)	12
13	Other	31,026,415	31,026,415	31,026,415	13
14	Net cash used in investing activities	(296,242,426)	(268,973,585)	(268,973,585)	14
	CASH FLOWS FROM FINANCING ACTIVITIES:				
15	Issuance of common stock	65,896,688	38,000,000	38,000,000	15
16	Issuance of preferred securities, net	-	-	-	16
17	Retirement of preferred securities	-	-	-	17
18	Dividends paid	(34,012,501)	(35,212,501)	(35,212,501)	18
19	Issuance of long-term debt, net	55,948,400	-	-	19
20	Retirement of long-term debt	(139,989,000)	(25,000,000)	(25,000,000)	20
21	Issuance (repayment) of short-term debt	-	-	-	21
22	Net cash provided by (used in) financing activities	(52,156,413)	(22,212,501)	(22,212,501)	22
23	Change in cash and temporary cash investments	(58,869,260)	(7,320,634)	22,956,927	23
24	Cash at beginning of period	69,544,757	10,675,497	3,354,863	24
25	Cash at end of period	$ 10,675,497	$ 3,354,863	$ 26,311,790	25

[1] Supporting Schedule E-3
[2] Recap Schedule A-5

SOUTHWEST GAS CORPORATION
ARIZONA
CONSTRUCTION EXPENDITURES BY PROPERTY CLASSIFICATION
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007
AND PROJECTED TWELVE MONTHS ENDING APRIL 30, 2008, 2009, AND 2010

Line No.	Description	Test Year Ended 4/30/2007	Projected Year Ending 4/30/08	Projected Year Ending 4/30/09	Projected Year Ending 4/30/10	Line No.
	(a)	(b)	(c)	(d)	(e)	
	Intangible Plant					
1	Arizona Direct	$ 99,483	$ 310,000	$ 0	$ 0	1
2	System Allocable [1]	1,878,136	4,421,381	4,983,250	4,067,715	2
3	Total Intangible Plant	$ 1,977,619	$ 4,731,381	$ 4,983,250	$ 4,067,715	3
	Distribution Plant					
4	Arizona Direct	$ 174,032,007	$ 145,824,212	$ 126,357,261	$ 109,086,533	4
5	System Allocable [1]	0	0	0	0	5
6	Total Distribution Plant	$ 174,032,007	$ 145,824,212	$ 126,357,261	$ 109,086,533	6
	General Plant					
7	Arizona Direct	$ 12,289,092	$ 6,823,377	$ 856,199	$ 997,784	7
8	System Allocable [1]	3,398,607	7,827,929	7,993,746	6,762,111	8
9	Total General Plant	$ 15,687,699	$ 14,651,306	$ 8,849,945	$ 7,759,895	9
10	Total Arizona Plant Construction	$ 191,697,325	$ 165,206,899	$ 140,190,456	$ 120,914,143	10

[1] Allocation based on the 4-Factor (56.70%). Supporting Schedule C-1, Sh 17

SCHEDULE F-3
Sheet 1 of 1

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 April 30, 2007, were adjusted to give the annual effect for known and measurable changes occurring during the test year ending April 30, 2007. The operation and maintenance expenses for the projected year ending April 30, 2008, 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 April 30, 2007 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.

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY SUMMARY
PRESENT RATES
TEST YEAR ENDING APRIL 30, 2007

Line No.	Description	Allocation Factor No.	Total Amount	Single Family Residential	Multi-Family Residential	MMMHP	Small Gen. Service	Medium Gen. Service	Large Gen. Service	Trans. Eligible Service
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Rate Base									
1	Direct Net Plant		$1,267,124,121	$ 972,148,655	$ 26,208,345	$ 2,101,465	$ 21,567,888	$ 69,420,649	$ 106,428,942	$ 52,370,004
2	Systems Allocable Net Plant		34,448,206	26,428,964	712,504	57,131	586,347	1,887,279	2,893,391	1,423,738
3	Cash Working Capital	11.2	(10,379,937)	(8,277,078)	(202,429)	(11,552)	(244,332)	(578,417)	(686,594)	(266,389)
4	Materials & Supplies	1.1	12,389,898	9,505,637	256,264	20,548	210,890	678,793	1,040,659	512,072
5	Prepayments	Direct Net Plant	3,671,971	2,817,168	75,949	6,090	62,501	201,173	308,418	151,762
6	Gas Plant Acquisition Adjustment	Direct Net Plant	-	-	-	-	-	-	-	-
7	Customer Deposits	8	(31,921,898)	(29,695,451)	(1,113,765)	(5,508)	(564,803)	(542,371)	-	-
8	Customer Advances	8	(37,910,017)	(35,265,919)	(1,322,692)	(6,541)	(670,752)	(644,112)	-	-
9	Deferred Taxes	1.1	(142,632,297)	(109,428,740)	(2,950,111)	(236,549)	(2,427,763)	(7,814,252)	(11,980,045)	(5,894,966)
10	Deferred Gain Hdqtrs Bldg	4	-	-	-	-	-	-	-	-
11	Total Rate Base		$1,094,790,047	$ 828,233,236	$ 21,664,065	$ 1,925,083	$ 18,519,976	$ 62,608,741	$ 98,004,771	$ 48,296,221
	Margin									
12	Net Operating Margin	Direct	$ 381,188,845	$ 258,989,889	$ 7,115,596	$ 972,093	$ 7,867,642	$ 24,310,776	$ 53,003,981	$ 20,088,639
13	Special Contract Margin	Net Op. Marg.	$ 5,784,028	$ 3,929,823	$ 107,970	$ 14,750	$ 119,381	$ 368,883	$ 804,264	$ 304,818
14	Other Revenue	Net Op. Marg.	12,261,805	10,634,757	376,029	11,075	357,561	552,423	230,620	48,605
15	Total Revenue		$ 399,234,678	$ 273,554,469	$ 7,599,595	$ 997,919	$ 8,344,584	$ 25,232,083	$ 54,038,865	$ 20,442,062
	Operating Deductions									
16	O & M		$(130,087,761)	$(103,733,435)	$(2,536,969)	$(144,778)	$(3,062,120)	$(7,249,078)	$(8,604,815)	$(3,338,545)
17	A & G	O & M	(56,946,694)	(45,409,930)	(1,110,574)	(63,378)	(1,340,461)	(3,173,327)	(3,766,809)	(1,461,468)
18	Depreciation Expense		(87,887,713)	(67,428,218)	(1,817,811)	(145,758)	(1,495,948)	(4,815,015)	(7,381,910)	(3,632,383)
19	Interest on Customer Deposits	8	(1,915,314)	(1,781,727)	(66,826)	(330)	(33,888)	(32,542)	-	-
20	Taxes other than Income	1.1	(33,124,880)	(25,413,696)	(685,133)	(54,936)	(563,823)	(1,814,779)	(2,782,242)	(1,369,045)
21	Total Operating Deductions		$(309,962,361)	$(243,767,007)	$(6,217,312)	$(409,180)	$(6,496,241)	$(17,084,742)	$(22,535,776)	$(9,801,442)
	State Income Tax									
22	Taxable Income before Interest Exp.		$ 89,272,317	$ 29,787,462	$ 1,382,283	$ 588,739	$ 1,848,343	$ 8,147,341	$ 31,503,089	$ 10,640,620
23	Interest Expense	1.1	(48,035,008)	(36,852,876)	(993,524)	(79,664)	(817,610)	(2,631,645)	(4,034,581)	(1,985,278)
24	State Taxable Income		$ 41,237,309	$(7,065,414)	$ 388,759	$ 509,075	$ 1,030,733	$ 5,515,696	$ 27,468,508	$ 8,655,342
25	State Income Tax		2,873,416	(492,318)	27,089	35,472	71,821	384,334	1,914,006	603,104
26	South Georgia	1.1	29,686	22,775	614	49	505	1,626	2,493	1,227
27	Total State Income Tax		$ 2,903,102	$(469,543)	$ 27,703	$ 35,522	$ 72,327	$ 385,960	$ 1,916,499	$ 604,331
	Federal Income Tax									
28	Taxable Income before Interest Exp.		$ 89,272,317	$ 29,787,462	$ 1,382,283	$ 588,739	$ 1,848,343	$ 8,147,341	$ 31,503,089	$ 10,640,620
29	Interest Expense		(48,035,008)	(36,852,876)	(993,524)	(79,664)	(817,610)	(2,631,645)	(4,034,581)	(1,985,278)
30	Federal Taxable Income		$ 41,237,309	$(7,065,414)	$ 388,759	$ 509,075	$ 1,030,733	$ 5,515,696	$ 27,468,508	$ 8,655,342
31	Federal Income Tax		$ 13,427,363	$(2,300,584)	$ 126,585	$ 165,761	$ 335,619	$ 1,795,977	$ 8,944,076	$ 2,818,283
32	I T C	1.1	(528,360)	(405,362)	(10,928)	(876)	(8,993)	(28,947)	(44,378)	(21,837)
33	South Georgia	1.1	290,114	222,578	6,001	481	4,938	15,894	24,367	11,990
34	Total Federal Income Tax		$ 13,189,117	$(2,483,368)	$ 121,657	$ 165,366	$ 331,564	$ 1,782,924	$ 8,924,065	$ 2,808,437
35	Regulatory Amortization	Depr. Exp.	-	-	-	-	-	-	-	-
36	Net Income		$ 73,180,099	$ 32,740,373	$ 1,232,923	$ 387,851	$ 1,444,453	$ 5,978,457	$ 20,662,525	$ 7,227,852

SCHEDULE G-1
SHEET 1 OF 2

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY SUMMARY
PRESENT RATES
TEST YEAR ENDING APRIL 30, 2007

Line No.	Description	Allocation Factor No.	Total Amount	Air Conditioning	CNG Small	CNG Large	CNG Residential	Electric Generation	Small Ess. Agr.	Natural Gas Engines	Street Lighting
	(a)	(b)	(c)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
	Rate Base										
1	Direct Net Plant		$1,267,124,121	$ 206,853	$ 67,356	$ 757,197	$ 105,396	$ 4,647,622	$5,263,618	$ 5,381,166	$ 448,968
2	Systems Allocable Net Plant		34,448,206	5,624	1,831	20,585	2,865	126,351	143,097	146,293	12,206
3	Cash Working Capital	11.2	(10,379,937)	(1,182)	(555)	(5,054)	(929)	(24,562)	(32,177)	(46,535)	(2,151)
4	Materials & Supplies	1.1	12,389,898	2,023	659	7,404	1,031	45,444	51,467	52,617	4,390
5	Prepayments	Direct Net Plant	3,671,971	599	195	2,194	305	13,468	15,253	15,594	1,301
6	Gas Plant Acquisition Adjustment	Direct Net Plant	-	-	-	-	-	-	-	-	-
7	Customer Deposits	8	(31,921,898)	-	-	-	-	-	-	-	-
8	Customer Advances	8	(37,910,017)	-	-	-	-	-	-	-	-
9	Deferred Taxes	1.1	(142,632,297)	(23,284)	(7,582)	(85,233)	(11,864)	(523,154)	(592,493)	(605,724)	(50,538)
10	Deferred Gain Hdqtrs Bldg	4	-	-	-	-	-	-	-	-	-
11	Total Rate Base		$1,094,790,047	$ 190,632	$ 61,903	$ 697,093	$ 96,804	$ 4,285,169	$4,848,767	$ 4,943,410	$ 414,177
	Margin										
12	Net Operating Margin	Direct	$ 381,188,845	$ 123,697	$ 36,474	$ 404,946	$ 25,489	$ 2,529,330	$3,104,924	$ 2,559,519	$ 55,850
13	Special Contract Margin	Net Op. Marg.	$ 5,784,028	$ 1,877	$ 553	$ 6,145	$ 387	$ 38,379	$ 47,113	$ 38,837	$ 847
14	Other Revenue	Net Op. Marg.	12,261,805	576	373	919	1,670	6,008	5,770	26,581	8,837
15	Total Revenue		$ 399,234,678	$ 126,150	$ 37,401	$ 412,009	$ 27,545	$ 2,573,718	$3,157,807	$ 2,624,937	$ 65,534
	Operating Deductions										
16	O & M		$(130,087,761)	$(14,820)	$(6,961)	$(63,340)	$(11,646)	$(307,831)	$(403,259)	$(583,210)	$(26,953)
17	A & G	O & M	(56,946,694)	(6,487)	(3,047)	(27,727)	(5,098)	(134,755)	(176,529)	(255,304)	(11,799)
18	Depreciation Expense		(87,887,713)	(14,347)	(4,672)	(52,519)	(7,310)	(322,359)	(365,084)	(373,238)	(31,140)
19	Interest on Customer Deposits	8	(1,915,314)	-	-	-	-	-	-	-	-
20	Taxes other than Income	1.1	(33,124,880)	(5,408)	(1,761)	(19,794)	(2,755)	(121,497)	(137,600)	(140,673)	(11,737)
21	Total Operating Deductions		$(309,962,361)	$(41,062)	$(16,441)	$(163,381)	$(26,810)	$(886,442)	$(1,082,472)	$(1,352,425)	$(81,629)
	State Income Tax										
22	Taxable Income before Interest Exp.		$ 89,272,317	$ 85,088	$ 20,960	$ 248,628	$ 735	$ 1,687,275	$2,075,334	$ 1,272,512	$(16,095)
23	Interest Expense	1.1	(48,035,008)	(7,842)	(2,553)	(28,704)	(3,995)	(176,185)	(199,537)	(203,993)	(17,020)
24	State Taxable Income		$ 41,237,309	$ 77,247	$ 18,407	$ 219,924	$(3,260)	$ 1,511,090	$1,875,798	$ 1,068,520	$(33,114)
25	State Income Tax		2,873,416	5,383	1,283	15,324	(227)	105,293	130,706	74,454	(2,307)
26	South Georgia	1.1	29,686	5	2	18	2	109	123	126	11
27	Total State Income Tax		$ 2,903,102	$ 5,387	$ 1,284	$ 15,342	$(225)	$ 105,402	$ 130,829	$ 74,581	$(2,297)
	Federal Income Tax										
28	Taxable Income before Interest Exp.		$ 89,272,317	$ 85,088	$ 20,960	$ 248,628	$ 735	$ 1,687,275	$2,075,334	$ 1,272,512	$(16,095)
29	Interest Expense		(48,035,008)	(7,842)	(2,553)	(28,704)	(3,995)	(176,185)	(199,537)	(203,993)	(17,020)
30	Federal Taxable Income		$ 41,237,309	$ 77,247	$ 18,407	$ 219,924	$(3,260)	$ 1,511,090	$1,875,798	$ 1,068,520	$(33,114)
31	Federal Income Tax		$ 13,427,363	$ 25,152	$ 5,993	$ 71,610	$(1,061)	$ 492,029	$ 610,782	$ 347,923	$(10,782)
32	I T C	1.1	(528,360)	(86)	(28)	(316)	(44)	(1,938)	(2,195)	(2,244)	(187)
33	South Georgia	1.1	290,114	47	15	173	24	1,064	1,205	1,232	103
34	Total Federal Income Tax		$ 13,189,117	$ 25,114	$ 5,981	$ 71,467	$(1,081)	$ 491,155	$ 609,793	$ 346,911	$(10,867)
35	Regulatory Amortization	Depr. Exp.	-	-	-	-	-	-	-	-	-
36	Net Income		$ 73,180,099	$ 54,587	$ 13,695	$ 161,819	$ 2,041	$ 1,090,718	$1,334,713	$ 851,021	$(2,931)

SCHEDULE G-1
SHEET 2 OF 2

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY SUMMARY
PROPOSED RATES
TEST YEAR ENDING APRIL 30, 2007

Line No.	Description	Allocation Factor No.	Total Amount	Single Family Residential	Multi-Family Residential	MMMHP	Small Gen. Service	Medium Gen. Service	Large Gen. Service	Trans. Eligible Service
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	Rate Base									
1	Direct Net Plant		$1,267,124,121	$ 972,148,655	$ 26,208,345	$ 2,101,465	$ 21,567,888	$ 69,420,649	$ 106,428,942	$ 52,370,004
2	Systems Allocable Net Plant		34,448,206	26,428,964	712,504	57,131	586,347	1,887,279	2,893,391	1,423,738
3	Cash Working Capital	11.2	(10,379,937)	(8,277,078)	(202,429)	(11,552)	(244,332)	(578,417)	(686,594)	(266,389)
4	Materials & Supplies	1.1	12,389,898	9,505,637	256,264	20,548	210,890	678,793	1,040,659	512,072
5	Prepayments	Direct Net Plant	3,671,971	2,817,168	75,949	6,090	62,501	201,173	308,418	151,762
6	Gas Plant Acquisition Adjustment	Direct Net Plant	-	-	-	-	-	-	-	-
7	Customer Deposits	8	(31,921,898)	(29,695,451)	(1,113,765)	(5,508)	(564,803)	(542,371)	-	-
8	Customer Advances	8	(37,910,017)	(35,265,919)	(1,322,692)	(6,541)	(670,752)	(644,112)	-	-
9	Deferred Taxes	1.1	(142,632,297)	(109,428,740)	(2,950,111)	(236,549)	(2,427,763)	(7,814,252)	(11,980,045)	(5,894,966)
10	Deferred Gain Hdqtrs Bldg	4	-	-	-	-	-	-	-	-
11	Total Rate Base		$1,094,790,047	$ 828,233,236	$ 21,664,065	$ 1,925,083	$ 18,519,976	$ 62,608,741	$ 98,004,771	$ 48,296,221
12	Net Operating Margin	Direct	$ 431,409,491	$ 299,523,089	$ 6,921,522	$ 1,041,727	$ 8,853,467	$ 27,091,812	$ 56,721,948	$ 21,821,052
13	Special Contract&Optional&Resale M	Net Op. Marg.	$ 5,784,028	$ 4,015,790	$ 92,799	$ 13,967	$ 118,701	$ 363,228	$ 760,487	$ 292,561
14	Other Revenue	Net Op. Marg.	12,261,805	10,634,757	376,029	11,075	357,561	552,423	230,620	48,605
15	Total Revenue		$ 449,455,324	$ 314,173,635	$ 7,390,350	$ 1,066,769	$ 9,329,729	$ 28,007,463	$ 57,713,055	$ 22,162,218
	Operating Deductions									
16	O & M		$(130,237,868)	$(103,871,820)	$(2,542,160)	$(144,804)	$(3,064,752)	$(7,251,605)	$(8,605,930)	$(3,338,574)
17	A & G	O & M	(56,946,694)	(45,409,930)	(1,110,574)	(63,378)	(1,340,461)	(3,173,327)	(3,766,809)	(1,461,468)
18	Depreciation Expense		(87,887,713)	(67,428,218)	(1,817,811)	(145,758)	(1,495,948)	(4,815,015)	(7,381,910)	(3,632,383)
19	Interest on Customer Deposits	8	(1,915,314)	(1,781,727)	(66,826)	(330)	(33,888)	(32,542)	-	-
20	Taxes other than Income	1.1	(33,124,880)	(25,413,696)	(685,133)	(54,936)	(563,823)	(1,814,779)	(2,782,242)	(1,369,045)
21	Total Operating Deductions		$(310,112,468)	$(243,905,392)	$(6,222,502)	$(409,205)	$(6,498,873)	$(17,087,269)	$(22,536,891)	$(9,801,471)
	State Income Tax									
22	Taxable Income before Interest Exp.		$ 139,342,856	$ 70,268,244	$ 1,167,848	$ 657,564	$ 2,830,856	$ 10,920,194	$ 35,176,164	$ 12,360,747
23	Interest Expense	1.1	(48,035,008)	(36,852,876)	(993,524)	(79,664)	(817,610)	(2,631,645)	(4,034,581)	(1,985,278)
24	State Taxable Income		$ 91,307,848	$ 33,415,368	$ 174,324	$ 577,900	$ 2,013,246	$ 8,288,548	$ 31,141,583	$ 10,375,469
25	State Income Tax		$ 6,362,331	$ 2,328,383	$ 12,147	$ 40,268	$ 140,283	$ 577,546	$ 2,169,946	$ 722,963
26	South Georgia	1.1	29,686	22,775	614	49	505	1,626	2,493	1,227
27	Total State Income Tax		$ 6,392,017	$ 2,351,158	$ 12,761	$ 40,317	$ 140,788	$ 579,172	$ 2,172,439	$ 724,190
	Federal Income Tax									
28	Taxable Income before Interest Exp.		$ 139,342,856	$ 70,268,244	$ 1,167,848	$ 657,564	$ 2,830,856	$ 10,920,194	$ 35,176,164	$ 12,360,747
29	Interest Expense		(48,035,008)	(36,852,876)	(993,524)	(79,664)	(817,610)	(2,631,645)	(4,034,581)	(1,985,278)
30	Net Taxable Income		$ 91,307,848	$ 33,415,368	$ 174,324	$ 577,900	$ 2,013,246	$ 8,288,548	$ 31,141,583	$ 10,375,469
31	Federal Income Tax		$ 29,730,931	$ 10,880,445	$ 56,762	$ 188,171	$ 655,537	$ 2,698,851	$ 10,140,073	$ 3,378,377
32	I T C	1.1	(528,360)	(405,362)	(10,928)	(876)	(8,993)	(28,947)	(44,378)	(21,837)
33	South Georgia	1.1	290,114	222,578	6,001	481	4,938	15,894	24,367	11,990
34	Total Federal Income Tax		$ 29,492,685	$ 10,697,660	$ 51,834	$ 187,776	$ 651,482	$ 2,685,798	$ 10,120,062	$ 3,368,531
35	Regulatory Amortization	Depr. Exp.	-	-	-	-	-	-	-	-
36	Net Income		$ 103,458,154	$ 57,219,425	$ 1,103,253	$ 429,470	$ 2,038,586	$ 7,655,223	$ 22,883,663	$ 8,268,027
37	Rate of Return on Rate Base		9.45%	6.91%	5.09%	22.31%	11.01%	12.23%	23.35%	17.12%

SCHEDULE G-2
SHEET 1 OF 2

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY SUMMARY
PROPOSED RATES
TEST YEAR ENDING APRIL 30, 2007

Line No.	Description	Allocation Factor No.	Total Amount	Air Conditioning	CNG Small	CNG Large	CNG Residential	Electric Generation	Small Ess. Agr.	Natural Gas Engines	Street Lighting
	(a)	(b)	(c)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)
	Rate Base										
1	Direct Net Plant		$1,267,124,121	$ 206,853	$ 67,356	$ 757,197	$ 105,396	$ 4,647,622	$5,263,618	$ 5,381,166	$ 448,968
2	Systems Allocable Net Plant		34,448,206	5,624	1,831	20,585	2,865	126,351	143,097	146,293	12,206
3	Cash Working Capital	11.2	(10,379,937)	(1,182)	(555)	(5,054)	(929)	(24,562)	(32,177)	(46,535)	(2,151)
4	Materials & Supplies	1.1	12,389,898	2,023	659	7,404	1,031	45,444	51,467	52,617	4,390
5	Prepayments	Direct Net Plant	3,671,971	599	195	2,194	305	13,468	15,253	15,594	1,301
6	Gas Plant Acquisition Adjustment	Direct Net Plant	-	-	-	-	-	-	-	-	-
7	Customer Deposits	8	(31,921,898)	-	-	-	-	-	-	-	-
8	Customer Advances	8	(37,910,017)	-	-	-	-	-	-	-	-
9	Deferred Taxes	1.1	(142,632,297)	(23,284)	(7,582)	(85,233)	(11,864)	(523,154)	(592,493)	(605,724)	(50,538)
10	Deferred Gain Hdqtrs Bldg	4	-	-	-	-	-	-	-	-	-
11	Total Rate Base		$1,094,790,047	$ 190,632	$ 61,903	$ 697,093	$ 96,804	$ 4,285,169	$4,848,767	$ 4,943,410	$ 414,177
12	Net Operating Margin	Direct	$ 431,409,491	$ 130,409	$ 37,424	$ 433,248	$ 29,847	$ 2,678,104	$3,280,432	$ 2,773,911	$ 71,499
13	Special Contract&Optional&Resale M	Net Op. Marg.	$ 5,784,028	$ 1,748	$ 502	$ 5,809	$ 400	$ 35,906	$ 43,982	$ 37,191	$ 959
14	Other Revenue	Net Op. Marg.	12,261,805	576	373	919	1,670	6,008	5,770	26,581	8,837
15	Total Revenue		$ 449,455,324	$ 132,734	$ 38,299	$ 439,975	$ 31,917	$ 2,720,019	$3,330,183	$ 2,837,683	$ 81,294
	Operating Deductions										
16	O & M		$(130,237,868)	$(14,824)	$(6,964)	$(63,344)	$(11,663)	$(307,835)	$(403,274)	$(583,277)	$(27,042)
17	A & G	O & M	(56,946,694)	(6,487)	(3,047)	(27,727)	(5,098)	(134,755)	(176,529)	(255,304)	(11,799)
18	Depreciation Expense		(87,887,713)	(14,347)	(4,672)	(52,519)	(7,310)	(322,359)	(365,084)	(373,238)	(31,140)
19	Interest on Customer Deposits	8	(1,915,314)	-	-	-	-	-	-	-	-
20	Taxes other than Income	1.1	(33,124,880)	(5,408)	(1,761)	(19,794)	(2,755)	(121,497)	(137,600)	(140,673)	(11,737)
21	Total Operating Deductions		$(310,112,468)	$(41,066)	$(16,444)	$(163,385)	$(26,826)	$(886,446)	##########	$(1,352,491)	$(81,718)
	State Income Tax										
22	Taxable Income before Interest Exp.		$ 139,342,856	$ 91,668	$ 21,855	$ 276,591	$ 5,090	$ 1,833,573	$2,247,695	$ 1,485,191	$(423)
23	Interest Expense	1.1	(48,035,008)	(7,842)	(2,553)	(28,704)	(3,995)	(176,185)	(199,537)	(203,993)	(17,020)
24	State Taxable Income		$ 91,307,848	$ 83,826	$ 19,302	$ 247,886	$ 1,095	$ 1,657,388	$2,048,158	$ 1,281,198	$(17,443)
25	State Income Tax		$ 6,362,331	$ 5,841	$ 1,345	$ 17,273	$ 76	$ 115,487	$ 142,716	$ 89,274	$(1,215)
26	South Georgia	1.1	29,686	5	2	18	2	109	123	126	11
27	Total State Income Tax		$ 6,392,017	$ 5,846	$ 1,347	$ 17,290	$ 79	$ 115,596	$ 142,839	$ 89,400	$(1,205)
	Federal Income Tax										
28	Taxable Income before Interest Exp.		$ 139,342,856	$ 91,668	$ 21,855	$ 276,591	$ 5,090	$ 1,833,573	$2,247,695	$ 1,485,191	$(423)
29	Interest Expense		(48,035,008)	(7,842)	(2,553)	(28,704)	(3,995)	(176,185)	(199,537)	(203,993)	(17,020)
30	Net Taxable Income		$ 91,307,848	$ 83,826	$ 19,302	$ 247,886	$ 1,095	$ 1,657,388	$2,048,158	$ 1,281,198	$(17,443)
31	Federal Income Tax		$ 29,730,931	$ 27,295	$ 6,285	$ 80,715	$ 356	$ 539,665	$ 666,905	$ 417,174	$(5,680)
32	I T C	1.1	(528,360)	(86)	(28)	(316)	(44)	(1,938)	(2,195)	(2,244)	(187)
33	South Georgia	1.1	290,114	47	15	173	24	1,064	1,205	1,232	103
34	Total Federal Income Tax		$ 29,492,685	$ 27,256	$ 6,272	$ 80,572	$ 337	$ 538,791	$ 665,915	$ 416,162	$(5,764)
35	Regulatory Amortization	Depr. Exp.	-	-	-	-	-	-	-	-	-
36	Net Income		$ 103,458,154	$ 58,566	$ 14,236	$ 178,728	$ 4,675	$ 1,179,186	$1,438,941	$ 979,629	$ 6,546
37	Rate of Return on Rate Base		9.45%	30.72%	23.00%	25.64%	4.83%	27.52%	29.68%	19.82%	1.58%

SCHEDULE G-2
SHEET 2 OF 2

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Residential Gas Service Demand	Residential Gas Service Customer	Residential Gas Service Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Net Plant in Service - Direct					
		Intangible					
1	301	Organization	1.1	$ 42,653	$ 7,937	$ 24,717	$ 70
2	302	Franchise & Consent	1.1	1,213,609	225,820	703,280	1,992
3	303	Misc. Intangible	1.1	7,333	1,364	4,249	12
4		Total Intangible		$ 1,263,595	$ 235,121	$ 732,247	$ 2,074
5		Allocation Percentage	Intang. Plant	100.00%	18.61%	57.95%	0.16%
		Distribution					
6	374	Land & Land Rights	1.0	$ 1,084,811	$ 640,871	$ -	$ -
7	374	Rights of Way	1.0	739,109	436,641	-	-
8	375	Structures	1.0	46,534	27,491	-	-
9	376	Mains - Demand	1.0	353,902,646	209,074,046	-	-
10	376	Mains - Customer	5.0	275,401,498	-	253,894,761	-
11	376	Mains - Commodity	3.0	1	-	-	0
12	378	Measuring & Reg. Station	2.2	29,625,773	9,842,586	11,952,612	0
13	380	Services - Demand	1.0	0	0	-	-
14	380	Services - Customer	7.0	321,023,126	-	264,625,607	-
15	381	Meters	6.0	196,168,747	-	154,571,050	-
16	385	Industrial Meas. & Reg. Sta.	3.0	4,245,215	-	-	1,940,005
17	386	Other Prop. on Cust. Premises	1.0	-	-	-	-
18	387	Other Equipment	1.0	(97,479)	(57,587)	-	-
19		Total Distribution		$ 1,182,139,980	$ 219,964,047	$ 685,044,030	$ 1,940,005
20		Allocation Percentage	Dist. Plant	100.00%	18.61%	57.95%	0.16%
21	389-398	Total General Plant	1.1	$ 83,720,546	$ 15,578,113	$ 48,515,625	$ 137,393
22		Total Net Plant-Direct		$ 1,267,124,121	$ 235,777,281	$ 734,291,902	$ 2,079,472
		Systems Allocable Plant					
23	301-303	Intangible Plant	1.1	$ 18,412,951	$ 3,426,149	$ 10,670,210	$ 30,217
24	389-398	General Plant	1.1	$ 16,035,255	$ 2,983,724	$ 9,292,348	$ 26,315
25		Total Systems Allocable		34,448,206	6,409,873	19,962,558	56,533
26		Total Net Plant		$ 1,301,572,327	$ 242,187,153	$ 754,254,460	$ 2,136,005
		Other Rate Base Items					
27		Cash Working Capital	11.2	(10,379,937)	(1,000,782)	(7,227,188)	(49,108)
28		Materials & Supplies	1.1	12,389,898	2,305,422	7,179,882	20,333
29		Prepayments	1.1	3,671,971	683,254	2,127,888	6,026
30		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
31		Customer Deposits	8.0	(31,921,898)	-	(29,695,451)	-
32		Customer Advances	8.0	(37,910,017)	-	(35,265,919)	-
33		Deferred Taxes	1.1	(142,632,297)	(26,539,985)	(82,654,681)	(234,073)
34		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-
35		Total Allocated Rate Base		1,094,790,047	217,635,062	608,718,991	1,879,183

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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Multi-Family Residential Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(h)	(i)	(j)
		Net Plant in Service - Direct					
		Intangible					
1	301	Organization	1.1	$ 42,653	$ 149	$ 732	$ 2
2	302	Franchise & Consent	1.1	1,213,609	4,226	20,829	47
3	303	Misc. Intangible	1.1	7,333	26	126	0
4		Total Intangible		$ 1,263,595	$ 4,400	$ 21,687	$ 49
5		Allocation Percentage	Intang. Plant	100.00%	0.35%	1.72%	0.00%
		Distribution					
6	374	Land & Land Rights	1.0	$ 1,084,811	$ 11,992	$ -	$ -
7	374	Rights of Way	1.0	739,109	8,171	-	-
8	375	Structures	1.0	46,534	514	-	-
9	376	Mains - Demand	1.0	353,902,646	3,912,258	-	-
10	376	Mains - Customer	5.0	275,401,498	-	9,522,640	-
11	376	Mains - Commodity	3.0	1	-	-	0
12	378	Measuring & Reg. Station	2.2	29,625,773	184,177	448,298	0
13	380	Services - Demand	1.0	0	0	-	-
14	380	Services - Customer	7.0	321,023,126	-	4,911,024	-
15	381	Meters	6.0	196,168,747	-	5,406,606	-
16	385	Industrial Meas. & Reg. Sta.	3.0	4,245,215	-	-	45,988
17	386	Other Prop. on Cust. Premises	1.0	-	-	-	-
18	387	Other Equipment	1.0	(97,479)	(1,078)	-	-
19		Total Distribution		$ 1,182,139,980	$ 4,116,035	$ 20,288,568	$ 45,988
20		Allocation Percentage	Dist. Plant	100.00%	0.35%	1.72%	0.00%
21	389-398	Total General Plant	1.1	$ 83,720,546	$ 291,502	$ 1,436,860	$ 3,257
22		Total Net Plant-Direct		$ 1,267,124,121	$ 4,411,937	$ 21,747,115	$ 49,294
		Systems Allocable Plant					
23	301-303	Intangible Plant	1.1	$ 18,412,951	$ 64,111	$ 316,014	$ 716
24	389-398	General Plant	1.1	$ 16,035,255	$ 55,832	$ 275,206	$ 624
25		Total Systems Allocable		34,448,206	119,944	591,220	1,340
26		Total Net Plant		$ 1,301,572,327	$ 4,531,880	$ 22,338,335	$ 50,634
		Other Rate Base Items					
27		Cash Working Capital	11.2	(10,379,937)	(18,727)	(182,538)	(1,164)
28		Materials & Supplies	1.1	12,389,898	43,140	212,643	482
29		Prepayments	1.1	3,671,971	12,785	63,020	143
30		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
31		Customer Deposits	8.0	(31,921,898)	-	(1,113,765)	-
32		Customer Advances	8.0	(37,910,017)	-	(1,322,692)	-
33		Deferred Taxes	1.1	(142,632,297)	(496,624)	(2,447,938)	(5,549)
34		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-
35		Total Allocated Rate Base		1,094,790,047	4,072,454	17,547,064	44,546

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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	MMMHP Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(k)	(l)	(m)
		Net Plant in Service - Direct					
		Intangible					
1	301	Organization	1.1	$ 42,653	$ 56	$ 14	$ 1
2	302	Franchise & Consent	1.1	1,213,609	1,589	409	15
3	303	Misc. Intangible	1.1	7,333	10	2	0
4		Total Intangible		$ 1,263,595	$ 1,655	$ 425	$ 15
5		Allocation Percentage	Intang. Plant	100.00%	0.13%	0.03%	0.00%
		Distribution					
6	374	Land & Land Rights	1.0	$ 1,084,811	$ 4,510	$ -	$ -
7	374	Rights of Way	1.0	739,109	3,073	-	-
8	375	Structures	1.0	46,534	193	-	-
9	376	Mains - Demand	1.0	353,902,646	1,471,361	-	-
10	376	Mains - Customer	5.0	275,401,498	-	47,093	-
11	376	Mains - Commodity	3.0	1	-	-	0
12	378	Measuring & Reg. Station	2.2	29,625,773	69,267	2,217	0
13	380	Services - Demand	1.0	0	0	-	-
14	380	Services - Customer	7.0	321,023,126	-	256,978	-
15	381	Meters	6.0	196,168,747	-	91,750	-
16	385	Industrial Meas. & Reg. Sta.	3.0	4,245,215	-	-	14,485
17	386	Other Prop. on Cust. Premises	1.0	-	-	-	-
18	387	Other Equipment	1.0	(97,479)	(405)	-	-
19		Total Distribution		$ 1,182,139,980	$ 1,548,000	$ 398,038	$ 14,485
20		Allocation Percentage	Dist. Plant	100.00%	0.13%	0.03%	0.00%
21	389-398	Total General Plant	1.1	$ 83,720,546	$ 109,631	$ 28,190	$ 1,026
22		Total Net Plant-Direct		$ 1,267,124,121	$ 1,659,285	$ 426,653	$ 15,527
		Systems Allocable Plant					
23	301-303	Intangible Plant	1.1	$ 18,412,951	$ 24,112	$ 6,200	$ 226
24	389-398	General Plant	1.1	$ 16,035,255	$ 20,998	$ 5,399	$ 196
25		Total Systems Allocable		34,448,206	45,110	11,599	422
26		Total Net Plant		$ 1,301,572,327	$ 1,704,395	$ 438,252	$ 15,949
		Other Rate Base Items					
27		Cash Working Capital	11.2	(10,379,937)	(7,043)	(4,142)	(367)
28		Materials & Supplies	1.1	12,389,898	16,224	4,172	152
29		Prepayments	1.1	3,671,971	4,808	1,236	45
30		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
31		Customer Deposits	8.0	(31,921,898)	-	(5,508)	-
32		Customer Advances	8.0	(37,910,017)	-	(6,541)	-
33		Deferred Taxes	1.1	(142,632,297)	(186,775)	(48,026)	(1,748)
34		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-
35		Total Allocated Rate Base		1,094,790,047	1,531,609	379,443	14,031

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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Small General Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(n)	(o)	(p)
		Net Plant in Service - Direct					
		Intangible					
1	301	Organization	1.1	$ 42,653	$ 155	$ 570	$ 1
2	302	Franchise & Consent	1.1	1,213,609	4,416	16,207	34
3	303	Misc. Intangible	1.1	7,333	27	98	0
4		Total Intangible		$ 1,263,595	$ 4,598	$ 16,875	$ 35
5		Allocation Percentage	Intang. Plant	100.00%	0.36%	1.34%	0.00%
		Distribution					
6	374	Land & Land Rights	1.0	$ 1,084,811	$ 12,533	$ -	$ -
7	374	Rights of Way	1.0	739,109	8,539	-	-
8	375	Structures	1.0	46,534	538	-	-
9	376	Mains - Demand	1.0	353,902,646	4,088,669	-	-
10	376	Mains - Customer	5.0	275,401,498	-	4,829,040	-
11	376	Mains - Commodity	3.0	1	-	-	0
12	378	Measuring & Reg. Station	2.2	29,625,773	192,482	227,337	0
13	380	Services - Demand	1.0	0	0	-	-
14	380	Services - Customer	7.0	321,023,126	-	6,034,177	-
15	381	Meters	6.0	196,168,747	-	4,696,472	-
16	385	Industrial Meas. & Reg. Sta.	3.0	4,245,215	-	-	32,701
17	386	Other Prop. on Cust. Premises	1.0	-	-	-	-
18	387	Other Equipment	1.0	(97,479)	(1,126)	-	-
19		Total Distribution		$ 1,182,139,980	$ 4,301,635	$ 15,787,025	$ 32,701
20		Allocation Percentage	Dist. Plant	100.00%	0.36%	1.34%	0.00%
21	389-398	Total General Plant	1.1	$ 83,720,546	$ 304,647	$ 1,118,056	$ 2,316
22		Total Net Plant-Direct		$ 1,267,124,121	$ 4,610,880	$ 16,921,956	$ 35,052
		Systems Allocable Plant					
23	301-303	Intangible Plant	1.1	$ 18,412,951	$ 67,002	$ 245,898	$ 509
24	389-398	General Plant	1.1	$ 16,035,255	$ 58,350	$ 214,145	$ 444
25		Total Systems Allocable		34,448,206	125,352	460,043	953
26		Total Net Plant		$ 1,301,572,327	$ 4,736,232	$ 17,381,998	$ 36,005
		Other Rate Base Items					
27		Cash Working Capital	11.2	(10,379,937)	(19,571)	(223,933)	(828)
28		Materials & Supplies	1.1	12,389,898	45,085	165,462	343
29		Prepayments	1.1	3,671,971	13,362	49,038	102
30		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
31		Customer Deposits	8.0	(31,921,898)	-	(564,803)	-
32		Customer Advances	8.0	(37,910,017)	-	(670,752)	-
33		Deferred Taxes	1.1	(142,632,297)	(519,018)	(1,904,800)	(3,946)
34		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-
35		Total Allocated Rate Base		1,094,790,047	4,256,089	14,232,211	31,676

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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Medium General Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(d)	(e)	(f)
		Net Plant in Service - Direct					
		Intangible					
1	301	Organization	1.1	$ 42,653	$ 846	$ 1,480	$ 11
2	302	Franchise & Consent	1.1	1,213,609	24,086	42,099	304
3	303	Misc. Intangible	1.1	7,333	146	254	2
4		Total Intangible		$ 1,263,595	$ 25,078	$ 43,833	$ 317
5		Allocation Percentage	Intang. Plant	100.00%	1.98%	3.47%	0.03%
		Distribution					
6	374	Land & Land Rights	1.0	$ 1,084,811	$ 68,354	$ -	$ -
7	374	Rights of Way	1.0	739,109	46,571	-	-
8	375	Structures	1.0	46,534	2,932	-	-
9	376	Mains - Demand	1.0	353,902,646	22,299,503	-	-
10	376	Mains - Customer	5.0	275,401,498	-	4,637,247	-
11	376	Mains - Commodity	3.0	1	-	-	0
12	378	Measuring & Reg. Station	2.2	29,625,773	1,049,794	218,308	0
13	380	Services - Demand	1.0	0	0	-	-
14	380	Services - Customer	7.0	321,023,126	-	24,094,138	-
15	381	Meters	6.0	196,168,747	-	12,057,454	-
16	385	Industrial Meas. & Reg. Sta.	3.0	4,245,215	-	-	296,549
17	386	Other Prop. on Cust. Premises	1.0	-	-	-	-
18	387	Other Equipment	1.0	(97,479)	(6,142)	-	-
19		Total Distribution		$ 1,182,139,980	$ 23,461,013	$ 41,007,147	$ 296,549
20		Allocation Percentage	Dist. Plant	100.00%	1.98%	3.47%	0.03%
21	389-398	Total General Plant	1.1	$ 83,720,546	$ 1,661,537	$ 2,904,174	$ 21,002
22		Total Net Plant-Direct		$ 1,267,124,121	$ 25,147,627	$ 43,955,154	$ 317,867
		Systems Allocable Plant					
23	301-303	Intangible Plant	1.1	$ 18,412,951	$ 365,428	$ 638,725	$ 4,619
24	389-398	General Plant	1.1	$ 16,035,255	$ 318,239	$ 556,246	$ 4,023
25		Total Systems Allocable		34,448,206	683,667	1,194,971	8,642
26		Total Net Plant		$ 1,301,572,327	$ 25,831,294	$ 45,150,124	$ 326,509
		Other Rate Base Items					
27		Cash Working Capital	11.2	(10,379,937)	(106,742)	(464,169)	(7,507)
28		Materials & Supplies	1.1	12,389,898	245,893	429,792	3,108
29		Prepayments	1.1	3,671,971	72,875	127,377	921
30		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
31		Customer Deposits	8.0	(31,921,898)	-	(542,371)	-
32		Customer Advances	8.0	(37,910,017)	-	(644,112)	-
33		Deferred Taxes	1.1	(142,632,297)	(2,830,712)	(4,947,759)	(35,780)
34		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-
35		Total Allocated Rate Base		1,094,790,047	23,212,607	39,108,882	287,251

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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Large General Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(g)	(h)	(i)
		Net Plant in Service - Direct					
		Intangible					
1	301	Organization	1.1	$ 42,653	$ 2,312	$ 1,235	$ 35
2	302	Franchise & Consent	1.1	1,213,609	65,793	35,143	998
3	303	Misc. Intangible	1.1	7,333	398	212	6
4		Total Intangible		$ 1,263,595	$ 68,503	$ 36,591	$ 1,039
5		Allocation Percentage	Intang. Plant	100.00%	5.42%	2.90%	0.08%
		Distribution					
6	374	Land & Land Rights	1.0	$ 1,084,811	$ 186,719	$ -	$ -
7	374	Rights of Way	1.0	739,109	127,217	-	-
8	375	Structures	1.0	46,534	8,010	-	-
9	376	Mains - Demand	1.0	353,902,646	60,914,264	-	-
10	376	Mains - Customer	5.0	275,401,498	-	2,046,189	-
11	376	Mains - Commodity	3.0	1	-	-	0
12	378	Measuring & Reg. Station	2.2	29,625,773	2,867,663	96,329	0
13	380	Services - Demand	1.0	0	0	-	-
14	380	Services - Customer	7.0	321,023,126	-	18,170,806	-
15	381	Meters	6.0	196,168,747	-	13,918,572	-
16	385	Industrial Meas. & Reg. Sta.	3.0	4,245,215	-	-	971,921
17	386	Other Prop. on Cust. Premises	1.0	-	-	-	-
18	387	Other Equipment	1.0	(97,479)	(16,778)	-	-
19		Total Distribution		$ 1,182,139,980	$ 64,087,094	$ 34,231,895	$ 971,921
20		Allocation Percentage	Dist. Plant	100.00%	5.42%	2.90%	0.08%
21	389-398	Total General Plant	1.1	$ 83,720,546	$ 4,538,723	$ 2,424,343	$ 68,833
22		Total Net Plant-Direct		$ 1,267,124,121	$ 68,694,320	$ 36,692,829	$ 1,041,792
		Systems Allocable Plant					
23	301-303	Intangible Plant	1.1	$ 18,412,951	$ 998,217	$ 533,194	$ 15,139
24	389-398	General Plant	1.1	$ 16,035,255	$ 869,316	$ 464,342	$ 13,184
25		Total Systems Allocable		34,448,206	1,867,533	997,536	28,322
26		Total Net Plant		$ 1,301,572,327	$ 70,561,853	$ 37,690,365	$ 1,070,115
		Other Rate Base Items					
27		Cash Working Capital	11.2	(10,379,937)	(291,581)	(370,411)	(24,603)
28		Materials & Supplies	1.1	12,389,898	671,691	358,781	10,187
29		Prepayments	1.1	3,671,971	199,068	106,331	3,019
30		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
31		Customer Deposits	8.0	(31,921,898)	-	-	-
32		Customer Advances	8.0	(37,910,017)	-	-	-
33		Deferred Taxes	1.1	(142,632,297)	(7,732,493)	(4,130,284)	(117,268)
34		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-
35		Total Allocated Rate Base		1,094,790,047	63,408,538	33,654,783	941,450

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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Transportation Eligible Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(j)	(k)	(l)
		Net Plant in Service - Direct					
		Intangible					
1	301	Organization	1.1	$ 42,653	$ 1,589	$ 150	$ 23
2	302	Franchise & Consent	1.1	1,213,609	45,224	4,269	665
3	303	Misc. Intangible	1.1	7,333	273	26	4
4		Total Intangible		$ 1,263,595	$ 47,087	$ 4,445	$ 693
5		Allocation Percentage	Intang. Plant	100.00%	3.73%	0.35%	0.05%
		Distribution					
6	374	Land & Land Rights	1.0	$ 1,084,811	$ 128,344	$ -	$ -
7	374	Rights of Way	1.0	739,109	87,444	-	-
8	375	Structures	1.0	46,534	5,505	-	-
9	376	Mains - Demand	1.0	353,902,646	41,870,334	-	-
10	376	Mains - Customer	5.0	275,401,498	-	53,171	-
11	376	Mains - Commodity	3.0	1	-	-	0
12	378	Measuring & Reg. Station	2.2	29,625,773	1,971,131	2,503	0
13	380	Services - Demand	1.0	0	0	-	-
14	380	Services - Customer	7.0	321,023,126	-	1,099,282	-
15	381	Meters	6.0	196,168,747	-	3,003,206	-
16	385	Industrial Meas. & Reg. Sta.	3.0	4,245,215	-	-	648,237
17	386	Other Prop. on Cust. Premises	1.0	-	-	-	-
18	387	Other Equipment	1.0	(97,479)	(11,533)	-	-
19		Total Distribution		$ 1,182,139,980	$ 44,051,226	$ 4,158,161	$ 648,237
20		Allocation Percentage	Dist. Plant	100.00%	3.73%	0.35%	0.05%
21	389-398	Total General Plant	1.1	$ 83,720,546	$ 3,119,760	$ 294,486	$ 45,909
22		Total Net Plant-Direct		$ 1,267,124,121	$ 47,218,073	$ 4,457,092	$ 694,839
		Systems Allocable Plant					
23	301-303	Intangible Plant	1.1	$ 18,412,951	$ 686,140	$ 64,767	$ 10,097
24	389-398	General Plant	1.1	$ 16,035,255	$ 597,537	$ 56,404	$ 8,793
25		Total Systems Allocable		34,448,206	1,283,677	121,171	18,890
26		Total Net Plant		$ 1,301,572,327	$ 48,501,749	$ 4,578,263	$ 713,729
		Other Rate Base Items					
27		Cash Working Capital	11.2	(10,379,937)	(200,422)	(49,557)	(16,409)
28		Materials & Supplies	1.1	12,389,898	461,697	43,581	6,794
29		Prepayments	1.1	3,671,971	136,832	12,916	2,014
30		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
31		Customer Deposits	8.0	(31,921,898)	-	-	-
32		Customer Advances	8.0	(37,910,017)	-	-	-
33		Deferred Taxes	1.1	(142,632,297)	(5,315,045)	(501,707)	(78,214)
34		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-
35		Total Allocated Rate Base		1,094,790,047	43,584,811	4,083,496	627,914

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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Air-Conditioning Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(d)	(e)	(f)
		Net Plant in Service - Direct					
		Intangible					
1	301	Organization	1.1	$ 42,653	$ 6	$ 1	$ 0
2	302	Franchise & Consent	1.1	1,213,609	162	28	7
3	303	Misc. Intangible	1.1	7,333	1	0	0
4		Total Intangible		$ 1,263,595	$ 169	$ 29	$ 8
5		Allocation Percentage	Intang. Plant	100.00%	0.01%	0.00%	0.00%
		Distribution					
6	374	Land & Land Rights	1.0	$ 1,084,811	$ 461	$ -	$ -
7	374	Rights of Way	1.0	739,109	314	-	-
8	375	Structures	1.0	46,534	20	-	-
9	376	Mains - Demand	1.0	353,902,646	150,362	-	-
10	376	Mains - Customer	5.0	275,401,498	-	7,609	-
11	376	Mains - Commodity	3.0	1	-	-	0
12	378	Measuring & Reg. Station	2.2	29,625,773	7,079	358	0
13	380	Services - Demand	1.0	0	0	-	-
14	380	Services - Customer	7.0	321,023,126	-	11,030	-
15	381	Meters	6.0	196,168,747	-	8,505	-
16	385	Industrial Meas. & Reg. Sta.	3.0	4,245,215	-	-	7,283
17	386	Other Prop. on Cust. Premises	1.0	-	-	-	-
18	387	Other Equipment	1.0	(97,479)	(41)	-	-
19		Total Distribution		$ 1,182,139,980	$ 158,194	$ 27,502	$ 7,283
20		Allocation Percentage	Dist. Plant	100.00%	0.01%	0.00%	0.00%
21	389-398	Total General Plant	1.1	$ 83,720,546	$ 11,203	$ 1,948	$ 516
22		Total Net Plant-Direct		$ 1,267,124,121	$ 169,567	$ 29,479	$ 7,807
		Systems Allocable Plant					
23	301-303	Intangible Plant	1.1	$ 18,412,951	$ 2,464	$ 428	$ 113
24	389-398	General Plant	1.1	$ 16,035,255	$ 2,146	$ 373	$ 99
25		Total Systems Allocable		34,448,206	4,610	801	212
26		Total Net Plant		$ 1,301,572,327	$ 174,177	$ 30,281	$ 8,019
		Other Rate Base Items					
27		Cash Working Capital	11.2	(10,379,937)	(720)	(278)	(184)
28		Materials & Supplies	1.1	12,389,898	1,658	288	76
29		Prepayments	1.1	3,671,971	491	85	23
30		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
31		Customer Deposits	8.0	(31,921,898)	-	-	-
32		Customer Advances	8.0	(37,910,017)	-	-	-
33		Deferred Taxes	1.1	(142,632,297)	(19,087)	(3,318)	(879)
34		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-
35		Total Allocated Rate Base		1,094,790,047	156,519	27,058	7,055

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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Demand	CNG - Small Customer	Commodity
	(a)	(b)	(c)	(d)	(g)	(h)	(i)
		Net Plant in Service - Direct					
		Intangible					
1	301	Organization	1.1	$ 42,653	$ 1	$ 1	$ 0
2	302	Franchise & Consent	1.1	1,213,609	42	22	1
3	303	Misc. Intangible	1.1	7,333	0	0	0
4		Total Intangible		$ 1,263,595	$ 43	$ 23	$ 1
5		Allocation Percentage	Intang. Plant	100.00%	0.00%	0.00%	0.00%
		Distribution					
6	374	Land & Land Rights	1.0	$ 1,084,811	$ 118	$ -	$ -
7	374	Rights of Way	1.0	739,109	80	-	-
8	375	Structures	1.0	46,534	5	-	-
9	376	Mains - Demand	1.0	353,902,646	38,508	-	-
10	376	Mains - Customer	5.0	275,401,498	-	6,030	-
11	376	Mains - Commodity	3.0	1	-	-	0
12	378	Measuring & Reg. Station	2.2	29,625,773	1,813	284	0
13	380	Services - Demand	1.0	0	0	-	-
14	380	Services - Customer	7.0	321,023,126	-	10,847	-
15	381	Meters	6.0	196,168,747	-	4,008	-
16	385	Industrial Meas. & Reg. Sta.	3.0	4,245,215	-	-	1,156
17	386	Other Prop. on Cust. Premises	1.0	-	-	-	-
18	387	Other Equipment	1.0	(97,479)	(11)	-	-
19		Total Distribution		$ 1,182,139,980	$ 40,513	$ 21,169	$ 1,156
20		Allocation Percentage	Dist. Plant	100.00%	0.00%	0.00%	0.00%
21	389-398	Total General Plant	1.1	$ 83,720,546	$ 2,869	$ 1,499	$ 82
22		Total Net Plant-Direct		$ 1,267,124,121	$ 43,426	$ 22,690	$ 1,239
		Systems Allocable Plant					
23	301-303	Intangible Plant	1.1	$ 18,412,951	$ 631	$ 330	$ 18
24	389-398	General Plant	1.1	$ 16,035,255	$ 550	$ 287	$ 16
25		Total Systems Allocable		34,448,206	1,181	617	34
26		Total Net Plant		$ 1,301,572,327	$ 44,607	$ 23,307	$ 1,273
		Other Rate Base Items					
27		Cash Working Capital	11.2	(10,379,937)	(184)	(342)	(29)
28		Materials & Supplies	1.1	12,389,898	425	222	12
29		Prepayments	1.1	3,671,971	126	66	4
30		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
31		Customer Deposits	8.0	(31,921,898)	-	-	-
32		Customer Advances	8.0	(37,910,017)	-	-	-
33		Deferred Taxes	1.1	(142,632,297)	(4,888)	(2,554)	(139)
34		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-
35		Total Allocated Rate Base		1,094,790,047	40,085	20,699	1,120

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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Demand	CNG - Large Customer	Commodity
	(a)	(b)	(c)	(d)	(j)	(k)	(l)
		Net Plant in Service - Direct					
		Intangible					
1	301	Organization	1.1	$ 42,653	$ 17	$ 8	$ 0
2	302	Franchise & Consent	1.1	1,213,609	487	224	14
3	303	Misc. Intangible	1.1	7,333	3	1	0
4		Total Intangible		$ 1,263,595	$ 508	$ 233	$ 14
5		Allocation Percentage	Intang. Plant	100.00%	0.04%	0.02%	0.00%
		Distribution					
6	374	Land & Land Rights	1.0	$ 1,084,811	$ 1,383	$ -	$ -
7	374	Rights of Way	1.0	739,109	943	-	-
8	375	Structures	1.0	46,534	59	-	-
9	376	Mains - Demand	1.0	353,902,646	451,326	-	-
10	376	Mains - Customer	5.0	275,401,498	-	6,892	-
11	376	Mains - Commodity	3.0	1	-	-	0
12	378	Measuring & Reg. Station	2.2	29,625,773	21,247	324	0
13	380	Services - Demand	1.0	0	0	-	-
14	380	Services - Customer	7.0	321,023,126	-	88,292	-
15	381	Meters	6.0	196,168,747	-	122,653	-
16	385	Industrial Meas. & Reg. Sta.	3.0	4,245,215	-	-	13,418
17	386	Other Prop. on Cust. Premises	1.0	-	-	-	-
18	387	Other Equipment	1.0	(97,479)	(124)	-	-
19		Total Distribution		$ 1,182,139,980	$ 474,834	$ 218,161	$ 13,418
20		Allocation Percentage	Dist. Plant	100.00%	0.04%	0.02%	0.00%
21	389-398	Total General Plant	1.1	$ 83,720,546	$ 33,628	$ 15,450	$ 950
22		Total Net Plant-Direct		$ 1,267,124,121	$ 508,969	$ 233,845	$ 14,383
		Systems Allocable Plant					
23	301-303	Intangible Plant	1.1	$ 18,412,951	$ 7,396	$ 3,398	$ 209
24	389-398	General Plant	1.1	$ 16,035,255	$ 6,441	$ 2,959	$ 182
25		Total Systems Allocable		34,448,206	13,837	6,357	391
26		Total Net Plant		$ 1,301,572,327	$ 522,806	$ 240,202	$ 14,774
		Other Rate Base Items					
27		Cash Working Capital	11.2	(10,379,937)	(2,160)	(2,554)	(340)
28		Materials & Supplies	1.1	12,389,898	4,977	2,287	141
29		Prepayments	1.1	3,671,971	1,475	678	42
30		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
31		Customer Deposits	8.0	(31,921,898)	-	-	-
32		Customer Advances	8.0	(37,910,017)	-	-	-
33		Deferred Taxes	1.1	(142,632,297)	(57,292)	(26,322)	(1,619)
34		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-
35		Total Allocated Rate Base		1,094,790,047	469,806	214,290	12,998

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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	CNG - Residential Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(m)	(n)	(o)
		Net Plant in Service - Direct					
		Intangible					
1	301	Organization	1.1	$ 42,653	$ 1	$ 3	$ 0
2	302	Franchise & Consent	1.1	1,213,609	19	81	1
3	303	Misc. Intangible	1.1	7,333	0	0	0
4		Total Intangible		$ 1,263,595	$ 20	$ 84	$ 1
5		Allocation Percentage	Intang. Plant	100.00%	0.00%	0.01%	0.00%
		Distribution					
6	374	Land & Land Rights	1.0	$ 1,084,811	$ 55	$ -	$ -
7	374	Rights of Way	1.0	739,109	37	-	-
8	375	Structures	1.0	46,534	2	-	-
9	376	Mains - Demand	1.0	353,902,646	17,869	-	-
10	376	Mains - Customer	5.0	275,401,498	-	30,438	-
11	376	Mains - Commodity	3.0	1	-	-	0
12	378	Measuring & Reg. Station	2.2	29,625,773	841	1,433	0
13	380	Services - Demand	1.0	0	0	-	-
14	380	Services - Customer	7.0	321,023,126	-	31,691	-
15	381	Meters	6.0	196,168,747	-	15,462	-
16	385	Industrial Meas. & Reg. Sta.	3.0	4,245,215	-	-	504
17	386	Other Prop. on Cust. Premises	1.0	-	-	-	-
18	387	Other Equipment	1.0	(97,479)	(5)	-	-
19		Total Distribution		$ 1,182,139,980	$ 18,800	$ 79,023	$ 504
20		Allocation Percentage	Dist. Plant	100.00%	0.00%	0.01%	0.00%
21	389-398	Total General Plant	1.1	$ 83,720,546	$ 1,331	$ 5,597	$ 36
22		Total Net Plant-Direct		$ 1,267,124,121	$ 20,151	$ 84,704	$ 540
		Systems Allocable Plant					
23	301-303	Intangible Plant	1.1	$ 18,412,951	$ 293	$ 1,231	$ 8
24	389-398	General Plant	1.1	$ 16,035,255	$ 255	$ 1,072	$ 7
25		Total Systems Allocable		34,448,206	548	2,303	15
26		Total Net Plant		$ 1,301,572,327	$ 20,699	$ 87,007	$ 555
		Other Rate Base Items					
27		Cash Working Capital	11.2	(10,379,937)	(86)	(831)	(13)
28		Materials & Supplies	1.1	12,389,898	197	828	5
29		Prepayments	1.1	3,671,971	58	245	2
30		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
31		Customer Deposits	8.0	(31,921,898)	-	-	-
32		Customer Advances	8.0	(37,910,017)	-	-	-
33		Deferred Taxes	1.1	(142,632,297)	(2,268)	(9,535)	(61)
34		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-
35		Total Allocated Rate Base		1,094,790,047	18,601	77,715	488

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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Electric Generation Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(d)	(e)	(f)
		Net Plant in Service - Direct					
		Intangible					
1	301	Organization	1.1	$ 42,653	$ 143	$ 8	$ 5
2	302	Franchise & Consent	1.1	1,213,609	4,075	232	144
3	303	Misc. Intangible	1.1	7,333	25	1	1
4		Total Intangible		$ 1,263,595	$ 4,243	$ 242	$ 150
5		Allocation Percentage	Intang. Plant	100.00%	0.34%	0.02%	0.01%
		Distribution					
6	374	Land & Land Rights	1.0	$ 1,084,811	$ 11,565	$ -	$ -
7	374	Rights of Way	1.0	739,109	7,880	-	-
8	375	Structures	1.0	46,534	496	-	-
9	376	Mains - Demand	1.0	353,902,646	3,772,977	-	-
10	376	Mains - Customer	5.0	275,401,498	-	6,030	-
11	376	Mains - Commodity	3.0	1	-	-	0
12	378	Measuring & Reg. Station	2.2	29,625,773	177,621	284	0
13	380	Services - Demand	1.0	0	0	-	-
14	380	Services - Customer	7.0	321,023,126	-	49,890	-
15	381	Meters	6.0	196,168,747	-	170,032	-
16	385	Industrial Meas. & Reg. Sta.	3.0	4,245,215	-	-	140,177
17	386	Other Prop. on Cust. Premises	1.0	-	-	-	-
18	387	Other Equipment	1.0	(97,479)	(1,039)	-	-
19		Total Distribution		$ 1,182,139,980	$ 3,969,499	$ 226,236	$ 140,177
20		Allocation Percentage	Dist. Plant	100.00%	0.34%	0.02%	0.01%
21	389-398	Total General Plant	1.1	$ 83,720,546	$ 281,125	$ 16,022	$ 9,928
22		Total Net Plant-Direct		$ 1,267,124,121	$ 4,254,867	$ 242,501	$ 150,254
		Systems Allocable Plant					
23	301-303	Intangible Plant	1.1	$ 18,412,951	$ 61,829	$ 3,524	$ 2,183
24	389-398	General Plant	1.1	$ 16,035,255	$ 53,845	$ 3,069	$ 1,901
25		Total Systems Allocable		34,448,206	115,673	6,593	4,085
26		Total Net Plant		$ 1,301,572,327	$ 4,370,540	$ 249,093	$ 154,339
		Other Rate Base Items					
27		Cash Working Capital	11.2	(10,379,937)	(18,060)	(2,954)	(3,548)
28		Materials & Supplies	1.1	12,389,898	41,604	2,371	1,469
29		Prepayments	1.1	3,671,971	12,330	703	435
30		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
31		Customer Deposits	8.0	(31,921,898)	-	-	-
32		Customer Advances	8.0	(37,910,017)	-	-	-
33		Deferred Taxes	1.1	(142,632,297)	(478,944)	(27,297)	(16,913)
34		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-
35		Total Allocated Rate Base		1,094,790,047	3,927,470	221,917	135,782

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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Small Essential Agr. User Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(g)	(h)	(i)
		Net Plant in Service - Direct					
		Intangible					
1	301	Organization	1.1	$ 42,653	$ 150	$ 26	$ 2
2	302	Franchise & Consent	1.1	1,213,609	4,258	735	48
3	303	Misc. Intangible	1.1	7,333	26	4	0
4		Total Intangible		$ 1,263,595	$ 4,434	$ 765	$ 50
5		Allocation Percentage	Intang. Plant	100.00%	0.35%	0.06%	0.00%
		Distribution					
6	374	Land & Land Rights	1.0	$ 1,084,811	$ 12,085	$ -	$ -
7	374	Rights of Way	1.0	739,109	8,234	-	-
8	375	Structures	1.0	46,534	518	-	-
9	376	Mains - Demand	1.0	353,902,646	3,942,463	-	-
10	376	Mains - Customer	5.0	275,401,498	-	29,098	-
11	376	Mains - Commodity	3.0	1	-	-	0
12	378	Measuring & Reg. Station	2.2	29,625,773	185,599	1,370	0
13	380	Services - Demand	1.0	0	0	-	-
14	380	Services - Customer	7.0	321,023,126	-	288,362	-
15	381	Meters	6.0	196,168,747	-	396,961	-
16	385	Industrial Meas. & Reg. Sta.	3.0	4,245,215	-	-	46,991
17	386	Other Prop. on Cust. Premises	1.0	-	-	-	-
18	387	Other Equipment	1.0	(97,479)	(1,086)	-	-
19		Total Distribution		$ 1,182,139,980	$ 4,147,813	$ 715,791	$ 46,991
20		Allocation Percentage	Dist. Plant	100.00%	0.35%	0.06%	0.00%
21	389-398	Total General Plant	1.1	$ 83,720,546	$ 293,753	$ 50,693	$ 3,328
22		Total Net Plant-Direct		$ 1,267,124,121	$ 4,446,000	$ 767,249	$ 50,369
		Systems Allocable Plant					
23	301-303	Intangible Plant	1.1	$ 18,412,951	$ 64,606	$ 11,149	$ 732
24	389-398	General Plant	1.1	$ 16,035,255	$ 56,263	$ 9,709	$ 637
25		Total Systems Allocable		34,448,206	120,870	20,859	1,369
26		Total Net Plant		$ 1,301,572,327	$ 4,566,869	$ 788,108	$ 51,738
		Other Rate Base Items					
27		Cash Working Capital	11.2	(10,379,937)	(18,872)	(12,116)	(1,189)
28		Materials & Supplies	1.1	12,389,898	43,473	7,502	493
29		Prepayments	1.1	3,671,971	12,884	2,223	146
30		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
31		Customer Deposits	8.0	(31,921,898)	-	-	-
32		Customer Advances	8.0	(37,910,017)	-	-	-
33		Deferred Taxes	1.1	(142,632,297)	(500,459)	(86,364)	(5,670)
34		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-
35		Total Allocated Rate Base		1,094,790,047	4,103,896	699,353	45,518

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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Natural Gas Engine Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(j)	(k)	(l)
		Net Plant in Service - Direct					
		Intangible					
1	301	Organization	1.1	$ 42,653	$ 71	$ 107	$ 3
2	302	Franchise & Consent	1.1	1,213,609	2,021	3,046	87
3	303	Misc. Intangible	1.1	7,333	12	18	1
4		Total Intangible		$ 1,263,595	$ 2,104	$ 3,171	$ 91
5		Allocation Percentage	Intang. Plant	100.00%	0.17%	0.25%	0.01%
		Distribution					
6	374	Land & Land Rights	1.0	$ 1,084,811	$ 5,734	$ -	$ -
7	374	Rights of Way	1.0	739,109	3,907	-	-
8	375	Structures	1.0	46,534	246	-	-
9	376	Mains - Demand	1.0	353,902,646	1,870,737	-	-
10	376	Mains - Customer	5.0	275,401,498	-	122,159	-
11	376	Mains - Commodity	3.0	1	-	-	0
12	378	Measuring & Reg. Station	2.2	29,625,773	88,069	5,751	0
13	380	Services - Demand	1.0	0	0	-	-
14	380	Services - Customer	7.0	321,023,126	-	1,133,019	-
15	381	Meters	6.0	196,168,747	-	1,706,018	-
16	385	Industrial Meas. & Reg. Sta.	3.0	4,245,215	-	-	85,134
17	386	Other Prop. on Cust. Premises	1.0	-	-	-	-
18	387	Other Equipment	1.0	(97,479)	(515)	-	-
19		Total Distribution		$ 1,182,139,980	$ 1,968,178	$ 2,966,946	$ 85,134
20		Allocation Percentage	Dist. Plant	100.00%	0.17%	0.25%	0.01%
21	389-398	Total General Plant	1.1	$ 83,720,546	$ 139,389	$ 210,123	$ 6,029
22		Total Net Plant-Direct		$ 1,267,124,121	$ 2,109,671	$ 3,180,240	$ 91,254
		Systems Allocable Plant					
23	301-303	Intangible Plant	1.1	$ 18,412,951	$ 30,656	$ 46,213	$ 1,326
24	389-398	General Plant	1.1	$ 16,035,255	$ 26,698	$ 40,245	$ 1,155
25		Total Systems Allocable		34,448,206	57,354	86,458	2,481
26		Total Net Plant		$ 1,301,572,327	$ 2,167,025	$ 3,266,699	$ 93,735
		Other Rate Base Items					
27		Cash Working Capital	11.2	(10,379,937)	(8,955)	(35,426)	(2,155)
28		Materials & Supplies	1.1	12,389,898	20,628	31,096	892
29		Prepayments	1.1	3,671,971	6,114	9,216	264
30		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
31		Customer Deposits	8.0	(31,921,898)	-	-	-
32		Customer Advances	8.0	(37,910,017)	-	-	-
33		Deferred Taxes	1.1	(142,632,297)	(237,473)	(357,980)	(10,272)
34		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-
35		Total Allocated Rate Base		1,094,790,047	1,947,339	2,913,605	82,465

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Street Lighting Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(m)	(n)	(o)
		Net Plant in Service - Direct					
		Intangible					
1	301	Organization	1.1	$ 42,653	$ 1	$ 14	$ 0
2	302	Franchise & Consent	1.1	1,213,609	30	399	1
3	303	Misc. Intangible	1.1	7,333	0	2	0
4		Total Intangible		$ 1,263,595	$ 31	$ 416	$ 1
5		Allocation Percentage	Intang. Plant	100.00%	0.00%	0.03%	0.00%
		Distribution					
6	374	Land & Land Rights	1.0	$ 1,084,811	$ 86	$ -	$ -
7	374	Rights of Way	1.0	739,109	58	-	-
8	375	Structures	1.0	46,534	4	-	-
9	376	Mains - Demand	1.0	353,902,646	27,970	-	-
10	376	Mains - Customer	5.0	275,401,498	-	163,102	-
11	376	Mains - Commodity	3.0	1	-	-	0
12	378	Measuring & Reg. Station	2.2	29,625,773	1,317	7,678	0
13	380	Services - Demand	1.0	0	0	-	-
14	380	Services - Customer	7.0	321,023,126	-	217,983	-
15	381	Meters	6.0	196,168,747	-	-	-
16	385	Industrial Meas. & Reg. Sta.	3.0	4,245,215	-	-	666
17	386	Other Prop. on Cust. Premises	1.0	-	-	-	-
18	387	Other Equipment	1.0	(97,479)	(8)	-	-
19		Total Distribution		$ 1,182,139,980	$ 29,427	$ 388,763	$ 666
20		Allocation Percentage	Dist. Plant	100.00%	0.00%	0.03%	0.00%
21	389-398	Total General Plant	1.1	$ 83,720,546	$ 2,084	$ 27,533	$ 47
22		Total Net Plant-Direct		$ 1,267,124,121	$ 31,543	$ 416,711	$ 714
		Systems Allocable Plant					
23	301-303	Intangible Plant	1.1	$ 18,412,951	$ 458	$ 6,055	$ 10
24	389-398	General Plant	1.1	$ 16,035,255	$ 399	$ 5,273	$ 9
25		Total Systems Allocable		34,448,206	858	11,329	19
26		Total Net Plant		$ 1,301,572,327	$ 32,400	$ 428,040	$ 734
		Other Rate Base Items					
27		Cash Working Capital	11.2	(10,379,937)	(134)	(2,000)	(17)
28		Materials & Supplies	1.1	12,389,898	308	4,075	7
29		Prepayments	1.1	3,671,971	91	1,208	2
30		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
31		Customer Deposits	8.0	(31,921,898)	-	-	-
32		Customer Advances	8.0	(37,910,017)	-	-	-
33		Deferred Taxes	1.1	(142,632,297)	(3,551)	(46,907)	(80)
34		Deferred Gain Hdqtrs Bldg	4.0	-	-	-	-
35		Total Allocated Rate Base		1,094,790,047	29,116	384,416	645

SOUTHWEST GAS CORPORATION
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CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Residential Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Direct Depreciation Expense					
1	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 75,910,024	$ 14,124,788	$ 43,989,468	$ 124,576
5	389-398	General	1.1	$ 4,919,293	$ 915,346	$ 2,850,705	$ 8,073
6		Total Direct Dep. Exp.		$ 80,829,317	$ 15,040,134	$ 46,840,173	$ 132,649
		Systems Allocable Depreciation Expense					
7	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
8	389-398	General	1.1	$ 2,540,252	$ 472,672	$ 1,472,063	$ 4,169
		System Allocable Amortization					
9		Miscellaneous Intangible	1.1	4,002,161	744,693	2,319,232	6,568
10		Structures-Leasehold Improvements	1.1	104,525	19,449	60,572	172
11		Total System Allocable Amortization		4,106,686	764,142	2,379,804	6,739
12		Total System Alloc Dep. Exp. & Amortization		6,646,938	1,236,814	3,851,867	10,908
13		Total Depreciation Expense		87,476,255	16,276,948	50,692,039	143,557
14		Amortization	1.1	126,930	23,618	73,555	208
15		Amortization-Gas Plant Acquisition	1.1	(52,996)	(9,861)	(30,711)	(87)
16		Regulatory Amortizations	1.1	337,524	62,804	195,593	554
17		-	7.0	-	-	-	-
18		-	1.1	-	-	-	-
19		-	1.1	-	-	-	-
20		Total Depreciation & Amortization Expense		$ 87,887,713	$ 16,353,509	$ 50,930,477	$ 144,232
		Operation and Maintenance Expense					
		Gas Supply Expense					
21	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -
22	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-
23	805	Purchased Gas Cost Adj.	3.0	-	-	-	-
24	810	Gas Used for Compressor Sta. Fuel--	3.0	-	-	-	-
25	813	Other Gas Supply Expense	3.0	-	-	-	-
26		Labor & Labor Loading	3.0	641,618	-	-	293,211
27		Materials & Expenses	3.0	59,983	-	-	27,411
28		Total Gas Supply Expense		$ 701,601	$ -	$ -	$ 320,622

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
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Distribution Expenses					
1	870	Operation Supervision & Eng.					
2		Labor & Labor Loading	5.5	$ 8,990,906	$ 951,770	$ 5,941,395	$ 47,236
3		Materials & Expenses	5.5	1,458,368	154,382	963,722	7,662
4	871	Distribution Load Dispatching					
5		Labor & Labor Loading	3.0	258,538	-	-	118,148
6		Materials & Expenses	3.0	113,250	-	-	51,754
7	874	Mains & Svcs. Expense					
8		Labor & Labor Loading	4.4	6,159,141	1,355,024	3,360,569	0
9		Materials & Expenses	4.4	5,540,228	1,218,862	3,022,876	0
10	875	Meas. & Reg. Sta. Exp.-Gen.					
11		Labor & Labor Loading	2.2	1,859,618	617,822	750,269	0
12		Materials & Expenses	2.2	697,287	231,660	281,323	0
13	878	Meter & House Reg. Exp.					
14		Labor & Labor Loading	6.0	6,919,581	-	5,452,280	-
15		Materials & Expenses	6.0	1,213,237	-	955,969	-
16	879	Customer Installation Exp.					
17		Labor & Labor Loading	6.0	8,087,437	-	6,372,491	-
18		Materials & Expenses	6.0	1,490,584	-	1,174,505	-
19	880	Other Expenses					
20		Labor & Labor Loading	5.5	6,543,834	692,725	4,324,314	34,380
21		Materials & Expenses	5.5	4,535,239	480,096	2,996,989	23,827
22	881	Rents	5.5	2,250,258	238,210	1,487,022	11,822
23		Total Distribution-Operations		$ 56,117,507	$ 5,940,551	$ 37,083,724	$ 294,830
		Operation and Maintenance Expense					
		Distribution Expenses					
24	885	Maint. Supervision & Eng.					
25		Labor & Labor Loading	6.6	$ 2,797,818	$ 552,838	$ 1,598,179	$ 0
26		Materials & Expenses	6.6	338,062	66,800	193,109	0
27	886	Maint. of Structures & Imp.					
28		Labor & Labor Loading	1.0	26,673	15,758	-	-
29		Materials & Expenses	1.0	80,753	47,706	-	-
30	887	Maint. of Mains					
31		Labor & Labor Loading	2.2	8,500,012	2,823,963	3,429,357	0
32		Materials & Expenses	2.2	7,043,715	2,340,137	2,841,809	0
33	889	Maint. of Meas. & Reg. Sta-Gen					
34		Labor & Labor Loading	2.2	1,461,314	485,493	589,572	0
35		Materials & Expenses	2.2	580,480	192,853	234,196	0
36	892	Maint. of Services					
37		Labor & Labor Loading	3.3	6,159,505	0	5,077,400	-
38		Materials & Expenses	3.3	3,973,153	0	3,275,148	-
39	893	Maint of Meter & House Reg.					
40		Labor & Labor Loading	6.0	1,281,534	-	1,009,784	-
41		Materials & Expenses	6.0	781,684	-	615,927	-
42	894	Maint of Other Equip.					
43		Labor & Labor Loading	6.6	196,535	38,835	112,266	0
44		Materials & Expenses	6.6	189,711	37,486	108,367	0
45		Total Distribution-Maintenance		$ 33,410,949	$ 6,601,869	$ 19,085,113	$ 0
46		Total Distribution O & M		$ 89,528,455	$ 12,542,420	$ 56,168,837	$ 294,830

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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
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Customer Accounts Expenses					
1	901	Supervision					
2		Labor & Labor Loading	10.1	$ 4,093,979	$ -	$ 3,534,733	$ -
3		Materials & Expenses	10.1	275,497	-	237,864	-
4	902	Meter Reading Exp.					
5		Labor & Labor Loading	13.0	4,860,483	-	4,169,182	-
6		Materials & Expenses	13.0	2,194,002	-	1,881,952	-
7	903	Customer Records & Collections					
8		Labor & Labor Loading	13.0	-	-	-	-
9		Materials & Expenses	13.0	404,465	-	346,938	-
10	903	Customer Records & Collections - LCS					
11		Labor & Labor Loading - LCS	13.0	16,062,467	-	13,777,920	-
12		Materials & Expenses - LCS	13.0	7,441,028	-	6,382,699	-
13	904	Uncollectible Accounts Exp.	4.0	2,977,729	-	2,745,192	-
14	905	Misc. Customer Accounts Exp.					
15		Labor & Labor Loading	10.1	404,465	-	349,214	-
16		Materials & Expenses	10.1	16,795	-	14,501	-
17		Total Customer Accounts Expenses		$ 38,730,909	$ -	$ 33,440,194	$ -
		Customer Service & Info. Exp.					
18	908	Customer Assistance Exp.					
19		Labor & Labor Loading	13.0	$ 514,896	$ -	$ 441,663	$ -
20		Materials & Expenses	13.0	564,797	-	484,466	-
21	909	Info. & Instructional Exp.					
22		Labor & Labor Loading	13.0	-	-	-	-
23		Materials & Expenses	13.0	25,125	-	21,551	-
24	910	Misc. C.S. & I. Expense					
25		Labor & Labor Loading	13.0	-	-	-	-
26		Materials & Expenses	13.0	21,977	-	18,852	-
27		Total Customer Service & Info. Exp.		$ 1,126,796	$ -	$ 966,533	$ -
		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		$ 130,087,761	$ 12,542,420	$ 90,575,563	$ 615,452
39		Allocation Percentage	Total O&M	100.00%	9.64%	69.63%	0.47%
		Other Operating Deductions					
40		Administrative & General Expense	Total O&M	56,946,694	5,490,519	39,649,994	269,418
41		Interest on Customer Deposits	8.0	1,915,314	-	1,781,727	-
42		Taxes Other Than Income	1.1	33,124,880	6,163,638	19,195,697	54,361
43		Total Allocated Operating Deductions		$ 222,074,648	$ 24,196,577	$ 151,202,981	$ 939,231
		Tax Adjustments					
44		Interest Expense	1.1	48,035,008	8,938,006	27,836,040	78,830
45		State South Georgia	1.1	29,686	5,524	17,203	49
46		Investment Tax Credit	1.1	(528,360)	(98,313)	(306,182)	(867)
47		Federal South Georgia	1.1	290,114	53,982	168,120	476

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
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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
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		Summary of Allocated Cost of Service					
		Rate Base					
1		Direct Net Plant		$ 1,267,124,121	$ 235,777,281	$ 734,291,902	$ 2,079,472
2		Systems Allocable Net Plant		34,448,206	6,409,873	19,962,558	56,533
3		Cash Working Capital	1.1	(10,379,937)	(1,000,782)	(7,227,188)	(49,108)
4		Materials & Supplies	1.1	12,389,898	2,305,422	7,179,882	20,333
5		Prepayments	1.1	3,671,971	683,254	2,127,888	6,026
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
7		Customer Deposits	8.0	(31,921,898)	-	(29,695,451)	-
8		Customer Advances	8.0	(37,910,017)	-	(35,265,919)	-
9		Deferred Taxes	1.1	(142,632,297)	(26,539,985)	(82,654,681)	(234,073)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-
11		Total Rate Base		$ 1,094,790,047	$ 217,635,062	$ 608,718,991	$ 1,879,183
12		Net Operating Margin	Direct	$ 381,188,845	$ 156,910,084	$ 102,079,805	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 5,784,028	$ 2,380,899	$ 1,548,924	$ -
14		Late Charges	Direct	$ 2,430,203	$ 1,166,826	$ 759,093	
15		Service Establishment Charges	9	$ 8,267,657	-	7,392,250	-
16		Reconnect / Reread Charges	4	$ 569,215	-	524,764	-
17		Other Revenue - Labor	Net Op. Marg.	$ 1,313	$ 540	$ 351	$ -
18		Other Revenue - Parts & Material	Net Op. Marg.	$ 2,621	$ 1,079	$ 702	$ -
19		Other Revenue - Field Collection Fee	4	$ 304,887	-	281,078	-
20		Other Revenue - Returned Item Fee	4	$ 173,412	-	159,870	-
21		Other Revenue - Rental Income	Net Op. Marg.	$ 512,498	$ 210,961	$ 137,244	$ -
22		Total Revenue		399,234,678	160,670,390	112,884,079	-
23		O & M		(130,087,761)	(12,542,420)	(90,575,563)	(615,452)
24		A & G	Total O&M	(56,946,694)	(5,490,519)	(39,649,994)	(269,418)
25		Depreciation Expense		(87,887,713)	(16,353,509)	(50,930,477)	(144,232)
26		Interest on Customer Deposits	8.0	(1,915,314)	-	(1,781,727)	-
27		Taxes other than Income	1.1	(33,124,880)	(6,163,638)	(19,195,697)	(54,361)
		State Income Tax					
28		Taxable Income before Interest Exp.		$ 89,272,317	$ 120,120,304	$(89,249,379)	$(1,083,463)
29		Interest Expense	1.1	(48,035,008)	(8,938,006)	(27,836,040)	(78,830)
30		State Taxable Income		$ 41,237,309	$ 111,182,297	$(117,085,418)	$(1,162,293)
31		State Income Tax		2,873,416	7,747,182	(8,158,512)	(80,989)
32		South Georgia	1.1	29,686	5,524	17,203	49
33		State Income Tax		2,903,102	7,752,706	(8,141,309)	(80,940)
		Federal Income Tax					
34		Taxable Income before Interest Exp.		89,272,317	120,120,304	(89,249,379)	(1,083,463)
35		Interest Expense	1.1	(48,035,008)	(8,938,006)	(27,836,040)	(78,830)
36		Federal Taxable Income		41,237,309	111,182,297	(117,085,418)	(1,162,293)
37		Federal Income Tax		$ 13,427,363	$ 36,202,290	$(38,124,417)	$(378,457)
38		I T C	1.1	(528,360)	(98,313)	(306,182)	(867)
39		South Georgia	1.1	290,114	53,982	168,120	476
40		Total Federal Income Tax		$ 13,189,117	$ 36,157,959	$(38,262,480)	$(378,848)
41		Regulatory Amortization	1.1	-	-	-	-
42		Net Income		$ 73,180,099	$ 76,209,638	$(42,845,590)	$(623,676)
43		Rate of Return on Rate Base		6.68%	35.02%	(7.04%)	(33.19%)
44		Rate of Return by Class Total				3.95%	

SOUTHWEST GAS CORPORATION
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CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Multi-Family Residential Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(h)	(i)	(j)
		Direct Depreciation Expense					
1	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 75,910,024	$ 264,307	$ 1,302,812	$ 2,953
5	389-398	General	1.1	$ 4,919,293	$ 17,128	$ 84,428	$ 191
6		Total Direct Dep. Exp.		$ 80,829,317	$ 281,436	$ 1,387,239	$ 3,144
		Systems Allocable Depreciation Expense					
7	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
8	389-398	General	1.1	$ 2,540,252	$ 8,845	$ 43,597	$ 99
		System Allocable Amortization					
9		Miscellaneous Intangible	1.1	4,002,161	13,935	68,687	156
10		Structures-Leasehold Improvements	1.1	104,525	364	1,794	4
11		Total System Allocable Amortization		4,106,686	14,299	70,481	160
12		Total System Alloc Dep. Exp. & Amortization		6,646,938	23,144	114,079	259
13		Total Depreciation Expense		87,476,255	304,579	1,501,318	3,403
14		Amortization	1.1	126,930	442	2,178	5
15		Amortization-Gas Plant Acquisition	1.1	(52,996)	(185)	(910)	(2)
16		Regulatory Amortizations	1.1	337,524	1,175	5,793	13
17		-	7.0	-	-	-	-
18		-	1.1	-	-	-	-
19		-	1.1	-	-	-	-
20		Total Depreciation & Amortization Expense		$ 87,887,713	$ 306,012	$ 1,508,380	$ 3,419
		Operation and Maintenance Expense					
		Gas Supply Expense					
21	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -
22	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-
23	805	Purchased Gas Cost Adj.	3.0	-	-	-	-
24	810	Gas Used for Compressor Sta. Fuel--(	3.0	-	-	-	-
25	813	Other Gas Supply Expense	3.0	-	-	-	-
26		Labor & Labor Loading	3.0	641,618	-	-	6,951
27		Materials & Expenses	3.0	59,983	-	-	650
28		Total Gas Supply Expense		$ 701,601	$ -	$ -	$ 7,600

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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Multi-Family Residential Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(h)	(i)	(j)
		Distribution Expenses					
1	870	Operation Supervision & Eng.					
2		Labor & Labor Loading	5.5	$ 8,990,906	$ 17,810	$ 195,869	$ 1,120
3		Materials & Expenses	5.5	1,458,368	2,889	31,771	182
4	871	Distribution Load Dispatching					
5		Labor & Labor Loading	3.0	258,538	-	-	2,801
6		Materials & Expenses	3.0	113,250	-	-	1,227
7	874	Mains & Svcs. Expense					
8		Labor & Labor Loading	4.4	6,159,141	25,356	93,546	0
9		Materials & Expenses	4.4	5,540,228	22,808	84,146	0
10	875	Meas. & Reg. Sta. Exp.-Gen.					
11		Labor & Labor Loading	2.2	1,859,618	11,561	28,140	0
12		Materials & Expenses	2.2	697,287	4,335	10,551	0
13	878	Meter & House Reg. Exp.					
14		Labor & Labor Loading	6.0	6,919,581	-	190,711	-
15		Materials & Expenses	6.0	1,213,237	-	33,438	-
16	879	Customer Installation Exp.					
17		Labor & Labor Loading	6.0	8,087,437	-	222,898	-
18		Materials & Expenses	6.0	1,490,584	-	41,082	-
19	880	Other Expenses					
20		Labor & Labor Loading	5.5	6,543,834	12,962	142,559	815
21		Materials & Expenses	5.5	4,535,239	8,984	98,801	565
22	881	Rents	5.5	2,250,258	4,457	49,022	280
23		Total Distribution-Operations		$ 56,117,507	$ 111,161	$ 1,222,533	$ 6,989
		Operation and Maintenance Expense					
		Distribution Expenses					
24	885	Maint. Supervision & Eng.					
25		Labor & Labor Loading	6.6	$ 2,797,818	$ 10,345	$ 44,742	$ 0
26		Materials & Expenses	6.6	338,062	1,250	5,406	0
27	886	Maint. of Structures & Imp.					
28		Labor & Labor Loading	1.0	26,673	295	-	-
29		Materials & Expenses	1.0	80,753	893	-	-
30	887	Maint. of Mains					
31		Labor & Labor Loading	2.2	8,500,012	52,843	128,622	0
32		Materials & Expenses	2.2	7,043,715	43,789	106,586	0
33	889	Maint. of Meas. & Reg. Sta-Gen					
34		Labor & Labor Loading	2.2	1,461,314	9,085	22,113	0
35		Materials & Expenses	2.2	580,480	3,609	8,784	0
36	892	Maint. of Services					
37		Labor & Labor Loading	3.3	6,159,505	0	94,228	-
38		Materials & Expenses	3.3	3,973,153	0	60,781	-
39	893	Maint of Meter & House Reg.					
40		Labor & Labor Loading	6.0	1,281,534	-	35,320	-
41		Materials & Expenses	6.0	781,684	-	21,544	-
42	894	Maint of Other Equip.					
43		Labor & Labor Loading	6.6	196,535	727	3,143	0
44		Materials & Expenses	6.6	189,711	701	3,034	0
45		Total Distribution-Maintenance		$ 33,410,949	$ 123,536	$ 534,304	$ 0
46		Total Distribution O & M		$ 89,528,455	$ 234,698	$ 1,756,837	$ 6,989

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Multi-Family Residential Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(h)	(i)	(j)
		Customer Accounts Expenses					
1	901	Supervision					
2		Labor & Labor Loading	10.1	$ 4,093,979	$ -	$ 54,762	$ -
3		Materials & Expenses	10.1	275,497	-	3,685	-
4	902	Meter Reading Exp.					
5		Labor & Labor Loading	13.0	4,860,483	-	55,104	-
6		Materials & Expenses	13.0	2,194,002	-	24,874	-
7	903	Customer Records & Collections					
8		Labor & Labor Loading	13.0	-	-	-	-
9		Materials & Expenses	13.0	404,465	-	4,585	-
10	903	Customer Records & Collections - LCS					
11		Labor & Labor Loading - LCS	13.0	16,062,467	-	182,103	-
12		Materials & Expenses - LCS	13.0	7,441,028	-	84,360	-
13	904	Uncollectible Accounts Exp.	4.0	2,977,729	-	102,962	-
14	905	Misc. Customer Accounts Exp.					
15		Labor & Labor Loading	10.1	404,465	-	5,410	-
16		Materials & Expenses	10.1	16,795	-	225	-
17		Total Customer Accounts Expenses		$ 38,730,909	$ -	$ 518,071	$ -
		Customer Service & Info. Exp.					
18	908	Customer Assistance Exp.					
19		Labor & Labor Loading	13.0	$ 514,896	$ -	$ 5,837	$ -
20		Materials & Expenses	13.0	564,797	-	6,403	-
21	909	Info. & Instructional Exp.					
22		Labor & Labor Loading	13.0	-	-	-	-
23		Materials & Expenses	13.0	25,125	-	285	-
24	910	Misc. C.S. & I. Expense					
25		Labor & Labor Loading	13.0	-	-	-	-
26		Materials & Expenses	13.0	21,977	-	249	-
27		Total Customer Service & Info. Exp.		$ 1,126,796	$ -	$ 12,775	$ -
		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		$ 130,087,761	$ 234,698	$ 2,287,683	$ 14,589
39		Allocation Percentage	Total O&M	100.00%	0.18%	1.76%	0.01%
		Other Operating Deductions					
40		Administrative & General Expense	Total O&M	56,946,694	102,740	1,001,447	6,387
41		Interest on Customer Deposits	8.0	1,915,314	-	66,826	-
42		Taxes Other Than Income	1.1	33,124,880	115,336	568,508	1,289
43		Total Allocated Operating Deductions		$ 222,074,648	$ 452,774	$ 3,924,463	$ 22,265
		Tax Adjustments					
44		Interest Expense	1.1	48,035,008	167,251	824,405	1,869
45		State South Georgia	1.1	29,686	103	509	1
46		Investment Tax Credit	1.1	(528,360)	(1,840)	(9,068)	(21)
47		Federal South Georgia	1.1	290,114	1,010	4,979	11

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Multi-Family Residential Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(h)	(i)	(j)
		Summary of Allocated Cost of Service					
		Rate Base					
1		Direct Net Plant		$ 1,267,124,121	$ 4,411,937	$ 21,747,115	$ 49,294
2		Systems Allocable Net Plant		34,448,206	119,944	591,220	1,340
3		Cash Working Capital	1.1	(10,379,937)	(18,727)	(182,538)	(1,164)
4		Materials & Supplies	1.1	12,389,898	43,140	212,643	482
5		Prepayments	1.1	3,671,971	12,785	63,020	143
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
7		Customer Deposits	8.0	(31,921,898)	-	(1,113,765)	-
8		Customer Advances	8.0	(37,910,017)	-	(1,322,692)	-
9		Deferred Taxes	1.1	(142,632,297)	(496,624)	(2,447,938)	(5,549)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-
11		Total Rate Base		$ 1,094,790,047	$ 4,072,454	$ 17,547,064	$ 44,546
12		Net Operating Margin	Direct	$ 381,188,845	$ 3,699,991	$ 3,415,605	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 5,784,028	$ 56,142	$ 51,827	$ -
14		Late Charges	Direct	$ 2,430,203	$ 27,514	$ 25,399	
15		Service Establishment Charges	9	$ 8,267,657	-	277,256	-
16		Reconnect / Reread Charges	4	$ 569,215	-	19,682	-
17		Other Revenue - Labor	Net Op. Marg.	$ 1,313	$ 13	$ 12	$ -
18		Other Revenue - Parts & Material	Net Op. Marg.	$ 2,621	$ 25	$ 23	$ -
19		Other Revenue - Field Collection Fee	4	$ 304,887	-	10,542	-
20		Other Revenue - Returned Item Fee	4	$ 173,412	-	5,996	-
21		Other Revenue - Rental Income	Net Op. Marg.	$ 512,498	$ 4,975	$ 4,592	$ -
22		Total Revenue		399,234,678	3,788,660	3,810,935	-
23		O & M		(130,087,761)	(234,698)	(2,287,683)	(14,589)
24		A & G	Total O&M	(56,946,694)	(102,740)	(1,001,447)	(6,387)
25		Depreciation Expense		(87,887,713)	(306,012)	(1,508,380)	(3,419)
26		Interest on Customer Deposits	8.0	(1,915,314)	-	(66,826)	-
27		Taxes other than Income	1.1	(33,124,880)	(115,336)	(568,508)	(1,289)
		State Income Tax					
28		Taxable Income before Interest Exp.		$ 89,272,317	$ 3,029,875	$(1,621,908)	$(25,684)
29		Interest Expense	1.1	(48,035,008)	(167,251)	(824,405)	(1,869)
30		State Taxable Income		$ 41,237,309	$ 2,862,624	$(2,446,313)	$(27,552)
31		State Income Tax		2,873,416	199,468	(170,459)	(1,920)
32		South Georgia	1.1	29,686	103	509	1
33		State Income Tax		2,903,102	199,571	(169,950)	(1,919)
		Federal Income Tax					
34		Taxable Income before Interest Exp.		89,272,317	3,029,875	(1,621,908)	(25,684)
35		Interest Expense	1.1	(48,035,008)	(167,251)	(824,405)	(1,869)
36		Federal Taxable Income		41,237,309	2,862,624	(2,446,313)	(27,552)
37		Federal Income Tax		$ 13,427,363	$ 932,105	$(796,549)	$(8,971)
38		I T C	1.1	(528,360)	(1,840)	(9,068)	(21)
39		South Georgia	1.1	290,114	1,010	4,979	11
40		Total Federal Income Tax		$ 13,189,117	$ 931,275	$(800,638)	$(8,981)
41		Regulatory Amortization	1.1	-	-	-	-
42		Net Income		$ 73,180,099	$ 1,899,028	$(651,321)	$(14,784)
43		Rate of Return on Rate Base		6.68%	46.63%	(3.71%)	(33.19%)
44		Rate of Return by Class Total				5.69%	

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	MMMHP Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(k)	(l)	(m)
		Direct Depreciation Expense					
1	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 75,910,024	$ 99,403	$ 25,560	$ 930
5	389-398	General	1.1	$ 4,919,293	$ 6,442	$ 1,656	$ 60
6		Total Direct Dep. Exp.		$ 80,829,317	$ 105,845	$ 27,216	$ 990
		Systems Allocable Depreciation Expense					
7	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
8	389-398	General	1.1	$ 2,540,252	$ 3,326	$ 855	$ 31
		System Allocable Amortization					
9		Miscellaneous Intangible	1.1	4,002,161	5,241	1,348	49
10		Structures-Leasehold Improvements	1.1	104,525	137	35	1
11		Total System Allocable Amortization		4,106,686	5,378	1,383	50
12		Total System Alloc Dep. Exp. & Amortization		6,646,938	8,704	2,238	81
13		Total Depreciation Expense		87,476,255	114,549	29,454	1,072
14		Amortization	1.1	126,930	166	43	2
15		Amortization-Gas Plant Acquisition	1.1	(52,996)	(69)	(18)	(1)
16		Regulatory Amortizations	1.1	337,524	442	114	4
17		-	7.0	-	-	-	-
18		-	1.1	-	-	-	-
19		-	1.1	-	-	-	-
20		Total Depreciation & Amortization Expense		$ 87,887,713	$ 115,088	$ 29,593	$ 1,077
		Operation and Maintenance Expense					
		Gas Supply Expense					
21	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -
22	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-
23	805	Purchased Gas Cost Adj.	3.0	-	-	-	-
24	810	Gas Used for Compressor Sta. Fuel–	3.0	-	-	-	-
25	813	Other Gas Supply Expense	3.0	-	-	-	-
26		Labor & Labor Loading	3.0	641,618	-	-	2,189
27		Materials & Expenses	3.0	59,983	-	-	205
28		Total Gas Supply Expense		$ 701,601	$ -	$ -	$ 2,394

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	MMMHP Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(k)	(l)	(m)
		Distribution Expenses					
1	870	Operation Supervision & Eng.					
2		Labor & Labor Loading	5.5	$ 8,990,906	$ 6,698	$ 3,397	$ 353
3		Materials & Expenses	5.5	1,458,368	1,086	551	57
4	871	Distribution Load Dispatching					
5		Labor & Labor Loading	3.0	258,538	-	-	882
6		Materials & Expenses	3.0	113,250	-	-	386
7	874	Mains & Svcs. Expense					
8		Labor & Labor Loading	4.4	6,159,141	9,536	1,971	0
9		Materials & Expenses	4.4	5,540,228	8,578	1,773	0
10	875	Meas. & Reg. Sta. Exp.-Gen.					
11		Labor & Labor Loading	2.2	1,859,618	4,348	139	0
12		Materials & Expenses	2.2	697,287	1,630	52	0
13	878	Meter & House Reg. Exp.					
14		Labor & Labor Loading	6.0	6,919,581	-	3,236	-
15		Materials & Expenses	6.0	1,213,237	-	567	-
16	879	Customer Installation Exp.					
17		Labor & Labor Loading	6.0	8,087,437	-	3,783	-
18		Materials & Expenses	6.0	1,490,584	-	697	-
19	880	Other Expenses					
20		Labor & Labor Loading	5.5	6,543,834	4,875	2,472	257
21		Materials & Expenses	5.5	4,535,239	3,379	1,713	178
22	881	Rents	5.5	2,250,258	1,676	850	88
23		Total Distribution-Operations		$ 56,117,507	$ 41,807	$ 21,202	$ 2,201
		Operation and Maintenance Expense					
		Distribution Expenses					
24	885	Maint. Supervision & Eng.					
25		Labor & Labor Loading	6.6	$ 2,797,818	$ 3,891	$ 973	$ 0
26		Materials & Expenses	6.6	338,062	470	118	0
27	886	Maint. of Structures & Imp.					
28		Labor & Labor Loading	1.0	26,673	111	-	-
29		Materials & Expenses	1.0	80,753	336	-	-
30	887	Maint. of Mains					
31		Labor & Labor Loading	2.2	8,500,012	19,874	636	0
32		Materials & Expenses	2.2	7,043,715	16,469	527	0
33	889	Maint. of Meas. & Reg. Sta-Gen					
34		Labor & Labor Loading	2.2	1,461,314	3,417	109	0
35		Materials & Expenses	2.2	580,480	1,357	43	0
36	892	Maint. of Services					
37		Labor & Labor Loading	3.3	6,159,505	0	4,931	-
38		Materials & Expenses	3.3	3,973,153	0	3,181	-
39	893	Maint of Meter & House Reg.					
40		Labor & Labor Loading	6.0	1,281,534	-	599	-
41		Materials & Expenses	6.0	781,684	-	366	-
42	894	Maint of Other Equip.					
43		Labor & Labor Loading	6.6	196,535	273	68	0
44		Materials & Expenses	6.6	189,711	264	66	0
45		Total Distribution-Maintenance		$ 33,410,949	$ 46,461	$ 11,617	$ 0
46		Total Distribution O & M		$ 89,528,455	$ 88,267	$ 32,819	$ 2,201

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	MMMHP Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(k)	(l)	(m)
		Customer Accounts Expenses					
1	901	Supervision					
2		Labor & Labor Loading	10.1	$ 4,093,979	$ -	$ 1,958	$ -
3		Materials & Expenses	10.1	275,497	-	132	-
4	902	Meter Reading Exp.					
5		Labor & Labor Loading	13.0	4,860,483	-	2,468	-
6		Materials & Expenses	13.0	2,194,002	-	1,114	-
7	903	Customer Records & Collections					
8		Labor & Labor Loading	13.0	-	-	-	-
9		Materials & Expenses	13.0	404,465	-	205	-
10	903	Customer Records & Collections - LCS					
11		Labor & Labor Loading - LCS	13.0	16,062,467	-	8,157	-
12		Materials & Expenses - LCS	13.0	7,441,028	-	3,779	-
13	904	Uncollectible Accounts Exp.	4.0	2,977,729	-	509	-
14	905	Misc. Customer Accounts Exp.					
15		Labor & Labor Loading	10.1	404,465	-	193	-
16		Materials & Expenses	10.1	16,795	-	8	-
17		Total Customer Accounts Expenses		$ 38,730,909	$ -	$ 18,524	$ -
		Customer Service & Info. Exp.					
18	908	Customer Assistance Exp.					
19		Labor & Labor Loading	13.0	$ 514,896	$ -	$ 261	$ -
20		Materials & Expenses	13.0	564,797	-	287	-
21	909	Info. & Instructional Exp.					
22		Labor & Labor Loading	13.0	-	-	-	-
23		Materials & Expenses	13.0	25,125	-	13	-
24	910	Misc. C.S. & I. Expense					
25		Labor & Labor Loading	13.0	-	-	-	-
26		Materials & Expenses	13.0	21,977	-	11	-
27		Total Customer Service & Info. Exp.		$ 1,126,796	$ -	$ 572	$ -
		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		$ 130,087,761	$ 88,267	$ 51,915	$ 4,595
39		Allocation Percentage	Total O&M	100.00%	0.07%	0.04%	0.00%
		Other Operating Deductions					
40		Administrative & General Expense	Total O&M	56,946,694	38,640	22,726	2,012
41		Interest on Customer Deposits	8.0	1,915,314	-	330	-
42		Taxes Other Than Income	1.1	33,124,880	43,377	11,153	406
43		Total Allocated Operating Deductions		$ 222,074,648	$ 170,284	$ 86,126	$ 7,013
		Tax Adjustments					
44		Interest Expense	1.1	48,035,008	62,901	16,174	589
45		State South Georgia	1.1	29,686	39	10	0
46		Investment Tax Credit	1.1	(528,360)	(692)	(178)	(6)
47		Federal South Georgia	1.1	290,114	380	98	4

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	MMMHP Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(k)	(l)	(m)
		Summary of Allocated Cost of Service					
		Rate Base					
1		Direct Net Plant		$ 1,267,124,121	$ 1,659,285	$ 426,653	$ 15,527
2		Systems Allocable Net Plant		34,448,206	45,110	11,599	422
3		Cash Working Capital	1.1	(10,379,937)	(7,043)	(4,142)	(367)
4		Materials & Supplies	1.1	12,389,898	16,224	4,172	152
5		Prepayments	1.1	3,671,971	4,808	1,236	45
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
7		Customer Deposits	8.0	(31,921,898)	-	(5,508)	-
8		Customer Advances	8.0	(37,910,017)	-	(6,541)	-
9		Deferred Taxes	1.1	(142,632,297)	(186,775)	(48,026)	(1,748)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-
11		Total Rate Base		$ 1,094,790,047	$ 1,531,609	$ 379,443	$ 14,031
12		Net Operating Margin	Direct	$ 381,188,845	$ 854,013	$ 118,080	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 5,784,028	$ 12,958	$ 1,792	$ -
14		Late Charges	Direct	$ 2,430,203	$ 6,351	$ 878	
15		Service Establishment Charges	9	$ 8,267,657	-	2,350	-
16		Reconnect / Reread Charges	4	$ 569,215	-	97	-
17		Other Revenue - Labor	Net Op. Marg.	$ 1,313	$ 3	$ 0	$ -
18		Other Revenue - Parts & Material	Net Op. Marg.	$ 2,621	$ 6	$ 1	$ -
19		Other Revenue - Field Collection Fee	4	$ 304,887	-	52	-
20		Other Revenue - Returned Item Fee	4	$ 173,412	-	30	-
21		Other Revenue - Rental Income	Net Op. Marg.	$ 512,498	$ 1,148	$ 159	$ -
22		Total Revenue		399,234,678	874,479	123,439	-
23		O & M		(130,087,761)	(88,267)	(51,915)	(4,595)
24		A & G	Total O&M	(56,946,694)	(38,640)	(22,726)	(2,012)
25		Depreciation Expense		(87,887,713)	(115,088)	(29,593)	(1,077)
26		Interest on Customer Deposits	8.0	(1,915,314)	-	(330)	-
27		Taxes other than Income	1.1	(33,124,880)	(43,377)	(11,153)	(406)
		State Income Tax					
28		Taxable Income before Interest Exp.		$ 89,272,317	$ 589,107	$ 7,721	$(8,090)
29		Interest Expense	1.1	(48,035,008)	(62,901)	(16,174)	(589)
30		State Taxable Income		$ 41,237,309	$ 526,206	$(8,453)	$(8,678)
31		State Income Tax		2,873,416	36,666	(589)	(605)
32		South Georgia	1.1	29,686	39	10	0
33		State Income Tax		2,903,102	36,705	(579)	(604)
		Federal Income Tax					
34		Taxable Income before Interest Exp.		89,272,317	589,107	7,721	(8,090)
35		Interest Expense	1.1	(48,035,008)	(62,901)	(16,174)	(589)
36		Federal Taxable Income		41,237,309	526,206	(8,453)	(8,678)
37		Federal Income Tax		$ 13,427,363	$ 171,339	$(2,752)	$(2,826)
38		I T C	1.1	(528,360)	(692)	(178)	(6)
39		South Georgia	1.1	290,114	380	98	4
40		Total Federal Income Tax		$ 13,189,117	$ 171,027	$(2,833)	$(2,829)
41		Regulatory Amortization	1.1	-	-	-	-
42		Net Income		$ 73,180,099	$ 381,375	$ 11,133	$(4,657)
43		Rate of Return on Rate Base		6.68%	24.90%	2.93%	(33.19%)
44		Rate of Return by Class Total				20.15%	

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Small General Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(n)	(o)	(p)
		Direct Depreciation Expense					
1	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 75,910,024	$ 276,225	$ 1,013,749	$ 2,100
5	389-398	General	1.1	$ 4,919,293	$ 17,901	$ 65,695	$ 136
6		Total Direct Dep. Exp.		$ 80,829,317	$ 294,126	$ 1,079,444	$ 2,236
		Systems Allocable Depreciation Expense					
7	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
8	389-398	General	1.1	$ 2,540,252	$ 9,244	$ 33,924	$ 70
		System Allocable Amortization					
9		Miscellaneous Intangible	1.1	4,002,161	14,563	53,447	111
10		Structures-Leasehold Improvements	1.1	104,525	380	1,396	3
11		Total System Allocable Amortization		4,106,686	14,944	54,843	114
12		Total System Alloc Dep. Exp. & Amortization		6,646,938	24,187	88,767	184
13		Total Depreciation Expense		87,476,255	318,313	1,168,212	2,420
14		Amortization	1.1	126,930	462	1,695	4
15		Amortization-Gas Plant Acquisition	1.1	(52,996)	(193)	(708)	(1)
16		Regulatory Amortizations	1.1	337,524	1,228	4,508	9
17		-	7.0	-	-	-	-
18		-	1.1	-	-	-	-
19		-	1.1	-	-	-	-
20		Total Depreciation & Amortization Expense		$ 87,887,713	$ 319,811	$ 1,173,707	$ 2,431
		Operation and Maintenance Expense					
		Gas Supply Expense					
21	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -
22	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-
23	805	Purchased Gas Cost Adj.	3.0	-	-	-	-
24	810	Gas Used for Compressor Sta. Fuel--(	3.0	-	-	-	-
25	813	Other Gas Supply Expense	3.0	-	-	-	-
26		Labor & Labor Loading	3.0	641,618	-	-	4,942
27		Materials & Expenses	3.0	59,983	-	-	462
28		Total Gas Supply Expense		$ 701,601	$ -	$ -	$ 5,404

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Small General Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(n)	(o)	(p)
		Distribution Expenses					
1	870	Operation Supervision & Eng.					
2		Labor & Labor Loading	5.5	$ 8,990,906	$ 18,613	$ 160,522	$ 796
3		Materials & Expenses	5.5	1,458,368	3,019	26,037	129
4	871	Distribution Load Dispatching					
5		Labor & Labor Loading	3.0	258,538	-	-	1,992
6		Materials & Expenses	3.0	113,250	-	-	872
7	874	Mains & Svcs. Expense					
8		Labor & Labor Loading	4.4	6,159,141	26,499	70,405	0
9		Materials & Expenses	4.4	5,540,228	23,836	63,330	0
10	875	Meas. & Reg. Sta. Exp.-Gen.					
11		Labor & Labor Loading	2.2	1,859,618	12,082	14,270	0
12		Materials & Expenses	2.2	697,287	4,530	5,351	0
13	878	Meter & House Reg. Exp.					
14		Labor & Labor Loading	6.0	6,919,581	-	165,662	-
15		Materials & Expenses	6.0	1,213,237	-	29,046	-
16	879	Customer Installation Exp.					
17		Labor & Labor Loading	6.0	8,087,437	-	193,621	-
18		Materials & Expenses	6.0	1,490,584	-	35,686	-
19	880	Other Expenses					
20		Labor & Labor Loading	5.5	6,543,834	13,547	116,832	580
21		Materials & Expenses	5.5	4,535,239	9,389	80,971	402
22	881	Rents	5.5	2,250,258	4,658	40,176	199
23		Total Distribution-Operations		$ 56,117,507	$ 116,174	$ 1,001,909	$ 4,970
		Operation and Maintenance Expense					
		Distribution Expenses					
24	885	Maint. Supervision & Eng.					
25		Labor & Labor Loading	6.6	$ 2,797,818	$ 10,811	$ 35,084	$ 0
26		Materials & Expenses	6.6	338,062	1,306	4,239	0
27	886	Maint. of Structures & Imp.					
28		Labor & Labor Loading	1.0	26,673	308	-	-
29		Materials & Expenses	1.0	80,753	933	-	-
30	887	Maint. of Mains					
31		Labor & Labor Loading	2.2	8,500,012	55,226	65,226	0
32		Materials & Expenses	2.2	7,043,715	45,764	54,051	0
33	889	Maint. of Meas. & Reg. Sta-Gen					
34		Labor & Labor Loading	2.2	1,461,314	9,494	11,214	0
35		Materials & Expenses	2.2	580,480	3,771	4,454	0
36	892	Maint. of Services					
37		Labor & Labor Loading	3.3	6,159,505	0	115,778	-
38		Materials & Expenses	3.3	3,973,153	0	74,682	-
39	893	Maint of Meter & House Reg.					
40		Labor & Labor Loading	6.0	1,281,534	-	30,681	-
41		Materials & Expenses	6.0	781,684	-	18,714	-
42	894	Maint of Other Equip.					
43		Labor & Labor Loading	6.6	196,535	759	2,465	0
44		Materials & Expenses	6.6	189,711	733	2,379	0
45		Total Distribution-Maintenance		$ 33,410,949	$ 129,107	$ 418,967	$ 0
46		Total Distribution O & M		$ 89,528,455	$ 245,281	$ 1,420,877	$ 4,970

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Small General Gas Service Demand	Small General Gas Service Customer	Small General Gas Service Commodity
	(a)	(b)	(c)	(d)	(n)	(o)	(p)
		Customer Accounts Expenses					
1	901	Supervision					
2		Labor & Labor Loading	10.1	$ 4,093,979	$ -	$ 142,129	$ -
3		Materials & Expenses	10.1	275,497	-	9,564	-
4	902	Meter Reading Exp.					
5		Labor & Labor Loading	13.0	4,860,483	-	176,771	-
6		Materials & Expenses	13.0	2,194,002	-	79,794	-
7	903	Customer Records & Collections					
8		Labor & Labor Loading	13.0	-	-	-	-
9		Materials & Expenses	13.0	404,465	-	14,710	-
10	903	Customer Records & Collections - LCS					
11		Labor & Labor Loading - LCS	13.0	16,062,467	-	584,178	-
12		Materials & Expenses - LCS	13.0	7,441,028	-	270,624	-
13	904	Uncollectible Accounts Exp.	4.0	2,977,729	-	52,213	-
14	905	Misc. Customer Accounts Exp.					
15		Labor & Labor Loading	10.1	404,465	-	14,042	-
16		Materials & Expenses	10.1	16,795	-	583	-
17		Total Customer Accounts Expenses		$ 38,730,909	$ -	$ 1,344,608	$ -
		Customer Service & Info. Exp.					
18	908	Customer Assistance Exp.					
19		Labor & Labor Loading	13.0	$ 514,896	$ -	$ 18,726	$ -
20		Materials & Expenses	13.0	564,797	-	20,541	-
21	909	Info. & Instructional Exp.					
22		Labor & Labor Loading	13.0	-	-	-	-
23		Materials & Expenses	13.0	25,125	-	914	-
24	910	Misc. C.S. & I. Expense					
25		Labor & Labor Loading	13.0	-	-	-	-
26		Materials & Expenses	13.0	21,977	-	799	-
27		Total Customer Service & Info. Exp.		$ 1,126,796	$ -	$ 40,981	$ -
		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		$ 130,087,761	$ 245,281	$ 2,806,465	$ 10,374
39		Allocation Percentage	Total O&M	100.00%	0.19%	2.16%	0.01%
		Other Operating Deductions					
40		Administrative & General Expense	Total O&M	56,946,694	107,373	1,228,547	4,541
41		Interest on Customer Deposits	8.0	1,915,314	-	33,888	-
42		Taxes Other Than Income	1.1	33,124,880	120,537	442,370	916
43		Total Allocated Operating Deductions		$ 222,074,648	$ 473,190	$ 4,511,271	$ 15,832
		Tax Adjustments					
44		Interest Expense	1.1	48,035,008	174,792	641,489	1,329
45		State South Georgia	1.1	29,686	108	396	1
46		Investment Tax Credit	1.1	(528,360)	(1,923)	(7,056)	(15)
47		Federal South Georgia	1.1	290,114	1,056	3,874	8

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Small General Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(n)	(o)	(p)
		Summary of Allocated Cost of Service					
		Rate Base					
1		Direct Net Plant		$ 1,267,124,121	$ 4,610,880	$ 16,921,956	$ 35,052
2		Systems Allocable Net Plant		34,448,206	125,352	460,043	953
3		Cash Working Capital	1.1	(10,379,937)	(19,571)	(223,933)	(828)
4		Materials & Supplies	1.1	12,389,898	45,085	165,462	343
5		Prepayments	1.1	3,671,971	13,362	49,038	102
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
7		Customer Deposits	8.0	(31,921,898)	-	(564,803)	-
8		Customer Advances	8.0	(37,910,017)	-	(670,752)	-
9		Deferred Taxes	1.1	(142,632,297)	(519,018)	(1,904,800)	(3,946)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-
11		Total Rate Base		$ 1,094,790,047	$ 4,256,089	$ 14,232,211	$ 31,676
12		Net Operating Margin	Direct	$ 381,188,845	$ 2,822,517	$ 5,045,125	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 5,784,028	$ 42,828	$ 76,553	$ -
14		Late Charges	Direct	$ 2,430,203	$ 31,393	$ 56,114	
15		Service Establishment Charges	9	$ 8,267,657	-	241,028	-
16		Reconnect / Reread Charges	4	$ 569,215	-	9,981	-
17		Other Revenue - Labor	Net Op. Marg.	$ 1,313	$ 10	$ 17	$ -
18		Other Revenue - Parts & Material	Net Op. Marg.	$ 2,621	$ 19	$ 35	$ -
19		Other Revenue - Field Collection Fee	4	$ 304,887	-	5,346	-
20		Other Revenue - Returned Item Fee	4	$ 173,412	-	3,041	-
21		Other Revenue - Rental Income	Net Op. Marg.	$ 512,498	$ 3,795	$ 6,783	$ -
22		Total Revenue		399,234,678	2,900,562	5,444,022	-
23		O & M		(130,087,761)	(245,281)	(2,806,465)	(10,374)
24		A & G	Total O&M	(56,946,694)	(107,373)	(1,228,547)	(4,541)
25		Depreciation Expense		(87,887,713)	(319,811)	(1,173,707)	(2,431)
26		Interest on Customer Deposits	8.0	(1,915,314)	-	(33,888)	-
27		Taxes other than Income	1.1	(33,124,880)	(120,537)	(442,370)	(916)
		State Income Tax					
28		Taxable Income before Interest Exp.		$ 89,272,317	$ 2,107,561	$(240,955)	$(18,263)
29		Interest Expense	1.1	(48,035,008)	(174,792)	(641,489)	(1,329)
30		State Taxable Income		$ 41,237,309	$ 1,932,769	$(882,444)	$(19,592)
31		State Income Tax		2,873,416	134,675	(61,489)	(1,365)
32		South Georgia	1.1	29,686	108	396	1
33		State Income Tax		2,903,102	134,783	(61,092)	(1,364)
		Federal Income Tax					
34		Taxable Income before Interest Exp.		89,272,317	2,107,561	(240,955)	(18,263)
35		Interest Expense	1.1	(48,035,008)	(174,792)	(641,489)	(1,329)
36		Federal Taxable Income		41,237,309	1,932,769	(882,444)	(19,592)
37		Federal Income Tax		$ 13,427,363	$ 629,333	$(287,334)	$(6,379)
38		I T C	1.1	(528,360)	(1,923)	(7,056)	(15)
39		South Georgia	1.1	290,114	1,056	3,874	8
40		Total Federal Income Tax		$ 13,189,117	$ 628,466	$(290,516)	$(6,386)
41		Regulatory Amortization	1.1	-	-	-	-
42		Net Income		$ 73,180,099	$ 1,344,312	$ 110,653	$(10,513)
43		Rate of Return on Rate Base		6.68%	31.59%	0.78%	(33.19%)
44		Rate of Return by Class Total				7.80%	

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Medium General Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(d)	(e)	(f)
		Direct Depreciation Expense					
1	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 75,910,024	$ 1,506,527	$ 2,633,236	$ 19,043
5	389-398	General	1.1	$ 4,919,293	$ 97,629	$ 170,645	$ 1,234
6		Total Direct Dep. Exp.		$ 80,829,317	$ 1,604,157	$ 2,803,881	$ 20,277
		Systems Allocable Depreciation Expense					
7	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
8	389-398	General	1.1	$ 2,540,252	$ 50,414	$ 88,119	$ 637
		System Allocable Amortization					
9		Miscellaneous Intangible	1.1	4,002,161	79,428	138,831	1,004
10		Structures-Leasehold Improvements	1.1	104,525	2,074	3,626	26
11		Total System Allocable Amortization		4,106,686	81,502	142,456	1,030
12		Total System Alloc Dep. Exp. & Amortization		6,646,938	131,917	230,575	1,667
13		Total Depreciation Expense		87,476,255	1,736,073	3,034,456	21,944
14		Amortization	1.1	126,930	2,519	4,403	32
15		Amortization-Gas Plant Acquisition	1.1	(52,996)	(1,052)	(1,838)	(13)
16		Regulatory Amortizations	1.1	337,524	6,699	11,708	85
17		-	7.0	-	-	-	-
18		-	1.1	-	-	-	-
19		-	1.1	-	-	-	-
20		Total Depreciation & Amortization Expense		$ 87,887,713	$ 1,744,239	$ 3,048,729	$ 22,047
		Operation and Maintenance Expense					
		Gas Supply Expense					
21	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -
22	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-
23	805	Purchased Gas Cost Adj.	3.0	-	-	-	-
24	810	Gas Used for Compressor Sta. Fuel--	3.0	-	-	-	-
25	813	Other Gas Supply Expense	3.0	-	-	-	-
26		Labor & Labor Loading	3.0	641,618	-	-	44,820
27		Materials & Expenses	3.0	59,983	-	-	4,190
28		Total Gas Supply Expense		$ 701,601	$ -	$ -	$ 49,010

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Medium General Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(d)	(e)	(f)
		Distribution Expenses					
1	870	Operation Supervision & Eng.					
2		Labor & Labor Loading	5.5	$ 8,990,906	$ 101,514	$ 406,229	$ 7,221
3		Materials & Expenses	5.5	1,458,368	16,466	65,892	1,171
4	871	Distribution Load Dispatching					
5		Labor & Labor Loading	3.0	258,538	-	-	18,060
6		Materials & Expenses	3.0	113,250	-	-	7,911
7	874	Mains & Svcs. Expense					
8		Labor & Labor Loading	4.4	6,159,141	144,525	186,210	0
9		Materials & Expenses	4.4	5,540,228	130,002	167,499	0
10	875	Meas. & Reg. Sta. Exp.-Gen.					
11		Labor & Labor Loading	2.2	1,859,618	65,896	13,703	0
12		Materials & Expenses	2.2	697,287	24,708	5,138	0
13	878	Meter & House Reg. Exp.					
14		Labor & Labor Loading	6.0	6,919,581	-	425,310	-
15		Materials & Expenses	6.0	1,213,237	-	74,571	-
16	879	Customer Installation Exp.					
17		Labor & Labor Loading	6.0	8,087,437	-	497,092	-
18		Materials & Expenses	6.0	1,490,584	-	91,618	-
19	880	Other Expenses					
20		Labor & Labor Loading	5.5	6,543,834	73,885	295,665	5,255
21		Materials & Expenses	5.5	4,535,239	51,206	204,912	3,642
22	881	Rents	5.5	2,250,258	25,407	101,672	1,807
23		Total Distribution-Operations		$ 56,117,507	$ 633,610	$ 2,535,511	$ 45,068
		Operation and Maintenance Expense					
		Distribution Expenses					
24	885	Maint. Supervision & Eng.					
25		Labor & Labor Loading	6.6	$ 2,797,818	$ 58,965	$ 95,189	$ 0
26		Materials & Expenses	6.6	338,062	7,125	11,502	0
27	886	Maint. of Structures & Imp.					
28		Labor & Labor Loading	1.0	26,673	1,681	-	-
29		Materials & Expenses	1.0	80,753	5,088	-	-
30	887	Maint. of Mains					
31		Labor & Labor Loading	2.2	8,500,012	301,199	62,635	0
32		Materials & Expenses	2.2	7,043,715	249,595	51,904	0
33	889	Maint. of Meas. & Reg. Sta-Gen					
34		Labor & Labor Loading	2.2	1,461,314	51,782	10,768	0
35		Materials & Expenses	2.2	580,480	20,569	4,277	0
36	892	Maint. of Services					
37		Labor & Labor Loading	3.3	6,159,505	0	462,297	-
38		Materials & Expenses	3.3	3,973,153	0	298,202	-
39	893	Maint of Meter & House Reg.					
40		Labor & Labor Loading	6.0	1,281,534	-	78,769	-
41		Materials & Expenses	6.0	781,684	-	48,046	-
42	894	Maint of Other Equip.					
43		Labor & Labor Loading	6.6	196,535	4,142	6,687	0
44		Materials & Expenses	6.6	189,711	3,998	6,454	0
45		Total Distribution-Maintenance		$ 33,410,949	$ 704,145	$ 1,136,731	$ 0
46		Total Distribution O & M		$ 89,528,455	$ 1,337,754	$ 3,672,242	$ 45,068

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Medium General Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(d)	(e)	(f)
		Customer Accounts Expenses					
1	901	Supervision					
2		Labor & Labor Loading	10.1	$ 4,093,979	$ -	$ 219,913	$ -
3		Materials & Expenses	10.1	275,497	-	14,799	-
4	902	Meter Reading Exp.					
5		Labor & Labor Loading	13.0	4,860,483	-	278,326	-
6		Materials & Expenses	13.0	2,194,002	-	125,635	-
7	903	Customer Records & Collections					
8		Labor & Labor Loading	13.0	-	-	-	-
9		Materials & Expenses	13.0	404,465	-	23,161	-
10	903	Customer Records & Collections - LCS					
11		Labor & Labor Loading - LCS	13.0	16,062,467	-	919,784	-
12		Materials & Expenses - LCS	13.0	7,441,028	-	426,095	-
13	904	Uncollectible Accounts Exp.	4.0	2,977,729	-	50,139	-
14	905	Misc. Customer Accounts Exp.					
15		Labor & Labor Loading	10.1	404,465	-	21,726	-
16		Materials & Expenses	10.1	16,795	-	902	-
17		Total Customer Accounts Expenses		$ 38,730,909	$ -	$ 2,080,480	$ -
		Customer Service & Info. Exp.					
18	908	Customer Assistance Exp.					
19		Labor & Labor Loading	13.0	$ 514,896	$ -	$ 29,484	$ -
20		Materials & Expenses	13.0	564,797	-	32,342	-
21	909	Info. & Instructional Exp.					
22		Labor & Labor Loading	13.0	-	-	-	-
23		Materials & Expenses	13.0	25,125	-	1,439	-
24	910	Misc. C.S. & I. Expense					
25		Labor & Labor Loading	13.0	-	-	-	-
26		Materials & Expenses	13.0	21,977	-	1,258	-
27		Total Customer Service & Info. Exp.		$ 1,126,796	$ -	$ 64,524	$ -
		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		$ 130,087,761	$ 1,337,754	$ 5,817,246	$ 94,078
39		Allocation Percentage	Total O&M	100.00%	1.03%	4.47%	0.07%
		Other Operating Deductions					
40		Administrative & General Expense	Total O&M	56,946,694	585,610	2,546,534	41,183
41		Interest on Customer Deposits	8.0	1,915,314	-	32,542	-
42		Taxes Other Than Income	1.1	33,124,880	657,404	1,149,066	8,310
43		Total Allocated Operating Deductions		$ 222,074,648	$ 2,580,768	$ 9,545,388	$ 143,571
		Tax Adjustments					
44		Interest Expense	1.1	48,035,008	953,313	1,666,282	12,050
45		State South Georgia	1.1	29,686	589	1,030	7
46		Investment Tax Credit	1.1	(528,360)	(10,486)	(18,328)	(133)
47		Federal South Georgia	1.1	290,114	5,758	10,064	73

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Medium General Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(d)	(e)	(f)
		Summary of Allocated Cost of Service					
		Rate Base					
1		Direct Net Plant		$ 1,267,124,121	$25,147,627	$ 43,955,154	$ 317,867
2		Systems Allocable Net Plant		34,448,206	683,667	1,194,971	8,642
3		Cash Working Capital	1.1	(10,379,937)	(106,742)	(464,169)	(7,507)
4		Materials & Supplies	1.1	12,389,898	245,893	429,792	3,108
5		Prepayments	1.1	3,671,971	72,875	127,377	921
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
7		Customer Deposits	8.0	(31,921,898)	-	(542,371)	-
8		Customer Advances	8.0	(37,910,017)	-	(644,112)	-
9		Deferred Taxes	1.1	(142,632,297)	(2,830,712)	(4,947,759)	(35,780)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-
11		Total Rate Base		$ 1,094,790,047	$23,212,607	$ 39,108,882	$ 287,251
12		Net Operating Margin	Direct	$ 381,188,845	$17,915,706	$ 6,395,070	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 5,784,028	$ 271,847	$ 97,037	$ -
14		Late Charges	Direct	$ 2,430,203	$ 199,266	$ 71,129	
15		Service Establishment Charges	9	$ 8,267,657	-	231,455	-
16		Reconnect / Reread Charges	4	$ 569,215	-	9,585	-
17		Other Revenue - Labor	Net Op. Marg.	$ 1,313	$ 62	$ 22	$ -
18		Other Revenue - Parts & Material	Net Op. Marg.	$ 2,621	$ 123	$ 44	$ -
19		Other Revenue - Field Collection Fee	4	$ 304,887	-	5,134	-
20		Other Revenue - Returned Item Fee	4	$ 173,412	-	2,920	-
21		Other Revenue - Rental Income	Net Op. Marg.	$ 512,498	$ 24,087	$ 8,598	$ -
22		Total Revenue		399,234,678	18,411,091	6,820,992	-
23		O & M		(130,087,761)	(1,337,754)	(5,817,246)	(94,078)
24		A & G	Total O&M	(56,946,694)	(585,610)	(2,546,534)	(41,183)
25		Depreciation Expense		(87,887,713)	(1,744,239)	(3,048,729)	(22,047)
26		Interest on Customer Deposits	8.0	(1,915,314)	-	(32,542)	-
27		Taxes other than Income	1.1	(33,124,880)	(657,404)	(1,149,066)	(8,310)
		State Income Tax					
28		Taxable Income before Interest Exp.		$ 89,272,317	$14,086,083	$(5,773,124)	$(165,618)
29		Interest Expense	1.1	(48,035,008)	(953,313)	(1,666,282)	(12,050)
30		State Taxable Income		$ 41,237,309	$13,132,770	$(7,439,407)	$(177,668)
31		State Income Tax		2,873,416	915,091	(518,378)	(12,380)
32		South Georgia	1.1	29,686	589	1,030	7
33		State Income Tax		2,903,102	915,681	(517,348)	(12,372)
		Federal Income Tax					
34		Taxable Income before Interest Exp.		89,272,317	14,086,083	(5,773,124)	(165,618)
35		Interest Expense	1.1	(48,035,008)	(953,313)	(1,666,282)	(12,050)
36		Federal Taxable Income		41,237,309	13,132,770	(7,439,407)	(177,668)
37		Federal Income Tax		$ 13,427,363	$ 4,276,187	$(2,422,360)	$(57,851)
38		I T C	1.1	(528,360)	(10,486)	(18,328)	(133)
39		South Georgia	1.1	290,114	5,758	10,064	73
40		Total Federal Income Tax		$ 13,189,117	$ 4,271,459	$(2,430,625)	$(57,911)
41		Regulatory Amortization	1.1	-	-	-	-
42		Net Income		$ 73,180,099	$ 8,898,944	$(2,825,152)	$(95,335)
43		Rate of Return on Rate Base		6.68%	38.34%	(7.22%)	(33.19%)
44		Rate of Return by Class Total				9.55%	

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Large General Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(g)	(h)	(i)
		Direct Depreciation Expense					
1	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 75,910,024	$ 4,115,293	$ 2,198,169	$ 62,411
5	389-398	General	1.1	$ 4,919,293	$ 266,689	$ 142,451	$ 4,044
6		Total Direct Dep. Exp.		$ 80,829,317	$ 4,381,982	$ 2,340,620	$ 66,456
		Systems Allocable Depreciation Expense					
7	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
8	389-398	General	1.1	$ 2,540,252	$ 137,714	$ 73,560	$ 2,089
		System Allocable Amortization					
9		Miscellaneous Intangible	1.1	4,002,161	216,968	115,893	3,290
10		Structures-Leasehold Improvements	1.1	104,525	5,667	3,027	86
11		Total System Allocable Amortization		4,106,686	222,635	118,920	3,376
12		Total System Alloc Dep. Exp. & Amortization		6,646,938	360,349	192,479	5,465
13		Total Depreciation Expense		87,476,255	4,742,331	2,533,099	71,920
14		Amortization	1.1	126,930	6,881	3,676	104
15		Amortization-Gas Plant Acquisition	1.1	(52,996)	(2,873)	(1,535)	(44)
16		Regulatory Amortizations	1.1	337,524	18,298	9,774	278
17		-	7.0	-	-	-	-
18		-	1.1	-	-	-	-
19		-	1.1	-	-	-	-
20		Total Depreciation & Amortization Expense		$ 87,887,713	$ 4,764,637	$ 2,545,014	$ 72,259
		Operation and Maintenance Expense					
		Gas Supply Expense					
21	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -
22	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-
23	805	Purchased Gas Cost Adj.	3.0	-	-	-	-
24	810	Gas Used for Compressor Sta. Fuel--	3.0	-	-	-	-
25	813	Other Gas Supply Expense	3.0	-	-	-	-
26		Labor & Labor Loading	3.0	641,618	-	-	146,895
27		Materials & Expenses	3.0	59,983	-	-	13,733
28		Total Gas Supply Expense		$ 701,601	$ -	$ -	$ 160,628

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Large General Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(g)	(h)	(i)
		Distribution Expenses					
1	870	Operation Supervision & Eng.					
2		Labor & Labor Loading	5.5	$ 8,990,906	$ 277,301	$ 420,875	$ 23,665
3		Materials & Expenses	5.5	1,458,368	44,979	68,268	3,839
4	871	Distribution Load Dispatching					
5		Labor & Labor Loading	3.0	258,538	-	-	59,191
6		Materials & Expenses	3.0	113,250	-	-	25,928
7	874	Mains & Svcs. Expense					
8		Labor & Labor Loading	4.4	6,159,141	394,790	131,028	0
9		Materials & Expenses	4.4	5,540,228	355,119	117,861	0
10	875	Meas. & Reg. Sta. Exp.-Gen.					
11		Labor & Labor Loading	2.2	1,859,618	180,004	6,047	0
12		Materials & Expenses	2.2	697,287	67,495	2,267	0
13	878	Meter & House Reg. Exp.					
14		Labor & Labor Loading	6.0	6,919,581	-	490,958	-
15		Materials & Expenses	6.0	1,213,237	-	86,082	-
16	879	Customer Installation Exp.					
17		Labor & Labor Loading	6.0	8,087,437	-	573,820	-
18		Materials & Expenses	6.0	1,490,584	-	105,760	-
19	880	Other Expenses					
20		Labor & Labor Loading	5.5	6,543,834	201,827	306,325	17,224
21		Materials & Expenses	5.5	4,535,239	139,877	212,300	11,937
22	881	Rents	5.5	2,250,258	69,403	105,337	5,923
23		Total Distribution-Operations		$ 56,117,507	$ 1,730,795	$ 2,626,928	$ 147,706
		Operation and Maintenance Expense					
		Distribution Expenses					
24	885	Maint. Supervision & Eng.					
25		Labor & Labor Loading	6.6	$ 2,797,818	$ 161,071	$ 72,743	$ 0
26		Materials & Expenses	6.6	338,062	19,462	8,790	0
27	886	Maint. of Structures & Imp.					
28		Labor & Labor Loading	1.0	26,673	4,591	-	-
29		Materials & Expenses	1.0	80,753	13,899	-	-
30	887	Maint. of Mains					
31		Labor & Labor Loading	2.2	8,500,012	822,769	27,638	0
32		Materials & Expenses	2.2	7,043,715	681,805	22,903	0
33	889	Maint. of Meas. & Reg. Sta-Gen					
34		Labor & Labor Loading	2.2	1,461,314	141,450	4,751	0
35		Materials & Expenses	2.2	580,480	56,188	1,887	0
36	892	Maint. of Services					
37		Labor & Labor Loading	3.3	6,159,505	0	348,645	-
38		Materials & Expenses	3.3	3,973,153	0	224,892	-
39	893	Maint of Meter & House Reg.					
40		Labor & Labor Loading	6.0	1,281,534	-	90,927	-
41		Materials & Expenses	6.0	781,684	-	55,462	-
42	894	Maint of Other Equip.					
43		Labor & Labor Loading	6.6	196,535	11,315	5,110	0
44		Materials & Expenses	6.6	189,711	10,922	4,932	0
45		Total Distribution-Maintenance		$ 33,410,949	$ 1,923,472	$ 868,681	$ 0
46		Total Distribution O & M		$ 89,528,455	$ 3,654,266	$ 3,495,609	$ 147,706

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Large General Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(g)	(h)	(i)
		Customer Accounts Expenses					
1	901	Supervision					
2		Labor & Labor Loading	10.1	$ 4,093,979	$ -	$ 117,537	$ -
3		Materials & Expenses	10.1	275,497	-	7,909	-
4	902	Meter Reading Exp.					
5		Labor & Labor Loading	13.0	4,860,483	-	149,490	-
6		Materials & Expenses	13.0	2,194,002	-	67,479	-
7	903	Customer Records & Collections					
8		Labor & Labor Loading	13.0	-	-	-	-
9		Materials & Expenses	13.0	404,465	-	12,440	-
10	903	Customer Records & Collections - LCS					
11		Labor & Labor Loading - LCS	13.0	16,062,467	-	494,019	-
12		Materials & Expenses - LCS	13.0	7,441,028	-	228,857	-
13	904	Uncollectible Accounts Exp.	4.0	2,977,729	-	22,124	-
14	905	Misc. Customer Accounts Exp.					
15		Labor & Labor Loading	10.1	404,465	-	11,612	-
16		Materials & Expenses	10.1	16,795	-	482	-
17		Total Customer Accounts Expenses		$ 38,730,909	$ -	$ 1,111,949	$ -
		Customer Service & Info. Exp.					
18	908	Customer Assistance Exp.					
19		Labor & Labor Loading	13.0	$ 514,896	$ -	$ 15,836	$ -
20		Materials & Expenses	13.0	564,797	-	17,371	-
21	909	Info. & Instructional Exp.					
22		Labor & Labor Loading	13.0	-	-	-	-
23		Materials & Expenses	13.0	25,125	-	773	-
24	910	Misc. C.S. & I. Expense					
25		Labor & Labor Loading	13.0	-	-	-	-
26		Materials & Expenses	13.0	21,977	-	676	-
27		Total Customer Service & Info. Exp.		$ 1,126,796	$ -	$ 34,656	$ -
		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		$ 130,087,761	$ 3,654,266	$ 4,642,214	$ 308,335
39		Allocation Percentage	Total O&M	100.00%	2.81%	3.57%	0.24%
		Other Operating Deductions					
40		Administrative & General Expense	Total O&M	56,946,694	1,599,677	2,032,157	134,975
41		Interest on Customer Deposits	8.0	1,915,314	-	-	-
42		Taxes Other Than Income	1.1	33,124,880	1,795,792	959,216	27,234
43		Total Allocated Operating Deductions		$ 222,074,648	$ 7,049,735	$ 7,633,587	$ 470,544
		Tax Adjustments					
44		Interest Expense	1.1	48,035,008	2,604,111	1,390,977	39,493
45		State South Georgia	1.1	29,686	1,609	860	24
46		Investment Tax Credit	1.1	(528,360)	(28,644)	(15,300)	(434)
47		Federal South Georgia	1.1	290,114	15,728	8,401	239

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Large General Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(g)	(h)	(i)
		Summary of Allocated Cost of Service					
		Rate Base					
1		Direct Net Plant		$ 1,267,124,121	$ 68,694,320	$ 36,692,829	$ 1,041,792
2		Systems Allocable Net Plant		34,448,206	1,867,533	997,536	28,322
3		Cash Working Capital	1.1	(10,379,937)	(291,581)	(370,411)	(24,603)
4		Materials & Supplies	1.1	12,389,898	671,691	358,781	10,187
5		Prepayments	1.1	3,671,971	199,068	106,331	3,019
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
7		Customer Deposits	8.0	(31,921,898)	-	-	-
8		Customer Advances	8.0	(37,910,017)	-	-	-
9		Deferred Taxes	1.1	(142,632,297)	(7,732,493)	(4,130,284)	(117,268)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-
11		Total Rate Base		$ 1,094,790,047	$ 63,408,538	$ 33,654,783	$ 941,450
12		Net Operating Margin	Direct	$ 381,188,845	$ 40,605,031	$ 12,398,950	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 5,784,028	$ 616,127	$ 188,137	$ -
14		Late Charges	Direct	$ 2,430,203	$ 37,460	$ 11,439	
15		Service Establishment Charges	9	$ 8,267,657	-	102,130	-
16		Reconnect / Reread Charges	4	$ 569,215	-	4,229	-
17		Other Revenue - Labor	Net Op. Marg.	$ 1,313	$ 140	$ 43	$ -
18		Other Revenue - Parts & Material	Net Op. Marg.	$ 2,621	$ 279	$ 85	$ -
19		Other Revenue - Field Collection Fee	4	$ 304,887	-	2,265	-
20		Other Revenue - Returned Item Fee	4	$ 173,412	-	1,288	-
21		Other Revenue - Rental Income	Net Op. Marg.	$ 512,498	$ 54,592	$ 16,670	$ -
22		Total Revenue		399,234,678	41,313,629	12,725,236	-
23		O & M		(130,087,761)	(3,654,266)	(4,642,214)	(308,335)
24		A & G	Total O&M	(56,946,694)	(1,599,677)	(2,032,157)	(134,975)
25		Depreciation Expense		(87,887,713)	(4,764,637)	(2,545,014)	(72,259)
26		Interest on Customer Deposits	8.0	(1,915,314)	-	-	-
27		Taxes other than Income	1.1	(33,124,880)	(1,795,792)	(959,216)	(27,234)
		State Income Tax					
28		Taxable Income before Interest Exp.		$ 89,272,317	$ 29,499,257	$ 2,546,636	$(542,803)
29		Interest Expense	1.1	(48,035,008)	(2,604,111)	(1,390,977)	(39,493)
30		State Taxable Income		$ 41,237,309	$ 26,895,145	$ 1,155,659	$(582,296)
31		State Income Tax		2,873,416	1,874,054	80,526	(40,574)
32		South Georgia	1.1	29,686	1,609	860	24
33		State Income Tax		2,903,102	1,875,663	81,386	(40,550)
		Federal Income Tax					
34		Taxable Income before Interest Exp.		89,272,317	29,499,257	2,546,636	(542,803)
35		Interest Expense	1.1	(48,035,008)	(2,604,111)	(1,390,977)	(39,493)
36		Federal Taxable Income		41,237,309	26,895,145	1,155,659	(582,296)
37		Federal Income Tax		$ 13,427,363	$ 8,757,382	$ 376,296	$(189,603)
38		I T C	1.1	(528,360)	(28,644)	(15,300)	(434)
39		South Georgia	1.1	290,114	15,728	8,401	239
40		Total Federal Income Tax		$ 13,189,117	$ 8,744,466	$ 369,397	$(189,798)
41		Regulatory Amortization	1.1	-	-	-	-
42		Net Income		$ 73,180,099	$ 18,879,127	$ 2,095,852	$(312,455)
43		Rate of Return on Rate Base		6.68%	29.77%	6.23%	(33.19%)
44		Rate of Return by Class Total				21.08%	

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Transportation Eligible Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(j)	(k)	(l)
		Direct Depreciation Expense					
1	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 75,910,024	$ 2,828,709	$ 267,012	$ 41,626
5	389-398	General	1.1	$ 4,919,293	$ 183,312	$ 17,304	$ 2,698
6		Total Direct Dep. Exp.		$ 80,829,317	$ 3,012,021	$ 284,316	$ 44,323
		Systems Allocable Depreciation Expense					
7	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
8	389-398	General	1.1	$ 2,540,252	$ 94,660	$ 8,935	$ 1,393
		System Allocable Amortization					
9		Miscellaneous Intangible	1.1	4,002,161	149,136	14,078	2,195
10		Structures-Leasehold Improvements	1.1	104,525	3,895	368	57
11		Total System Allocable Amortization		4,106,686	153,031	14,445	2,252
12		Total System Alloc Dep. Exp. & Amortization		6,646,938	247,691	23,381	3,645
13		Total Depreciation Expense		87,476,255	3,259,712	307,697	47,968
14		Amortization	1.1	126,930	4,730	446	70
15		Amortization-Gas Plant Acquisition	1.1	(52,996)	(1,975)	(186)	(29)
16		Regulatory Amortizations	1.1	337,524	12,577	1,187	185
17		-	7.0	-	-	-	-
18		-	1.1	-	-	-	-
19		-	1.1	-	-	-	-
20		Total Depreciation & Amortization Expense		$ 87,887,713	$ 3,275,045	$ 309,144	$ 48,194
		Operation and Maintenance Expense					
		Gas Supply Expense					
21	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -
22	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-
23	805	Purchased Gas Cost Adj.	3.0	-	-	-	-
24	810	Gas Used for Compressor Sta. Fuel--	3.0	-	-	-	-
25	813	Other Gas Supply Expense	3.0	-	-	-	-
26		Labor & Labor Loading	3.0	641,618	-	-	97,974
27		Materials & Expenses	3.0	59,983	-	-	9,159
28		Total Gas Supply Expense		$ 701,601	$ -	$ -	$ 107,133

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Transportation Eligible Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(j)	(k)	(l)
		Distribution Expenses					
1	870	Operation Supervision & Eng.					
2		Labor & Labor Loading	5.5	$ 8,990,906	$ 190,607	$ 79,387	$ 15,784
3		Materials & Expenses	5.5	1,458,368	30,917	12,877	2,560
4	871	Distribution Load Dispatching					
5		Labor & Labor Loading	3.0	258,538	-	-	39,478
6		Materials & Expenses	3.0	113,250	-	-	17,293
7	874	Mains & Svcs. Expense					
8		Labor & Labor Loading	4.4	6,159,141	271,365	7,469	0
9		Materials & Expenses	4.4	5,540,228	244,096	6,719	0
10	875	Meas. & Reg. Sta. Exp.-Gen.					
11		Labor & Labor Loading	2.2	1,859,618	123,728	157	0
12		Materials & Expenses	2.2	697,287	46,394	59	0
13	878	Meter & House Reg. Exp.					
14		Labor & Labor Loading	6.0	6,919,581	-	105,934	-
15		Materials & Expenses	6.0	1,213,237	-	18,574	-
16	879	Customer Installation Exp.					
17		Labor & Labor Loading	6.0	8,087,437	-	123,813	-
18		Materials & Expenses	6.0	1,490,584	-	22,820	-
19	880	Other Expenses					
20		Labor & Labor Loading	5.5	6,543,834	138,729	57,780	11,488
21		Materials & Expenses	5.5	4,535,239	96,147	40,045	7,962
22	881	Rents	5.5	2,250,258	47,705	19,869	3,950
23		Total Distribution-Operations		$ 56,117,507	$ 1,189,688	$ 495,503	$ 98,515
		Operation and Maintenance Expense					
		Distribution Expenses					
24	885	Maint. Supervision & Eng.					
25		Labor & Labor Loading	6.6	$ 2,797,818	$ 110,714	$ 6,344	$ 0
26		Materials & Expenses	6.6	338,062	13,378	767	0
27	886	Maint. of Structures & Imp.					
28		Labor & Labor Loading	1.0	26,673	3,156	-	-
29		Materials & Expenses	1.0	80,753	9,554	-	-
30	887	Maint. of Mains					
31		Labor & Labor Loading	2.2	8,500,012	565,543	718	0
32		Materials & Expenses	2.2	7,043,715	468,649	595	0
33	889	Maint. of Meas. & Reg. Sta-Gen					
34		Labor & Labor Loading	2.2	1,461,314	97,228	123	0
35		Materials & Expenses	2.2	580,480	38,622	49	0
36	892	Maint. of Services					
37		Labor & Labor Loading	3.3	6,159,505	0	21,092	-
38		Materials & Expenses	3.3	3,973,153	0	13,605	-
39	893	Maint of Meter & House Reg.					
40		Labor & Labor Loading	6.0	1,281,534	-	19,619	-
41		Materials & Expenses	6.0	781,684	-	11,967	-
42	894	Maint of Other Equip.					
43		Labor & Labor Loading	6.6	196,535	7,777	446	0
44		Materials & Expenses	6.6	189,711	7,507	430	0
45		Total Distribution-Maintenance		$ 33,410,949	$ 1,322,127	$ 75,756	$ 0
46		Total Distribution O & M		$ 89,528,455	$ 2,511,815	$ 571,259	$ 98,515

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Transportation Eligible Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(j)	(k)	(l)
		Customer Accounts Expenses					
1	901	Supervision					
2		Labor & Labor Loading	10.1	$ 4,093,979	$ -	$ 5,106	$ -
3		Materials & Expenses	10.1	275,497	-	344	-
4	902	Meter Reading Exp.					
5		Labor & Labor Loading	13.0	4,860,483	-	6,555	-
6		Materials & Expenses	13.0	2,194,002	-	2,959	-
7	903	Customer Records & Collections					
8		Labor & Labor Loading	13.0	-	-	-	-
9		Materials & Expenses	13.0	404,465	-	545	-
10	903	Customer Records & Collections - LCS					
11		Labor & Labor Loading - LCS	13.0	16,062,467	-	21,661	-
12		Materials & Expenses - LCS	13.0	7,441,028	-	10,035	-
13	904	Uncollectible Accounts Exp.	4.0	2,977,729	-	575	-
14	905	Misc. Customer Accounts Exp.					
15		Labor & Labor Loading	10.1	404,465	-	504	-
16		Materials & Expenses	10.1	16,795	-	21	-
17		Total Customer Accounts Expenses		$ 38,730,909	$ -	$ 48,304	$ -
		Customer Service & Info. Exp.					
18	908	Customer Assistance Exp.					
19		Labor & Labor Loading	13.0	$ 514,896	$ -	$ 694	$ -
20		Materials & Expenses	13.0	564,797	-	762	-
21	909	Info. & Instructional Exp.					
22		Labor & Labor Loading	13.0	-	-	-	-
23		Materials & Expenses	13.0	25,125	-	34	-
24	910	Misc. C.S. & I. Expense					
25		Labor & Labor Loading	13.0	-	-	-	-
26		Materials & Expenses	13.0	21,977	-	30	-
27		Total Customer Service & Info. Exp.		$ 1,126,796	$ -	$ 1,520	$ -
		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		$ 130,087,761	$ 2,511,815	$ 621,082	$ 205,648
39		Allocation Percentage	Total O&M	100.00%	1.93%	0.48%	0.16%
		Other Operating Deductions					
40		Administrative & General Expense	Total O&M	56,946,694	1,099,562	271,882	90,024
41		Interest on Customer Deposits	8.0	1,915,314	-	-	-
42		Taxes Other Than Income	1.1	33,124,880	1,234,364	116,516	18,164
43		Total Allocated Operating Deductions		$ 222,074,648	$ 4,845,741	$ 1,009,481	$ 313,836
		Tax Adjustments					
44		Interest Expense	1.1	48,035,008	1,789,975	168,962	26,340
45		State South Georgia	1.1	29,686	1,106	104	16
46		Investment Tax Credit	1.1	(528,360)	(19,689)	(1,858)	(290)
47		Federal South Georgia	1.1	290,114	10,811	1,020	159

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Transportation Eligible Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(j)	(k)	(l)
		Summary of Allocated Cost of Service					
		Rate Base					
1		Direct Net Plant		$ 1,267,124,121	$ 47,218,073	$ 4,457,092	$ 694,839
2		Systems Allocable Net Plant		34,448,206	1,283,677	121,171	18,890
3		Cash Working Capital	1.1	(10,379,937)	(200,422)	(49,557)	(16,409)
4		Materials & Supplies	1.1	12,389,898	461,697	43,581	6,794
5		Prepayments	1.1	3,671,971	136,832	12,916	2,014
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
7		Customer Deposits	8.0	(31,921,898)	-	-	-
8		Customer Advances	8.0	(37,910,017)	-	-	-
9		Deferred Taxes	1.1	(142,632,297)	(5,315,045)	(501,707)	(78,214)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-
11		Total Rate Base		$ 1,094,790,047	$ 43,584,811	$ 4,083,496	$ 627,914
12		Net Operating Margin	Direct	$ 381,188,845	$ 18,488,799	$ 1,599,840	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 5,784,028	$ 280,543	$ 24,275	$ -
14		Late Charges	Direct	$ 2,430,203	$ 17,057	$ 1,476	
15		Service Establishment Charges	9	$ 8,267,657	-	2,654	-
16		Reconnect / Reread Charges	4	$ 569,215	-	110	-
17		Other Revenue - Labor	Net Op. Marg.	$ 1,313	$ 64	$ 6	$ -
18		Other Revenue - Parts & Material	Net Op. Marg.	$ 2,621	$ 127	$ 11	$ -
19		Other Revenue - Field Collection Fee	4	$ 304,887	-	59	-
20		Other Revenue - Returned Item Fee	4	$ 173,412	-	33	-
21		Other Revenue - Rental Income	Net Op. Marg.	$ 512,498	$ 24,858	$ 2,151	$ -
22		Total Revenue		399,234,678	18,811,447	1,630,615	-
23		O & M		(130,087,761)	(2,511,815)	(621,082)	(205,648)
24		A & G	Total O&M	(56,946,694)	(1,099,562)	(271,882)	(90,024)
25		Depreciation Expense		(87,887,713)	(3,275,045)	(309,144)	(48,194)
26		Interest on Customer Deposits	8.0	(1,915,314)	-	-	-
27		Taxes other than Income	1.1	(33,124,880)	(1,234,364)	(116,516)	(18,164)
		State Income Tax					
28		Taxable Income before Interest Exp.		$ 89,272,317	$ 10,690,661	$ 311,990	$(362,030)
29		Interest Expense	1.1	(48,035,008)	(1,789,975)	(168,962)	(26,340)
30		State Taxable Income		$ 41,237,309	$ 8,900,686	$ 143,028	$(388,371)
31		State Income Tax		2,873,416	620,200	9,966	(27,062)
32		South Georgia	1.1	29,686	1,106	104	16
33		State Income Tax		2,903,102	621,306	10,071	(27,045)
		Federal Income Tax					
34		Taxable Income before Interest Exp.		89,272,317	10,690,661	311,990	(362,030)
35		Interest Expense	1.1	(48,035,008)	(1,789,975)	(168,962)	(26,340)
36		Federal Taxable Income		41,237,309	8,900,686	143,028	(388,371)
37		Federal Income Tax		$ 13,427,363	$ 2,898,170	$ 46,571	$(126,458)
38		I T C	1.1	(528,360)	(19,689)	(1,858)	(290)
39		South Georgia	1.1	290,114	10,811	1,020	159
40		Total Federal Income Tax		$ 13,189,117	$ 2,889,292	$ 45,733	$(126,589)
41		Regulatory Amortization	1.1	-	-	-	-
42		Net Income		$ 73,180,099	$ 7,180,063	$ 256,186	$(208,396)
43		Rate of Return on Rate Base		6.68%	16.47%	6.27%	(33.19%)
44		Rate of Return by Class Total				14.97%	

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Air-Conditioning Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(d)	(e)	(f)
		Direct Depreciation Expense					
1	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 75,910,024	$ 10,158	$ 1,766	$ 468
5	389-398	General	1.1	$ 4,919,293	$ 658	$ 114	$ 30
6		Total Direct Dep. Exp.		$ 80,829,317	$ 10,817	$ 1,880	$ 498
		Systems Allocable Depreciation Expense					
7	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
8	389-398	General	1.1	$ 2,540,252	$ 340	$ 59	$ 16
		System Allocable Amortization					
9		Miscellaneous Intangible	1.1	4,002,161	536	93	25
10		Structures-Leasehold Improvements	1.1	104,525	14	2	1
11		Total System Allocable Amortization		4,106,686	550	96	25
12		Total System Alloc Dep. Exp. & Amortization		6,646,938	889	155	41
13		Total Depreciation Expense		87,476,255	11,706	2,035	539
14		Amortization	1.1	126,930	17	3	1
15		Amortization-Gas Plant Acquisition	1.1	(52,996)	(7)	(1)	(0)
16		Regulatory Amortizations	1.1	337,524	45	8	2
17		-	7.0	-	-	-	-
18		-	1.1	-	-	-	-
19		-	1.1	-	-	-	-
20		Total Depreciation & Amortization Expense		$ 87,887,713	$ 11,761	$ 2,045	$ 541
		Operation and Maintenance Expense					
		Gas Supply Expense					
21	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -
22	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-
23	805	Purchased Gas Cost Adj.	3.0	-	-	-	-
24	810	Gas Used for Compressor Sta. Fuel--	3.0	-	-	-	-
25	813	Other Gas Supply Expense	3.0	-	-	-	-
26		Labor & Labor Loading	3.0	641,618	-	-	1,101
27		Materials & Expenses	3.0	59,983	-	-	103
28		Total Gas Supply Expense		$ 701,601	$ -	$ -	$ 1,204

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Air-Conditioning Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(d)	(e)	(f)
		Distribution Expenses					
1	870	Operation Supervision & Eng.					
2		Labor & Labor Loading	5.5	$ 8,990,906	$ 684	$ 286	$ 177
3		Materials & Expenses	5.5	1,458,368	111	46	29
4	871	Distribution Load Dispatching					
5		Labor & Labor Loading	3.0	258,538	-	-	444
6		Materials & Expenses	3.0	113,250	-	-	194
7	874	Mains & Svcs. Expense					
8		Labor & Labor Loading	4.4	6,159,141	975	121	0
9		Materials & Expenses	4.4	5,540,228	877	109	0
10	875	Meas. & Reg. Sta. Exp.-Gen.					
11		Labor & Labor Loading	2.2	1,859,618	444	22	0
12		Materials & Expenses	2.2	697,287	167	8	0
13	878	Meter & House Reg. Exp.					
14		Labor & Labor Loading	6.0	6,919,581	-	300	-
15		Materials & Expenses	6.0	1,213,237	-	53	-
16	879	Customer Installation Exp.					
17		Labor & Labor Loading	6.0	8,087,437	-	351	-
18		Materials & Expenses	6.0	1,490,584	-	65	-
19	880	Other Expenses					
20		Labor & Labor Loading	5.5	6,543,834	498	208	129
21		Materials & Expenses	5.5	4,535,239	345	144	89
22	881	Rents	5.5	2,250,258	171	72	44
23		Total Distribution-Operations		$ 56,117,507	$ 4,272	$ 1,784	$ 1,107
		Operation and Maintenance Expense					
		Distribution Expenses					
24	885	Maint. Supervision & Eng.					
25		Labor & Labor Loading	6.6	$ 2,797,818	$ 398	$ 61	$ 0
26		Materials & Expenses	6.6	338,062	48	7	0
27	886	Maint. of Structures & Imp.					
28		Labor & Labor Loading	1.0	26,673	11	-	-
29		Materials & Expenses	1.0	80,753	34	-	-
30	887	Maint. of Mains					
31		Labor & Labor Loading	2.2	8,500,012	2,031	103	0
32		Materials & Expenses	2.2	7,043,715	1,683	85	0
33	889	Maint. of Meas. & Reg. Sta-Gen					
34		Labor & Labor Loading	2.2	1,461,314	349	18	0
35		Materials & Expenses	2.2	580,480	139	7	0
36	892	Maint. of Services					
37		Labor & Labor Loading	3.3	6,159,505	0	212	-
38		Materials & Expenses	3.3	3,973,153	0	137	-
39	893	Maint of Meter & House Reg.					
40		Labor & Labor Loading	6.0	1,281,534	-	56	-
41		Materials & Expenses	6.0	781,684	-	34	-
42	894	Maint of Other Equip.					
43		Labor & Labor Loading	6.6	196,535	28	4	0
44		Materials & Expenses	6.6	189,711	27	4	0
45		Total Distribution-Maintenance		$ 33,410,949	$ 4,748	$ 727	$ 0
46		Total Distribution O & M		$ 89,528,455	$ 9,020	$ 2,511	$ 1,107

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Air-Conditioning Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(d)	(e)	(f)
		Customer Accounts Expenses					
1	901	Supervision					
2		Labor & Labor Loading	10.1	$ 4,093,979	$ -	$ 100	$ -
3		Materials & Expenses	10.1	275,497	-	7	-
4	902	Meter Reading Exp.					
5		Labor & Labor Loading	13.0	4,860,483	-	118	-
6		Materials & Expenses	13.0	2,194,002	-	53	-
7	903	Customer Records & Collections					
8		Labor & Labor Loading	13.0	-	-	-	-
9		Materials & Expenses	13.0	404,465	-	10	-
10	903	Customer Records & Collections - LCS					
11		Labor & Labor Loading - LCS	13.0	16,062,467	-	389	-
12		Materials & Expenses - LCS	13.0	7,441,028	-	180	-
13	904	Uncollectible Accounts Exp.	4.0	2,977,729	-	82	-
14	905	Misc. Customer Accounts Exp.					
15		Labor & Labor Loading	10.1	404,465	-	10	-
16		Materials & Expenses	10.1	16,795	-	0	-
17		Total Customer Accounts Expenses		$ 38,730,909	$ -	$ 950	$ -
		Customer Service & Info. Exp.					
18	908	Customer Assistance Exp.					
19		Labor & Labor Loading	13.0	$ 514,896	$ -	$ 12	$ -
20		Materials & Expenses	13.0	564,797	-	14	-
21	909	Info. & Instructional Exp.					
22		Labor & Labor Loading	13.0	-	-	-	-
23		Materials & Expenses	13.0	25,125	-	1	-
24	910	Misc. C.S. & I. Expense					
25		Labor & Labor Loading	13.0	-	-	-	-
26		Materials & Expenses	13.0	21,977	-	1	-
27		Total Customer Service & Info. Exp.		$ 1,126,796	$ -	$ 27	$ -
		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		$ 130,087,761	$ 9,020	$ 3,489	$ 2,311
39		Allocation Percentage	Total O&M	100.00%	0.01%	0.00%	0.00%
		Other Operating Deductions					
40		Administrative & General Expense	Total O&M	56,946,694	3,949	1,527	1,011
41		Interest on Customer Deposits	8.0	1,915,314	-	-	-
42		Taxes Other Than Income	1.1	33,124,880	4,433	771	204
43		Total Allocated Operating Deductions		$ 222,074,648	$ 17,402	$ 5,787	$ 3,526
		Tax Adjustments					
44		Interest Expense	1.1	48,035,008	6,428	1,118	296
45		State South Georgia	1.1	29,686	4	1	0
46		Investment Tax Credit	1.1	(528,360)	(71)	(12)	(3)
47		Federal South Georgia	1.1	290,114	39	7	2

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Air-Conditioning Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(d)	(e)	(f)
		Summary of Allocated Cost of Service					
		Rate Base					
1		Direct Net Plant		$ 1,267,124,121	$ 169,567	$ 29,479	$ 7,807
2		Systems Allocable Net Plant		34,448,206	4,610	801	212
3		Cash Working Capital	1.1	(10,379,937)	(720)	(278)	(184)
4		Materials & Supplies	1.1	12,389,898	1,658	288	76
5		Prepayments	1.1	3,671,971	491	85	23
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
7		Customer Deposits	8.0	(31,921,898)	-	-	-
8		Customer Advances	8.0	(37,910,017)	-	-	-
9		Deferred Taxes	1.1	(142,632,297)	(19,087)	(3,318)	(879)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-
11		Total Rate Base		$ 1,094,790,047	$ 156,519	$ 27,058	$ 7,055
12		Net Operating Margin	Direct	$ 381,188,845	$ 110,707	$ 12,990	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 5,784,028	$ 1,680	$ 197	$ -
14		Late Charges	Direct	$ 2,430,203			
15		Service Establishment Charges	9	$ 8,267,657	-	380	-
16		Reconnect / Reread Charges	4	$ 569,215	-	16	-
17		Other Revenue - Labor	Net Op. Marg.	$ 1,313	$ 0	$ 0	$ -
18		Other Revenue - Parts & Material	Net Op. Marg.	$ 2,621	$ 1	$ 0	$ -
19		Other Revenue - Field Collection Fee	4	$ 304,887	-	8	-
20		Other Revenue - Returned Item Fee	4	$ 173,412	-	5	-
21		Other Revenue - Rental Income	Net Op. Marg.	$ 512,498	$ 149	$ 17	$ -
22		Total Revenue		399,234,678	112,537	13,613	-
23		O & M		(130,087,761)	(9,020)	(3,489)	(2,311)
24		A & G	Total O&M	(56,946,694)	(3,949)	(1,527)	(1,011)
25		Depreciation Expense		(87,887,713)	(11,761)	(2,045)	(541)
26		Interest on Customer Deposits	8.0	(1,915,314)	-	-	-
27		Taxes other than Income	1.1	(33,124,880)	(4,433)	(771)	(204)
		State Income Tax					
28		Taxable Income before Interest Exp.		$ 89,272,317	$ 83,374	$ 5,782	$(4,068)
29		Interest Expense	1.1	(48,035,008)	(6,428)	(1,118)	(296)
30		State Taxable Income		$ 41,237,309	$ 76,946	$ 4,664	$(4,364)
31		State Income Tax		2,873,416	5,362	325	(304)
32		South Georgia	1.1	29,686	4	1	0
33		State Income Tax		2,903,102	5,366	326	(304)
		Federal Income Tax					
34		Taxable Income before Interest Exp.		89,272,317	83,374	5,782	(4,068)
35		Interest Expense	1.1	(48,035,008)	(6,428)	(1,118)	(296)
36		Federal Taxable Income		41,237,309	76,946	4,664	(4,364)
37		Federal Income Tax		$ 13,427,363	$ 25,055	$ 1,519	$(1,421)
38		I T C	1.1	(528,360)	(71)	(12)	(3)
39		South Georgia	1.1	290,114	39	7	2
40		Total Federal Income Tax		$ 13,189,117	$ 25,023	$ 1,513	$(1,422)
41		Regulatory Amortization	1.1	-	-	-	-
42		Net Income		$ 73,180,099	$ 52,986	$ 3,943	$(2,341)
43		Rate of Return on Rate Base		6.68%	33.85%	14.57%	(33.19%)
44		Rate of Return by Class Total				28.63%	

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Demand	CNG - Small Customer	Commodity
	(a)	(b)	(c)	(d)	(g)	(h)	(i)
		Direct Depreciation Expense					
1	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 75,910,024	$ 2,602	$ 1,359	$ 74
5	389-398	General	1.1	$ 4,919,293	$ 169	$ 88	$ 5
6		Total Direct Dep. Exp.		$ 80,829,317	$ 2,770	$ 1,447	$ 79
		Systems Allocable Depreciation Expense					
7	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
8	389-398	General	1.1	$ 2,540,252	$ 87	$ 45	$ 2
		System Allocable Amortization					
9		Miscellaneous Intangible	1.1	4,002,161	137	72	4
10		Structures-Leasehold Improvements	1.1	104,525	4	2	0
11		Total System Allocable Amortization		4,106,686	141	74	4
12		Total System Alloc Dep. Exp. & Amortization		6,646,938	228	119	7
13		Total Depreciation Expense		87,476,255	2,998	1,566	86
14		Amortization	1.1	126,930	4	2	0
15		Amortization-Gas Plant Acquisition	1.1	(52,996)	(2)	(1)	(0)
16		Regulatory Amortizations	1.1	337,524	12	6	0
17		-	7.0	-	-	-	-
18		-	1.1	-	-	-	-
19		-	1.1	-	-	-	-
20		Total Depreciation & Amortization Expense		$ 87,887,713	$ 3,012	$ 1,574	$ 86
		Operation and Maintenance Expense					
		Gas Supply Expense					
21	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -
22	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-
23	805	Purchased Gas Cost Adj.	3.0	-	-	-	-
24	810	Gas Used for Compressor Sta. Fuel--	3.0	-	-	-	-
25	813	Other Gas Supply Expense	3.0	-	-	-	-
26		Labor & Labor Loading	3.0	641,618	-	-	175
27		Materials & Expenses	3.0	59,983	-	-	16
28		Total Gas Supply Expense		$ 701,601	$ -	$ -	$ 191

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Demand	CNG - Small Customer	Commodity
	(a)	(b)	(c)	(d)	(g)	(h)	(i)
		Distribution Expenses					
1	870	Operation Supervision & Eng.					
2		Labor & Labor Loading	5.5	$ 8,990,906	$ 175	$ 165	$ 28
3		Materials & Expenses	5.5	1,458,368	28	27	5
4	871	Distribution Load Dispatching					
5		Labor & Labor Loading	3.0	258,538	-	-	70
6		Materials & Expenses	3.0	113,250	-	-	31
7	874	Mains & Svcs. Expense					
8		Labor & Labor Loading	4.4	6,159,141	250	109	0
9		Materials & Expenses	4.4	5,540,228	224	98	0
10	875	Meas. & Reg. Sta. Exp.-Gen.					
11		Labor & Labor Loading	2.2	1,859,618	114	18	0
12		Materials & Expenses	2.2	697,287	43	7	0
13	878	Meter & House Reg. Exp.					
14		Labor & Labor Loading	6.0	6,919,581	-	141	-
15		Materials & Expenses	6.0	1,213,237	-	25	-
16	879	Customer Installation Exp.					
17		Labor & Labor Loading	6.0	8,087,437	-	165	-
18		Materials & Expenses	6.0	1,490,584	-	30	-
19	880	Other Expenses					
20		Labor & Labor Loading	5.5	6,543,834	128	120	20
21		Materials & Expenses	5.5	4,535,239	88	83	14
22	881	Rents	5.5	2,250,258	44	41	7
23		Total Distribution-Operations		$ 56,117,507	$ 1,094	$ 1,031	$ 176
		Operation and Maintenance Expense					
		Distribution Expenses					
24	885	Maint. Supervision & Eng.					
25		Labor & Labor Loading	6.6	$ 2,797,818	$ 102	$ 52	$ 0
26		Materials & Expenses	6.6	338,062	12	6	0
27	886	Maint. of Structures & Imp.					
28		Labor & Labor Loading	1.0	26,673	3	-	-
29		Materials & Expenses	1.0	80,753	9	-	-
30	887	Maint. of Mains					
31		Labor & Labor Loading	2.2	8,500,012	520	81	0
32		Materials & Expenses	2.2	7,043,715	431	67	0
33	889	Maint. of Meas. & Reg. Sta-Gen					
34		Labor & Labor Loading	2.2	1,461,314	89	14	0
35		Materials & Expenses	2.2	580,480	36	6	0
36	892	Maint. of Services					
37		Labor & Labor Loading	3.3	6,159,505	0	208	-
38		Materials & Expenses	3.3	3,973,153	0	134	-
39	893	Maint of Meter & House Reg.					
40		Labor & Labor Loading	6.0	1,281,534	-	26	-
41		Materials & Expenses	6.0	781,684	-	16	-
42	894	Maint of Other Equip.					
43		Labor & Labor Loading	6.6	196,535	7	4	0
44		Materials & Expenses	6.6	189,711	7	4	0
45		Total Distribution-Maintenance		$ 33,410,949	$ 1,216	$ 618	$ 0
46		Total Distribution O & M		$ 89,528,455	$ 2,310	$ 1,649	$ 176

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Demand	CNG - Small Customer	Commodity
	(a)	(b)	(c)	(d)	(g)	(h)	(i)
		Customer Accounts Expenses					
1	901	Supervision					
2		Labor & Labor Loading	10.1	$ 4,093,979	$ -	$ 270	$ -
3		Materials & Expenses	10.1	275,497	-	18	-
4	902	Meter Reading Exp.					
5		Labor & Labor Loading	13.0	4,860,483	-	341	-
6		Materials & Expenses	13.0	2,194,002	-	154	-
7	903	Customer Records & Collections					
8		Labor & Labor Loading	13.0	-	-	-	-
9		Materials & Expenses	13.0	404,465	-	28	-
10	903	Customer Records & Collections - LCS					
11		Labor & Labor Loading - LCS	13.0	16,062,467	-	1,128	-
12		Materials & Expenses - LCS	13.0	7,441,028	-	523	-
13	904	Uncollectible Accounts Exp.	4.0	2,977,729	-	65	-
14	905	Misc. Customer Accounts Exp.					
15		Labor & Labor Loading	10.1	404,465	-	27	-
16		Materials & Expenses	10.1	16,795	-	1	-
17		Total Customer Accounts Expenses		$ 38,730,909	$ -	$ 2,556	$ -
		Customer Service & Info. Exp.					
18	908	Customer Assistance Exp.					
19		Labor & Labor Loading	13.0	$ 514,896	$ -	$ 36	$ -
20		Materials & Expenses	13.0	564,797	-	40	-
21	909	Info. & Instructional Exp.					
22		Labor & Labor Loading	13.0	-	-	-	-
23		Materials & Expenses	13.0	25,125	-	2	-
24	910	Misc. C.S. & I. Expense					
25		Labor & Labor Loading	13.0	-	-	-	-
26		Materials & Expenses	13.0	21,977	-	2	-
27		Total Customer Service & Info. Exp.		$ 1,126,796	$ -	$ 79	$ -
		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		$ 130,087,761	$ 2,310	$ 4,284	$ 367
39		Allocation Percentage	Total O&M	100.00%	0.00%	0.00%	0.00%
		Other Operating Deductions					
40		Administrative & General Expense	Total O&M	56,946,694	1,011	1,875	161
41		Interest on Customer Deposits	8.0	1,915,314	-	-	-
42		Taxes Other Than Income	1.1	33,124,880	1,135	593	32
43		Total Allocated Operating Deductions		$ 222,074,648	$ 4,457	$ 6,753	$ 560
		Tax Adjustments					
44		Interest Expense	1.1	48,035,008	1,646	860	47
45		State South Georgia	1.1	29,686	1	1	0
46		Investment Tax Credit	1.1	(528,360)	(18)	(9)	(1)
47		Federal South Georgia	1.1	290,114	10	5	0

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Demand	CNG - Small Customer	Commodity
	(a)	(b)	(c)	(d)	(g)	(h)	(i)
		Summary of Allocated Cost of Service					
		Rate Base					
1		Direct Net Plant		$ 1,267,124,121	$ 43,426	$ 22,690	$ 1,239
2		Systems Allocable Net Plant		34,448,206	1,181	617	34
3		Cash Working Capital	1.1	(10,379,937)	(184)	(342)	(29)
4		Materials & Supplies	1.1	12,389,898	425	222	12
5		Prepayments	1.1	3,671,971	126	66	4
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
7		Customer Deposits	8.0	(31,921,898)	-	-	-
8		Customer Advances	8.0	(37,910,017)	-	-	-
9		Deferred Taxes	1.1	(142,632,297)	(4,888)	(2,554)	(139)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-
11		Total Rate Base		$ 1,094,790,047	$ 40,085	$ 20,699	$ 1,120
12		Net Operating Margin	Direct	$ 381,188,845	$ 30,174	$ 6,300	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 5,784,028	$ 458	$ 96	$ -
14		Late Charges	Direct	$ 2,430,203			
15		Service Establishment Charges	9	$ 8,267,657	-	301	-
16		Reconnect / Reread Charges	4	$ 569,215	-	12	-
17		Other Revenue - Labor	Net Op. Marg.	$ 1,313	$ 0	$ 0	$ -
18		Other Revenue - Parts & Material	Net Op. Marg.	$ 2,621	$ 0	$ 0	$ -
19		Other Revenue - Field Collection Fee	4	$ 304,887	-	7	-
20		Other Revenue - Returned Item Fee	4	$ 173,412	-	4	-
21		Other Revenue - Rental Income	Net Op. Marg.	$ 512,498	$ 41	$ 8	$ -
22		Total Revenue		399,234,678	30,673	6,728	-
23		O & M		(130,087,761)	(2,310)	(4,284)	(367)
24		A & G	Total O&M	(56,946,694)	(1,011)	(1,875)	(161)
25		Depreciation Expense		(87,887,713)	(3,012)	(1,574)	(86)
26		Interest on Customer Deposits	8.0	(1,915,314)	-	-	-
27		Taxes other than Income	1.1	(33,124,880)	(1,135)	(593)	(32)
		State Income Tax					
28		Taxable Income before Interest Exp.		$ 89,272,317	$ 23,204	$(1,598)	$(646)
29		Interest Expense	1.1	(48,035,008)	(1,646)	(860)	(47)
30		State Taxable Income		$ 41,237,309	$ 21,558	$(2,459)	$(693)
31		State Income Tax		2,873,416	1,502	(171)	(48)
32		South Georgia	1.1	29,686	1	1	0
33		State Income Tax		2,903,102	1,503	(171)	(48)
		Federal Income Tax					
34		Taxable Income before Interest Exp.		89,272,317	23,204	(1,598)	(646)
35		Interest Expense	1.1	(48,035,008)	(1,646)	(860)	(47)
36		Federal Taxable Income		41,237,309	21,558	(2,459)	(693)
37		Federal Income Tax		$ 13,427,363	$ 7,020	$(801)	$(226)
38		I T C	1.1	(528,360)	(18)	(9)	(1)
39		South Georgia	1.1	290,114	10	5	0
40		Total Federal Income Tax		$ 13,189,117	$ 7,011	$(805)	$(226)
41		Regulatory Amortization	1.1	-	-	-	-
42		Net Income		$ 73,180,099	$ 14,690	$(623)	$(372)
43		Rate of Return on Rate Base		6.68%	36.65%	(3.01%)	(33.19%)
44		Rate of Return by Class Total				22.12%	

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Demand	CNG - Large Customer	Commodity
	(a)	(b)	(c)	(d)	(j)	(k)	(l)
		Direct Depreciation Expense					
1	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 75,910,024	$ 30,491	$ 14,009	$ 862
5	389-398	General	1.1	$ 4,919,293	$ 1,976	$ 908	$ 56
6		Total Direct Dep. Exp.		$ 80,829,317	$ 32,467	$ 14,917	$ 917
		Systems Allocable Depreciation Expense					
7	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
8	389-398	General	1.1	$ 2,540,252	$ 1,020	$ 469	$ 29
		System Allocable Amortization					
9		Miscellaneous Intangible	1.1	4,002,161	1,608	739	45
10		Structures-Leasehold Improvements	1.1	104,525	42	19	1
11		Total System Allocable Amortization		4,106,686	1,650	758	47
12		Total System Alloc Dep. Exp. & Amortization		6,646,938	2,670	1,227	75
13		Total Depreciation Expense		87,476,255	35,137	16,144	993
14		Amortization	1.1	126,930	51	23	1
15		Amortization-Gas Plant Acquisition	1.1	(52,996)	(21)	(10)	(1)
16		Regulatory Amortizations	1.1	337,524	136	62	4
17		-	7.0	-	-	-	-
18		-	1.1	-	-	-	-
19		-	1.1	-	-	-	-
20		Total Depreciation & Amortization Expense		$ 87,887,713	$ 35,302	$ 16,219	$ 998
		Operation and Maintenance Expense					
		Gas Supply Expense					
21	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -
22	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-
23	805	Purchased Gas Cost Adj.	3.0	-	-	-	-
24	810	Gas Used for Compressor Sta. Fuel--	3.0	-	-	-	-
25	813	Other Gas Supply Expense	3.0	-	-	-	-
26		Labor & Labor Loading	3.0	641,618	-	-	2,028
27		Materials & Expenses	3.0	59,983	-	-	190
28		Total Gas Supply Expense		$ 701,601	$ -	$ -	$ 2,218

SOUTHWEST GAS CORPORATION
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CLASS COST OF SERVICE STUDY
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APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Demand	CNG - Large Customer	Commodity
	(a)	(b)	(c)	(d)	(j)	(k)	(l)
		Distribution Expenses					
1	870	Operation Supervision & Eng.					
2		Labor & Labor Loading	5.5	$ 8,990,906	$ 2,055	$ 3,412	$ 327
3		Materials & Expenses	5.5	1,458,368	333	553	53
4	871	Distribution Load Dispatching					
5		Labor & Labor Loading	3.0	258,538	-	-	817
6		Materials & Expenses	3.0	113,250	-	-	358
7	874	Mains & Svcs. Expense					
8		Labor & Labor Loading	4.4	6,159,141	2,925	617	0
9		Materials & Expenses	4.4	5,540,228	2,631	555	0
10	875	Meas. & Reg. Sta. Exp.-Gen.					
11		Labor & Labor Loading	2.2	1,859,618	1,334	20	0
12		Materials & Expenses	2.2	697,287	500	8	0
13	878	Meter & House Reg. Exp.					
14		Labor & Labor Loading	6.0	6,919,581	-	4,326	-
15		Materials & Expenses	6.0	1,213,237	-	759	-
16	879	Customer Installation Exp.					
17		Labor & Labor Loading	6.0	8,087,437	-	5,057	-
18		Materials & Expenses	6.0	1,490,584	-	932	-
19	880	Other Expenses					
20		Labor & Labor Loading	5.5	6,543,834	1,495	2,484	238
21		Materials & Expenses	5.5	4,535,239	1,036	1,721	165
22	881	Rents	5.5	2,250,258	514	854	82
23		Total Distribution-Operations		$ 56,117,507	$ 12,824	$ 21,298	$ 2,039
		Operation and Maintenance Expense					
		Distribution Expenses					
24	885	Maint. Supervision & Eng.					
25		Labor & Labor Loading	6.6	$ 2,797,818	$ 1,193	$ 400	$ 0
26		Materials & Expenses	6.6	338,062	144	48	0
27	886	Maint. of Structures & Imp.					
28		Labor & Labor Loading	1.0	26,673	34	-	-
29		Materials & Expenses	1.0	80,753	103	-	-
30	887	Maint. of Mains					
31		Labor & Labor Loading	2.2	8,500,012	6,096	93	0
32		Materials & Expenses	2.2	7,043,715	5,052	77	0
33	889	Maint. of Meas. & Reg. Sta-Gen					
34		Labor & Labor Loading	2.2	1,461,314	1,048	16	0
35		Materials & Expenses	2.2	580,480	416	6	0
36	892	Maint. of Services					
37		Labor & Labor Loading	3.3	6,159,505	0	1,694	-
38		Materials & Expenses	3.3	3,973,153	0	1,093	-
39	893	Maint of Meter & House Reg.					
40		Labor & Labor Loading	6.0	1,281,534	-	801	-
41		Materials & Expenses	6.0	781,684	-	489	-
42	894	Maint of Other Equip.					
43		Labor & Labor Loading	6.6	196,535	84	28	0
44		Materials & Expenses	6.6	189,711	81	27	0
45		Total Distribution-Maintenance		$ 33,410,949	$ 14,251	$ 4,773	$ 0
46		Total Distribution O & M		$ 89,528,455	$ 27,075	$ 26,070	$ 2,039

SOUTHWEST GAS CORPORATION
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APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Demand	CNG - Large Customer	Commodity
	(a)	(b)	(c)	(d)	(j)	(k)	(l)
		Customer Accounts Expenses					
1	901	Supervision					
2		Labor & Labor Loading	10.1	$ 4,093,979	$ -	$ 609	$ -
3		Materials & Expenses	10.1	275,497	-	41	-
4	902	Meter Reading Exp.					
5		Labor & Labor Loading	13.0	4,860,483	-	780	-
6		Materials & Expenses	13.0	2,194,002	-	352	-
7	903	Customer Records & Collections					
8		Labor & Labor Loading	13.0	-	-	-	-
9		Materials & Expenses	13.0	404,465	-	65	-
10	903	Customer Records & Collections - LCS					
11		Labor & Labor Loading - LCS	13.0	16,062,467	-	2,578	-
12		Materials & Expenses - LCS	13.0	7,441,028	-	1,194	-
13	904	Uncollectible Accounts Exp.	4.0	2,977,729	-	75	-
14	905	Misc. Customer Accounts Exp.					
15		Labor & Labor Loading	10.1	404,465	-	60	-
16		Materials & Expenses	10.1	16,795	-	2	-
17		Total Customer Accounts Expenses		$ 38,730,909	$ -	$ 5,757	$ -
		Customer Service & Info. Exp.					
18	908	Customer Assistance Exp.					
19		Labor & Labor Loading	13.0	$ 514,896	$ -	$ 83	$ -
20		Materials & Expenses	13.0	564,797	-	91	-
21	909	Info. & Instructional Exp.					
22		Labor & Labor Loading	13.0	-	-	-	-
23		Materials & Expenses	13.0	25,125	-	4	-
24	910	Misc. C.S. & I. Expense					
25		Labor & Labor Loading	13.0	-	-	-	-
26		Materials & Expenses	13.0	21,977	-	4	-
27		Total Customer Service & Info. Exp.		$ 1,126,796	$ -	$ 181	$ -
		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		$ 130,087,761	$ 27,075	$ 32,008	$ 4,257
39		Allocation Percentage	Total O&M	100.00%	0.02%	0.02%	0.00%
		Other Operating Deductions					
40		Administrative & General Expense	Total O&M	56,946,694	11,852	14,012	1,863
41		Interest on Customer Deposits	8.0	1,915,314	-	-	-
42		Taxes Other Than Income	1.1	33,124,880	13,305	6,113	376
43		Total Allocated Operating Deductions		$ 222,074,648	$ 52,233	$ 52,133	$ 6,496
		Tax Adjustments					
44		Interest Expense	1.1	48,035,008	19,294	8,865	545
45		State South Georgia	1.1	29,686	12	5	0
46		Investment Tax Credit	1.1	(528,360)	(212)	(98)	(6)
47		Federal South Georgia	1.1	290,114	117	54	3

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Demand	CNG - Large Customer	Commodity
	(a)	(b)	(c)	(d)	(j)	(k)	(l)
		Summary of Allocated Cost of Service					
		Rate Base					
1		Direct Net Plant		$ 1,267,124,121	$ 508,969	$ 233,845	$ 14,383
2		Systems Allocable Net Plant		34,448,206	13,837	6,357	391
3		Cash Working Capital	1.1	(10,379,937)	(2,160)	(2,554)	(340)
4		Materials & Supplies	1.1	12,389,898	4,977	2,287	141
5		Prepayments	1.1	3,671,971	1,475	678	42
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
7		Customer Deposits	8.0	(31,921,898)	-	-	-
8		Customer Advances	8.0	(37,910,017)	-	-	-
9		Deferred Taxes	1.1	(142,632,297)	(57,292)	(26,322)	(1,619)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-
11		Total Rate Base		$ 1,094,790,047	$ 469,806	$ 214,290	$ 12,998
12		Net Operating Margin	Direct	$ 381,188,845	$ 350,226	$ 54,720	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 5,784,028	$ 5,314	$ 830	$ -
14		Late Charges	Direct	$ 2,430,203			
15		Service Establishment Charges	9	$ 8,267,657	-	344	-
16		Reconnect / Reread Charges	4	$ 569,215	-	14	-
17		Other Revenue - Labor	Net Op. Marg.	$ 1,313	$ 1	$ 0	$ -
18		Other Revenue - Parts & Material	Net Op. Marg.	$ 2,621	$ 2	$ 0	$ -
19		Other Revenue - Field Collection Fee	4	$ 304,887	-	8	-
20		Other Revenue - Returned Item Fee	4	$ 173,412	-	4	-
21		Other Revenue - Rental Income	Net Op. Marg.	$ 512,498	$ 471	$ 74	$ -
22		Total Revenue		399,234,678	356,015	55,995	-
23		O & M		(130,087,761)	(27,075)	(32,008)	(4,257)
24		A & G	Total O&M	(56,946,694)	(11,852)	(14,012)	(1,863)
25		Depreciation Expense		(87,887,713)	(35,302)	(16,219)	(998)
26		Interest on Customer Deposits	8.0	(1,915,314)	-	-	-
27		Taxes other than Income	1.1	(33,124,880)	(13,305)	(6,113)	(376)
		State Income Tax					
28		Taxable Income before Interest Exp.		$ 89,272,317	$ 268,480	$(12,358)	$(7,494)
29		Interest Expense	1.1	(48,035,008)	(19,294)	(8,865)	(545)
30		State Taxable Income		$ 41,237,309	$ 249,185	$(21,222)	$(8,039)
31		State Income Tax		2,873,416	17,363	(1,479)	(560)
32		South Georgia	1.1	29,686	12	5	0
33		State Income Tax		2,903,102	17,375	(1,473)	(560)
		Federal Income Tax					
34		Taxable Income before Interest Exp.		89,272,317	268,480	(12,358)	(7,494)
35		Interest Expense	1.1	(48,035,008)	(19,294)	(8,865)	(545)
36		Federal Taxable Income		41,237,309	249,185	(21,222)	(8,039)
37		Federal Income Tax		$ 13,427,363	$ 81,138	$(6,910)	$(2,618)
38		I T C	1.1	(528,360)	(212)	(98)	(6)
39		South Georgia	1.1	290,114	117	54	3
40		Total Federal Income Tax		$ 13,189,117	$ 81,042	$(6,954)	$(2,620)
41		Regulatory Amortization	1.1	-	-	-	-
42		Net Income		$ 73,180,099	$ 170,063	$(3,930)	$(4,314)
43		Rate of Return on Rate Base		6.68%	36.20%	(1.83%)	(33.19%)
44		Rate of Return by Class Total				23.21%	

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	CNG - Residential Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(m)	(n)	(o)
		Direct Depreciation Expense					
1	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 75,910,024	$ 1,207	$ 5,074	$ 32
5	389-398	General	1.1	$ 4,919,293	$ 78	$ 329	$ 2
6		Total Direct Dep. Exp.		$ 80,829,317	$ 1,285	$ 5,403	$ 34
		Systems Allocable Depreciation Expense					
7	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
8	389-398	General	1.1	$ 2,540,252	$ 40	$ 170	$ 1
		System Allocable Amortization					
9		Miscellaneous Intangible	1.1	4,002,161	64	268	2
10		Structures-Leasehold Improvements	1.1	104,525	2	7	0
11		Total System Allocable Amortization		4,106,686	65	275	2
12		Total System Alloc Dep. Exp. & Amortization		6,646,938	106	444	3
13		Total Depreciation Expense		87,476,255	1,391	5,848	37
14		Amortization	1.1	126,930	2	8	0
15		Amortization-Gas Plant Acquisition	1.1	(52,996)	(1)	(4)	(0)
16		Regulatory Amortizations	1.1	337,524	5	23	0
17		-	7.0	-	-	-	-
18		-	1.1	-	-	-	-
19		-	1.1	-	-	-	-
20		Total Depreciation & Amortization Expense		$ 87,887,713	$ 1,398	$ 5,875	$ 37
		Operation and Maintenance Expense					
		Gas Supply Expense					
21	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -
22	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-
23	805	Purchased Gas Cost Adj.	3.0	-	-	-	-
24	810	Gas Used for Compressor Sta. Fuel--	3.0	-	-	-	-
25	813	Other Gas Supply Expense	3.0	-	-	-	-
26		Labor & Labor Loading	3.0	641,618	-	-	76
27		Materials & Expenses	3.0	59,983	-	-	7
28		Total Gas Supply Expense		$ 701,601	$ -	$ -	$ 83

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	CNG - Residential Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(m)	(n)	(o)
		Distribution Expenses					
1	870	Operation Supervision & Eng.					
2		Labor & Labor Loading	5.5	$ 8,990,906	$ 81	$ 635	$ 12
3		Materials & Expenses	5.5	1,458,368	13	103	2
4	871	Distribution Load Dispatching					
5		Labor & Labor Loading	3.0	258,538	-	-	31
6		Materials & Expenses	3.0	113,250	-	-	13
7	874	Mains & Svcs. Expense					
8		Labor & Labor Loading	4.4	6,159,141	116	403	0
9		Materials & Expenses	4.4	5,540,228	104	362	0
10	875	Meas. & Reg. Sta. Exp.-Gen.					
11		Labor & Labor Loading	2.2	1,859,618	53	90	0
12		Materials & Expenses	2.2	697,287	20	34	0
13	878	Meter & House Reg. Exp.					
14		Labor & Labor Loading	6.0	6,919,581	-	545	-
15		Materials & Expenses	6.0	1,213,237	-	96	-
16	879	Customer Installation Exp.					
17		Labor & Labor Loading	6.0	8,087,437	-	637	-
18		Materials & Expenses	6.0	1,490,584	-	117	-
19	880	Other Expenses					
20		Labor & Labor Loading	5.5	6,543,834	59	462	9
21		Materials & Expenses	5.5	4,535,239	41	320	6
22	881	Rents	5.5	2,250,258	20	159	3
23		Total Distribution-Operations		$ 56,117,507	$ 508	$ 3,964	$ 77
		Operation and Maintenance Expense					
		Distribution Expenses					
24	885	Maint. Supervision & Eng.					
25		Labor & Labor Loading	6.6	$ 2,797,818	$ 47	$ 188	$ 0
26		Materials & Expenses	6.6	338,062	6	23	0
27	886	Maint. of Structures & Imp.					
28		Labor & Labor Loading	1.0	26,673	1	-	-
29		Materials & Expenses	1.0	80,753	4	-	-
30	887	Maint. of Mains					
31		Labor & Labor Loading	2.2	8,500,012	241	411	0
32		Materials & Expenses	2.2	7,043,715	200	341	0
33	889	Maint. of Meas. & Reg. Sta-Gen					
34		Labor & Labor Loading	2.2	1,461,314	41	71	0
35		Materials & Expenses	2.2	580,480	16	28	0
36	892	Maint. of Services					
37		Labor & Labor Loading	3.3	6,159,505	0	608	-
38		Materials & Expenses	3.3	3,973,153	0	392	-
39	893	Maint of Meter & House Reg.					
40		Labor & Labor Loading	6.0	1,281,534	-	101	-
41		Materials & Expenses	6.0	781,684	-	62	-
42	894	Maint of Other Equip.					
43		Labor & Labor Loading	6.6	196,535	3	13	0
44		Materials & Expenses	6.6	189,711	3	13	0
45		Total Distribution-Maintenance		$ 33,410,949	$ 564	$ 2,251	$ 0
46		Total Distribution O & M		$ 89,528,455	$ 1,072	$ 6,215	$ 77

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	CNG - Residential Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(m)	(n)	(o)
		Customer Accounts Expenses					
1	901	Supervision					
2		Labor & Labor Loading	10.1	$ 4,093,979	$ -	$ 431	$ -
3		Materials & Expenses	10.1	275,497	-	29	-
4	902	Meter Reading Exp.					
5		Labor & Labor Loading	13.0	4,860,483	-	510	-
6		Materials & Expenses	13.0	2,194,002	-	230	-
7	903	Customer Records & Collections					
8		Labor & Labor Loading	13.0	-	-	-	-
9		Materials & Expenses	13.0	404,465	-	42	-
10	903	Customer Records & Collections - LCS					
11		Labor & Labor Loading - LCS	13.0	16,062,467	-	1,685	-
12		Materials & Expenses - LCS	13.0	7,441,028	-	780	-
13	904	Uncollectible Accounts Exp.	4.0	2,977,729	-	329	-
14	905	Misc. Customer Accounts Exp.					
15		Labor & Labor Loading	10.1	404,465	-	43	-
16		Materials & Expenses	10.1	16,795	-	2	-
17		Total Customer Accounts Expenses		$ 38,730,909	$ -	$ 4,081	$ -
		Customer Service & Info. Exp.					
18	908	Customer Assistance Exp.					
19		Labor & Labor Loading	13.0	$ 514,896	$ -	$ 54	$ -
20		Materials & Expenses	13.0	564,797	-	59	-
21	909	Info. & Instructional Exp.					
22		Labor & Labor Loading	13.0	-	-	-	-
23		Materials & Expenses	13.0	25,125	-	3	-
24	910	Misc. C.S. & I. Expense					
25		Labor & Labor Loading	13.0	-	-	-	-
26		Materials & Expenses	13.0	21,977	-	2	-
27		Total Customer Service & Info. Exp.		$ 1,126,796	$ -	$ 118	$ -
		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		$ 130,087,761	$ 1,072	$ 10,414	$ 160
39		Allocation Percentage	Total O&M	100.00%	0.00%	0.01%	0.00%
		Other Operating Deductions					
40		Administrative & General Expense	Total O&M	56,946,694	469	4,559	70
41		Interest on Customer Deposits	8.0	1,915,314	-	-	-
42		Taxes Other Than Income	1.1	33,124,880	527	2,214	14
43		Total Allocated Operating Deductions		$ 222,074,648	$ 2,068	$ 17,188	$ 244
		Tax Adjustments					
44		Interest Expense	1.1	48,035,008	764	3,211	20
45		State South Georgia	1.1	29,686	0	2	0
46		Investment Tax Credit	1.1	(528,360)	(8)	(35)	(0)
47		Federal South Georgia	1.1	290,114	5	19	0

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	CNG - Residential Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(m)	(n)	(o)
		Summary of Allocated Cost of Service					
		Rate Base					
1		Direct Net Plant		$ 1,267,124,121	$ 20,151	$ 84,704	$ 540
2		Systems Allocable Net Plant		34,448,206	548	2,303	15
3		Cash Working Capital	1.1	(10,379,937)	(86)	(831)	(13)
4		Materials & Supplies	1.1	12,389,898	197	828	5
5		Prepayments	1.1	3,671,971	58	245	2
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
7		Customer Deposits	8.0	(31,921,898)	-	-	-
8		Customer Advances	8.0	(37,910,017)	-	-	-
9		Deferred Taxes	1.1	(142,632,297)	(2,268)	(9,535)	(61)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-
11		Total Rate Base		$ 1,094,790,047	$ 18,601	$ 77,715	$ 488
12		Net Operating Margin	Direct	$ 381,188,845	$ 13,151	$ 12,338	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 5,784,028	$ 200	$ 187	$ -
14		Late Charges	Direct	$ 2,430,203			
15		Service Establishment Charges	9	$ 8,267,657	-	1,519	-
16		Reconnect / Reread Charges	4	$ 569,215	-	63	-
17		Other Revenue - Labor	Net Op. Marg.	$ 1,313	$ 0	$ 0	$ -
18		Other Revenue - Parts & Material	Net Op. Marg.	$ 2,621	$ 0	$ 0	$ -
19		Other Revenue - Field Collection Fee	4	$ 304,887	-	34	-
20		Other Revenue - Returned Item Fee	4	$ 173,412	-	19	-
21		Other Revenue - Rental Income	Net Op. Marg.	$ 512,498	$ 18	$ 17	$ -
22		Total Revenue		399,234,678	13,368	14,177	-
23		O & M		(130,087,761)	(1,072)	(10,414)	(160)
24		A & G	Total O&M	(56,946,694)	(469)	(4,559)	(70)
25		Depreciation Expense		(87,887,713)	(1,398)	(5,875)	(37)
26		Interest on Customer Deposits	8.0	(1,915,314)	-	-	-
27		Taxes other than Income	1.1	(33,124,880)	(527)	(2,214)	(14)
		State Income Tax					
28		Taxable Income before Interest Exp.		$ 89,272,317	$ 9,903	$(8,886)	$(281)
29		Interest Expense	1.1	(48,035,008)	(764)	(3,211)	(20)
30		State Taxable Income		$ 41,237,309	$ 9,139	$(12,097)	$(302)
31		State Income Tax		2,873,416	637	(843)	(21)
32		South Georgia	1.1	29,686	0	2	0
33		State Income Tax		2,903,102	637	(841)	(21)
		Federal Income Tax					
34		Taxable Income before Interest Exp.		89,272,317	9,903	(8,886)	(281)
35		Interest Expense	1.1	(48,035,008)	(764)	(3,211)	(20)
36		Federal Taxable Income		41,237,309	9,139	(12,097)	(302)
37		Federal Income Tax		$ 13,427,363	$ 2,976	$(3,939)	$(98)
38		I T C	1.1	(528,360)	(8)	(35)	(0)
39		South Georgia	1.1	290,114	5	19	0
40		Total Federal Income Tax		$ 13,189,117	$ 2,972	$(3,955)	$(98)
41		Regulatory Amortization	1.1	-	-	-	-
42		Net Income		$ 73,180,099	$ 6,293	$(4,090)	$(162)
43		Rate of Return on Rate Base		6.68%	33.83%	(5.26%)	(33.19%)
44		Rate of Return by Class Total				2.11%	

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Electric Generation Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(d)	(e)	(f)
		Direct Depreciation Expense					
1	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 75,910,024	$ 254,898	$ 14,528	$ 9,001
5	389-398	General	1.1	$ 4,919,293	$ 16,518	$ 941	$ 583
6		Total Direct Dep. Exp.		$ 80,829,317	$ 271,416	$ 15,469	$ 9,585
		Systems Allocable Depreciation Expense					
7	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
8	389-398	General	1.1	$ 2,540,252	$ 8,530	$ 486	$ 301
		System Allocable Amortization					
9		Miscellaneous Intangible	1.1	4,002,161	13,439	766	475
10		Structures-Leasehold Improvements	1.1	104,525	351	20	12
11		Total System Allocable Amortization		4,106,686	13,790	786	487
12		Total System Alloc Dep. Exp. & Amortization		6,646,938	22,320	1,272	788
13		Total Depreciation Expense		87,476,255	293,736	16,741	10,373
14		Amortization	1.1	126,930	426	24	15
15		Amortization-Gas Plant Acquisition	1.1	(52,996)	(178)	(10)	(6)
16		Regulatory Amortizations	1.1	337,524	1,133	65	40
17		-	7.0	-	-	-	-
18		-	1.1	-	-	-	-
19		-	1.1	-	-	-	-
20		Total Depreciation & Amortization Expense		$ 87,887,713	$ 295,117	$ 16,820	$ 10,422
		Operation and Maintenance Expense					
		Gas Supply Expense					
21	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -
22	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-
23	805	Purchased Gas Cost Adj.	3.0	-	-	-	-
24	810	Gas Used for Compressor Sta. Fuel--	3.0	-	-	-	-
25	813	Other Gas Supply Expense	3.0	-	-	-	-
26		Labor & Labor Loading	3.0	641,618	-	-	21,186
27		Materials & Expenses	3.0	59,983	-	-	1,981
28		Total Gas Supply Expense		$ 701,601	$ -	$ -	$ 23,167

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Electric Generation Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(d)	(e)	(f)
		Distribution Expenses					
1	870	Operation Supervision & Eng.					
2		Labor & Labor Loading	5.5	$ 8,990,906	$ 17,176	$ 4,466	$ 3,413
3		Materials & Expenses	5.5	1,458,368	2,786	724	554
4	871	Distribution Load Dispatching					
5		Labor & Labor Loading	3.0	258,538	-	-	8,537
6		Materials & Expenses	3.0	113,250	-	-	3,740
7	874	Mains & Svcs. Expense					
8		Labor & Labor Loading	4.4	6,159,141	24,453	362	0
9		Materials & Expenses	4.4	5,540,228	21,996	326	0
10	875	Meas. & Reg. Sta. Exp.-Gen.					
11		Labor & Labor Loading	2.2	1,859,618	11,149	18	0
12		Materials & Expenses	2.2	697,287	4,181	7	0
13	878	Meter & House Reg. Exp.					
14		Labor & Labor Loading	6.0	6,919,581	-	5,998	-
15		Materials & Expenses	6.0	1,213,237	-	1,052	-
16	879	Customer Installation Exp.					
17		Labor & Labor Loading	6.0	8,087,437	-	7,010	-
18		Materials & Expenses	6.0	1,490,584	-	1,292	-
19	880	Other Expenses					
20		Labor & Labor Loading	5.5	6,543,834	12,501	3,251	2,484
21		Materials & Expenses	5.5	4,535,239	8,664	2,253	1,722
22	881	Rents	5.5	2,250,258	4,299	1,118	854
23		Total Distribution-Operations		$ 56,117,507	$ 107,204	$ 27,876	$ 21,303
		Operation and Maintenance Expense					
		Distribution Expenses					
24	885	Maint. Supervision & Eng.					
25		Labor & Labor Loading	6.6	$ 2,797,818	$ 9,977	$ 331	$ 0
26		Materials & Expenses	6.6	338,062	1,205	40	0
27	886	Maint. of Structures & Imp.					
28		Labor & Labor Loading	1.0	26,673	284	-	-
29		Materials & Expenses	1.0	80,753	861	-	-
30	887	Maint. of Mains					
31		Labor & Labor Loading	2.2	8,500,012	50,962	81	0
32		Materials & Expenses	2.2	7,043,715	42,230	67	0
33	889	Maint. of Meas. & Reg. Sta-Gen					
34		Labor & Labor Loading	2.2	1,461,314	8,761	14	0
35		Materials & Expenses	2.2	580,480	3,480	6	0
36	892	Maint. of Services					
37		Labor & Labor Loading	3.3	6,159,505	0	957	-
38		Materials & Expenses	3.3	3,973,153	0	617	-
39	893	Maint of Meter & House Reg.					
40		Labor & Labor Loading	6.0	1,281,534	-	1,111	-
41		Materials & Expenses	6.0	781,684	-	678	-
42	894	Maint of Other Equip.					
43		Labor & Labor Loading	6.6	196,535	701	23	0
44		Materials & Expenses	6.6	189,711	676	22	0
45		Total Distribution-Maintenance		$ 33,410,949	$ 119,138	$ 3,948	$ 0
46		Total Distribution O & M		$ 89,528,455	$ 226,342	$ 31,824	$ 21,303

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Electric Generation Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(d)	(e)	(f)
		Customer Accounts Expenses					
1	901	Supervision					
2		Labor & Labor Loading	10.1	$ 4,093,979	$ -	$ 532	$ -
3		Materials & Expenses	10.1	275,497	-	36	-
4	902	Meter Reading Exp.					
5		Labor & Labor Loading	13.0	4,860,483	-	683	-
6		Materials & Expenses	13.0	2,194,002	-	308	-
7	903	Customer Records & Collections					
8		Labor & Labor Loading	13.0	-	-	-	-
9		Materials & Expenses	13.0	404,465	-	57	-
10	903	Customer Records & Collections - LCS					
11		Labor & Labor Loading - LCS	13.0	16,062,467	-	2,256	-
12		Materials & Expenses - LCS	13.0	7,441,028	-	1,045	-
13	904	Uncollectible Accounts Exp.	4.0	2,977,729	-	65	-
14	905	Misc. Customer Accounts Exp.					
15		Labor & Labor Loading	10.1	404,465	-	53	-
16		Materials & Expenses	10.1	16,795	-	2	-
17		Total Customer Accounts Expenses		$ 38,730,909	$ -	$ 5,037	$ -
		Customer Service & Info. Exp.					
18	908	Customer Assistance Exp.					
19		Labor & Labor Loading	13.0	$ 514,896	$ -	$ 72	$ -
20		Materials & Expenses	13.0	564,797	-	79	-
21	909	Info. & Instructional Exp.					
22		Labor & Labor Loading	13.0	-	-	-	-
23		Materials & Expenses	13.0	25,125	-	4	-
24	910	Misc. C.S. & I. Expense					
25		Labor & Labor Loading	13.0	-	-	-	-
26		Materials & Expenses	13.0	21,977	-	3	-
27		Total Customer Service & Info. Exp.		$ 1,126,796	$ -	$ 158	$ -
		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		$ 130,087,761	$ 226,342	$ 37,019	$ 44,470
39		Allocation Percentage	Total O&M	100.00%	0.17%	0.03%	0.03%
		Other Operating Deductions					
40		Administrative & General Expense	Total O&M	56,946,694	99,083	16,205	19,467
41		Interest on Customer Deposits	8.0	1,915,314	-	-	-
42		Taxes Other Than Income	1.1	33,124,880	111,230	6,339	3,928
43		Total Allocated Operating Deductions		$ 222,074,648	$ 436,654	$ 59,564	$ 67,865
		Tax Adjustments					
44		Interest Expense	1.1	48,035,008	161,296	9,193	5,696
45		State South Georgia	1.1	29,686	100	6	4
46		Investment Tax Credit	1.1	(528,360)	(1,774)	(101)	(63)
47		Federal South Georgia	1.1	290,114	974	56	34

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Electric Generation Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(d)	(e)	(f)
		Summary of Allocated Cost of Service					
		Rate Base					
1		Direct Net Plant		$ 1,267,124,121	$ 4,254,867	$ 242,501	$ 150,254
2		Systems Allocable Net Plant		34,448,206	115,673	6,593	4,085
3		Cash Working Capital	1.1	(10,379,937)	(18,060)	(2,954)	(3,548)
4		Materials & Supplies	1.1	12,389,898	41,604	2,371	1,469
5		Prepayments	1.1	3,671,971	12,330	703	435
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
7		Customer Deposits	8.0	(31,921,898)	-	-	-
8		Customer Advances	8.0	(37,910,017)	-	-	-
9		Deferred Taxes	1.1	(142,632,297)	(478,944)	(27,297)	(16,913)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-
11		Total Rate Base		$ 1,094,790,047	$ 3,927,470	$ 221,917	$ 135,782
12		Net Operating Margin	Direct	$ 381,188,845	$ 2,453,502	$ 75,828	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 5,784,028	$ 37,229	$ 1,151	$ -
14		Late Charges	Direct	$ 2,430,203	$ 2,190	$ 68	
15		Service Establishment Charges	9	$ 8,267,657	-	301	-
16		Reconnect / Reread Charges	4	$ 569,215	-	12	-
17		Other Revenue - Labor	Net Op. Marg.	$ 1,313	$ 8	$ 0	$ -
18		Other Revenue - Parts & Material	Net Op. Marg.	$ 2,621	$ 17	$ 1	$ -
19		Other Revenue - Field Collection Fee	4	$ 304,887	-	7	-
20		Other Revenue - Returned Item Fee	4	$ 173,412	-	4	-
21		Other Revenue - Rental Income	Net Op. Marg.	$ 512,498	$ 3,299	$ 102	$ -
22		Total Revenue		399,234,678	2,496,245	77,473	-
23		O & M		(130,087,761)	(226,342)	(37,019)	(44,470)
24		A & G	Total O&M	(56,946,694)	(99,083)	(16,205)	(19,467)
25		Depreciation Expense		(87,887,713)	(295,117)	(16,820)	(10,422)
26		Interest on Customer Deposits	8.0	(1,915,314)	-	-	-
27		Taxes other than Income	1.1	(33,124,880)	(111,230)	(6,339)	(3,928)
		State Income Tax					
28		Taxable Income before Interest Exp.		$ 89,272,317	$ 1,764,473	$ 1,089	$(78,287)
29		Interest Expense	1.1	(48,035,008)	(161,296)	(9,193)	(5,696)
30		State Taxable Income		$ 41,237,309	$ 1,603,176	$(8,104)	$(83,983)
31		State Income Tax		2,873,416	111,709	(565)	(5,852)
32		South Georgia	1.1	29,686	100	6	4
33		State Income Tax		2,903,102	111,809	(559)	(5,848)
		Federal Income Tax					
34		Taxable Income before Interest Exp.		89,272,317	1,764,473	1,089	(78,287)
35		Interest Expense	1.1	(48,035,008)	(161,296)	(9,193)	(5,696)
36		Federal Taxable Income		41,237,309	1,603,176	(8,104)	(83,983)
37		Federal Income Tax		$ 13,427,363	$ 522,013	$(2,639)	$(27,346)
38		I T C	1.1	(528,360)	(1,774)	(101)	(63)
39		South Georgia	1.1	290,114	974	56	34
40		Total Federal Income Tax		$ 13,189,117	$ 521,213	$(2,684)	$(27,374)
41		Regulatory Amortization	1.1	-	-	-	-
42		Net Income		$ 73,180,099	$ 1,131,450	$ 4,332	$(45,064)
43		Rate of Return on Rate Base		6.68%	28.81%	1.95%	(33.19%)
44		Rate of Return by Class Total				25.45%	

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Small Essential Agr. User Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(g)	(h)	(i)
		Direct Depreciation Expense					
1	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 75,910,024	$ 266,348	$ 45,964	$ 3,017
5	389-398	General	1.1	$ 4,919,293	$ 17,260	$ 2,979	$ 196
6		Total Direct Dep. Exp.		$ 80,829,317	$ 283,608	$ 48,943	$ 3,213
		Systems Allocable Depreciation Expense					
7	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
8	389-398	General	1.1	$ 2,540,252	$ 8,913	$ 1,538	$ 101
		System Allocable Amortization					
9		Miscellaneous Intangible	1.1	4,002,161	14,043	2,423	159
10		Structures-Leasehold Improvements	1.1	104,525	367	63	4
11		Total System Allocable Amortization		4,106,686	14,409	2,487	163
12		Total System Alloc Dep. Exp. & Amortization		6,646,938	23,322	4,025	264
13		Total Depreciation Expense		87,476,255	306,931	52,967	3,477
14		Amortization	1.1	126,930	445	77	5
15		Amortization-Gas Plant Acquisition	1.1	(52,996)	(186)	(32)	(2)
16		Regulatory Amortizations	1.1	337,524	1,184	204	13
17		-	7.0	-	-	-	-
18		-	1.1	-	-	-	-
19		-	1.1	-	-	-	-
20		Total Depreciation & Amortization Expense		$ 87,887,713	$ 308,374	$ 53,216	$ 3,494
		Operation and Maintenance Expense					
		Gas Supply Expense					
21	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -
22	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-
23	805	Purchased Gas Cost Adj.	3.0	-	-	-	-
24	810	Gas Used for Compressor Sta. Fuel--	3.0	-	-	-	-
25	813	Other Gas Supply Expense	3.0	-	-	-	-
26		Labor & Labor Loading	3.0	641,618	-	-	7,102
27		Materials & Expenses	3.0	59,983	-	-	664
28		Total Gas Supply Expense		$ 701,601	$ -	$ -	$ 7,766

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Small Essential Agr. User Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(g)	(h)	(i)
		Distribution Expenses					
1	870	Operation Supervision & Eng.					
2		Labor & Labor Loading	5.5	$ 8,990,906	$ 17,947	$ 11,083	$ 1,144
3		Materials & Expenses	5.5	1,458,368	2,911	1,798	186
4	871	Distribution Load Dispatching					
5		Labor & Labor Loading	3.0	258,538	-	-	2,862
6		Materials & Expenses	3.0	113,250	-	-	1,254
7	874	Mains & Svcs. Expense					
8		Labor & Labor Loading	4.4	6,159,141	25,551	2,057	0
9		Materials & Expenses	4.4	5,540,228	22,984	1,851	0
10	875	Meas. & Reg. Sta. Exp.-Gen.					
11		Labor & Labor Loading	2.2	1,859,618	11,650	86	0
12		Materials & Expenses	2.2	697,287	4,368	32	0
13	878	Meter & House Reg. Exp.					
14		Labor & Labor Loading	6.0	6,919,581	-	14,002	-
15		Materials & Expenses	6.0	1,213,237	-	2,455	-
16	879	Customer Installation Exp.					
17		Labor & Labor Loading	6.0	8,087,437	-	16,365	-
18		Materials & Expenses	6.0	1,490,584	-	3,016	-
19	880	Other Expenses					
20		Labor & Labor Loading	5.5	6,543,834	13,063	8,067	833
21		Materials & Expenses	5.5	4,535,239	9,053	5,591	577
22	881	Rents	5.5	2,250,258	4,492	2,774	286
23		Total Distribution-Operations		$ 56,117,507	$ 112,020	$ 69,178	$ 7,141
		Operation and Maintenance Expense					
		Distribution Expenses					
24	885	Maint. Supervision & Eng.					
25		Labor & Labor Loading	6.6	$ 2,797,818	$ 10,425	$ 1,319	$ 0
26		Materials & Expenses	6.6	338,062	1,260	159	0
27	886	Maint. of Structures & Imp.					
28		Labor & Labor Loading	1.0	26,673	297	-	-
29		Materials & Expenses	1.0	80,753	900	-	-
30	887	Maint. of Mains					
31		Labor & Labor Loading	2.2	8,500,012	53,251	393	0
32		Materials & Expenses	2.2	7,043,715	44,127	326	0
33	889	Maint. of Meas. & Reg. Sta-Gen					
34		Labor & Labor Loading	2.2	1,461,314	9,155	68	0
35		Materials & Expenses	2.2	580,480	3,637	27	0
36	892	Maint. of Services					
37		Labor & Labor Loading	3.3	6,159,505	0	5,533	-
38		Materials & Expenses	3.3	3,973,153	0	3,569	-
39	893	Maint of Meter & House Reg.					
40		Labor & Labor Loading	6.0	1,281,534	-	2,593	-
41		Materials & Expenses	6.0	781,684	-	1,582	-
42	894	Maint of Other Equip.					
43		Labor & Labor Loading	6.6	196,535	732	93	0
44		Materials & Expenses	6.6	189,711	707	89	0
45		Total Distribution-Maintenance		$ 33,410,949	$ 124,490	$ 15,750	$ 0
46		Total Distribution O & M		$ 89,528,455	$ 236,510	$ 84,929	$ 7,141

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Small Essential Agr. User Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(g)	(h)	(i)
		Customer Accounts Expenses					
1	901	Supervision					
2		Labor & Labor Loading	10.1	$ 4,093,979	$ -	$ 6,855	$ -
3		Materials & Expenses	10.1	275,497	-	461	-
4	902	Meter Reading Exp.					
5		Labor & Labor Loading	13.0	4,860,483	-	8,872	-
6		Materials & Expenses	13.0	2,194,002	-	4,005	-
7	903	Customer Records & Collections					
8		Labor & Labor Loading	13.0	-	-	-	-
9		Materials & Expenses	13.0	404,465	-	738	-
10	903	Customer Records & Collections - LCS					
11		Labor & Labor Loading - LCS	13.0	16,062,467	-	29,321	-
12		Materials & Expenses - LCS	13.0	7,441,028	-	13,583	-
13	904	Uncollectible Accounts Exp.	4.0	2,977,729	-	315	-
14	905	Misc. Customer Accounts Exp.					
15		Labor & Labor Loading	10.1	404,465	-	677	-
16		Materials & Expenses	10.1	16,795	-	28	-
17		Total Customer Accounts Expenses		$ 38,730,909	$ -	$ 64,856	$ -
		Customer Service & Info. Exp.					
18	908	Customer Assistance Exp.					
19		Labor & Labor Loading	13.0	$ 514,896	$ -	$ 940	$ -
20		Materials & Expenses	13.0	564,797	-	1,031	-
21	909	Info. & Instructional Exp.					
22		Labor & Labor Loading	13.0	-	-	-	-
23		Materials & Expenses	13.0	25,125	-	46	-
24	910	Misc. C.S. & I. Expense					
25		Labor & Labor Loading	13.0	-	-	-	-
26		Materials & Expenses	13.0	21,977	-	40	-
27		Total Customer Service & Info. Exp.		$ 1,126,796	$ -	$ 2,057	$ -
		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		$ 130,087,761	$ 236,510	$ 151,841	$ 14,907
39		Allocation Percentage	Total O&M	100.00%	0.18%	0.12%	0.01%
		Other Operating Deductions					
40		Administrative & General Expense	Total O&M	56,946,694	103,533	66,470	6,526
41		Interest on Customer Deposits	8.0	1,915,314	-	-	-
42		Taxes Other Than Income	1.1	33,124,880	116,226	20,057	1,317
43		Total Allocated Operating Deductions		$ 222,074,648	$ 456,269	$ 238,368	$ 22,750
		Tax Adjustments					
44		Interest Expense	1.1	48,035,008	168,542	29,085	1,909
45		State South Georgia	1.1	29,686	104	18	1
46		Investment Tax Credit	1.1	(528,360)	(1,854)	(320)	(21)
47		Federal South Georgia	1.1	290,114	1,018	176	12

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Small Essential Agr. User Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(g)	(h)	(i)
		Summary of Allocated Cost of Service					
		Rate Base					
1		Direct Net Plant		$ 1,267,124,121	$ 4,446,000	$ 767,249	$ 50,369
2		Systems Allocable Net Plant		34,448,206	120,870	20,859	1,369
3		Cash Working Capital	1.1	(10,379,937)	(18,872)	(12,116)	(1,189)
4		Materials & Supplies	1.1	12,389,898	43,473	7,502	493
5		Prepayments	1.1	3,671,971	12,884	2,223	146
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
7		Customer Deposits	8.0	(31,921,898)	-	-	-
8		Customer Advances	8.0	(37,910,017)	-	-	-
9		Deferred Taxes	1.1	(142,632,297)	(500,459)	(86,364)	(5,670)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-
11		Total Rate Base		$ 1,094,790,047	$ 4,103,896	$ 699,353	$ 45,518
12		Net Operating Margin	Direct	$ 381,188,845	$ 2,995,484	$ 109,440	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 5,784,028	$ 45,452	$ 1,661	$ -
14		Late Charges	Direct	$ 2,430,203			
15		Service Establishment Charges	9	$ 8,267,657	-	1,452	-
16		Reconnect / Reread Charges	4	$ 569,215	-	60	-
17		Other Revenue - Labor	Net Op. Marg.	$ 1,313	$ 10	$ 0	$ -
18		Other Revenue - Parts & Material	Net Op. Marg.	$ 2,621	$ 21	$ 1	$ -
19		Other Revenue - Field Collection Fee	4	$ 304,887	-	32	-
20		Other Revenue - Returned Item Fee	4	$ 173,412	-	18	-
21		Other Revenue - Rental Income	Net Op. Marg.	$ 512,498	$ 4,027	$ 147	$ -
22		Total Revenue		399,234,678	3,044,995	112,812	-
23		O & M		(130,087,761)	(236,510)	(151,841)	(14,907)
24		A & G	Total O&M	(56,946,694)	(103,533)	(66,470)	(6,526)
25		Depreciation Expense		(87,887,713)	(308,374)	(53,216)	(3,494)
26		Interest on Customer Deposits	8.0	(1,915,314)	-	-	-
27		Taxes other than Income	1.1	(33,124,880)	(116,226)	(20,057)	(1,317)
		State Income Tax					
28		Taxable Income before Interest Exp.		$ 89,272,317	$ 2,280,351	$(178,773)	$(26,244)
29		Interest Expense	1.1	(48,035,008)	(168,542)	(29,085)	(1,909)
30		State Taxable Income		$ 41,237,309	$ 2,111,809	$(207,858)	$(28,153)
31		State Income Tax		2,873,416	147,151	(14,484)	(1,962)
32		South Georgia	1.1	29,686	104	18	1
33		State Income Tax		2,903,102	147,255	(14,466)	(1,961)
		Federal Income Tax					
34		Taxable Income before Interest Exp.		89,272,317	2,280,351	(178,773)	(26,244)
35		Interest Expense	1.1	(48,035,008)	(168,542)	(29,085)	(1,909)
36		Federal Taxable Income		41,237,309	2,111,809	(207,858)	(28,153)
37		Federal Income Tax		$ 13,427,363	$ 687,630	$(67,681)	$(9,167)
38		I T C	1.1	(528,360)	(1,854)	(320)	(21)
39		South Georgia	1.1	290,114	1,018	176	12
40		Total Federal Income Tax		$ 13,189,117	$ 686,794	$(67,825)	$(9,176)
41		Regulatory Amortization	1.1	-	-	-	-
42		Net Income		$ 73,180,099	$ 1,446,301	$(96,482)	$(15,107)
43		Rate of Return on Rate Base		6.68%	35.24%	(13.80%)	(33.19%)
44		Rate of Return by Class Total				27.53%	

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Natural Gas Engine Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(j)	(k)	(l)
		Direct Depreciation Expense					
1	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 75,910,024	$ 126,385	$ 190,520	$ 5,467
5	389-398	General	1.1	$ 4,919,293	$ 8,190	$ 12,346	$ 354
6		Total Direct Dep. Exp.		$ 80,829,317	$ 134,575	$ 202,866	$ 5,821
		Systems Allocable Depreciation Expense					
7	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
8	389-398	General	1.1	$ 2,540,252	$ 4,229	$ 6,376	$ 183
		System Allocable Amortization					
9		Miscellaneous Intangible	1.1	4,002,161	6,663	10,045	288
10		Structures-Leasehold Improvements	1.1	104,525	174	262	8
11		Total System Allocable Amortization		4,106,686	6,837	10,307	296
12		Total System Alloc Dep. Exp. & Amortization		6,646,938	11,067	16,683	479
13		Total Depreciation Expense		87,476,255	145,642	219,549	6,300
14		Amortization	1.1	126,930	211	319	9
15		Amortization-Gas Plant Acquisition	1.1	(52,996)	(88)	(133)	(4)
16		Regulatory Amortizations	1.1	337,524	562	847	24
17		-	7.0	-	-	-	-
18		-	1.1	-	-	-	-
19		-	1.1	-	-	-	-
20		Total Depreciation & Amortization Expense		$ 87,887,713	$ 146,327	$ 220,581	$ 6,329
		Operation and Maintenance Expense					
		Gas Supply Expense					
21	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -
22	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-
23	805	Purchased Gas Cost Adj.	3.0	-	-	-	-
24	810	Gas Used for Compressor Sta. Fuel--	3.0	-	-	-	-
25	813	Other Gas Supply Expense	3.0	-	-	-	-
26		Labor & Labor Loading	3.0	641,618	-	-	12,867
27		Materials & Expenses	3.0	59,983	-	-	1,203
28		Total Gas Supply Expense		$ 701,601	$ -	$ -	$ 14,070

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Natural Gas Engine Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(j)	(k)	(l)
		Distribution Expenses					
1	870	Operation Supervision & Eng.					
2		Labor & Labor Loading	5.5	$ 8,990,906	$ 8,516	$ 47,256	$ 2,073
3		Materials & Expenses	5.5	1,458,368	1,381	7,665	336
4	871	Distribution Load Dispatching					
5		Labor & Labor Loading	3.0	258,538	-	-	5,185
6		Materials & Expenses	3.0	113,250	-	-	2,271
7	874	Mains & Svcs. Expense					
8		Labor & Labor Loading	4.4	6,159,141	12,124	8,135	0
9		Materials & Expenses	4.4	5,540,228	10,906	7,317	0
10	875	Meas. & Reg. Sta. Exp.-Gen.					
11		Labor & Labor Loading	2.2	1,859,618	5,528	361	0
12		Materials & Expenses	2.2	697,287	2,073	135	0
13	878	Meter & House Reg. Exp.					
14		Labor & Labor Loading	6.0	6,919,581	-	60,177	-
15		Materials & Expenses	6.0	1,213,237	-	10,551	-
16	879	Customer Installation Exp.					
17		Labor & Labor Loading	6.0	8,087,437	-	70,334	-
18		Materials & Expenses	6.0	1,490,584	-	12,963	-
19	880	Other Expenses					
20		Labor & Labor Loading	5.5	6,543,834	6,198	34,395	1,509
21		Materials & Expenses	5.5	4,535,239	4,296	23,837	1,046
22	881	Rents	5.5	2,250,258	2,131	11,827	519
23		Total Distribution-Operations		$ 56,117,507	$ 53,154	$ 294,955	$ 12,938
		Operation and Maintenance Expense					
		Distribution Expenses					
24	885	Maint. Supervision & Eng.					
25		Labor & Labor Loading	6.6	$ 2,797,818	$ 4,947	$ 5,347	$ 0
26		Materials & Expenses	6.6	338,062	598	646	0
27	886	Maint. of Structures & Imp.					
28		Labor & Labor Loading	1.0	26,673	141	-	-
29		Materials & Expenses	1.0	80,753	427	-	-
30	887	Maint. of Mains					
31		Labor & Labor Loading	2.2	8,500,012	25,268	1,650	0
32		Materials & Expenses	2.2	7,043,715	20,939	1,367	0
33	889	Maint. of Meas. & Reg. Sta-Gen					
34		Labor & Labor Loading	2.2	1,461,314	4,344	284	0
35		Materials & Expenses	2.2	580,480	1,726	113	0
36	892	Maint. of Services					
37		Labor & Labor Loading	3.3	6,159,505	0	21,739	-
38		Materials & Expenses	3.3	3,973,153	0	14,023	-
39	893	Maint of Meter & House Reg.					
40		Labor & Labor Loading	6.0	1,281,534	-	11,145	-
41		Materials & Expenses	6.0	781,684	-	6,798	-
42	894	Maint of Other Equip.					
43		Labor & Labor Loading	6.6	196,535	347	376	0
44		Materials & Expenses	6.6	189,711	335	363	0
45		Total Distribution-Maintenance		$ 33,410,949	$ 59,072	$ 63,850	$ 0
46		Total Distribution O & M		$ 89,528,455	$ 112,226	$ 358,805	$ 12,938

SOUTHWEST GAS CORPORATION
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CLASS COST OF SERVICE STUDY
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APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Natural Gas Engine Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(j)	(k)	(l)
		Customer Accounts Expenses					
1	901	Supervision					
2		Labor & Labor Loading	10.1	$ 4,093,979	$ -	$ 8,729	$ -
3		Materials & Expenses	10.1	275,497	-	587	-
4	902	Meter Reading Exp.					
5		Labor & Labor Loading	13.0	4,860,483	-	11,153	-
6		Materials & Expenses	13.0	2,194,002	-	5,035	-
7	903	Customer Records & Collections					
8		Labor & Labor Loading	13.0	-	-	-	-
9		Materials & Expenses	13.0	404,465	-	928	-
10	903	Customer Records & Collections - LCS					
11		Labor & Labor Loading - LCS	13.0	16,062,467	-	36,858	-
12		Materials & Expenses - LCS	13.0	7,441,028	-	17,075	-
13	904	Uncollectible Accounts Exp.	4.0	2,977,729	-	1,321	-
14	905	Misc. Customer Accounts Exp.					
15		Labor & Labor Loading	10.1	404,465	-	862	-
16		Materials & Expenses	10.1	16,795	-	36	-
17		Total Customer Accounts Expenses		$ 38,730,909	$ -	$ 82,585	$ -
		Customer Service & Info. Exp.					
18	908	Customer Assistance Exp.					
19		Labor & Labor Loading	13.0	$ 514,896	$ -	$ 1,182	$ -
20		Materials & Expenses	13.0	564,797	-	1,296	-
21	909	Info. & Instructional Exp.					
22		Labor & Labor Loading	13.0	-	-	-	-
23		Materials & Expenses	13.0	25,125	-	58	-
24	910	Misc. C.S. & I. Expense					
25		Labor & Labor Loading	13.0	-	-	-	-
26		Materials & Expenses	13.0	21,977	-	50	-
27		Total Customer Service & Info. Exp.		$ 1,126,796	$ -	$ 2,586	$ -
		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		$ 130,087,761	$ 112,226	$ 443,976	$ 27,008
39		Allocation Percentage	Total O&M	100.00%	0.09%	0.34%	0.02%
		Other Operating Deductions					
40		Administrative & General Expense	Total O&M	56,946,694	49,128	194,353	11,823
41		Interest on Customer Deposits	8.0	1,915,314	-	-	-
42		Taxes Other Than Income	1.1	33,124,880	55,151	83,137	2,386
43		Total Allocated Operating Deductions		$ 222,074,648	$ 216,504	$ 721,466	$ 41,217
		Tax Adjustments					
44		Interest Expense	1.1	48,035,008	79,975	120,559	3,459
45		State South Georgia	1.1	29,686	49	75	2
46		Investment Tax Credit	1.1	(528,360)	(880)	(1,326)	(38)
47		Federal South Georgia	1.1	290,114	483	728	21

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Natural Gas Engine Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(j)	(k)	(l)
		Summary of Allocated Cost of Service					
		Rate Base					
1		Direct Net Plant		$ 1,267,124,121	$ 2,109,671	$ 3,180,240	$ 91,254
2		Systems Allocable Net Plant		34,448,206	57,354	86,458	2,481
3		Cash Working Capital	1.1	(10,379,937)	(8,955)	(35,426)	(2,155)
4		Materials & Supplies	1.1	12,389,898	20,628	31,096	892
5		Prepayments	1.1	3,671,971	6,114	9,216	264
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
7		Customer Deposits	8.0	(31,921,898)	-	-	-
8		Customer Advances	8.0	(37,910,017)	-	-	-
9		Deferred Taxes	1.1	(142,632,297)	(237,473)	(357,980)	(10,272)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-
11		Total Rate Base		$ 1,094,790,047	$ 1,947,339	$ 2,913,605	$ 82,465
12		Net Operating Margin	Direct	$ 381,188,845	$ 2,313,564	$ 245,955	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 5,784,028	$ 35,105	$ 3,732	$ -
14		Late Charges	Direct	$ 2,430,203	$ 14,961	$ 1,590	
15		Service Establishment Charges	9	$ 8,267,657	-	6,097	-
16		Reconnect / Reread Charges	4	$ 569,215	-	252	-
17		Other Revenue - Labor	Net Op. Marg.	$ 1,313	$ 8	$ 1	$ -
18		Other Revenue - Parts & Material	Net Op. Marg.	$ 2,621	$ 16	$ 2	$ -
19		Other Revenue - Field Collection Fee	4	$ 304,887	-	135	-
20		Other Revenue - Returned Item Fee	4	$ 173,412	-	77	-
21		Other Revenue - Rental Income	Net Op. Marg.	$ 512,498	$ 3,111	$ 331	$ -
22		Total Revenue		399,234,678	2,366,765	258,173	-
23		O & M		(130,087,761)	(112,226)	(443,976)	(27,008)
24		A & G	Total O&M	(56,946,694)	(49,128)	(194,353)	(11,823)
25		Depreciation Expense		(87,887,713)	(146,327)	(220,581)	(6,329)
26		Interest on Customer Deposits	8.0	(1,915,314)	-	-	-
27		Taxes other than Income	1.1	(33,124,880)	(55,151)	(83,137)	(2,386)
		State Income Tax					
28		Taxable Income before Interest Exp.		$ 89,272,317	$ 2,003,933	$(683,875)	$(47,546)
29		Interest Expense	1.1	(48,035,008)	(79,975)	(120,559)	(3,459)
30		State Taxable Income		$ 41,237,309	$ 1,923,959	$(804,434)	$(51,005)
31		State Income Tax		2,873,416	134,061	(56,053)	(3,554)
32		South Georgia	1.1	29,686	49	75	2
33		State Income Tax		2,903,102	134,111	(55,978)	(3,552)
		Federal Income Tax					
34		Taxable Income before Interest Exp.		89,272,317	2,003,933	(683,875)	(47,546)
35		Interest Expense	1.1	(48,035,008)	(79,975)	(120,559)	(3,459)
36		Federal Taxable Income		41,237,309	1,923,959	(804,434)	(51,005)
37		Federal Income Tax		$ 13,427,363	$ 626,464	$(261,933)	$(16,608)
38		I T C	1.1	(528,360)	(880)	(1,326)	(38)
39		South Georgia	1.1	290,114	483	728	21
40		Total Federal Income Tax		$ 13,189,117	$ 626,067	$(262,531)	$(16,625)
41		Regulatory Amortization	1.1	-	-	-	-
42		Net Income		$ 73,180,099	$ 1,243,755	$(365,365)	$(27,369)
43		Rate of Return on Rate Base		6.68%	63.87%	(12.54%)	(33.19%)
44		Rate of Return by Class Total				17.22%	

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Street Lighting Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(m)	(n)	(o)
		Direct Depreciation Expense					
1	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
2	325.5-336	Production Plant	Prod. Plant	$ -	$ -	$ -	$ -
3	366.1-371	Transmission	Trans. Plant	$ -	$ -	$ -	$ -
4	374.1-387	Distribution	Dist. Plant	$ 75,910,024	$ 1,890	$ 24,964	$ 43
5	389-398	General	1.1	$ 4,919,293	$ 122	$ 1,618	$ 3
6		Total Direct Dep. Exp.		$ 80,829,317	$ 2,012	$ 26,582	$ 46
		Systems Allocable Depreciation Expense					
7	301-303	Intangible	Intang. Plant	$ -	$ -	$ -	$ -
8	389-398	General	1.1	$ 2,540,252	$ 63	$ 835	$ 1
		System Allocable Amortization					
9		Miscellaneous Intangible	1.1	4,002,161	100	1,316	2
10		Structures-Leasehold Improvements	1.1	104,525	3	34	0
11		Total System Allocable Amortization		4,106,686	102	1,351	2
12		Total System Alloc Dep. Exp. & Amortization		6,646,938	165	2,186	4
13		Total Depreciation Expense		87,476,255	2,178	28,768	49
14		Amortization	1.1	126,930	3	42	0
15		Amortization-Gas Plant Acquisition	1.1	(52,996)	(1)	(17)	(0)
16		Regulatory Amortizations	1.1	337,524	8	111	0
17		-	7.0	-	-	-	-
18		-	1.1	-	-	-	-
19		-	1.1	-	-	-	-
20		Total Depreciation & Amortization Expense		$ 87,887,713	$ 2,188	$ 28,903	$ 50
		Operation and Maintenance Expense					
		Gas Supply Expense					
21	800	Natural Gas Wellhead Purchases	3.0	$ -	$ -	$ -	$ -
22	803	Natural Gas Transmission Line Purch	3.0	-	-	-	-
23	805	Purchased Gas Cost Adj.	3.0	-	-	-	-
24	810	Gas Used for Compressor Sta. Fuel--I	3.0	-	-	-	-
25	813	Other Gas Supply Expense	3.0	-	-	-	-
26		Labor & Labor Loading	3.0	641,618	-	-	101
27		Materials & Expenses	3.0	59,983	-	-	9
28		Total Gas Supply Expense		$ 701,601	$ -	$ -	$ 110

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
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Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Street Lighting Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(m)	(n)	(o)
		Distribution Expenses					
1	870	Operation Supervision & Eng.					
2		Labor & Labor Loading	5.5	$ 8,990,906	$ 127	$ 1,489	$ 16
3		Materials & Expenses	5.5	1,458,368	21	241	3
4	871	Distribution Load Dispatching					
5		Labor & Labor Loading	3.0	258,538	-	-	41
6		Materials & Expenses	3.0	113,250	-	-	18
7	874	Mains & Svcs. Expense					
8		Labor & Labor Loading	4.4	6,159,141	181	2,470	0
9		Materials & Expenses	4.4	5,540,228	163	2,222	0
10	875	Meas. & Reg. Sta. Exp.-Gen.					
11		Labor & Labor Loading	2.2	1,859,618	83	482	0
12		Materials & Expenses	2.2	697,287	31	181	0
13	878	Meter & House Reg. Exp.					
14		Labor & Labor Loading	6.0	6,919,581	-	-	-
15		Materials & Expenses	6.0	1,213,237	-	-	-
16	879	Customer Installation Exp.					
17		Labor & Labor Loading	6.0	8,087,437	-	-	-
18		Materials & Expenses	6.0	1,490,584	-	-	-
19	880	Other Expenses					
20		Labor & Labor Loading	5.5	6,543,834	93	1,083	12
21		Materials & Expenses	5.5	4,535,239	64	751	8
22	881	Rents	5.5	2,250,258	32	373	4
23		Total Distribution-Operations		$ 56,117,507	$ 795	$ 9,291	$ 101
		Operation and Maintenance Expense					
		Distribution Expenses					
24	885	Maint. Supervision & Eng.					
25		Labor & Labor Loading	6.6	$ 2,797,818	$ 74	$ 1,071	$ 0
26		Materials & Expenses	6.6	338,062	9	129	0
27	886	Maint. of Structures & Imp.					
28		Labor & Labor Loading	1.0	26,673	2	-	-
29		Materials & Expenses	1.0	80,753	6	-	-
30	887	Maint. of Mains					
31		Labor & Labor Loading	2.2	8,500,012	378	2,203	0
32		Materials & Expenses	2.2	7,043,715	313	1,826	0
33	889	Maint. of Meas. & Reg. Sta-Gen					
34		Labor & Labor Loading	2.2	1,461,314	65	379	0
35		Materials & Expenses	2.2	580,480	26	150	0
36	892	Maint. of Services					
37		Labor & Labor Loading	3.3	6,159,505	0	4,182	-
38		Materials & Expenses	3.3	3,973,153	0	2,698	-
39	893	Maint of Meter & House Reg.					
40		Labor & Labor Loading	6.0	1,281,534	-	-	-
41		Materials & Expenses	6.0	781,684	-	-	-
42	894	Maint of Other Equip.					
43		Labor & Labor Loading	6.6	196,535	5	75	0
44		Materials & Expenses	6.6	189,711	5	73	0
45		Total Distribution-Maintenance		$ 33,410,949	$ 883	$ 12,786	$ 0
46		Total Distribution O & M		$ 89,528,455	$ 1,678	$ 22,077	$ 101

SOUTHWEST GAS CORPORATION
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CLASS COST OF SERVICE STUDY
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APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Street Lighting Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(m)	(n)	(o)
		Customer Accounts Expenses					
1	901	Supervision					
2		Labor & Labor Loading	10.1	$ 4,093,979	$ -	$ 312	$ -
3		Materials & Expenses	10.1	275,497	-	21	-
4	902	Meter Reading Exp.					
5		Labor & Labor Loading	13.0	4,860,483	-	130	-
6		Materials & Expenses	13.0	2,194,002	-	59	-
7	903	Customer Records & Collections					
8		Labor & Labor Loading	13.0	-	-	-	-
9		Materials & Expenses	13.0	404,465	-	11	-
10	903	Customer Records & Collections - LCS					
11		Labor & Labor Loading - LCS	13.0	16,062,467	-	429	-
12		Materials & Expenses - LCS	13.0	7,441,028	-	199	-
13	904	Uncollectible Accounts Exp.	4.0	2,977,729	-	1,764	-
14	905	Misc. Customer Accounts Exp.					
15		Labor & Labor Loading	10.1	404,465	-	31	-
16		Materials & Expenses	10.1	16,795	-	1	-
17		Total Customer Accounts Expenses		$ 38,730,909	$ -	$ 2,956	$ -
		Customer Service & Info. Exp.					
18	908	Customer Assistance Exp.					
19		Labor & Labor Loading	13.0	$ 514,896	$ -	$ 14	$ -
20		Materials & Expenses	13.0	564,797	-	15	-
21	909	Info. & Instructional Exp.					
22		Labor & Labor Loading	13.0	-	-	-	-
23		Materials & Expenses	13.0	25,125	-	1	-
24	910	Misc. C.S. & I. Expense					
25		Labor & Labor Loading	13.0	-	-	-	-
26		Materials & Expenses	13.0	21,977	-	1	-
27		Total Customer Service & Info. Exp.		$ 1,126,796	$ -	$ 30	$ -
		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		$ 130,087,761	$ 1,678	$ 25,063	$ 211
39		Allocation Percentage	Total O&M	100.00%	0.00%	0.02%	0.00%
		Other Operating Deductions					
40		Administrative & General Expense	Total O&M	56,946,694	735	10,972	93
41		Interest on Customer Deposits	8.0	1,915,314	-	-	-
42		Taxes Other Than Income	1.1	33,124,880	825	10,894	19
43		Total Allocated Operating Deductions		$ 222,074,648	$ 3,237	$ 46,929	$ 323
		Tax Adjustments					
44		Interest Expense	1.1	48,035,008	1,196	15,797	27
45		State South Georgia	1.1	29,686	1	10	0
46		Investment Tax Credit	1.1	(528,360)	(13)	(174)	(0)
47		Federal South Georgia	1.1	290,114	7	95	0

SOUTHWEST GAS CORPORATION
ARIZONA
CLASS COST OF SERVICE STUDY
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Account No.	Description	Allocation Factor No.	Total Amount	Street Lighting Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(m)	(n)	(o)
		Summary of Allocated Cost of Service					
		Rate Base					
1		Direct Net Plant		$ 1,267,124,121	$ 31,543	$ 416,711	$ 714
2		Systems Allocable Net Plant		34,448,206	858	11,329	19
3		Cash Working Capital	1.1	(10,379,937)	(134)	(2,000)	(17)
4		Materials & Supplies	1.1	12,389,898	308	4,075	7
5		Prepayments	1.1	3,671,971	91	1,208	2
6		Gas Plant Acquisition Adjustment	1.1	-	-	-	-
7		Customer Deposits	8.0	(31,921,898)	-	-	-
8		Customer Advances	8.0	(37,910,017)	-	-	-
9		Deferred Taxes	1.1	(142,632,297)	(3,551)	(46,907)	(80)
10		Deferred Gain Hdqtrs Bldg	7.0	-	-	-	-
11		Total Rate Base		$ 1,094,790,047	$ 29,116	$ 384,416	$ 645
12		Net Operating Margin	Direct	$ 381,188,845	$ 55,850	$ -	$ -
13		Special Contract & Optional Margin	Net Op. Marg.	$ 5,784,028	$ 847	$ -	$ -
14		Late Charges	Direct	$ 2,430,203			
15		Service Establishment Charges	9	$ 8,267,657	-	8,141	-
16		Reconnect / Reread Charges	4	$ 569,215	-	337	-
17		Other Revenue - Labor	Net Op. Marg.	$ 1,313	$ 0	$ -	$ -
18		Other Revenue - Parts & Material	Net Op. Marg.	$ 2,621	$ 0	$ -	$ -
19		Other Revenue - Field Collection Fee	4	$ 304,887	-	181	-
20		Other Revenue - Returned Item Fee	4	$ 173,412	-	103	-
21		Other Revenue - Rental Income	Net Op. Marg.	$ 512,498	$ 75	$ -	$ -
22		Total Revenue		399,234,678	56,773	8,761	-
23		O & M		(130,087,761)	(1,678)	(25,063)	(211)
24		A & G	Total O&M	(56,946,694)	(735)	(10,972)	(93)
25		Depreciation Expense		(87,887,713)	(2,188)	(28,903)	(50)
26		Interest on Customer Deposits	8.0	(1,915,314)	-	-	-
27		Taxes other than Income	1.1	(33,124,880)	(825)	(10,894)	(19)
		State Income Tax					
28		Taxable Income before Interest Exp.		$ 89,272,317	$ 51,348	$(67,071)	$(372)
29		Interest Expense	1.1	(48,035,008)	(1,196)	(15,797)	(27)
30		State Taxable Income		$ 41,237,309	$ 50,153	$(82,868)	$(399)
31		State Income Tax		2,873,416	3,495	(5,774)	(28)
32		South Georgia	1.1	29,686	1	10	0
33		State Income Tax		2,903,102	3,495	(5,764)	(28)
		Federal Income Tax					
34		Taxable Income before Interest Exp.		89,272,317	51,348	(67,071)	(372)
35		Interest Expense	1.1	(48,035,008)	(1,196)	(15,797)	(27)
36		Federal Taxable Income		41,237,309	50,153	(82,868)	(399)
37		Federal Income Tax		$ 13,427,363	$ 16,330	$(26,983)	$(130)
38		I T C	1.1	(528,360)	(13)	(174)	(0)
39		South Georgia	1.1	290,114	7	95	0
40		Total Federal Income Tax		$ 13,189,117	$ 16,324	$(27,061)	$(130)
41		Regulatory Amortization	1.1	-	-	-	-
42		Net Income		$ 73,180,099	$ 31,529	$(34,245)	$(214)
43		Rate of Return on Rate Base		6.68%	108.29%	(8.91%)	(33.19%)
44		Rate of Return by Class Total				(0.71%)	

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)
		Net Plant in Service															
		Direct															
		Intangible															
1	301	Organization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,833	$ 28,598	$ 1,222	$ -	$ -	$ -
2	302	Franchise & Consent	-	-	-	-	-	-	-	-	-	365,144	813,693	34,773	-	-	-
3	303	Misc. Intangible	-	-	-	-	-	-	-	-	-	2,206	4,917	210	-	-	-
		Total Intangible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 380,183	$ 847,207	$ 36,205	$ -	$ -	$ -
		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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,084,811	$ -	$ -	$ -	$ -	$ -
21	374.2	Rights of Way	-	-	-	-	-	-	-	-	-	739,109	-	-	-	-	-
22	375	Structures	-	-	-	-	-	-	-	-	-	46,534	-	-	-	-	-
23	376	Mains	-	-	-	-	-	-	-	-	-	353,902,646	275,401,498	1	-	-	-
24	378	Measuring & Reg. Station	-	-	-	-	-	-	-	-	-	-	-	29,625,773	-	-	-
25	380	Services	-	-	-	-	-	-	-	-	-	0	321,023,126	0	-	-	-
26	381	Meters	-	-	-	-	-	-	-	-	-	-	196,168,747	-	-	-	-
27	385	Industrial Meas. & Reg. Sta.	-	-	-	-	-	-	-	-	-	-	-	4,245,215	-	-	-
28	386	Other Prop. on Cust. Premises	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	387	Other Equipment	-	-	-	-	-	-	-	-	-	(97,479)	-	-	-	-	-
30		Total Distribution	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 355,675,621	$ 792,593,371	$ 33,870,989	$ -	$ -	$ -
31		Total Trans., Dist., Prod.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 355,675,621	$ 792,593,371	$ 33,870,989	$ -	$ -	$ -

SCHEDULE G-5
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				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)
		General															
1	389	Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 2,532,886	$ 5,644,324	$ 241,207	$ -	$ -	$ -
2	390.1	Structures & Improvements	-	-	-	-	-	-	-	-	-	5,503,084	12,263,163	524,059	-	-	-
3	390.2	Struct. & Imp.-Leasehold	-	-	-	-	-	-	-	-	-	80,738	179,917	7,689	-	-	-
4	391.0	Office Furn. & Equip.	-	-	-	-	-	-	-	-	-	1,424,835	3,175,126	135,687	-	-	-
5	391.1	Office Furn. & Computer Equip.	-	-	-	-	-	-	-	-	-	2,835,666	6,319,045	270,040	-	-	-
6	392.1	Transp. Equip.-Light	-	-	-	-	-	-	-	-	-	8,415,404	18,753,025	801,399	-	-	-
7	392.0	Transp. Equip.-Heavy	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	393	Stores Equipment	-	-	-	-	-	-	-	-	-	155,241	345,942	14,784	-	-	-
9	394	Tools, Shop, & Garage Equip.	-	-	-	-	-	-	-	-	-	2,605,465	5,806,061	248,118	-	-	-
10	395	Laboratory Equip.	-	-	-	-	-	-	-	-	-	165,997	369,910	15,808	-	-	-
11	396	Power Operated Equip.	-	-	-	-	-	-	-	-	-	1,028,022	2,290,861	97,899	-	-	-
12	397.1	Comm. Equip.-General	-	-	-	-	-	-	-	-	-	10,546	23,501	1,004	-	-	-
13	397.2	Comm. Equip.-Telemetering	-	-	-	-	-	-	-	-	-	168,478	375,439	16,044	-	-	-
14	398	Miscellaneous Equip.	-	-	-	-	-	-	-	-	-	263,004	586,083	25,046	-	-	-
15		Total General	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 25,189,366	$ 56,132,396	$ 2,398,783	$ -	$ -	$ -
		Systems Allocable															
		Intangible															
16	301	Organization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,546	$ 23,500	$ 1,004	$ -	$ -	$ -
17	302	Franchise & Consent	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	303	Miscellaneous Intang.	-	-	-	-	-	-	-	-	-	5,529,439	12,321,893	526,568	-	-	-
19		Total Intangible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,539,985	$ 12,345,393	$ 527,573	$ -	$ -	$ -
		General															
20	389	Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 66,755	$ 148,759	$ 6,357	$ -	$ -	$ -
21	390.10	Structures & Improvements	-	-	-	-	-	-	-	-	-	1,744,804	3,888,149	166,158	-	-	-
22	390.20	Struct. & Imp.-Leasehold	-	-	-	-	-	-	-	-	-	190,023	423,451	18,096	-	-	-
23	391.00	Office Furn. & Equip.	-	-	-	-	-	-	-	-	-	1,394,943	3,108,513	132,840	-	-	-
24	391.10	Office Furn. & Computer Equip.	-	-	-	-	-	-	-	-	-	333,451	743,068	31,755	-	-	-
25	392.11	Transp. Equip.-Light	-	-	-	-	-	-	-	-	-	486,161	1,083,368	46,297	-	-	-
26	392.12	Transp. Equip.-Heavy	-	-	-	-	-	-	-	-	-	21,153	47,139	2,014	-	-	-
27	392.22	Aircraft-Left Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	392.23	Aircraft-Right Engine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	393	Stores Equipment	-	-	-	-	-	-	-	-	-	3,208	7,150	306	-	-	-
30	394	Tools, Shop, & Garage Equip.	-	-	-	-	-	-	-	-	-	43,850	97,716	4,176	-	-	-
31	395	Laboratory Equip.	-	-	-	-	-	-	-	-	-	35,054	78,114	3,338	-	-	-
32	397.0	Comm. Equip.-General	-	-	-	-	-	-	-	-	-	301,138	671,062	28,677	-	-	-
33	397.2	Telemetering Equipment	-	-	-	-	-	-	-	-	-	44,235	98,574	4,213	-	-	-
34	398	Miscellaneous Equip.	-	-	-	-	-	-	-	-	-	159,822	356,150	15,220	-	-	-
35		Total General	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,824,597	$ 10,751,212	$ 459,446	$ -	$ -	$ -
36		Total Net Plant-Direct	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 381,245,171	$ 849,572,973	$ 36,305,977	$ -	$ -	$ -
37		Total Net Plant-Systems Alloc.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,364,582	$ 23,096,605	$ 987,019	$ -	$ -	$ -
38		Total Net Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 391,609,753	$ 872,669,578	$ 37,292,996	$ -	$ -	$ -
39		Cash Working Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$(3,123,057)	$(6,959,471)	$(297,409)	$ -	$ -	$ -
40		Materials and Supplies	-	-	-	-	-	-	-	-	-	3,727,803	8,307,096	354,999	-	-	-
41		Prepayments	-	-	-	-	-	-	-	-	-	1,104,802	2,461,959	105,210	-	-	-
42		Gas Plant Acquisition Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43		Customer Deposits	-	-	-	-	-	-	-	-	-	-	(31,921,898)	-	-	-	-
44		Customer Advances	-	-	-	-	-	-	-	-	-	-	(37,910,017)	-	-	-	-
45		Deferred Taxes	-	-	-	-	-	-	-	-	-	(42,914,402)	(95,631,156)	(4,086,738)	-	-	-
46		Deferred Gain Headquarters Bldg.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47		Total Rate Base	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 350,404,898	$ 711,016,091	$ 33,369,058	$ -	$ -	$ -

SCHEDULE G-5
SHEET 2 OF 2

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)
		Depreciation Expense & Amortizatic															
		Direct															
		Intangible															
1	301	Organization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	302	Franchise & Consent	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	303	Misc. Intangible	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4		Total Intangible Dep. Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		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	-	-	-	-	-	-	-	-	-	23,051	-	-	-	-	-
23	375	Structures	-	-	-	-	-	-	-	-	-	431	-	-	-	-	-
24	376	Mains	-	-	-	-	-	-	-	-	-	21,156,166	16,463,397	0	-	-	-
25	378	Measuring & Reg. Station	-	-	-	-	-	-	-	-	-	-	-	1,349,469	-	-	-
26	380	Services	-	-	-	-	-	-	-	-	-	0	32,079,098	0	-	-	-
27	381	Meters	-	-	-	-	-	-	-	-	-	-	4,487,932	-	-	-	-
28	385	Industrial Meas. & Reg. Sta.	-	-	-	-	-	-	-	-	-	-	-	326,141	-	-	-
29	386	Other Prop. on Cust. Premises															
30	387	Other Equipment	-	-	-	-	-	-	-	-	-	24,340	-	-	-	-	-
31		Total Distribution Dep. Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 21,203,987	$ 53,030,427	$ 1,675,610	$ -	$ -	$ -

SCHEDULE G-6
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				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)
		General															
1	389	Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	390.1	Structures & Improvements	-	-	-	-	-	-	-	-	-	144,450	321,894	13,756	-	-	-
3	390.2	Struct. & Imp.-Leasehold	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	391	Office Furn. & Equip.	-	-	-	-	-	-	-	-	-	46,455	103,521	4,424	-	-	-
5	391	Office Furn. & Computer Equip.	-	-	-	-	-	-	-	-	-	383,125	853,763	36,485	-	-	-
6	392	Transp. Equip.	-	-	-	-	-	-	-	-	-	717,058	1,597,903	68,285	-	-	-
7	393	Stores Equipment	-	-	-	-	-	-	-	-	-	3,395	7,566	323	-	-	-
8	394	Tools, Shop, & Garage Equip.	-	-	-	-	-	-	-	-	-	34,114	76,020	3,249	-	-	-
9	395	Laboratory Equip.	-	-	-	-	-	-	-	-	-	3,300	7,353	314	-	-	-
10	396	Power Operated Equip.	-	-	-	-	-	-	-	-	-	50,306	112,104	4,791	-	-	-
11	397.1	Comm. Equip.-General	-	-	-	-	-	-	-	-	-	71,022	158,268	6,763	-	-	-
12	397.2	Comm. Equip.-Telemetering	-	-	-	-	-	-	-	-	-	14,701	32,761	1,400	-	-	-
13	398	Miscellaneous Equip.	-	-	-	-	-	-	-	-	-	12,162	27,103	1,158	-	-	-
14		Total General Dep. Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,480,089	$ 3,298,255	$ 140,949	$ -	$ -	$ -
		Systems Allocable															
		Intangible															
15	301	Organization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	302	Franchise & Consent															
17	303	Miscellaneous Intang.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18		Total Intangible Dep. Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		General															
19	389	Land & Land Rights	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	390.1	Structures	-	-	-	-	-	-	-	-	-	59,535	132,669	5,670	-	-	-
21	390.2	Structures - Leasehold Improvements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	391	Office Furniture & Equipment	-	-	-	-	-	-	-	-	-	131,436	292,895	12,517	-	-	-
23	391.1	Computer Equipment	-	-	-	-	-	-	-	-	-	407,512	908,105	38,807	-	-	-
24	392.11	Transportation Equipment - Light	-	-	-	-	-	-	-	-	-	42,939	95,686	4,089	-	-	-
25	392.12	Transportation Equipment - Heavy	-	-	-	-	-	-	-	-	-	1,060	2,362	101	-	-	-
26	393	Stores Equipment	-	-	-	-	-	-	-	-	-	659	1,469	63	-	-	-
27	394	Tools, Shop, & Garage Equipment	-	-	-	-	-	-	-	-	-	4,419	9,847	421	-	-	-
28	395	Laboratory Equipment	-	-	-	-	-	-	-	-	-	2,287	5,097	218	-	-	-
29	396	Power Operated Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	397.1	Communication Equipment	-	-	-	-	-	-	-	-	-	78,064	173,958	7,434	-	-	-
31	397.2	Telemetering Equipment	-	-	-	-	-	-	-	-	-	19,694	43,887	1,875	-	-	-
32	398	Miscellaneous Equipment	-	-	-	-	-	-	-	-	-	16,692	37,197	1,590	-	-	-
33		Total General Dep. Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 764,297	$ 1,703,171	$ 72,784	$ -	$ -	$ -
		System Allocable Amortization															
34		Miscellaneous Intangible	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,204,148	$ 2,683,342	$ 114,671	$ -	$ -	$ -
35		Structures-Leasehold Improvements	-	-	-	-	-	-	-	-	-	31,449	70,081	2,995	-	-	-
36		Total System Allocable Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,235,597	$ 2,753,424	$ 117,666	$ -	$ -	$ -
37		Total Depreciation Exp.-Direct	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 22,684,077	$ 56,328,681	$ 1,816,559	$ -	$ -	$ -
38		Total Dep. Exp.-Systems Alloc.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,999,893	$ 4,456,595	$ 190,450	$ -	$ -	$ -
39		Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 35,622	$ 88,455	$ 2,853	$ -	$ -	$ -
40		Amortization-Gas Plant Acquisition	-	-	-	-	-	-	-	-	-	(14,873)	(36,932)	(1,191)	-	-	-
41		Regulatory Amortizations	-	-	-	-	-	-	-	-	-	94,723	235,215	7,586	-	-	-
42			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43												-	-	-			
44			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
45		Total Depreciation Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 24,799,442	$ 61,072,015	$ 2,016,256	$ -	$ -	$ -

SCHEDULE G-6
SHEET 2 OF 7

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 Purc	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	805.1	Purchased Gas Cost Adj.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	810	Gas Used for Compressor Sta. Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	813	Other Gas Supply Expense	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	641,618	-	-	-
7		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	59,983	-	-	-
8		Total Gas Supply Expense	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 701,601	$ -	$ -	$ -
		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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

SCHEDULE G-6
SHEET 3 OF 7

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)
		Distribution Expenses															
1	870	Operation Supervision & Eng.															
2		Labor & Labor Loading	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,262,981	$ 6,965,368	$ 762,557	$ -	$ -	$ -
3		Materials & Expenses	-	-	-	-	-	-	-	-	-	204,862	1,129,816	123,690	-	-	-
4	871	Distribution Load Dispatching															
5		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	129,269	-	129,269	-	-	-
6		Materials & Expenses	-	-	-	-	-	-	-	-	-	56,625	-	56,625	-	-	-
7	874	Mains & Svcs. Expense															
8		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	2,293,669	3,865,472	0	-	-	-
9		Materials & Expenses	-	-	-	-	-	-	-	-	-	2,063,185	3,477,043	0	-	-	-
10	875	Meas. & Reg. Sta. Exp.-Gen.															
11		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	1,859,618	-	-	-
12		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	697,287	-	-	-
13	878	Meter & House Reg. Exp.															
14		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	6,919,581	-	-	-	-
15		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	1,213,237	-	-	-	-
16	879	Customer Installation Exp.															
17		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	8,087,437	-	-	-	-
18		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	1,490,584	-	-	-	-
19	880	Other Expenses															
20		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	919,233	5,069,590	555,010	-	-	-
21		Materials & Expenses	-	-	-	-	-	-	-	-	-	637,079	3,513,506	384,653	-	-	-
22	881	Rents	-	-	-	-	-	-	-	-	-	316,101	1,743,303	190,854	-	-	-
23		Total Distribution-Operations	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,883,005	$ 43,474,938	$ 4,759,564	$ -	$ -	$ -
24	885	Maint. Supervision & Eng.															
25		Labor & Labor Loading	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 828,312	$ 1,778,379	$ 191,127	$ -	$ -	$ -
26		Materials & Expenses	-	-	-	-	-	-	-	-	-	100,085	214,883	23,094	-	-	-
27	886	Maint. of Structures & Imp.															
28		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	26,673	-	-	-	-	-
29		Materials & Expenses	-	-	-	-	-	-	-	-	-	80,753	-	-	-	-	-
30	887	Maint. of Mains															
31		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	4,780,163	3,719,848	0	-	-	-
32		Materials & Expenses	-	-	-	-	-	-	-	-	-	3,961,184	3,082,531	0	-	-	-
33	889	Maint. of Meas. & Reg. Sta-Gen															
34		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	1,461,314	-	-	-
35		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	580,480	-	-	-
36	892	Maint. of Services															
37		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	0	6,159,505	0	-	-	-
38		Materials & Expenses	-	-	-	-	-	-	-	-	-	0	3,973,153	0	-	-	-
39	893	Maint of Meter & House Reg.															
40		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	1,281,534	-	-	-	-
41		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	781,684	-	-	-	-
42	894	Maint of Other Equip.															
43		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	58,186	124,924	13,426	-	-	-
44		Materials & Expenses	-	-	-	-	-	-	-	-	-	56,165	120,586	12,960	-	-	-
45		Total Distribution-Maintenance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9,891,521	$ 21,237,027	$ 2,282,401	$ -	$ -	$ -
46		Total Distribution O & M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 17,774,526	$ 64,711,965	$ 7,041,965	$ -	$ -	$ -

SCHEDULE G-6
SHEET 4 OF 7

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)
		Customer Accounts Expenses															
1	901	Supervision															
2		Labor & Labor Loading	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,093,979
3		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	275,497
4	902	Meter Reading Exp.															
5		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,860,483
6		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,194,002
7	903	Customer Records & Collections															
8		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	404,465
10	903	Customer Records & Collections - L															
11		Labor & Labor Loading - LCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16,062,467
12		Materials & Expenses - LCS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7,441,028
13	904	Uncollectible Accounts Exp.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,977,729
14	905	Misc. Customer Accounts Exp.															
15		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	404,465
16		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	16,795
17		Total Customer Accounts Expenses	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 38,730,909
		Customer Service & Info. Exp.															
18	908	Customer Assistance Exp.															
19		Labor & Labor Loading	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 514,896
20		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	564,797
21	909	Info. & Instructional Exp.															
22		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	25,125
24	910	Misc. C.S. & I. Expense															
25		Labor & Labor Loading	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26		Materials & Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	21,977
27		Total Customer Service & Info. Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,126,796
		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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 17,774,526	$ 64,711,965	$ 7,743,566	$ -	$ -	$ 39,857,704

SCHEDULE G-6
SHEET 5 OF 7

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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,780,905	$ 28,328,049	$ 3,389,792	$ -	$ -	$ 17,447,948
2		Interest on Customer Deposits	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,915,314
3		Taxes other than Income	-	-	-	-	-	-	-	-	-	10,602,142	21,513,095	1,009,642	-	-	-
4		Interest Expense	-	-	-	-	-	-	-	-	-	15,374,365	31,196,542	1,464,101	-	-	-
5		South Georgia - State	-	-	-	-	-	-	-	-	-	9,501	19,280	905	-	-	-
6		Investment Tas Credit (I T C)	-	-	-	-	-	-	-	-	-	(169,110)	(343,146)	(16,104)	-	-	-
7		South Georgia - Federal	-	-	-	-	-	-	-	-	-	92,856	188,416	8,843	-	-	-
8		Regulatory Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9		SIT Rate															
10		FIT Rate															
		Rate Base															
11		Direct Net Plant	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 381,245,171	$ 849,572,973	$ 36,305,977	$ -	$ -	$ -
12		Systems Allocable Net Plant	-	-	-	-	-	-	-	-	-	10,364,582	23,096,605	987,019	-	-	-
13		Cash Working Capital	-	-	-	-	-	-	-	-	-	(3,123,057)	(6,959,471)	(297,409)	-	-	-
14		Materials & Supplies	-	-	-	-	-	-	-	-	-	3,727,803	8,307,096	354,999	-	-	-
15		Prepayments	-	-	-	-	-	-	-	-	-	1,104,802	2,461,959	105,210	-	-	-
16		Gas Plant Acquisition Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17		Customer Deposits	-	-	-	-	-	-	-	-	-	-	(31,921,898)	-	-	-	-
18		Customer Advances	-	-	-	-	-	-	-	-	-	-	(37,910,017)	-	-	-	-
19		Deferred Taxes	-	-	-	-	-	-	-	-	-	(42,914,402)	(95,631,156)	(4,086,738)	-	-	-
20		Deferred Gain Hdqtrs Bldg	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21		Total Rate Base	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 350,404,898	$ 711,016,091	$ 33,369,058	$ -	$ -	$ -
22		Net Operating Margin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 122,005,529	$ 247,564,730	$ 11,618,586	$ -	$ -	$ -
23		Special Contract & Optional	-	-	-	-	-	-	-	-	-	1,851,270	3,756,462	176,296	-	-	-
24		Late Charges	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,430,203
25		Service Establishment Charges	-	-	-	-	-	-	-	-	-	-	-	-	-	-	8,267,657
26		Reconnect / Reread Charges	-	-	-	-	-	-	-	-	-	-	-	-	-	-	569,215
27		Other Revenue - Labor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,313
28		Other Revenue - Parts & Material	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,621
29		Other Revenue - Field Collection Fee	-	-	-	-	-	-	-	-	-	-	-	-	-	-	304,887
30		Other Revenue - Returned Item Fee	-	-	-	-	-	-	-	-	-	-	-	-	-	-	173,412
31		Other Revenue - Rental Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	512,498
32		Total Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 123,856,799	$ 251,321,192	$ 11,794,883	$ -	$ -	$ 12,261,805
		Operating Deductions															
33		O & M	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$(17,774,526)	$(64,711,965)	$(7,743,566)	$ -	$ -	$(39,857,704)
34		A & G	-	-	-	-	-	-	-	-	-	(7,780,905)	(28,328,049)	(3,389,792)	-	-	(17,447,948)
35		Depreciation Expense	-	-	-	-	-	-	-	-	-	(24,799,442)	(61,072,015)	(2,016,256)	-	-	-
36		Interest on Customer Deposits	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,915,314)
37		Taxes other than Income	-	-	-	-	-	-	-	-	-	(10,602,142)	(21,513,095)	(1,009,642)	-	-	-

SCHEDULE G-6
SHEET 6 OF 7

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)
		State Income Tax															
1		Taxable Income before Interest Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 62,899,783	$ 75,696,068	$(2,364,373)	$ -	$ -	$(46,959,161)
2		Interest Expense	-	-	-	-	-	-	-	-	-	(15,374,365)	(31,196,542)	(1,464,101)	-	-	-
3		State Taxable Income	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 47,525,418	$ 44,499,526	$(3,828,474)	$ -	$ -	$(46,959,161)
4		State Income Tax @ 6.9680%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,311,571	$ 3,100,727	$(266,768)	$ -	$ -	$(3,272,114)
5		South Georgia	-	-	-	-	-	-	-	-	-	9,501	19,280	905	-	-	-
6		State Income Tax	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,321,073	$ 3,120,007	$(265,863)	$ -	$ -	$(3,272,114)
		Federal Income Tax															
7		Taxable Income before Interest Exp.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 62,899,783	$ 75,696,068	$(2,364,373)	$ -	$ -	$(46,959,161)
8		Interest Expense	-	-	-	-	-	-	-	-	-	(15,374,365)	(31,196,542)	(1,464,101)	-	-	-
9		Federal Taxable Income	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 47,525,418	$ 44,499,526	$(3,828,474)	$ -	$ -	$(46,959,161)
10		Federal Income Tax @ 32.5612%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,474,846	$ 14,489,580	$(1,246,597)	$ -	$ -	$(15,290,466)
11		I T C	-	-	-	-	-	-	-	-	-	(169,110)	(343,146)	(16,104)	-	-	-
12		South Georgia	-	-	-	-	-	-	-	-	-	92,856	188,416	8,843	-	-	-
13		Total Federal Income Tax	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 15,398,592	$ 14,334,850	$(1,253,859)	$ -	$ -	$(15,290,466)
14		Regulatory Amortization	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15		Net Income	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 44,180,118	$ 58,241,212	$(844,651)	$ -	$ -	$(28,396,580)

SCHEDULE G-6
SHEET 7 OF 7

SOUTHWEST GAS CORPORATION
ARIZONA
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Description	Allocation Factor No.	Total	Residential Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(d)	(e)	(f)
1	CP Monthly Demand		118,455,410	69,979,561		
		1	100.0000%	59.076712%	0.000000%	0.000000%
2	NCP Demand		121,419,774	69,979,561		
		2	100.0000%	57.634402%	0.000000%	0.000000%
3	Throughput		651,784,739	0		297,856,607
		3	100.0000%	0.000000%	0.000000%	45.698616%
4	Customers		959,083		884,186	
		4	100.0000%	0.000000%	92.190770%	0.000000%
5	Customers With Mains		959,083	0	884,186	0
		5	100.0000%	0.000000%	92.190770%	0.000000%
6	Meters for Customers		1,122,135		884,186	
		6	100.0000%	0.000000%	78.794942%	0.000000%
7	Service Lines for Customers		1,072,625		884,186	
		7	100.0000%	0.000000%	82.431945%	0.000000%
8	Res., MMMHP & Small, Medium GS		950,479	0	884,186	0
		8	100.0000%	0.000000%	93.025331%	0.000000%
9	Service Establishment Charges		34,611,268	0	30,946,510	0
		9	100.0000%	0.000000%	89.411663%	0.000000%
10	Extra		0	0	0	0
		10	0.0000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0
		11	0.0000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		7,311	0	0	0
		12	100.0000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		1,010,689	0	866,940	0
		13	100.0000%	0.000000%	85.777111%	0.000000%
14	Extra		0	0	0	0
		14	0.0000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0
		15	0.0000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors					
16	Net Production, Transmission, & Distribution Plant		1,182,139,980	219,964,047	685,044,030	1,940,005
		1.1	100.0000%	18.607276%	57.949485%	0.164110%
17	Distribution Mains		629,304,144	209,074,046	253,894,761	0
		2.2	100.0000%	33.223052%	40.345318%	0.000000%
18	Distribution Services		321,023,126	0	264,625,607	0
		3.3	100.0000%	0.000000%	82.431945%	0.000000%
19	Distribution Mains & Services		950,327,271	209,074,046	518,520,368	0
		4.4	100.0000%	22.000215%	54.562295%	0.000000%
20	Allocable Distribution Operating Expenses		32,338,902	3,423,368	21,370,282	169,902
		5.5	100.0000%	10.585914%	66.082273%	0.525379%
21	Allocable Distribution Maintenance Expenses		29,888,822	5,905,911	17,073,192	0
		6.6	100.0000%	19.759597%	57.122332%	0.000000%
22	Transmission Operating Expense		0	0	0	0
		7.7	0.0000%	0.000000%	0.000000%	0.000000%
23	Transmission Mains		0	0	0	0
		8.8	0.0000%	0.000000%	0.000000%	0.000000%
24	Transmission Maintenance Expense		0	0	0	0
		9.9	0.0000%	0.000000%	0.000000%	0.000000%
25	Customer Accounting Expense		33,940,174	0	29,303,882	0
		10.1	100.0000%	0.000000%	86.339812%	0.000000%
26	Total O & M Expense		130,087,761	12,542,420	90,575,563	615,452
		11.2	100.0000%	9.641506%	69.626507%	0.473105%

SOUTHWEST GAS CORPORATION
ARIZONA
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Description	Allocation Factor No.	Total	Multi-Family Residential Demand	Customer	Commodity
	(a)	(b)	(c)	(g)	(h)	(i)
1	CP Monthly Demand		118,455,410	1,309,479		
		1	100.0000%	1.105462%	0.000000%	0.000000%
2	NCP Demand		121,419,774	1,309,479		
		2	100.0000%	1.078473%	0.000000%	0.000000%
3	Throughput		651,784,739	0		7,060,702
		3	100.0000%	0.000000%	0.000000%	1.083287%
4	Customers		959,083		33,163	
		4	100.0000%	0.000000%	3.457730%	0.000000%
5	Customers With Mains		959,083	0	33,163	0
		5	100.0000%	0.000000%	3.457730%	0.000000%
6	Meters for Customers		1,122,135		30,927	
		6	100.0000%	0.000000%	2.756100%	0.000000%
7	Service Lines for Customers		1,072,625		16,409	
		7	100.0000%	0.000000%	1.529804%	0.000000%
8	Res., MMMHP & Small, Medium GS		950,479	0	33,163	0
		8	100.0000%	0.000000%	3.489031%	0.000000%
9	Service Establishment Charges		34,611,268	0	1,160,688	0
		9	100.0000%	0.000000%	3.353496%	0.000000%
10	Extra		0	0	0	0
		10	0.0000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0
		11	0.0000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		7,311	0	0	0
		12	100.0000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		1,010,689	0	11,458	0
		13	100.0000%	0.000000%	1.133719%	0.000000%
14	Extra		0	0	0	0
		14	0.0000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0
		15	0.0000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors					
16	Net Production, Transmission, & Distribution Plant		1,182,139,980	4,116,035	20,288,568	45,988
		1.1	100.0000%	0.348185%	1.716258%	0.003890%
17	Distribution Mains		629,304,144	3,912,258	9,522,640	0
		2.2	100.0000%	0.621680%	1.513202%	0.000000%
18	Distribution Services		321,023,126	0	4,911,024	0
		3.3	100.0000%	0.000000%	1.529804%	0.000000%
19	Distribution Mains & Services		950,327,271	3,912,258	14,433,664	0
		4.4	100.0000%	0.411675%	1.518810%	0.000000%
20	Allocable Distribution Operating Expenses		32,338,902	64,059	704,511	4,028
		5.5	100.0000%	0.198087%	2.178524%	0.012454%
21	Allocable Distribution Maintenance Expenses		29,888,822	110,513	477,978	0
		6.6	100.0000%	0.369748%	1.599188%	0.000000%
22	Transmission Operating Expense		0	0	0	0
		7.7	0.0000%	0.000000%	0.000000%	0.000000%
23	Transmission Mains		0	0	0	0
		8.8	0.0000%	0.000000%	0.000000%	0.000000%
24	Transmission Maintenance Expense		0	0	0	0
		9.9	0.0000%	0.000000%	0.000000%	0.000000%
25	Customer Accounting Expense		33,940,174	0	453,989	0
		10.1	100.0000%	0.000000%	1.337616%	0.000000%
26	Total O & M Expense		130,087,761	234,698	2,287,683	14,589
		11.2	100.0000%	0.180415%	1.758569%	0.011215%

SOUTHWEST GAS CORPORATION
ARIZONA
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Description	Allocation Factor No.	Total	MMMHP Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(j)	(k)	(l)
1	CP Monthly Demand		118,455,410	492,482		
		1	100.0000%	0.415753%	0.000000%	0.000000%
2	NCP Demand		121,419,774	492,482		
		2	100.0000%	0.405603%	0.000000%	0.000000%
3	Throughput		651,784,739			2,223,993
		3	100.0000%	0.000000%	0.000000%	0.341216%
4	Customers		959,083		164	
		4	100.0000%	0.000000%	0.017100%	0.000000%
5	Customers With Mains		959,083	0	164	0
		5	100.0000%	0.000000%	0.017100%	0.000000%
6	Meters for Customers		1,122,135		525	
		6	100.0000%	0.000000%	0.046771%	0.000000%
7	Service Lines for Customers		1,072,625		859	
		7	100.0000%	0.000000%	0.080050%	0.000000%
8	Res., MMMHP & Small, Medium GS		950,479	0	164	0
		8	100.0000%	0.000000%	0.017254%	0.000000%
9	Service Establishment Charges		34,611,268	0	9,840	0
		9	100.0000%	0.000000%	0.028430%	0.000000%
10	Extra		0	0	0	0
		10	0.0000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0
		11	0.0000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		7,311	0	0	0
		12	100.0000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		1,010,689	0	513	0
		13	100.0000%	0.000000%	0.050783%	0.000000%
14	Extra		0	0	0	0
		14	0.0000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0
		15	0.0000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors					
16	Net Production, Transmission, & Distribution Plant		1,182,139,980	1,548,000	398,038	14,485
		1.1	100.0000%	0.130949%	0.033671%	0.001225%
17	Distribution Mains		629,304,144	1,471,361	47,093	0
		2.2	100.0000%	0.233808%	0.007483%	0.000000%
18	Distribution Services		321,023,126	0	256,978	0
		3.3	100.0000%	0.000000%	0.080050%	0.000000%
19	Distribution Mains & Services		950,327,271	1,471,361	304,071	0
		4.4	100.0000%	0.154827%	0.031996%	0.000000%
20	Allocable Distribution Operating Expenses		32,338,902	24,092	12,218	1,269
		5.5	100.0000%	0.074498%	0.037782%	0.003923%
21	Allocable Distribution Maintenance Expenses		29,888,822	41,563	10,392	0
		6.6	100.0000%	0.139058%	0.034769%	0.000000%
22	Transmission Operating Expense		0	0	0	0
		7.7	0.0000%	0.000000%	0.000000%	0.000000%
23	Transmission Mains		0	0	0	0
		8.8	0.0000%	0.000000%	0.000000%	0.000000%
24	Transmission Maintenance Expense		0	0	0	0
		9.9	0.0000%	0.000000%	0.000000%	0.000000%
25	Customer Accounting Expense		33,940,174	0	16,233	0
		10.1	100.0000%	0.000000%	0.047828%	0.000000%
26	Total O & M Expense		130,087,761	88,267	51,915	4,595
		11.2	100.0000%	0.067852%	0.039908%	0.003533%

SOUTHWEST GAS CORPORATION
ARIZONA
DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Description	Allocation Factor No.	Total	Small General Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(m)	(n)	(o)
1	CP Monthly Demand		118,455,410	1,368,526		
		1	100.0000%	1.155309%	0.000000%	0.000000%
2	NCP Demand		121,419,774	1,368,526		
		2	100.0000%	1.127103%	0.000000%	0.000000%
3	Throughput		651,784,739			5,020,754
		3	100.0000%	0.000000%	0.000000%	0.770309%
4	Customers		959,083		16,817	
		4	100.0000%	0.000000%	1.753454%	0.000000%
5	Customers With Mains		959,083	0	16,817	0
		5	100.0000%	0.000000%	1.753454%	0.000000%
6	Meters for Customers		1,122,135		26,865	
		6	100.0000%	0.000000%	2.394098%	0.000000%
7	Service Lines for Customers		1,072,625		20,162	
		7	100.0000%	0.000000%	1.879671%	0.000000%
8	Res., MMMHP & Small, Medium GS		950,479	0	16,817	0
		8	100.0000%	0.000000%	1.769328%	0.000000%
9	Service Establishment Charges		34,611,268	0	1,009,025	0
		9	100.0000%	0.000000%	2.915308%	0.000000%
10	Extra		0	0	0	0
		10	0.0000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0
		11	0.0000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		7,311	0	0	0
		12	100.0000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		1,010,689	0	36,758	0
		13	100.0000%	0.000000%	3.636912%	0.000000%
14	Extra		0	0	0	0
		14	0.0000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0
		15	0.0000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors					
16	Net Production, Transmission, & Distribution Plant		1,182,139,980	4,301,635	15,787,025	32,701
		1.1	100.0000%	0.363885%	1.335462%	0.002766%
17	Distribution Mains		629,304,144	4,088,669	4,829,040	0
		2.2	100.0000%	0.649713%	0.767362%	0.000000%
18	Distribution Services		321,023,126	0	6,034,177	0
		3.3	100.0000%	0.000000%	1.879671%	0.000000%
19	Distribution Mains & Services		950,327,271	4,088,669	10,863,217	0
		4.4	100.0000%	0.430238%	1.143103%	0.000000%
20	Allocable Distribution Operating Expenses		32,338,902	66,948	577,371	2,864
		5.5	100.0000%	0.207019%	1.785377%	0.008856%
21	Allocable Distribution Maintenance Expenses		29,888,822	115,496	374,801	0
		6.6	100.0000%	0.386420%	1.253982%	0.000000%
22	Transmission Operating Expense		0	0	0	0
		7.7	0.0000%	0.000000%	0.000000%	0.000000%
23	Transmission Mains		0	0	0	0
		8.8	0.0000%	0.000000%	0.000000%	0.000000%
24	Transmission Maintenance Expense		0	0	0	0
		9.9	0.0000%	0.000000%	0.000000%	0.000000%
25	Customer Accounting Expense		33,940,174	0	1,178,290	0
		10.1	100.0000%	0.000000%	3.471667%	0.000000%
26	Total O & M Expense		130,087,761	245,281	2,806,465	10,374
		11.2	100.0000%	0.188550%	2.157363%	0.007975%

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Line No.	Description	Allocation Factor No.	Total	Medium General Gas Service		
				Demand	Customer	Commodity
	(a)	(b)	(c)	(c)	(d)	(e)
1	CP Monthly Demand		118,455,410	7,463,908		
		1	100.0000%	6.301028%	0.000000%	0.000000%
2	NCP Demand		121,419,774	7,463,908		
		2	100.0000%	6.147193%	0.000000%	0.000000%
3	Throughput		651,784,739			45,530,269
		3	100.0000%	0.000000%	0.000000%	6.985476%
4	Customers		959,083		16,149	
		4	100.0000%	0.000000%	1.683813%	0.000000%
5	Customers With Mains		959,083	0	16,149	0
		5	100.0000%	0.000000%	1.683813%	0.000000%
6	Meters for Customers		1,122,135		68,972	
		6	100.0000%	0.000000%	6.146470%	0.000000%
7	Service Lines for Customers		1,072,625		80,505	
		7	100.0000%	0.000000%	7.505421%	0.000000%
8	Res., MMMHP & Small, Medium GS		950,479	0	16,149	
		8	100.0000%	0.000000%	1.699056%	0.000000%
9	Service Establishment Charges		34,611,268	0	968,950	0
		9	100.0000%	0.000000%	2.799522%	0.000000%
10	Extra		0	0	0	0
		10	0.0000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0
		11	0.0000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		7,311	0	0	0
		12	100.0000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		1,010,689	0	57,875	0
		13	100.0000%	0.000000%	5.726294%	0.000000%
14	Extra		0	0	0	0
		14	0.0000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0
		15	0.0000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors					
16	Net Production, Transmission, & Distribution Plant		1,182,139,980	23,461,013	41,007,147	296,549
		1.1	100.0000%	1.984622%	3.468891%	0.025086%
17	Distribution Mains		629,304,144	22,299,503	4,637,247	0
		2.2	100.0000%	3.543518%	0.736885%	0.000000%
18	Distribution Services		321,023,126	0	24,094,138	0
		3.3	100.0000%	0.000000%	7.505421%	0.000000%
19	Distribution Mains & Services		950,327,271	22,299,503	28,731,385	0
		4.4	100.0000%	2.346508%	3.023315%	0.000000%
20	Allocable Distribution Operating Expenses		32,338,902	365,131	1,461,142	25,971
		5.5	100.0000%	1.129077%	4.518217%	0.080309%
21	Allocable Distribution Maintenance Expenses		29,888,822	629,915	1,016,899	0
		6.6	100.0000%	2.107527%	3.402271%	0.000000%
22	Transmission Operating Expense		0	0	0	0
		7.7	0.0000%	0.000000%	0.000000%	0.000000%
23	Transmission Mains		0	0	0	0
		8.8	0.0000%	0.000000%	0.000000%	0.000000%
24	Transmission Maintenance Expense		0	0	0	0
		9.9	0.0000%	0.000000%	0.000000%	0.000000%
25	Customer Accounting Expense		33,940,174	0	1,823,140	0
		10.1	100.0000%	0.000000%	5.371628%	0.000000%
26	Total O & M Expense		130,087,761	1,337,754	5,817,246	94,078
		11.2	100.0000%	1.028348%	4.471785%	0.072319%

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Line No.	Description	Allocation Factor No.	Total	Large General Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(f)	(g)	(h)
1	CP Monthly Demand		118,455,410	20,388,726		
		1	100.0000%	17.212153%	0.000000%	0.000000%
2	NCP Demand		121,419,774	20,388,726		
		2	100.0000%	16.791932%	0.000000%	0.000000%
3	Throughput		651,784,739			149,222,854
		3	100.0000%	0.000000%	0.000000%	22.894499%
4	Customers		959,083		7,126	
		4	100.0000%	0.000000%	0.742984%	0.000000%
5	Customers With Mains		959,083	0	7,126	0
		5	100.0000%	0.000000%	0.742984%	0.000000%
6	Meters for Customers		1,122,135		79,618	
		6	100.0000%	0.000000%	7.095204%	0.000000%
7	Service Lines for Customers		1,072,625		60,714	
		7	100.0000%	0.000000%	5.660279%	0.000000%
8	Res., MMMHP & Small, Medium GS		950,479			
		8	100.0000%	0.000000%	0.000000%	0.000000%
9	Service Establishment Charges		34,611,268	0	427,550	0
		9	100.0000%	0.000000%	1.235291%	0.000000%
10	Extra		0	0	0	0
		10	0.0000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0
		11	0.0000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		7,311	0	7,126	0
		12	100.0000%	0.000000%	97.467287%	0.000000%
13	Weighted Customers for Meter Reading		1,010,689	0	31,085	0
		13	100.0000%	0.000000%	3.075614%	0.000000%
14	Extra		0	0	0	0
		14	0.0000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0
		15	0.0000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors					
16	Net Production, Transmission, & Distribution Plant		1,182,139,980	64,087,094	34,231,895	971,921
		1.1	100.0000%	5.421278%	2.895756%	0.082217%
17	Distribution Mains		629,304,144	60,914,264	2,046,189	0
		2.2	100.0000%	9.679622%	0.325151%	0.000000%
18	Distribution Services		321,023,126	0	18,170,806	0
		3.3	100.0000%	0.000000%	5.660279%	0.000000%
19	Distribution Mains & Services		950,327,271	60,914,264	20,216,995	0
		4.4	100.0000%	6.409820%	2.127372%	0.000000%
20	Allocable Distribution Operating Expenses		32,338,902	997,407	1,513,823	85,119
		5.5	100.0000%	3.084233%	4.681121%	0.263209%
21	Allocable Distribution Maintenance Expenses		29,888,822	1,720,702	777,106	0
		6.6	100.0000%	5.757010%	2.599988%	0.000000%
22	Transmission Operating Expense		0	0	0	0
		7.7	0.0000%	0.000000%	0.000000%	0.000000%
23	Transmission Mains		0	0	0	0
		8.8	0.0000%	0.000000%	0.000000%	0.000000%
24	Transmission Maintenance Expense		0	0	0	0
		9.9	0.0000%	0.000000%	0.000000%	0.000000%
25	Customer Accounting Expense		33,940,174	0	974,409	0
		10.1	100.0000%	0.000000%	2.870961%	0.000000%
26	Total O & M Expense		130,087,761	3,654,266	4,642,214	308,335
		11.2	100.0000%	2.809078%	3.568525%	0.237020%

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Line No.	Description	Allocation Factor No.	Total	Transportation Eligible Service Demand	Customer	Commodity
	(a)	(b)	(c)	(i)	(j)	(k)
1	CP Monthly Demand		118,455,410	14,014,497		
		1	100.0000%	11.831032%	0.000000%	0.000000%
2	NCP Demand		121,419,774	14,014,497		
		2	100.0000%	11.542187%	0.000000%	0.000000%
3	Throughput		651,784,739			99,526,400
		3	100.0000%	0.000000%	0.000000%	15.269827%
4	Customers		959,083		185	
		4	100.0000%	0.000000%	0.019307%	0.000000%
5	Customers With Mains		959,083	0	185	0
		5	100.0000%	0.000000%	0.019307%	0.000000%
6	Meters for Customers		1,122,135		17,179	
		6	100.0000%	0.000000%	1.530930%	0.000000%
7	Service Lines for Customers		1,072,625		3,673	
		7	100.0000%	0.000000%	0.342431%	0.000000%
8	Res., MMMHP & Small, Medium GS		950,479			
		8	100.0000%	0.000000%	0.000000%	0.000000%
9	Service Establishment Charges		34,611,268	0	11,110	0
		9	100.0000%	0.000000%	0.032099%	0.000000%
10	Extra		0	0	0	0
		10	0.0000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0
		11	0.0000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		7,311	0	185	0
		12	100.0000%	0.000000%	2.532713%	0.000000%
13	Weighted Customers for Meter Reading		1,010,689	0	1,363	0
		13	100.0000%	0.000000%	0.134854%	0.000000%
14	Extra		0	0	0	0
		14	0.0000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0
		15	0.0000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors					
16	Net Production, Transmission, & Distribution Plant		1,182,139,980	44,051,226	4,158,161	648,237
		1.1	100.0000%	3.726397%	0.351749%	0.054836%
17	Distribution Mains		629,304,144	41,870,334	53,171	0
		2.2	100.0000%	6.653434%	0.008449%	0.000000%
18	Distribution Services		321,023,126	0	1,099,282	0
		3.3	100.0000%	0.000000%	0.342431%	0.000000%
19	Distribution Mains & Services		950,327,271	41,870,334	1,152,452	0
		4.4	100.0000%	4.405886%	0.121269%	0.000000%
20	Allocable Distribution Operating Expenses		32,338,902	685,583	285,544	56,771
		5.5	100.0000%	2.119994%	0.882975%	0.175551%
21	Allocable Distribution Maintenance Expenses		29,888,822	1,182,751	67,770	0
		6.6	100.0000%	3.957167%	0.226739%	0.000000%
22	Transmission Operating Expense		0	0	0	0
		7.7	0.0000%	0.000000%	0.000000%	0.000000%
23	Transmission Mains		0	0	0	0
		8.8	0.0000%	0.000000%	0.000000%	0.000000%
24	Transmission Maintenance Expense		0	0	0	0
		9.9	0.0000%	0.000000%	0.000000%	0.000000%
25	Customer Accounting Expense		33,940,174	0	42,329	0
		10.1	100.0000%	0.000000%	0.124716%	0.000000%
26	Total O & M Expense		130,087,761	2,511,815	621,082	205,648
		11.2	100.0000%	1.930862%	0.477433%	0.158084%

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Line No.	Description	Allocation Factor No.	Total	Air-Conditioning Gas Service		
				Demand	Customer	Commodity
	(a)	(b)	(c)	(c)	(d)	(e)
1	CP Monthly Demand		118,455,410	50,328		
		1	100.0000%	0.042487%	0.000000%	0.000000%
2	NCP Demand		121,419,774	175,550		
		2	100.0000%	0.144581%	0.000000%	0.000000%
3	Throughput		651,784,739			1,118,252
		3	100.0000%	0.000000%	0.000000%	0.171568%
4	Customers		959,083		27	
		4	100.0000%	0.000000%	0.002763%	0.000000%
5	Customers With Mains		959,083	0	27	0
		5	100.0000%	0.000000%	0.002763%	0.000000%
6	Meters for Customers		1,122,135		49	
		6	100.0000%	0.000000%	0.004335%	0.000000%
7	Service Lines for Customers		1,072,625		37	
		7	100.0000%	0.000000%	0.003436%	0.000000%
8	Res., MMMHP & Small, Medium GS		950,479			
		8	100.0000%	0.000000%	0.000000%	0.000000%
9	Service Establishment Charges		34,611,268	0	1,590	0
		9	100.0000%	0.000000%	0.004594%	0.000000%
10	Extra		0	0	0	0
		10	0.0000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0
		11	0.0000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		7,311	0	0	0
		12	100.0000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		1,010,689	0	25	0
		13	100.0000%	0.000000%	0.002424%	0.000000%
14	Extra		0	0	0	0
		14	0.0000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0
		15	0.0000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors					
16	Net Production, Transmission, & Distribution Plant		1,182,139,980	158,194	27,502	7,283
		1.1	100.0000%	0.013382%	0.002326%	0.000616%
17	Distribution Mains		629,304,144	150,362	7,609	0
		2.2	100.0000%	0.023893%	0.001209%	0.000000%
18	Distribution Services		321,023,126	0	11,030	0
		3.3	100.0000%	0.000000%	0.003436%	0.000000%
19	Distribution Mains & Services		950,327,271	150,362	18,639	0
		4.4	100.0000%	0.015822%	0.001961%	0.000000%
20	Allocable Distribution Operating Expenses		32,338,902	2,462	1,028	638
		5.5	100.0000%	0.007613%	0.003180%	0.001972%
21	Allocable Distribution Maintenance Expenses		29,888,822	4,247	650	0
		6.6	100.0000%	0.014211%	0.002176%	0.000000%
22	Transmission Operating Expense		0	0	0	0
		7.7	0.0000%	0.000000%	0.000000%	0.000000%
23	Transmission Mains		0	0	0	0
		8.8	0.0000%	0.000000%	0.000000%	0.000000%
24	Transmission Maintenance Expense		0	0	0	0
		9.9	0.0000%	0.000000%	0.000000%	0.000000%
25	Customer Accounting Expense		33,940,174	0	833	0
		10.1	100.0000%	0.000000%	0.002454%	0.000000%
26	Total O & M Expense		130,087,761	9,020	3,489	2,311
		11.2	100.0000%	0.006934%	0.002682%	0.001776%

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Line No.	Description	Allocation Factor No.	Total	Demand	CNG - Small Customer	Commodity
	(a)	(b)	(c)	(f)	(g)	(h)
1	CP Monthly Demand		118,455,410	12,889		
		1	100.0000%	0.010881%	0.000000%	0.000000%
2	NCP Demand		121,419,774	18,345		
		2	100.0000%	0.015109%	0.000000%	0.000000%
3	Throughput		651,784,739			177,495
		3	100.0000%	0.000000%	0.000000%	0.027232%
4	Customers		959,083		21	
		4	100.0000%	0.000000%	0.002190%	0.000000%
5	Customers With Mains		959,083	0	21	0
		5	100.0000%	0.000000%	0.002190%	0.000000%
6	Meters for Customers		1,122,135		23	
		6	100.0000%	0.000000%	0.002043%	0.000000%
7	Service Lines for Customers		1,072,625		36	
		7	100.0000%	0.000000%	0.003379%	0.000000%
8	Res., MMMHP & Small, Medium GS		950,479			
		8	100.0000%	0.000000%	0.000000%	0.000000%
9	Service Establishment Charges		34,611,268	0	1,260	0
		9	100.0000%	0.000000%	0.003640%	0.000000%
10	Extra		0	0	0	0
		10	0.0000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0
		11	0.0000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		7,311	0	0	0
		12	100.0000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		1,010,689	0	71	0
		13	100.0000%	0.000000%	0.007023%	0.000000%
14	Extra		0	0	0	0
		14	0.0000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0
		15	0.0000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors					
16	Net Production, Transmission, & Distribution Plant		1,182,139,980	40,513	21,169	1,156
		1.1	100.0000%	0.003427%	0.001791%	0.000098%
17	Distribution Mains		629,304,144	38,508	6,030	0
		2.2	100.0000%	0.006119%	0.000958%	0.000000%
18	Distribution Services		321,023,126	0	10,847	0
		3.3	100.0000%	0.000000%	0.003379%	0.000000%
19	Distribution Mains & Services		950,327,271	38,508	16,877	0
		4.4	100.0000%	0.004052%	0.001776%	0.000000%
20	Allocable Distribution Operating Expenses		32,338,902	631	594	101
		5.5	100.0000%	0.001950%	0.001837%	0.000313%
21	Allocable Distribution Maintenance Expenses		29,888,822	1,088	553	0
		6.6	100.0000%	0.003639%	0.001850%	0.000000%
22	Transmission Operating Expense		0	0	0	0
		7.7	0.0000%	0.000000%	0.000000%	0.000000%
23	Transmission Mains		0	0	0	0
		8.8	0.0000%	0.000000%	0.000000%	0.000000%
24	Transmission Maintenance Expense		0	0	0	0
		9.9	0.0000%	0.000000%	0.000000%	0.000000%
25	Customer Accounting Expense		33,940,174	0	2,240	0
		10.1	100.0000%	0.000000%	0.006599%	0.000000%
26	Total O & M Expense		130,087,761	2,310	4,284	367
		11.2	100.0000%	0.001776%	0.003293%	0.000282%

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DEVELOPMENT OF ALLOCATION FACTORS
TEST YEAR ENDING
APRIL 30, 2007

Line No.	Description	Allocation Factor No.	Total	Demand	CNG - Large Customer	Commodity
	(a)	(b)	(c)	(i)	(j)	(k)
1	CP Monthly Demand		118,455,410	151,064		
		1	100.0000%	0.127528%	0.000000%	0.000000%
2	NCP Demand		121,419,774	202,347		
		2	100.0000%	0.166651%	0.000000%	0.000000%
3	Throughput		651,784,739			2,060,152
		3	100.0000%	0.000000%	0.000000%	0.316079%
4	Customers		959,083		24	
		4	100.0000%	0.000000%	0.002502%	0.000000%
5	Customers With Mains		959,083	0	24	0
		5	100.0000%	0.000000%	0.002502%	0.000000%
6	Meters for Customers		1,122,135		702	
		6	100.0000%	0.000000%	0.062524%	0.000000%
7	Service Lines for Customers		1,072,625		295	
		7	100.0000%	0.000000%	0.027503%	0.000000%
8	Res., MMMHP & Small, Medium GS		950,479			
		8	100.0000%	0.000000%	0.000000%	0.000000%
9	Service Establishment Charges		34,611,268	0	1,440	0
		9	100.0000%	0.000000%	0.004160%	0.000000%
10	Extra		0	0	0	0
		10	0.0000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0
		11	0.0000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		7,311	0	0	0
		12	100.0000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		1,010,689	0	162	0
		13	100.0000%	0.000000%	0.016052%	0.000000%
14	Extra		0	0	0	0
		14	0.0000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0
		15	0.0000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors					
16	Net Production, Transmission, & Distribution Plant		1,182,139,980	474,834	218,161	13,418
		1.1	100.0000%	0.040167%	0.018455%	0.001135%
17	Distribution Mains		629,304,144	451,326	6,892	0
		2.2	100.0000%	0.071718%	0.001095%	0.000000%
18	Distribution Services		321,023,126	0	88,292	0
		3.3	100.0000%	0.000000%	0.027503%	0.000000%
19	Distribution Mains & Services		950,327,271	451,326	95,184	0
		4.4	100.0000%	0.047492%	0.010016%	0.000000%
20	Allocable Distribution Operating Expenses		32,338,902	7,390	12,273	1,175
		5.5	100.0000%	0.022852%	0.037952%	0.003634%
21	Allocable Distribution Maintenance Expenses		29,888,822	12,749	4,269	0
		6.6	100.0000%	0.042655%	0.014284%	0.000000%
22	Transmission Operating Expense		0	0	0	0
		7.7	0.0000%	0.000000%	0.000000%	0.000000%
23	Transmission Mains		0	0	0	0
		8.8	0.0000%	0.000000%	0.000000%	0.000000%
24	Transmission Maintenance Expense		0	0	0	0
		9.9	0.0000%	0.000000%	0.000000%	0.000000%
25	Customer Accounting Expense		33,940,174	0	5,045	0
		10.1	100.0000%	0.000000%	0.014864%	0.000000%
26	Total O & M Expense		130,087,761	27,075	32,008	4,257
		11.2	100.0000%	0.020813%	0.024605%	0.003272%

SOUTHWEST GAS CORPORATION
ARIZONA
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Line No.	Description	Allocation Factor No.	Total	CNG - Residential Demand	Customer	Commodity
	(a)	(b)	(c)	(l)	(m)	(n)
1	CP Monthly Demand		118,455,410	5,981		
		1	100.0000%	0.005049%	0.000000%	0.000000%
2	NCP Demand		121,419,774	6,936		
		2	100.0000%	0.005712%	0.000000%	0.000000%
3	Throughput		651,784,739			77,361
		3	100.0000%	0.000000%	0.000000%	0.011869%
4	Customers		959,083		106	
		4	100.0000%	0.000000%	0.011052%	0.000000%
5	Customers With Mains		959,083	0	106	0
		5	100.0000%	0.000000%	0.011052%	0.000000%
6	Meters for Customers		1,122,135		88	
		6	100.0000%	0.000000%	0.007882%	0.000000%
7	Service Lines for Customers		1,072,625		106	
		7	100.0000%	0.000000%	0.009872%	0.000000%
8	Res., MMMHP & Small, Medium GS		950,479			
		8	100.0000%	0.000000%	0.000000%	0.000000%
9	Service Establishment Charges		34,611,268	0	6,360	0
		9	100.0000%	0.000000%	0.018376%	0.000000%
10	Extra		0	0	0	0
		10	0.0000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0
		11	0.0000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		7,311	0	0	0
		12	100.0000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		1,010,689	0	106	0
		13	100.0000%	0.000000%	0.010488%	0.000000%
14	Extra		0	0	0	0
		14	0.0000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0
		15	0.0000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors					
16	Net Production, Transmission, & Distribution Plant		1,182,139,980	18,800	79,023	504
		1.1	100.0000%	0.001590%	0.006685%	0.000043%
17	Distribution Mains		629,304,144	17,869	30,438	0
		2.2	100.0000%	0.002840%	0.004837%	0.000000%
18	Distribution Services		321,023,126	0	31,691	0
		3.3	100.0000%	0.000000%	0.009872%	0.000000%
19	Distribution Mains & Services		950,327,271	17,869	62,129	0
		4.4	100.0000%	0.001880%	0.006538%	0.000000%
20	Allocable Distribution Operating Expenses		32,338,902	293	2,284	44
		5.5	100.0000%	0.000905%	0.007064%	0.000136%
21	Allocable Distribution Maintenance Expenses		29,888,822	505	2,013	0
		6.6	100.0000%	0.001689%	0.006737%	0.000000%
22	Transmission Operating Expense		0	0	0	0
		7.7	0.0000%	0.000000%	0.000000%	0.000000%
23	Transmission Mains		0	0	0	0
		8.8	0.0000%	0.000000%	0.000000%	0.000000%
24	Transmission Maintenance Expense		0	0	0	0
		9.9	0.0000%	0.000000%	0.000000%	0.000000%
25	Customer Accounting Expense		33,940,174	0	3,576	0
		10.1	100.0000%	0.000000%	0.010537%	0.000000%
26	Total O & M Expense		130,087,761	1,072	10,414	160
		11.2	100.0000%	0.000824%	0.008006%	0.000123%

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Line No.	Description	Allocation Factor No.	Total	Electric Generation Gas Service		
				Demand	Customer	Commodity
	(a)	(b)	(c)	(c)	(d)	(e)
1	CP Monthly Demand		118,455,410	1,262,860		
		1	100.0000%	1.066106%	0.000000%	0.000000%
2	NCP Demand		121,419,774	2,613,148		
		2	100.0000%	2.152160%	0.000000%	0.000000%
3	Throughput		651,784,739			21,521,946
		3	100.0000%	0.000000%	0.000000%	3.302002%
4	Customers		959,083		21	
		4	100.0000%	0.000000%	0.002190%	0.000000%
5	Customers With Mains		959,083	0	21	0
		5	100.0000%	0.000000%	0.002190%	0.000000%
6	Meters for Customers		1,122,135		973	
		6	100.0000%	0.000000%	0.086677%	0.000000%
7	Service Lines for Customers		1,072,625		167	
		7	100.0000%	0.000000%	0.015541%	0.000000%
8	Res., MMMHP & Small, Medium GS		950,479			
		8	100.0000%	0.000000%	0.000000%	0.000000%
9	Service Establishment Charges		34,611,268	0	1,260	0
		9	100.0000%	0.000000%	0.003640%	0.000000%
10	Extra		0	0	0	0
		10	0.0000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0
		11	0.0000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		7,311	0	0	0
		12	100.0000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		1,010,689	0	142	0
		13	100.0000%	0.000000%	0.014046%	0.000000%
14	Extra		0	0	0	0
		14	0.0000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0
		15	0.0000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors					
16	Net Production, Transmission, & Distribution Plant		1,182,139,980	3,969,499	226,236	140,177
		1.1	100.0000%	0.335789%	0.019138%	0.011858%
17	Distribution Mains		629,304,144	3,772,977	6,030	0
		2.2	100.0000%	0.599547%	0.000958%	0.000000%
18	Distribution Services		321,023,126	0	49,890	0
		3.3	100.0000%	0.000000%	0.015541%	0.000000%
19	Distribution Mains & Services		950,327,271	3,772,977	55,920	0
		4.4	100.0000%	0.397019%	0.005884%	0.000000%
20	Allocable Distribution Operating Expenses		32,338,902	61,779	16,064	12,276
		5.5	100.0000%	0.191035%	0.049674%	0.037962%
21	Allocable Distribution Maintenance Expenses		29,888,822	106,579	3,532	0
		6.6	100.0000%	0.356584%	0.011816%	0.000000%
22	Transmission Operating Expense		0	0	0	0
		7.7	0.0000%	0.000000%	0.000000%	0.000000%
23	Transmission Mains		0	0	0	0
		8.8	0.0000%	0.000000%	0.000000%	0.000000%
24	Transmission Maintenance Expense		0	0	0	0
		9.9	0.0000%	0.000000%	0.000000%	0.000000%
25	Customer Accounting Expense		33,940,174	0	4,414	0
		10.1	100.0000%	0.000000%	0.013006%	0.000000%
26	Total O & M Expense		130,087,761	226,342	37,019	44,470
		11.2	100.0000%	0.173992%	0.028457%	0.034185%

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Line No.	Description	Allocation Factor No.	Total	Small Essential Agr. User Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(f)	(g)	(h)
1	CP Monthly Demand		118,455,410	1,319,589		
		1	100.0000%	1.113996%	0.000000%	0.000000%
2	NCP Demand		121,419,774	1,466,488		
		2	100.0000%	1.207784%	0.000000%	0.000000%
3	Throughput		651,784,739			7,214,684
		3	100.0000%	0.000000%	0.000000%	1.106912%
4	Customers		959,083		101	
		4	100.0000%	0.000000%	0.010566%	0.000000%
5	Customers With Mains		959,083	0	101	0
		5	100.0000%	0.000000%	0.010566%	0.000000%
6	Meters for Customers		1,122,135		2,271	
		6	100.0000%	0.000000%	0.202357%	0.000000%
7	Service Lines for Customers		1,072,625		963	
		7	100.0000%	0.000000%	0.089826%	0.000000%
8	Res., MMMHP & Small, Medium GS		950,479			
		8	100.0000%	0.000000%	0.000000%	0.000000%
9	Service Establishment Charges		34,611,268	0	6,080	0
		9	100.0000%	0.000000%	0.017567%	0.000000%
10	Extra		0	0	0	0
		10	0.0000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0
		11	0.0000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		7,311	0	0	0
		12	100.0000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		1,010,689	0	1,845	0
		13	100.0000%	0.000000%	0.182541%	0.000000%
14	Extra		0	0	0	0
		14	0.0000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0
		15	0.0000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors					
16	Net Production, Transmission, & Distribution Plant		1,182,139,980	4,147,813	715,791	46,991
		1.1	100.0000%	0.350873%	0.060550%	0.003975%
17	Distribution Mains		629,304,144	3,942,463	29,098	0
		2.2	100.0000%	0.626480%	0.004624%	0.000000%
18	Distribution Services		321,023,126	0	288,362	0
		3.3	100.0000%	0.000000%	0.089826%	0.000000%
19	Distribution Mains & Services		950,327,271	3,942,463	317,460	0
		4.4	100.0000%	0.414853%	0.033405%	0.000000%
20	Allocable Distribution Operating Expenses		32,338,902	64,554	39,866	4,115
		5.5	100.0000%	0.199616%	0.123274%	0.012726%
21	Allocable Distribution Maintenance Expenses		29,888,822	111,366	14,090	0
		6.6	100.0000%	0.372602%	0.047141%	0.000000%
22	Transmission Operating Expense		0	0	0	0
		7.7	0.0000%	0.000000%	0.000000%	0.000000%
23	Transmission Mains		0	0	0	0
		8.8	0.0000%	0.000000%	0.000000%	0.000000%
24	Transmission Maintenance Expense		0	0	0	0
		9.9	0.0000%	0.000000%	0.000000%	0.000000%
25	Customer Accounting Expense		33,940,174	0	56,834	0
		10.1	100.0000%	0.000000%	0.167452%	0.000000%
26	Total O & M Expense		130,087,761	236,510	151,841	14,907
		11.2	100.0000%	0.181808%	0.116722%	0.011460%

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Line No.	Description	Allocation Factor No.	Total	Natural Gas Engine Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(i)	(j)	(k)
1	CP Monthly Demand		118,455,410	626,158		
		1	100.0000%	0.528602%	0.000000%	0.000000%
2	NCP Demand		121,419,774	1,910,419		
		2	100.0000%	1.573400%	0.000000%	0.000000%
3	Throughput		651,784,739			13,070,981
		3	100.0000%	0.000000%	0.000000%	2.005414%
4	Customers		959,083		425	
		4	100.0000%	0.000000%	0.044357%	0.000000%
5	Customers With Mains		959,083	0	425	0
		5	100.0000%	0.000000%	0.044357%	0.000000%
6	Meters for Customers		1,122,135		9,759	
		6	100.0000%	0.000000%	0.869669%	0.000000%
7	Service Lines for Customers		1,072,625		3,786	
		7	100.0000%	0.000000%	0.352940%	0.000000%
8	Res., MMMHP & Small, Medium GS		950,479			
		8	100.0000%	0.000000%	0.000000%	0.000000%
9	Service Establishment Charges		34,611,268	0	25,525	0
		9	100.0000%	0.000000%	0.073748%	0.000000%
10	Extra		0	0	0	0
		10	0.0000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0
		11	0.0000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		7,311	0	0	0
		12	100.0000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		1,010,689	0	2,319	0
		13	100.0000%	0.000000%	0.229468%	0.000000%
14	Extra		0	0	0	0
		14	0.0000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0
		15	0.0000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors					
16	Net Production, Transmission, & Distribution Plant		1,182,139,980	1,968,178	2,966,946	85,134
		1.1	100.0000%	0.166493%	0.250981%	0.007202%
17	Distribution Mains		629,304,144	1,870,737	122,159	0
		2.2	100.0000%	0.297271%	0.019412%	0.000000%
18	Distribution Services		321,023,126	0	1,133,019	0
		3.3	100.0000%	0.000000%	0.352940%	0.000000%
19	Distribution Mains & Services		950,327,271	1,870,737	1,255,178	0
		4.4	100.0000%	0.196852%	0.132078%	0.000000%
20	Allocable Distribution Operating Expenses		32,338,902	30,631	169,974	7,456
		5.5	100.0000%	0.094720%	0.525603%	0.023055%
21	Allocable Distribution Maintenance Expenses		29,888,822	52,844	57,119	0
		6.6	100.0000%	0.176803%	0.191105%	0.000000%
22	Transmission Operating Expense		0	0	0	0
		7.7	0.0000%	0.000000%	0.000000%	0.000000%
23	Transmission Mains		0	0	0	0
		8.8	0.0000%	0.000000%	0.000000%	0.000000%
24	Transmission Maintenance Expense		0	0	0	0
		9.9	0.0000%	0.000000%	0.000000%	0.000000%
25	Customer Accounting Expense		33,940,174	0	72,370	0
		10.1	100.0000%	0.000000%	0.213227%	0.000000%
26	Total O & M Expense		130,087,761	112,226	443,976	27,008
		11.2	100.0000%	0.086270%	0.341289%	0.020761%

SOUTHWEST GAS CORPORATION
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Line No.	Description	Allocation Factor No.	Total	Street Lighting Gas Service Demand	Customer	Commodity
	(a)	(b)	(c)	(l)	(m)	(n)
1	CP Monthly Demand		118,455,410	9,362		
		1	100.0000%	0.007903%	0.000000%	0.000000%
2	NCP Demand		121,419,774	9,362		
		2	100.0000%	0.007710%	0.000000%	0.000000%
3	Throughput		651,784,739			102,289
		3	100.0000%	0.000000%	0.000000%	0.015694%
4	Customers		959,083		568	
		4	100.0000%	0.000000%	0.059223%	0.000000%
5	Customers With Mains		959,083	0	568	0
		5	100.0000%	0.000000%	0.059223%	0.000000%
6	Meters for Customers		1,122,135		0	
		6	100.0000%	0.000000%	0.000000%	0.000000%
7	Service Lines for Customers		1,072,625		728	
		7	100.0000%	0.000000%	0.067903%	0.000000%
8	Res., MMMHP & Small, Medium GS		950,479			
		8	100.0000%	0.000000%	0.000000%	0.000000%
9	Service Establishment Charges		34,611,268	0	34,080	0
		9	100.0000%	0.000000%	0.098465%	0.000000%
10	Extra		0	0	0	0
		10	0.0000%	0.000000%	0.000000%	0.000000%
11	Extra		0	0	0	0
		11	0.0000%	0.000000%	0.000000%	0.000000%
12	Industrial Meas. & Reg.		7,311	0	0	0
		12	100.0000%	0.000000%	0.000000%	0.000000%
13	Weighted Customers for Meter Reading		1,010,689	0	27	0
		13	100.0000%	0.000000%	0.002671%	0.000000%
14	Extra		0	0	0	0
		14	0.0000%	0.000000%	0.000000%	0.000000%
15	Extra		0	0	0	0
		15	0.0000%	0.000000%	0.000000%	0.000000%
	Internally Generated Allocation Factors					
16	Net Production, Transmission, & Distribution Plant		1,182,139,980	29,427	388,763	666
		1.1	100.0000%	0.002489%	0.032886%	0.000056%
17	Distribution Mains		629,304,144	27,970	163,102	0
		2.2	100.0000%	0.004445%	0.025918%	0.000000%
18	Distribution Services		321,023,126	0	217,983	0
		3.3	100.0000%	0.000000%	0.067903%	0.000000%
19	Distribution Mains & Services		950,327,271	27,970	381,085	0
		4.4	100.0000%	0.002943%	0.040100%	0.000000%
20	Allocable Distribution Operating Expenses		32,338,902	458	5,354	58
		5.5	100.0000%	0.001416%	0.016556%	0.000180%
21	Allocable Distribution Maintenance Expenses		29,888,822	790	11,438	0
		6.6	100.0000%	0.002643%	0.038269%	0.000000%
22	Transmission Operating Expense		0	0	0	0
		7.7	0.0000%	0.000000%	0.000000%	0.000000%
23	Transmission Mains		0	0	0	0
		8.8	0.0000%	0.000000%	0.000000%	0.000000%
24	Transmission Maintenance Expense		0	0	0	0
		9.9	0.0000%	0.000000%	0.000000%	0.000000%
25	Customer Accounting Expense		33,940,174	0	2,591	0
		10.1	100.0000%	0.000000%	0.007633%	0.000000%
26	Total O & M Expense		130,087,761	1,678	25,063	211
		11.2	100.0000%	0.001290%	0.019267%	0.000162%

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF REVENUES AT PRESENT AND PROPOSED RATES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Proposed Schedule Number	Revenues		Increase/(Decrease)		Line No.
			Present Rates [1]	Proposed Rates [2]	Dollars	Percent	
	(a)	(b)	(c)	(d)	(e)	(f)	
	Sales Service						
1	Residential Gas Service	G-5	$ 522,983,992	$ 562,696,282	$ 39,712,290	7.59%	1
2	Multi-Family Residential Gas Service	G-6	12,732,540	12,925,127	192,587	1.51%	2
3	Low Income Residential Gas Service	G-10	13,827,935	14,205,326	377,391	2.73%	3
4	Low Income Multi-Family Residential	G-11	932,166	963,216	31,050	3.33%	4
5	Special Residential Gas Service	G-15	201,538	226,215	24,677	12.24%	5
6	Master Metered Mobile Home Park Gas Service	G-20	3,055,730	3,125,364	69,634	2.28%	6
	General Gas Service	G-25					
7	Small		12,523,176	13,509,001	985,825	7.87%	7
8	Medium		66,520,230	69,301,266	2,781,036	4.18%	8
9	Large		191,013,943	194,731,910	3,717,967	1.95%	9
10	Transporation Eligible		108,820,468	110,552,881	1,732,413	1.59%	10
11	Optional Gas Service	G-30	43,678,213	43,678,213	0	0.00%	11
12	Air Conditioning Gas Service	G-40	1,119,715	1,126,427	6,712	0.60%	12
13	Street Lighting Gas Service	G-45	150,721	166,370	15,649	10.38%	13
	Gas Service for Compression on Customer's Premises	G-55					
14	Small		201,097	202,047	950	0.47%	14
15	Large		2,315,696	2,343,998	28,302	1.22%	15
16	Residential		97,240	101,598	4,358	4.48%	16
17	Electric Generation Gas Service	G-60	22,490,504	22,639,278	148,774	0.66%	17
18	Small Essential Agriculture User Gas Service	G-75	14,879,470	15,054,978	175,508	1.18%	18
19	Natural Gas Engine Gas Service	G-80	12,150,874	12,365,266	214,392	1.76%	19
20							20
21	Total Gas Sales		$1,029,695,248	$ 1,079,914,763	$ 50,219,515	4.88%	21
22	Special Contract Service	B-1	2,528,029	2,528,029	0	0.00%	22
23	Other Operating Revenue		12,261,805	12,261,805	0	0.00%	23
24	Total Arizona Revenue		$1,044,485,083	$ 1,094,704,598	$ 50,219,515	4.81%	24
25	Total Requirement			$ 1,094,703,780			25
26	Over/(Under) Requirement			$ 818			26
	Low Income Residential Including Discount [3]						
27	Low Income Residential Gas Service	G-10	$ 12,009,932	$ 12,350,661	$ 340,729	2.84%	27
28	Low Income Multi-Family Residential	G-11	$ 826,454	$ 855,050	$ 28,596	3.46%	28

[1] Schedule H-2, Sheets 1-4, including estimated gas cost for transporation customers.
[2] Schedule H-2, Sheets 5-9, including estimated gas cost for transportation customers.
[3] Revenue including low income benefit reflected on Schedule H-2, Sheet 9.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF MARGIN AT PRESENT AND PROPOSED RATES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Proposed Schedule Number	Margin		Increase/(Decrease)		Line No.
			Present Rates [1]	Proposed Rates [2]	Dollars	Percent	
	(a)	(b)	(c)	(d)	(e)	(f)	
	Sales Service						
1	Residential Gas Service	G-5	$ 252,170,209	$ 292,104,765	$ 39,934,556	15.84%	1
2	Multi-Family Residential Gas Service	G-6	6,635,205	6,462,646	(172,559)	(2.60%)	2
3	Low Income Residential Gas Service	G-10	6,749,399	7,377,773	628,374	9.31%	3
4	Low Income Multi-Family Residential	G-11	480,391	458,876	(21,515)	(4.48%)	4
5	Special Residential Gas Service	G-15	70,281	40,551	(29,730)	(42.30%)	5
6	Master Metered Mobile Home Park Gas Service	G-20	972,093	1,041,727	69,634	7.16%	6
	General Gas Service	G-25					
7	Small		7,867,642	8,853,467	985,825	12.53%	7
8	Medium		24,310,776	27,091,812	2,781,036	11.44%	8
9	Large		53,003,981	56,721,948	3,717,967	7.01%	9
10	Transporation Eligible		20,088,639	21,821,052	1,732,413	8.62%	10
11	Optional Gas Service	G-30	3,255,998	3,255,998	0	0.00%	11
12	Air Conditioning Gas Service	G-40	123,697	130,409	6,712	5.43%	12
13	Street Lighting Gas Service	G-45	55,850	71,499	15,649	28.02%	13
	Gas Service for Compression on Customer's Premises	G-55					
14	Small		36,474	37,424	950	2.60%	14
15	Large		404,946	433,248	28,302	6.99%	15
16	Residential		25,489	29,847	4,358	17.10%	16
17	Electric Generation Gas Service	G-60	2,529,330	2,678,104	148,774	5.88%	17
18	Small Essential Agriculture User Gas Service	G-75	3,104,924	3,280,432	175,508	5.65%	18
19	Natural Gas Engine Gas Service	G-80	2,559,519	2,773,911	214,392	8.38%	19
20	Total Sales and Full Margin Transportation		$ 384,444,843	$ 434,665,489	$ 50,220,646	13.06%	20
21	Special Contract Service	B-1	2,528,029	2,528,029	0	0.00%	21
22	Other Operating Revenue		12,261,805	12,261,805	0	0.00%	22
23	Total Arizona Revenue		$ 399,234,678	$ 449,455,324	$ 50,220,646	12.58%	23
24	Total Requirement			$ 449,454,506			24
25	Over/(Under) Requirement			$ 818			25

[1] Schedule H-2, Sheets 1-4.
[2] Schedule H-2, Sheets 5-9.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF GAS COST AT PRESENT AND PROPOSED RATES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Schedule Number	Gas Cost Present Rates [1]	Gas Cost 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	$ 270,813,783	$ 270,591,517	$(222,266)	(0.08%)	1
2	Multi-Family Residential Gas Service	G-6	6,097,335	6,462,481	365,146	5.99%	2
3	Low Income Residential Gas Service	G-10	7,078,536	6,827,553	(250,983)	(3.55%)	3
4	Low Income Multi-Family Residential	G-11	451,775	504,340	52,565	11.64%	4
5	Special Residential Gas Service	G-15	131,257	185,664	54,407	41.45%	5
6	Total Residential		$ 284,572,686	$ 284,571,555	$(1,131)	(0.00%)	6
7	Master Metered Mobile Home Park Gas Service	G-20	2,083,637	2,083,637	0	0.00%	7
	General Gas Service	G-25					
8	Small		4,655,534	4,655,534	0	0.00%	8
9	Medium		42,209,454	42,209,454	0	0.00%	9
10	Large		138,009,962	138,009,962	0	0.00%	10
11	Transporation Eligible		88,731,829	88,731,829	0	0.00%	11
12	Optional Gas Service	G-30	40,422,215	40,422,215	0	0.00%	12
13	Air Conditioning Gas Service	G-40	996,018	996,018	0	0.00%	13
14	Street Lighting Gas Service	G-45	94,871	94,871	0	0.00%	14
	Gas Service for Compression on Customer's Premises	G-55					
15	Small		164,623	164,623	0	0.00%	15
16	Large		1,910,750	1,910,750	0	0.00%	16
17	Residential		71,751	71,751	0	0.00%	17
18	Electric Generation Gas Service	G-60	19,961,174	19,961,174	0	0.00%	18
19	Small Essential Agriculture User Gas Service	G-75	11,774,546	11,774,546	0	0.00%	19
20	Natural Gas Engine Gas Service	G-80	9,591,355	9,591,355	0	0.00%	20
21	Total Gas Sales		$ 645,250,405	$ 645,249,274	$(1,131)	(0.00%)	21
22	Special Contract Service	B-1	0	0	0	n/a	22
23	Other Operating Revenue		0	0	0	n/a	23
24	Total Arizona Revenue		$ 645,250,405	$ 645,249,274	$(1,131)	(0.00%)	24

[1] Schedule H-2, Sheets 1-4.
[2] Schedule H-2, Sheets 5-9.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF REVENUES AT PRESENT RATES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

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 (May - October)											
1	Basic Service Charge per Month		5,107,859		$ 9.70		$ 49,546,232		$ 49,546,232		$ 49,546,232	1
	Commodity Charge per Therm											
2	First 15 Therms			48,048,640		$ 0.54200		$ 26,042,363	26,042,363	$ 45,016,291	71,058,654	2
3	Over 15 Therms			16,007,105		0.50100		8,019,559	8,019,559	14,996,896	23,016,455	3
	Winter (November - April)											
4	Basic Service Charge per Month		5,190,171		$ 9.70		$ 50,344,659		$ 50,344,659		$ 50,344,659	4
	Commodity Charge per Therm											
5	First 35 Therms			133,956,357		$ 0.54200		72,604,346	72,604,346	125,502,371	198,106,717	5
6	Over 35 Therms			91,044,013		0.50100		45,613,050	45,613,050	85,298,225	130,911,275	6
						0.00000		0	0	0	0	
7	Total Single-Family Residential Gas Service		10,298,030	289,056,115			$ 99,890,891	$ 152,279,318	$ 252,170,209	$ 270,813,783	$ 522,983,992	7
	Low Income Single-Family Residential Gas Svc	G-10										
	Summer (May - October)											
8	Basic Service Charge		153,923		$ 7.00		$ 1,077,461		$ 1,077,461		$ 1,077,461	8
	Commodity Charge per Therm											
	Summer (May - October)											
9	First 15 Therms			1,499,731		$ 0.54200		$ 812,854	812,854	$ 1,226,000	2,038,854	9
10	Over 15 Therms			343,792		0.50100		172,240	172,240	281,043	453,283	10
	Winter (November - April)											
11	Basic Service Charge per Month		156,983		$ 7.00		$ 1,098,881		$ 1,098,881		$ 1,098,881	11
	Commodity Charge per Therm											
12	First 35 Therms			4,229,842		0.54200		2,292,574	2,292,574	3,457,811	5,750,385	12
13	Next 115 Therms			2,532,839		0.50100		1,268,952	1,268,952	2,070,545	3,339,497	13
14	Over 150 Therms			52,769		0.50100		26,437	26,437	43,137	69,574	14
15	Total Low Income Single-Family Residential Gas Service		310,906	8,658,972			$ 2,176,342	$ 4,573,057	$ 6,749,399	$ 7,078,536	$ 13,827,935	15
	Special Residential Gas Service for Air Conditioning	G-15										
	Summer (May - October)											
16	Basic Service Charge per Month		648		$ 9.70		$ 6,286		$ 6,286		$ 6,286	16
	Commodity Charge per Therm											
17	First 15 Therms			7,899		$ 0.54200		$ 4,281	4,281	$ 7,326	11,607	17
18	Over 15 Therms			65,327		0.28200		18,422	18,422	60,589	79,011	18
	Winter (November - April)											
19	Basic Service Charge per Month		648		$ 9.70		$ 6,286		$ 6,286		$ 6,286	19
	Commodity Charge per Therm											
20	First 35 Therms			19,309		0.54200		10,465	10,465	17,909	28,374	20
21	Over 35 Therms			48,985		0.50100		24,541	24,541	45,433	69,974	21
22	Total Special Residential Gas Service		1,296	141,520			$ 12,572	$ 57,709	$ 70,281	$ 131,257	$ 201,538	22

[1] Margin rates effective March 1, 2006 per Decision No. 68487.
[2] Gas Cost and Rate Adjustment effective May 1, 2007.

SCHEDULE H-2
SHEET 1 OF 9

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF REVENUES AT PRESENT RATES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

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)	
	Multi-Family Residential Gas Service	G-6										
	Summer (May - October)											
1	Basic Service Charge per Month		182,409		$ 8.70		$ 1,586,958		$ 1,586,958		$ 1,586,958	1
	Commodity Charge per Therm											
2	First 7 Therms			1,044,432		$ 0.54200		$ 566,082	566,082	$ 978,518	1,544,600	2
3	Over 7 Therms			950,005		$ 0.50100		475,953	475,953	890,050	1,366,003	3
	Winter (November - April)											
4	Basic Service Charge per Month		188,153		$ 8.70		$ 1,636,931		$ 1,636,931		$ 1,636,931	4
	Commodity Charge per Therm											
5	First 18 Therms			2,633,090		0.54200		1,427,135	1,427,135	2,466,916	3,894,051	5
6	Over 18 Therms			1,880,532		0.50100		942,146	942,146	1,761,851	2,703,997	6
7	Total Multi-Family Residential Gas Service		370,562	6,508,059			$ 3,223,889	$ 3,411,316	$ 6,635,205	$ 6,097,335	$ 12,732,540	7
	Low Income Multi-Family Residential Gas Svc	G-11										
	Summer (May - October)											
8	Basic Service Charge per Month		13,560		$ 7.00		$ 94,920		$ 94,920		$ 94,920	8
	Commodity Charge per Therm											
9	First 7 Therms			79,822		$ 0.54200		$ 43,264	43,264	$ 65,253	108,517	9
10	Over 7 Therms			78,071		0.50100		39,114	39,114	63,822	102,936	10
	Winter (November - April)											
11	Basic Service Charge per Month		13,828		$ 7.00		$ 96,796		$ 96,796		$ 96,796	11
	Commodity Charge per Therm											
12	First 18 Therms			207,982		0.54200		112,726	112,726	170,021	282,747	12
13	Next 132 Therms			186,423		0.50100		93,398	93,398	152,397	245,795	13
14	Over 150 Therms			345		0.50100		173	173	282	455	14
15	Total Low Income Multi-Family Residential Gas Service		27,388	552,643			$ 191,716	$ 288,675	$ 480,391	$ 451,775	$ 932,166	15
16	Total Residential Gas Service		11,008,182	304,917,309			105,495,410	160,610,075	266,105,485	284,572,686	550,678,171	16
	Master Metered Mobile Home Park Gas Service	G-20										
17	Basic Service Charge per Month		1,968		$ 60.00		$ 118,080		$ 118,080		$ 118,080	17
	Commodity Charge per Therm All Usage											
18	All Usage			2,223,993		$ 0.38400		$ 854,013	854,013	2,083,637	2,937,650	18
19	Total MMMHP Gas Service		1,968	2,223,993			$ 118,080	$ 854,013	$ 972,093	$ 2,083,637	$ 3,055,730	19
	General Gas Service - Small	G-25(S)										
20	Basic Service Charge Per Month		201,805		$ 25.00		$ 5,045,125		$ 5,045,125		$ 5,045,125	20
	Commodity Charge per Therm All Usage											
21	Transportation Customers			10,138		$ 0.56217		$ 5,699	5,699	$ 8,288	13,987	21
22	Sales Customers			5,010,616		0.56217		$ 2,816,818	2,816,818	$ 4,647,246	7,464,064	22
23	Total Small General Gas Service		201,805	5,020,754			5,045,125	2,822,517	7,867,642	4,655,534	12,523,176	23
	General Gas Service - Medium	G-25(M)										
24	Basic Service Charge		193,790		$ 33.00		$ 6,395,070		$ 6,395,070		$ 6,395,070	24
	Commodity Charge per Therm All Usage											
25	Transportation Customers			172,365		$ 0.39349		$ 67,824	67,824	140,905	208,729	25
26	Sales Customers			45,357,904		0.39349		17,847,882	17,847,882	42,068,549	59,916,431	26
27	Total Medium General Gas Service		193,790	45,530,269			$ 6,395,070	$ 17,915,706	$ 24,310,776	$ 42,209,454	$ 66,520,230	27

[1] Margin rates effective March 1, 2006 per Decision No. 68487.
[2] Gas Cost and Rate Adjustment effective May 1, 2007.

SCHEDULE H-2
SHEET 2 OF 9

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF REVENUES AT PRESENT RATES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

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 - Large	G-25(L)										
1	Basic Service Charge		85,510		$ 145.00		$ 12,398,950		$ 12,398,950		$ 12,398,950	1
	Commodity Charge per Therm All Usage											
2	Transportation Customers			3,556,829		$ 0.27211		$ 967,849	967,849	$ 2,907,637	3,875,486	2
3	Sales Customers			145,666,025		0.27211		39,637,182	39,637,182	135,102,325	174,739,507	3
4	Total Large General Gas Service		85,510	149,222,854			$ 12,398,950	$ 40,605,031	53,003,981	$ 138,009,962	$ 191,013,943	4
	General Gas Service - Transportation Eligible	G-25(TE)										
5	Basic Service Charge		2,222		$ 720.00		$ 1,599,840		1,599,840		$ 1,599,840	5
6	Demand Charge per Month			12,803,712	0.062340			9,578,201	9,578,201		9,578,201	6
	Commodity Charge per Therm All Usage											
7	Transportation Customers			32,517,415		$ 0.08953		$ 2,911,284	2,911,284	$ 26,582,336	29,493,620	7
8	Sales Customers			67,008,985		0.08953		5,999,314	5,999,314	62,149,493	68,148,807	8
9	Total Transportation Eligible General Gas Service		2,222	99,526,400			$ 1,599,840	$ 18,488,799	$ 20,088,639	$ 88,731,829	$ 108,820,468	9
10	Total General Gas Service		483,327	299,300,277			$ 25,438,985	$ 79,832,053	$ 105,271,038	$ 273,606,779	$ 378,877,817	10
	Air Conditioning Gas Service	G-40										
	Basic Service Charge											
11	With Other Service - No BSC		60		$ 0.00		$ 0		$ 0		$ 0	11
12	General Service - Small		198		25.00		4,950		4,950		4,950	12
13	General Service - Medium		0		33.00		0		0		0	13
14	General Service - Large		48		145.00		6,960		6,960		6,960	14
15	Essential Agricultural		12		90.00		1,080		1,080		1,080	15
	Commodity Charge per Therm All Usage											
16	Transportation Customers			373,987		$ 0.09900		$ 37,025	37,025	$ 305,727	342,752	16
17	Sales Customers			744,265		0.09900		73,682	73,682	690,291	763,973	17
18	Total Air Conditioning Gas Service		318	1,118,252			$ 12,990	$ 110,707	$ 123,697	$ 996,018	$ 1,119,715	18
	Street Lighting Gas Service	G-45										
	Commodity Charge per Therm of Rated Capacity											
19	All Usage		324	102,289		$ 0.54600		$ 55,850	55,850	94,871	150,721	19
20	Total Street Lighting Gas Service		324	102,289			$ 0	$ 55,850	$ 55,850	$ 94,871	$ 150,721	20
	Gas Service for Compression on Customer's Premises	G-55										
	Basic Service Charge											
21	Small		252		$ 25.00		$ 6,300		$ 6,300		$ 6,300	21
22	Large		288		190.00		54,720		54,720		54,720	22
23	Residential		1,272		9.70		12,338		12,338		12,338	23
	Commodity Charge per Therm All Usage											
24	Transportation Customers			0		$ 0.17000		$ 0	0	$ 0	0	24
	Sales Customers											
25	Small			177,495		0.17000		30,174	30,174	164,623	194,797	25
26	Large			2,060,152		0.17000		350,226	350,226	1,910,750	2,260,976	26
27	Residential			77,361		0.17000		13,151	13,151	71,751	84,902	27
28	Total CNG Gas Service		1,812	2,315,008			$ 73,358	$ 393,551	$ 466,909	$ 2,147,124	$ 2,614,033	28

[1] Margin rates effective March 1, 2006 per Decision No. 68487.
[2] Gas Cost and Rate Adjustment effective May 1, 2007.

SCHEDULE H-2
SHEET 3 OF 9

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF REVENUES AT PRESENT RATES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

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)	
	Electric Generation Gas Service	G-60										
	Basic Service Charge											
1	General Service - Small		36		$ 25.00		$ 900		$ 900		$ 900	1
2	General Service - Medium		36		33.00		1,188		1,188		1,188	2
3	General Service - Large		84		145.00		12,180		12,180		12,180	3
4	General Service - Transportation Eligible		84		720.00		60,480		60,480		60,480	4
5	Essential Agricultural		12		90.00		1,080		1,080		1,080	5
	Commodity Charge per Therm All Usage											
6	Transportation Customers			0		$ 0.11400		$ 0	0	$ 0	0	6
7	Sales Customers			21,521,946		0.11400		2,453,502	2,453,502	19,961,174	22,414,676	7
8	Total Electric Generation Gas Service		252	21,521,946			$ 75,828	$ 2,453,502	$ 2,529,330	$ 19,961,174	$ 22,490,504	8
	Essential Agriculture User Gas Service	G-75										
9	Basic Service Charge		1,216		$ 90.00		$ 109,440		$ 109,440		$ 109,440	9
	Commodity Charge per Therm All Usage											
10	Transportation Customers			6,217,976		$ 0.22300		$ 1,386,609	1,386,609	$ 5,083,071	6,469,680	10
11	Sales Customers			7,214,684		0.22300		1,608,875	1,608,875	6,691,475	8,300,350	11
12	Total Essential Agricultural Gas Service		1,216	13,432,660			$ 109,440	$ 2,995,484	$ 3,104,924	$ 11,774,546	$ 14,879,470	12
	Natural Gas Engine Gas Service	G-80										
	Basic Service Charge											
13	Off-Peak Season (Oct. - March)		2,516		$ 0.00		$ 0		$ 0		$ 0	13
14	Peak Season (April - September)		2,589		95.00		245,955		245,955		245,955	14
	Commodity Charge per Therm All Usage											
15	Transportation Customers			0		$ 0.17700		$ 0	0	$ 0	0	15
16	Sales Customers			13,070,981		0.17700		2,313,564	2,313,564	9,591,355	11,904,919	16
17	Total Natural Gas Engine Gas Service		5,105	13,070,981			$ 245,955	$ 2,313,564	$ 2,559,519	$ 9,591,355	$ 12,150,874	17
18	Total Tariff Sales		11,502,504	658,002,715			131,570,046	249,618,799	381,188,845	604,828,190	986,017,035	18
19	Optional Gas Service	G-30	84	49,447,344			$ 120,540	$ 3,135,458	$ 3,255,998	$ 40,422,215	$ 43,678,213	19
20	Special Contract Service	B-1	244	35,660,859			$ 449,274	$ 2,078,755	$ 2,528,029		$ 2,528,029	20
21	Other Operating Revenues						$ 12,261,805		$ 12,261,805		$ 12,261,805	21
22	Total		11,502,832	743,110,918			$ 144,401,665	$ 254,833,013	$ 399,234,678	$ 645,250,405	$1,044,485,083	22
23	Total Revenue Requirement								449,454,506			23
24	Over/(Under)								$ (50,219,828)			24

[1] Margin rates effective March 1, 2006 per Decision No. 68487.
[2] Gas Cost and Rate Adjustment effective May 1, 2007.

SCHEDULE H-2
SHEET 4 OF 9

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF PRESENT AND PROPOSED REVENUES BY RATE COMPONENT
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Proposed Schedule Number	Billing Determinants: Number of Bills	Billing Determinants: Sales (Therms)	Revenue at Proposed Rates: Basic Service Charge [1]	Revenue at Proposed Rates: Commodity Charge [1]	Revenue at Proposed Rates: Basic Service Charge	Revenue at Proposed Rates: Commodity Charge	Revenue at Proposed Rates: Total Margin	Revenue at Proposed Rates: Gas Cost [2]	Revenue at Proposed Rates: Total Revenue	Revenue at Present Rates [3]	Increase / Decrease: Dollars	Increase / Decrease: Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
	Single-Family Residential Gas Service	G-5													
	Summer (May - October)														
1	Basic Service Charge per Month		5,107,859		$ 12.80		$ 65,380,595		$ 65,380,595		$ 65,380,595	$ 49,546,232	$ 15,834,363		1
	Commodity Charge per Therm														
2	First 15 Therms			48,048,640		$ 0.88069		$ 42,315,957	42,315,957	$ 29,307,749	71,623,706	71,058,654	565,052		2
3	Over 15 Therms			16,007,105		0.00000		0	0	23,860,990	23,860,990	23,016,455	844,535		3
	Winter (November - April)														
4	Basic Service Charge per Month		5,190,171		$ 12.80		$ 66,434,189		$ 66,434,189		$ 66,434,189	$ 50,344,659	$ 16,089,530		4
	Commodity Charge per Therm														
5	First 35 Therms			133,956,357		0.88069		117,974,024	117,974,024	81,708,020	199,682,044	198,106,717	1,575,327		5
6	Over 35 Therms			91,044,013		0.00000		0	0	135,714,758	135,714,758	130,911,275	4,803,483		6
7	Total Single-Family Residential Gas Service		10,298,030	289,056,115			$ 131,814,784	$ 160,289,981	$ 292,104,765	$ 270,591,517	$ 562,696,282	$ 522,983,992	$ 39,712,290	7.59%	7
	Low Income Single-Family Residential Gas Service	G-10													
	Summer (May - October)														
8	Basic Service Charge		153,923		$ 7.50		$ 1,154,423		$ 1,154,423		$ 1,154,423	$ 1,077,461	$ 76,962		8
	Commodity Charge per Therm														
	Summer (May - October)														
9	First 15 Therms			1,499,731		$ 0.88069		$ 1,320,798	1,320,798	$ 735,693	2,056,491	2,038,854	17,637		9
10	Over 15 Therms			343,792		0.00000		0	0	471,422	471,422	453,283	18,139		10
	Winter (November - April)														
11	Basic Service Charge per Month		156,983		$ 7.50		$ 1,177,373		$ 1,177,373		$ 1,177,373	$ 1,098,881	$ 78,492		11
	Commodity Charge per Therm														
12	First 35 Therms			4,229,842		0.88069		3,725,179	3,725,179	2,074,949	5,800,128	5,750,385	49,743		12
13	Next 115 Therms			2,532,839		0.00000		0	0	3,473,130	3,473,130	3,339,497	133,633		13
14	Over 150 Therms			52,769		0.00000		0	0	72,359	72,359	69,574	2,785		14
15	Total Low Income Single-Family Residential Gas Service		310,906	8,658,972			$ 2,331,796	$ 5,045,977	$ 7,377,773	$ 6,827,553	$ 14,205,326	$ 13,827,935	$ 377,391	2.73%	15
	Multi-Family Residential Gas Service	G-6													
	Summer (May - October)														
16	Basic Service Charge per Month		182,409		$ 8.70		$ 1,586,958		$ 1,586,958		$ 1,586,958	$ 1,586,958	$ -		16
	Commodity Charge per Therm														
17	First 7 Therms			1,044,432		$ 0.88069		$ 919,821	919,821	$ 637,062	1,556,883	1,544,600	12,283		17
18	Over 7 Therms			950,005		0.00000		0	0	1,416,125	1,416,125	1,366,003	50,122		18
	Winter (November - April)														
19	Basic Service Charge per Month		188,153		$ 8.70		$ 1,636,931		$ 1,636,931		$ 1,636,931	$ 1,636,931	$ -		19
	Commodity Charge per Therm														
20	First 18 Therms			2,633,090		0.88069		2,318,936	2,318,936	1,606,080	3,925,016	3,894,051	30,965		20
21	Over 18 Therms			1,880,532		0.00000		0	0	2,803,214	2,803,214	2,703,997	99,217		21
22	Total Multi-Family Residential Gas Service		370,562	6,508,059			$ 3,223,889	$ 3,238,757	$ 6,462,646	$ 6,462,481	$ 12,925,127	$ 12,732,540	$ 192,587	1.51%	22

[1] Exhibit No. (ABC_3), Sheets 5-8.
[2] Schedule H-3, Columns (j) and (k).
[3] Schedule H-2, Sheets 1-4.

SCHEDULE H-2
SHEET 5 OF 9

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF PRESENT AND PROPOSED REVENUES BY RATE COMPONENT
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Proposed Schedule Number	Billing Determinants: Number of Bills	Billing Determinants: Sales (Therms)	Revenue at Proposed Rates: Basic Service Charge [1]	Revenue at Proposed Rates: Commodity Charge [1]	Revenue at Proposed Rates: Basic Service Charge	Revenue at Proposed Rates: Commodity Charge	Revenue at Proposed Rates: Total Margin	Revenue at Proposed Rates: Gas Cost [2]	Revenue at Proposed Rates: Total Revenue	Revenue at Present Rates [3]	Increase / Decrease: Dollars	Increase / Decrease: Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
	Low Income Multi-Family Residential Gas Service	G-11													
	Summer (May - October)														
1	Basic Service Charge per Month		13,560		$ 7.50		$ 101,700		$ 101,700		$ 101,700	$ 94,920	$ 6,780		1
	Commodity Charge per Therm														
2	First 7 Therms			79,822		$ 0.88069		$ 70,298	70,298	$ 39,157	109,455	108,517	938		2
3	Over 7 Therms			78,071		0.00000		0	0	107,054	107,054	102,936	4,118		3
	Winter (November - April)														
4	Basic Service Charge per Month		13,828		$ 7.50		$ 103,710		$ 103,710		$ 103,710	$ 96,796	$ 6,914		4
	Commodity Charge per Therm														
5	First 18 Therms			207,982		0.88069		183,168	183,168	102,026	285,194	282,747	2,447		5
6	Next 132 Therms			186,423		0.00000		0	0	255,630	255,630	246,250	9,380		6
7	Over 150 Therms			345		0.00000		0	0	473	473	932,621	(932,148)		7
8	Total Low Income Multi-Family Residential Gas Service		27,388	552,643			$ 205,410	$ 253,466	$ 458,876	$ 504,340	$ 963,216	$ 1,864,787	$ (901,571)	-48.35%	8
	Special Residential Gas Service for A/C	G-15													
	Summer (May - October)														
9	Basic Service Charge per Month		648		$ 12.80		$ 8,294		$ 8,294		$ 8,294	$ 6,286	$ 2,008		9
	Commodity Charge per Therm														
10	First 15 Therms			7,899		$ 0.88069		$ 6,957	6,957	$ 4,744	11,701	11,607	94		10
11	Over 15 Therms			65,327		$ 0.00000		0	0	96,765	96,765	79,011	17,754		11
	Winter (November - April)														
12	Basic Service Charge per Month		648		$ 12.80		$ 8,294		$ 8,294		$ 8,294	$ 6,286	$ 2,008		12
	Commodity Charge per Therm														
13	First 35 Therms			19,309		$ 0.88069		17,005	17,005	11,596	28,601	28,374	227		13
14	Over 35 Therms			48,985		$ 0.00000		0	0	72,559	72,559	69,974	2,585		14
15	Total Special Residential Gas Service		1,296	141,520			$ 16,589	$ 23,962	$ 40,551	$ 185,664	$ 226,215	$ 201,538	$ 24,677	12.24%	15
16	Total Residential Gas Service		11,008,182	304,917,309			$137,592,468	$ 168,852,143	$ 306,444,611	$ 284,571,555	$ 591,016,166	$ 551,610,792	$ 39,405,374	7.14%	16
	Master Metered Mobile Home Park Gas Service	G-20													
17	Basic Service Charge per Month		1,968		$ 60.00		$ 118,080		$ 118,080		$ 118,080	$ 118,080	$ -		17
	Commodity Charge per Therm All Usage														
18	All Usage			2,223,993		$ 0.41531		$ 923,647	923,647	2,083,637	3,007,284	2,937,650	69,634		18
19	Total MMMHP Gas Service		1,968	2,223,993			$ 118,080	$ 923,647	$ 1,041,727	$ 2,083,637	$ 3,125,364	3,055,730	69,634	2.28%	19
	General Gas Service - Small	G-25(S)													
20	Basic Service Charge		201,805		$ 25.00		$ 5,045,125		$ 5,045,125		$ 5,045,125	$ 5,045,125	0		20
	Commodity Charge per Therm All Usage														
21	Transportation Customers			10,138		$ 0.75852		$ 7,690	7,690	$ 8,288	15,978	13,987	1,991		21
22	Sales Customers			5,010,616		0.75852		3,800,652	$ 3,800,652	4,647,246	8,447,898	7,464,064	983,834		22
23	Total Small General Gas Service		201,805	5,020,754			$ 5,045,125	$ 3,808,342	$ 8,853,467	$ 4,655,534	$ 13,509,001	$ 12,523,176	$ 985,825	7.87%	23
	General Gas Service - Medium	G-25(M)													
24	Basic Service Charge		193,790		$ 43.50		$ 8,429,865		$ 8,429,865		$ 8,429,865	$ 6,395,070	$ 2,034,795		24
	Commodity Charge per Therm All Usage														
25	Transportation Customers			172,365		$ 0.40988		$ 70,649	70,649	$ 140,905	211,554	208,729	2,825		25
26	Sales Customers			45,357,904		0.40988		18,591,298	18,591,298	42,068,549	60,659,847	59,916,431	743,416		26
27	Total Medium General Gas Service		193,790	45,530,269			$ 8,429,865	$ 18,661,947	$ 27,091,812	$ 42,209,454	$ 69,301,266	$ 66,520,230	$ 2,781,036	4.18%	27

[1] Exhibit No. (ABC_3), Sheets 5-8.
[2] Schedule H-3, Columns (j) and (k).
[3] Schedule H-2, Sheets 1-4.

SCHEDULE H-2
SHEET 6 OF 9

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF PRESENT AND PROPOSED REVENUES BY RATE COMPONENT
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Proposed Schedule Number	Billing Determinants: Number of Bills	Billing Determinants: Sales (Therms)	Revenue at Proposed Rates: Basic Service Charge [1]	Revenue at Proposed Rates: Commodity Charge [1]	Revenue at Proposed Rates: Basic Service Charge	Revenue at Proposed Rates: Commodity Charge	Revenue at Proposed Rates: Total Margin	Revenue at Proposed Rates: Gas Cost [2]	Revenue at Proposed Rates: Total Revenue	Revenue at Present Rates [3]	Increase / Decrease: Dollars	Increase / Decrease: Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
	General Gas Service - Large	G-25(L)													
1	Basic Service Charge		85,510		$ 160.00		$ 13,681,600		$ 13,681,600		$ 13,681,600	$ 12,398,950	$ 1,282,650		1
	Commodity Charge per Therm All Usage														
2	Transportation Customers			3,556,829		0.28843		1,025,896	1,025,896	$ 2,907,637	3,933,533	3,875,486	58,047		2
3	Sales Customers			145,666,025		0.28843		42,014,452	42,014,452	135,102,325	177,116,777	174,739,507	2,377,270		3
4	Total Large General Gas Service		85,510	149,222,854			13,681,600	43,040,348	56,721,948	138,009,962	194,731,910	$ 191,013,943	3,717,967	1.95%	4
	General Gas Service - Transportation Eligible	G-25(TE)													
5	Basic Service Charge		2,222		$ 950.00		$ 2,110,900		$ 2,110,900		$ 2,110,900	$ 1,599,840	$ 511,060		5
6	Demand Charge per Month			12,803,712	0.064142			9,855,048	9,855,048		9,855,048	9,578,201	276,847		6
	Commodity Charge per Therm All Usage														
7	Transportation Customers			32,517,415		$ 0.09902		$ 3,219,874	3,219,874	$ 26,582,336	29,802,210	29,493,620	308,590		7
8	Sales Customers			67,008,985		$ 0.09902		$ 6,635,230	6,635,230	62,149,493	68,784,723	68,148,807	635,916		8
9	Total Transportation Eligible General Gas Service		2,222	99,526,400			$ 2,110,900	$ 19,710,152	$ 21,821,052	$ 88,731,829	$ 110,552,881	$ 108,820,468	$ 1,732,413	1.59%	9
10	Total General Gas Service		483,327	299,300,277			$ 29,267,490	$ 85,220,789	$ 114,488,279	$ 273,606,779	$ 388,095,058	$ 378,877,817	$ 9,217,241	2.43%	10
	Air Conditioning Gas Service	G-40													
	Basic Service Charge														
11	W/ Other Service (No BSC)		60		$ 0.00		$ 0		$ 0		$ 0	$ 0	$ 0		11
12	General Service - Small		198		25.00		4,950		4,950		4,950	4,950	0		12
13	General Service - Medium		0		43.50		0		0		0	0	0		13
14	General Service - Large		48		160.00		7,680		7,680		7,680	6,960	720		14
15	General Service -Transportation Eligible		12		950.00		11,400		11,400		11,400		11,400		15
16	Essential Agricultural		0		120.00		0		0		0	1,080	(1,080)		16
	Commodity Charge per Therm All Usage														
17	Transportation Customers			373,987		$ 0.09513		$ 35,577	35,577	$ 305,727	341,304	342,752	(1,448)		17
18	Sales Customers			744,265		0.09513		70,802	70,802	690,291	761,093	763,973	(2,880)		18
19	Total Air Conditioning Gas Service		318	1,118,252			$ 24,030	$ 106,379	$ 130,409	$ 996,018	$ 1,126,427	$ 1,119,715	$ 6,712	0.60%	19
	Street Lighting Gas Service	G-45													
	Commodity Charge per Therm of Rated Capacity														
20	All Usage		324	102,289		$ 0.69899		$ 71,499	71,499	94,871	166,370	150,721	15,649		20
21	Total Street Lighting Gas Service		324	102,289			$ 0	$ 71,499	$ 71,499	$ 94,871	$ 166,370	$ 150,721	$ 15,649	10.38%	21
	Gas Service for Compression on Customer's Premises	G-55													
	Basic Service Charge														
22	Small		252		$ 25.00		$ 6,300		$ 6,300		$ 6,300	$ 6,300	$ 0		22
23	Large		288		250.00		72,000		72,000		72,000	54,720	17,280		23
24	Residential		1,272		12.80		16,282		16,282		16,282	12,338	3,944		24
	Commodity Charge per Therm All Usage														
25	Transportation Customers			0		$ 0.17535		$ 0	0	$ 0	0	0	0		25
	Sales Customers														
26	Small			177,495		0.17535		31,124	31,124	164,623	195,747	194,797	950		26
27	Large			2,060,152		0.17535		361,248	361,248	1,910,750	2,271,998	2,260,976	11,022		27
28	Residential			77,361		0.17535		13,565	13,565	71,751	85,316	84,902	414		28
29	Total CNG Gas Service		1,812	2,315,008			$ 94,582	$ 405,937	$ 500,519	$ 2,147,124	$ 2,647,643	$ 2,614,033	$ 33,610	1.29%	29

[1] Exhibit No. (ABC_3), Sheets 5-8.
[2] Schedule H-3, Columns (j) and (k).
[3] Schedule H-2, Sheets 1-4.

SCHEDULE H-2
SHEET 7 OF 9

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF PRESENT AND PROPOSED REVENUES BY RATE COMPONENT
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Proposed Schedule Number	Billing Determinants: Number of Bills	Billing Determinants: Sales (Therms)	Revenue at Proposed Rates: Basic Service Charge [1]	Revenue at Proposed Rates: Commodity Charge [1]	Revenue at Proposed Rates: Basic Service Charge	Revenue at Proposed Rates: Commodity Charge	Revenue at Proposed Rates: Total Margin	Revenue at Proposed Rates: Gas Cost [2]	Revenue at Proposed Rates: Total Revenue	Revenue at Present Rates [3]	Increase / Decrease: Dollars	Increase / Decrease: Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
	Electric Generation Gas Service	G-60													
	Basic Service Charge														
1	General Service - Small		36		$ 25.00		$ 900		$ 900		$ 900	$ 900	$ 0		1
2	General Service - Medium		36		43.50		1,566		1,566		1,566	1,188	378		2
3	General Service - Large		84		160.00		13,440		13,440		13,440	12,180	1,260		3
4	General Service - Transportation Eligible		84		0.00		0		0		0	60,480	(60,480)		4
5	Essential Agricultural		12		120.00		1,440		1,440		1,440	1,080	360		5
	Commodity Charge per Therm All Usage														
6	Transportation Customers			0		$ 0.12363		$ 0	0	$ 0	0	0	0		6
7	Sales Customers			21,521,946		0.12363		2,660,758	2,660,758	19,961,174	22,621,932	22,414,676	207,256		7
8	Total Electric Generation Gas Service		252	21,521,946			$ 17,346	$ 2,660,758	$ 2,678,104	$ 19,961,174	$ 22,639,278	$ 22,490,504	$ 148,774	0.66%	8
	Small Essential Agriculture User Gas Service	G-75													
9	Basic Service Charge		1,216		$ 120.00		$ 145,920		$ 145,920		$ 145,920	$ 109,440	$ 36,480		9
	Commodity Charge per Therm All Usage														
10	Transportation Customers			6,217,976		$ 0.23335		$ 1,450,965	1,450,965	$ 5,083,071	6,534,036	6,469,680	64,356		10
11	Sales Customers			7,214,684		0.23335		1,683,547	1,683,547	6,691,475	8,375,022	8,300,350	74,672		11
12	Total Essential Agricultural Gas Service		1,216	13,432,660			$ 145,920	$ 3,134,512	$ 3,280,432	$ 11,774,546	$ 15,054,978	$ 14,879,470	$ 175,508	1.18%	12
	Natural Gas Engine Gas Service	G-80													
	Basic Service Charge														
13	Off-Peak Season (Oct. - March)		2,516		$ 0.00		$ 0		$ 0		$ 0	$ 0	$ 0		13
14	Peak Season (April - September)		2,589		125.00		323,625		323,625		323,625	245,955	77,670		14
	Commodity Charge per Therm All Usage														
15	Transportation Customers			0		$ 0.18746		$ 0	0	$ 0	0	0	0		15
16	Sales Customers			13,070,981		0.18746		2,450,286	2,450,286	9,591,355	12,041,641	11,904,919	136,722		16
17	Total Natural Gas Engine Gas Service		5,105	13,070,981			$ 323,625	$ 2,450,286	$ 2,773,911	$ 9,591,355	$ 12,365,266	$ 12,150,874	$ 214,392	1.76%	17
18	Total Tariff Sales		11,502,504	658,002,715			$167,583,541	$263,825,950	$ 431,409,491	$ 604,827,059	$ 1,036,236,550	$ 986,017,035	$ 50,219,515	5.09%	18
19	Optional Gas Service	G-30	84	49,447,344			$ 120,540	$ 3,135,458	3,255,998	$ 40,422,215	$ 43,678,213	$ 43,678,213	$ 0	0.00%	19
20	Special Contract Service	B-1	244	35,660,859			$ 449,274	$ 2,078,755	$ 2,528,029		$ 2,528,029	$ 2,528,029	$ 0	0.00%	20
21	Other Operating Revenues						$ 12,261,805		$ 12,261,805		$ 12,261,805	$ 12,261,805	$ 0	0.00%	21
22	Total Revenue		11,502,832	743,110,918			$ 180,415,160	$ 269,040,163	$ 449,455,324	$ 645,249,274	$ 1,094,704,598	$ 1,044,485,083	$ 50,219,515	4.81%	22
23	Total Revenue Requirement								$ 449,454,506	$ 645,249,274	$ 1,094,703,780				23
24	Over/(Under)								$818	$ 0	$818				24

[1] Exhibit No. (ABC_3), Sheets 5-8.
[2] Schedule H-3, Columns (j) and (k).
[3] Schedule H-2, Sheets 1-4.

SCHEDULE H-2
SHEET 8 OF 9

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF LOW INCOME DISCOUNT AT PRESENT AND PROPOSED RATES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Proposed Schedule Number	Billing Determinants: Number of Bills	Billing Determinants: Sales (Therms)	Total Revenue Before Discount: Basic Service Charge	Total Revenue Before Discount: Commodity Charge	Total Revenue Before Discount: Total Revenue	Total Revenue After Discount: Basic Service Charge	Total Revenue After Discount: Commodity Charge	Total Revenue After Discount: Total Revenue	Low Income Discount: Dollars	Low Income Discount: Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(k)	(e)	(f)	(k)	(m)	(n)	
	Low Income Discount at Present Rates												
	Single-Family Residential Gas Service	G-10											
	Summer (May - October)												
1	Basic Service Charge		153,923		$ 9.70		$ 1,493,053	$ 7.00		$ 1,077,461	$ (415,592)		1
	Commodity Charge per Therm												
2	First 15 Therms			1,499,731		$ 1.47889	2,217,937		$ 1.35948	2,038,854	(179,083)		2
3	Over 15 Therms			343,792		1.43789	494,335		1.31848	453,283	(41,052)		3
	Winter (November - April)												
4	Basic Service Charge per Month		156,983		$ 9.70		$ 1,522,735	$ 7.00		$ 1,098,881	(423,854)		4
	Commodity Charge per Therm												
5	First 35 Therms			4,229,842		1.47889	6,255,471		$ 1.08758	4,600,291	(1,655,180)		5
6	Next 115 Therms			2,532,839		1.43789	3,641,943		1.05478	2,671,587	(970,356)		6
7	Over 150 Therms			52,769		1.43789	75,876		1.31848	69,575	(6,301)		7
8	Total Low Income Residential Gas Service		310,906	8,658,972			$ 15,701,350			$ 12,009,932	(3,691,418)	-23.51%	8
	Multi-Family Residential Gas Service	G-11											
	Summer (May - October)												
9	Basic Service Charge per Month		13,560		$ 8.70		$ 117,972	$ 7.00		$ 94,920	$ (23,052)		9
	Commodity Charge per Therm												
10	First 7 Therms			79,822		$ 1.47889	118,048		$ 1.35948	108,516	(9,532)		10
11	Over 7 Therms			78,071		1.43789	112,258		1.31848	102,935	(9,323)		11
	Winter (November - April)												
12	Basic Service Charge per Month		13,828		$ 8.70		$ 120,304	$ 7.00		$ 96,796	(23,508)		12
	Commodity Charge per Therm												
13	First 18 Therms			207,982		$ 1.47889	307,583		$ 1.08758	226,197	(81,386)		13
14	Next 132 Therms			186,423		1.43789	268,055		1.05478	196,635	(71,420)		14
15	Over 150 Therms			345		1.43789	496		1.31848	455	(41)		15
16	Total Low Income Multi-Family Residential Gas Service		27,388	552,643			$ 1,044,716			$ 826,454	(218,262)	-20.89%	16
17	Total Low Income Residential Gas Service at Present Rates		338,294	9,211,615			$16,746,066			$ 12,836,386	$ (3,909,680)	-23.35%	17
	Low Income Discount at Proposed Rates												
	Single-Family Residential Gas Service	G-10											
	Summer (April - November)												
18	Basic Service Charge		153,923		$ 12.80		$ 1,970,214	$ 7.50		$ 1,154,423	$ (815,791)		18
	Commodity Charge per Therm												
19	First 15 Therms			1,499,731		$ 1.49065	2,235,574		$ 1.37124	2,056,491	(179,083)		19
20	Over 15 Therms			343,792		1.49065	512,474		1.37124	471,422	(41,052)		20
	Winter (December - March)												
21	Basic Service Charge per Month		156,983		$ 12.80		$ 2,009,382	$ 7.50		$ 1,177,373	(832,009)		21
	Commodity Charge per Therm												
22	First 35 Therms			4,229,842		$ 1.49065	6,305,213		$ 1.09699	4,640,094	(1,665,119)		22
23	Next 115 Therms			2,532,839		1.49065	3,775,576		1.09699	2,778,499	(997,077)		23
24	Over 150 Therms			52,769		1.49065	78,660		1.37124	72,359	(6,301)		24
25	Total Low Income Residential Gas Service		310,906	8,658,972			16,887,093			12,350,661	(4,536,432)	-26.86%	25
	Multi-Family Residential Gas Service	G-11											
	Summer (April - November)												
26	Basic Service Charge per Month		13,560		$ 8.70		$ 117,972	$ 7.50		$ 101,700	$ (16,272)		26
	Commodity Charge per Therm												
27	First 7 Therms			79,822		$ 1.49065	118,987		$ 1.37124	109,455	(9,532)		27
28	Over 7 Therms			78,071		1.49065	116,377		1.37124	107,054	(9,323)		28
	Winter (December - March)												
29	Basic Service Charge per Month		13,828		$ 8.70		$ 120,304	$ 7.50		$ 103,710	(16,594)		29
	Commodity Charge per Therm												
30	First 18 Therms			207,982		$ 1.49065	310,029		$ 1.09699	228,154	(81,875)		30
31	Next 132 Therms			186,423		1.49065	277,891		1.09699	204,504	(73,387)		31
32	Over 150 Therms			345		1.49065	514		1.37124	473	(41)		32
33	Total Low Incom Multi-Family Residential Gas Service		27,388	552,643			1,062,074			855,050	(207,024)	-19.49%	33
34	Total Low Income Residential Gas Service at Proposed Rates		338,294	9,211,615			$17,949,167			$ 13,205,711	$ (4,743,456)	-26.43%	34
	Total Proposed Increase to Low Income Customers												
35	Dollars									$ 369,325			35
36	Percent									2.88%			36

SCHEDULE H-2
SHEET 9 OF 9

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF PRESENT AND PROPOSED RATES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Schedule	Present Rates [1] Margin	Rate Adjustment	Gas Cost	Currently Effective Tariff Rate	Description	Schedule	Proposed Rates [2] Margin	Rate Adjustment	Gas Cost	Currently Effective Tariff Rate	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
	Residential Gas Service	G-5					Single-Family Residential Gas Service	G-5					
	Summer (May - October)						Summer (May - October)						
1	Basic Service Charge per Month		$ 9.70			$ 9.70	Basic Service Charge per Month		$ 12.80			$ 12.80	1
	Commodity Charge per Therm						Commodity Charge per Therm						
2	First 15 Therms		$ 0.54200	$ 0.01263	$ 0.92426	$ 1.47889	First 15 Therms		$ 0.88069	$ 0.01263	$ 0.59733	$ 1.49065	2
3	Over 15 Therms		0.50100	0.01263	0.92426	1.43789	Over 15 Therms		0.00000	0.01263	$ 1.47802	1.49065	3
	Winter (November - April)						Winter (November - April)						
4	Basic Service Charge per Month		$ 9.70			$ 9.70	Basic Service Charge per Month		$ 12.80			$ 12.80	4
	Commodity Charge per Therm						Commodity Charge per Therm						
5	First 35 Therms		$ 0.54200	$ 0.01263	$ 0.92426	$ 1.47889	First 35 Therms		$ 0.88069	$ 0.01263	$ 0.59733	$ 1.49065	5
6	Over 35 Therms		0.50100	0.01263	0.92426	1.43789	Over 35 Therms		0.00000	0.01263	1.47802	1.49065	6
	Multi-Family Residential Gas Service	G-6					Multi-Family Residential Gas Service	G-6					
	Summer (May - October)						Summer (May - October)						
7	Basic Service Charge per Month		$ 8.70			$ 8.70	Basic Service Charge per Month		$ 8.70			$ 8.70	7
	Commodity Charge per Therm						Commodity Charge per Therm						
8	First 7 Therms		$0.54200	0.01263	0.92426	$1.47889	First 7 Therms		$ 0.88069	$ 0.01263	$ 0.59733	$ 1.49065	8
9	Over 7 Therms		0.50100	0.01263	0.92426	1.43789	Over 7 Therms		0.00000	0.01263	1.47802	1.49065	9
	Winter (November - April)						Winter (November - April)						
10	Basic Service Charge per Month		$ 8.70			$ 8.70	Basic Service Charge per Month		$ 8.70			$ 8.70	10
	Commodity Charge per Therm						Commodity Charge per Therm						
11	First 18 Therms		$0.54200	0.01263	0.92426	$1.47889	First 18 Therms		$ 0.88069	$ 0.01263	$ 0.59733	$ 1.49065	11
12	Over 18 Therms		0.50100	0.01263	0.92426	1.43789	Over 18 Therms		0.00000	0.01263	1.47802	1.49065	12
	Low Income Residential Gas Service	G-10					Single-Family Low-Income Residential Gas Service	G-10					
	Summer (May - October)						Summer (May - October)						
13	Basic Service Charge per Month		$ 7.00			$ 7.00	Basic Service Charge per Month		$ 7.50			$ 7.50	13
	Commodity Charge per Therm						Commodity Charge per Therm						
14	First 15 Therms		$ 0.54200	$ 0.00322	$ 0.81426	$ 1.35948	First 15 Therms		$ 0.88069	$ 0.00322	$ 0.48733	$ 1.37124	14
15	Over 15 Therms		0.50100	0.00322	0.81426	1.31848	Over 15 Therms		0.00000	0.00322	1.36802	1.37124	15
	Winter (November - April)						Winter (November - April)						
16	Basic Service Charge per Month		$ 7.00			$ 7.00	Basic Service Charge per Month		$ 7.50			$ 7.50	16
	Commodity Charge per Therm						Commodity Charge per Therm						
17	First 35 Therms		$ 0.27010	$ 0.00322	$ 0.81426	$ 1.08758	First 35 Therms		$ 0.60644	$ 0.00322	$ 0.48733	$ 1.09699	17
18	Next 115 Therms		0.23730	0.00322	0.81426	1.05478	Next 115 Therms		(0.27425)	0.00322	1.36802	1.09699	18
19	Over 150 Therms		0.50100	0.00322	0.81426	1.31848	Over 150 Therms		0.00000	0.00322	1.36802	1.37124	19
	Low Income Multi-Family Residential G S	G-11					Multi-Family Low-Income Residential Gas Service	G-11					
	Summer (May - October)						Summer (May - October)						
20	Basic Service Charge per Month		$ 7.00			$ 7.00	Basic Service Charge per Month		$ 7.50			$ 7.50	20
	Commodity Charge per Therm						Commodity Charge per Therm						
21	First 7 Therms		$ 0.54200	$ 0.00322	$ 0.81426	$ 1.35948	First 7 Therms		$ 0.88069	$ 0.00322	$ 0.48733	$ 1.37124	21
22	Over 7 Therms		0.50100	0.00322	0.81426	1.31848	Over 7 Therms		0.00000	0.00322	1.36802	1.37124	22
	Winter (November - April)						Winter (November - April)						
23	Basic Service Charge per Month		$ 7.00			$ 7.00	Basic Service Charge per Month		$ 7.50			$ 7.50	23
	Commodity Charge per Therm						Commodity Charge per Therm						
24	First 18 Therms		$ 0.27010	$ 0.00322	$ 0.81426	$ 1.08758	First 18 Therms		$ 0.60644	$ 0.00322	$ 0.48733	$ 1.09699	24
25	Next 132Therms		0.23730	0.00322	0.81426	1.05478	Next 132 Therms		(0.27425)	0.00322	1.36802	1.09699	25
26	Over 150 Therms		0.50100	0.00322	0.81426	1.31848	Over 150 Therms		0.00000	0.00322	1.36802	1.37124	26

[1] Margin rates effective March 1, 2006 per Decision No. 68487. Gas Cost and RateAdjustment effective May 1, 2007.
[2] Proposed margin rates per Exhibit No. (ABC_3), Sheets 5-8.

SCHEDULE H-3
SHEET 1 OF 3

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF PRESENT AND PROPOSED RATES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Schedule	Present Rates [1] Margin	Rate Adjustment	Gas Cost	Currently Effective Tariff Rate	Description	Schedule	Proposed Rates [2] Margin	Rate Adjustment	Gas Cost	Currently Effective Tariff Rate	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
	Special Residential Gas Service for Air Conditioning	G-15					Special Residential Gas Service for Air Conditioning	G-15					
	Summer (May - October)						Summer (May - October)						
1	Basic Service Charge per Month		$ 9.70			$ 9.70	Basic Service Charge per Month		$ 12.80			$ 12.80	1
	Commodity Charge per Therm						Commodity Charge per Therm						
2	First 15 Therms		$ 0.54200	$ 0.00322	$ 0.92426	$ 1.46948	First 15 Therms		$ 0.88069	$ 0.00322	$ 0.59733	$ 1.48124	2
3	Over 15 Therms		0.28200	0.00322	0.92426	1.20948	Over 15 Therms		0.00000	0.00322	1.47802	1.48124	3
	Winter (November - April)						Winter (November - April)						
4	Basic Service Charge per Month		$ 9.70			$ 9.70	Basic Service Charge per Month		$ 12.80			$ 12.80	4
5	First 35 Therms		$ 0.54200	$ 0.00322	$ 0.92426	$ 1.46948	First 35 Therms		$ 0.88069	$ 0.00322	$ 0.59733	$ 1.48124	5
6	Over 35 Therms		0.50100	0.00322	0.92426	1.42848	Over 35 Therms		0.00000	0.00322	1.47802	1.48124	6
	Master Metered Mobile Home Park Gas Service	G-20					Master Metered Mobile Home Park Gas Service	G-20					
7	Basic Service Charge per Month		$ 60.00			$ 60.00	Basic Service Charge per Month		$ 60.00			$ 60.00	7
	Commodity Charge per Therm						Commodity Charge per Therm						
8	All Usage		$ 0.38400	$ 0.01263	$ 0.92426	$ 1.32089	All Usage		$ 0.41531	$ 0.01263	$ 0.92426	$ 1.35220	8
	General Gas Service	G-25					General Gas Service	G-25					
	Basic Service Charge per Month						Basic Service Charge per Month						
9	Small		$ 25.00			$ 25.00	Small		$ 25.00			$ 25.00	9
10	Medium		33.00			33.00	Medium		43.50			43.50	10
11	Large		145.00			145.00	Large		160.00			160.00	11
12	Transportation Eligible		720.00			720.00	Transportation Eligible		950.00			950.00	12
	Commodity Charge per Therm						Commodity Charge per Therm						
13	Small, All Usage		$ 0.56217	$ 0.00322	$ 0.92426	$ 1.48965	Small, All Usage		$ 0.75852	$ 0.00322	$ 0.92426	$ 1.68600	13
14	Medium, All Usge		0.39349	0.00322	0.92426	1.32097	Medium, All Usge		0.40988	0.00322	0.92426	1.33736	14
15	Large, All Usage		0.27211	0.00322	0.92426	1.19959	Large, All Usage		0.26843	0.00322	0.92426	1.21591	15
16	Transportation Eligible		0.08953	0.00322	0.92426	1.01701	Transportation Eligible, All Usage		0.09902	0.00322	0.92426	1.02650	16
	Demand Charge per Month						Demand Charge per Month						
	TE General Service Peak Winter Month Usage						Transportation Eligible Peak Month Usage						
17	Times Demand Rate per Therm		$0.062340			$0.062340	Times Demand Rate per Therm		$ 0.064142			$0.064142	17
	Optional Gas Service	G-30					Optional Gas Service	G-30					
18	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.				18
	Commodity Charge per Therm						Commodity Charge per Therm						
19	All Usage		As Specified on A.C.C. Sheet No. 28.				All Usage		As Specified on A.C.C. Sheet No. 28.				19
	Air-Conditioning Gas Service	G-40					Air-Conditioning Gas Service	G-40					
20	Basic Service Charge per Month		As Specified on A.C.C. Sheet No. 32.				Basic Service Charge per Month		As Specified on A.C.C. Sheet No. 32.				20
	Commodity Charge per Therm						Commodity Charge per Therm						
21	All Usage		$ 0.09900	$ 0.00322	$ 0.92426	$ 1.02648	All Usage		$ 0.09513	$ 0.00322	$ 0.92426	$ 1.02261	21
	Street Lighting Gas Service	G-45					Street Lighting Gas Service	G-45					
	Commodity Charge per Therm of Rated Capacity						Commodity Charge per Therm of Rated Capacity						
22	All Usage		$ 0.54600	$ 0.00322	$ 0.92426	$ 1.47348	All Usage		$ 0.69899	$ 0.00322	$ 0.92426	$ 1.62647	22

[1] Margin rates effective March 1, 2006 per Decision No. 68487. Gas Cost and RateAdjustment effective May 1, 2007.
[2] Proposed margin rates per Exhibit No. (ABC_3), Sheets 5-8.

SCHEDULE H-3
SHEET 2 OF 3

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF PRESENT AND PROPOSED RATES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Schedule	Present Rates [1] Margin	Rate Adjustment	Gas Cost	Currently Effective Tariff Rate	Description	Schedule	Proposed Rates [2] Margin	Rate Adjustment	Gas Cost	Currently Effective Tariff Rate	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
	Gas Service for Compression on Customer's Premises	G-55					Gas Service for Compression on Customer's Premises	G-55					
	Basic Service Charge per Month						Basic Service Charge per Month						
1	Small		$ 25.00			$ 25.00	Small		$ 25.00			$ 25.00	1
2	Large		190.00			190.00	Large		250.00			250.00	2
3	Residential		9.70			9.70	Residential		12.80			12.80	3
	Commodity Charge per Therm						Commodity Charge per Therm						
4	All Usage		$ 0.17000	$ 0.00322	$ 0.92426	$ 1.09748	All Usage		$ 0.17535	$ 0.00322	$ 0.92426	$ 1.10283	4
	Electric Generation Gas Service	G-60					Electric Generation Gas Service	G-60					
5	Basic Service Charge per Month		As Specified on A.C.C. Sheet No. 40.				Basic Service Charge per Month		As Specified on A.C.C. Sheet No. 40.				5
	Commodity Charge per Therm						Commodity Charge per Therm						
6	All Usage		$ 0.11400	$ 0.00322	$ 0.92426	$ 1.04148	All Usage		$ 0.12363	$ 0.00322	$ 0.92426	$ 1.05111	6
	Small Essential Agriculture User Gas Service	G-75					Small Essential Agriculture User Gas Service	G-75					
7	Basic Service Charge per Month		$ 90.00			$ 90.00	Basic Service Charge per Month		$ 120.00			$ 120.00	7
	Commodity Charge per Therm						Commodity Charge per Therm						
8	All Usage		$ 0.22300	$ 0.00322	$ 0.92426	$ 1.15048	All Usage		$ 0.23335	$ 0.00322	$ 0.92426	$ 1.16083	8
	Natural Gas Engine Gas Service	G-80					Natural Gas Engine Gas Service	G-80					
	Basic Service Charge per Month						Basic Service Charge per Month						
9	Off-Peak Season (October - March)		$ 0.00			$ 0.00	Off-Peak Season (October - March)		$ 0.00			$ 0.00	9
10	Peak Season (April - September)		95.00			95.00	Peak Season (April - September)		125.00			125.00	10
	Commodity Charge per Therm						Commodity Charge per Therm						
11	All Usage		$ 0.17700	$ 0.00322	$ 0.73057	$ 0.91079	All Usage		$ 0.18746	$ 0.00322	$ 0.73057	$ 0.92125	11

[1] Margin rates effective March 1, 2006 per Decision No. 68487. Gas Cost and RateAdjustment effective May 1, 2007.
[2] Proposed margin rates per Exhibit No. (ABC_3), Sheets 5-8.

SCHEDULE H-3
SHEET 3 OF 3

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PROPOSED vs. CURRENTLY EFFECTIVE RATES
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	10	24.49	$ 27.71	$ 3.22	13.15%	1
2	Average Summer Use [1]	13	28.93	$ 32.18	3.25	11.23%	2
3	125 Percent Average Use	16	33.32	$ 36.65	3.33	9.99%	3
	Winter Season Bills						
4	75 Percent Average Use	32	57.02	$ 60.50	$ 3.48	6.10%	4
5	Average Winter Use [1]	43	72.96	$ 76.90	3.94	5.40%	5
6	125 Percent Average Use	54	88.78	$ 93.30	4.52	5.09%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge per Month	$ 9.70
Commodity Charge Summer	
First 15 Therms	$ 1.47889
Over 15 Therms	1.43789
Commodity Charge Winter	
First 35 Therms	$ 1.47889
Over 35 Therms	1.43789

Proposed Tariff Rates [3]	
Basic Service Charge per Month	$ 12.80
Commodity Charge	
All Usage	$ 1.49065

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective May 1, 2007 including all adjustments.
[3] Schedule H-3, Sheets 1 - 3.

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	9	19.24	$ 19.84	$ 0.60	3.12%	1
2	Average Summer Use [1]	12	23.31	$ 23.95	0.64	2.75%	2
3	125 Percent Average Use	15	27.39	$ 28.07	0.68	2.48%	3
	Winter Season Bills						
4	75 Percent Average Use	32	41.80	$ 42.60	$ 0.80	1.91%	4
5	Average Winter Use [1]	43	53.50	$ 54.67	1.17	2.19%	5
6	125 Percent Average Use	54	65.11	$ 66.74	1.63	2.50%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge per Month	$ 7.00
Commodity Charge Summer	
First 15 Therms	$ 1.35948
Over 15 Therms	1.31848
Commodity Charge Winter	
First 35 Therms	$ 1.08758
Next 115 Therms	1.05478
Over 150 Therms	1.31848

Proposed Tariff Rates [3]	
Basic Service Charge per Month	$ 7.50
Commodity Charge Summer	
All Usage	$ 1.37124
Commodity Charge Winter	
First 150 Therms	$ 1.09699
Over 150 Therms	1.37124

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective May 1, 2007 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	8	20.49	$ 20.63	$ 0.14	0.68%	1
2	Average Summer Use [1]	11	24.80	$ 25.10	0.30	1.21%	2
3	125 Percent Average Use	14	29.12	$ 29.57	0.45	1.55%	3
	Winter Season Bills						
4	75 Percent Average Use	18	35.32	$ 35.53	$ 0.21	0.59%	4
5	Average Winter Use [1]	24	43.95	$ 44.48	0.53	1.21%	5
6	125 Percent Average Use	30	52.57	$ 53.42	0.85	1.62%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge per Month	$ 8.70
Commodity Charge Summer	
First 7 Therms	$ 1.47889
Over 7 Therms	1.43789
Commodity Charge Winter	
First 18 Therms	$ 1.47889
Over 18 Therms	1.43789

Proposed Tariff Rates [3]	
Basic Service Charge per Month	$ 8.70
Commodity Charge	
All Usage	$ 1.49065

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective May 1, 2007 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	9	19.15	$ 19.84	$ 0.69	3.60%	1
2	Average Summer Use [1]	12	23.11	$ 23.95	0.84	3.63%	2
3	125 Percent Average Use	15	27.06	$ 28.07	1.01	3.73%	3
	Winter Season Bills						
4	75 Percent Average Use	22	30.87	$ 31.63	$ 0.76	2.46%	4
5	Average Winter Use [1]	29	38.27	$ 39.31	1.04	2.72%	5
6	125 Percent Average Use	36	45.68	$ 46.99	1.31	2.87%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge per Month	$ 7.00
Commodity Charge Summer	
First 7 Therms	$ 1.35948
Over 7 Therms	1.31848
Commodity Charge Winter	
First 18 Therms	$ 1.09080
Next 132 Therms	1.05800
Over 150 Therms	1.31848

Proposed Tariff Rates [3]	
Basic Service Charge per Month	$ 7.50
Commodity Charge Summer	
All Usage	$ 1.37124
Commodity Charge Winter	
First 150 Therms	$ 1.09699
Over 150 Therms	1.37124

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective May 1, 2007 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	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	354	527.60	538.68	$ 11.08	2.10%	1
2	Average Summer Use [1]	472	683.46	698.24	14.78	2.16%	2
3	125 Percent Average Use	590	839.33	857.80	18.47	2.20%	3
	Winter Season Bills						
4	75 Percent Average Use	1,341	1,831.31	1,873.30	41.99	2.29%	4
5	Average Winter Use [1]	1,788	2,421.75	2,477.73	55.98	2.31%	5
6	125 Percent Average Use	2,235	3,012.19	3,082.17	69.98	2.32%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 60.00
Commodity Charge	
All Usage	$ 1.32089

Proposed Tariff Rates [3]	
Basic Service Charge	$ 60.00
Commodity Charge	
All Usage	$ 1.35220

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective May 1, 2007 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	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	8	$ 36.92	$ 38.49	$ 1.57	4.25%	1
2	Average Summer Use [1]	10	$ 39.90	$ 41.86	1.96	4.92%	2
3	125 Percent Average Use	13	$ 44.37	$ 46.92	2.55	5.75%	3
	Winter Season Bills						
4	75 Percent Average Use	29	$ 68.20	$ 73.89	5.69	8.35%	4
5	Average Winter Use [1]	39	$ 83.10	$ 90.75	7.66	9.22%	5
6	125 Percent Average Use	49	$ 97.99	$ 107.61	9.62	9.82%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 25.00
Commodity Charge	
All Usage	$ 1.48965

Proposed Tariff Rates [3]	
Basic Service Charge	$ 25.00
Commodity Charge	
All Usage	$ 1.68600

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective May 1, 2007 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	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	115	$ 184.91	$ 197.30	$ 12.38	6.70%	1
2	Average Summer Use [1]	153	$ 235.11	$ 248.12	13.01	5.53%	2
3	125 Percent Average Use	191	$ 285.31	$ 298.94	13.63	4.78%	3
	Winter Season Bills						
4	75 Percent Average Use	236	$ 344.75	$ 359.12	14.37	4.17%	4
5	Average Winter Use [1]	315	$ 449.11	$ 464.77	15.66	3.49%	5
6	125 Percent Average Use	394	$ 553.46	$ 570.42	16.96	3.06%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 33.00
Commodity Charge	
All Usage	$ 1.32097
Proposed Tariff Rates [3]	
Basic Service Charge	$ 43.50
Commodity Charge	
All Usage	$ 1.33736

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective May 1, 2007 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	929	$ 1,259.42	$ 1,289.58	$ 30.16	2.39%	1
2	Average Summer Use [1]	1,239	$ 1,631.29	$ 1,666.51	35.22	2.16%	2
3	125 Percent Average Use	1,549	$ 2,003.16	$ 2,043.44	40.28	2.01%	3
	Winter Season Bills						
4	75 Percent Average Use	1,665	$ 2,142.32	$ 2,184.49	42.17	1.97%	4
5	Average Winter Use [1]	2,220	$ 2,808.09	$ 2,859.32	51.23	1.82%	5
6	125 Percent Average Use	2,775	$ 3,473.86	$ 3,534.15	60.29	1.74%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 145.00
Commodity Charge	
All Usage	$ 1.19959

Proposed Tariff Rates [3]	
Basic Service Charge	$ 160.00
Commodity Charge	
All Usage	$ 1.21591

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective May 1, 2007 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	605	$ 688.98	$ 692.21	$ 3.24	0.47%	1
2	Average Summer Use [1]	806	$ 909.57	$ 913.88	4.31	0.47%	2
3	125 Percent Average Use	1,008	$ 1,131.26	$ 1,136.65	5.39	0.48%	3
	Winter Season Bills						
4	75 Percent Average Use	452	$ 521.06	$ 523.48	2.42	0.46%	4
5	Average Winter Use [1]	602	$ 685.68	$ 688.90	3.22	0.47%	5
6	125 Percent Average Use	753	$ 851.40	$ 855.43	4.03	0.47%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 25.00
Commodity Charge	
All Usage	$ 1.09748

Proposed Tariff Rates [3]	
Basic Service Charge	$ 25.00
Commodity Charge	
All Usage	$ 1.10283

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective May 1, 2007 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

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	5,655	$ 6,396.25	$ 6,486.50	$ 90.25	1.41%	1
2	Average Summer Use [1]	7,540	$ 8,465.00	$ 8,565.34	100.34	1.19%	2
3	125 Percent Average Use	9,425	$ 10,533.75	$ 10,644.17	110.42	1.05%	3
	Winter Season Bills						
4	75 Percent Average Use	5,075	$ 5,759.71	$ 5,846.86	87.15	1.51%	4
5	Average Winter Use [1]	6,767	$ 7,616.65	$ 7,712.85	96.20	1.26%	5
6	125 Percent Average Use	8,459	$ 9,473.58	$ 9,578.84	105.26	1.11%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 190.00
Commodity Charge	
All Usage	$ 1.09748

Proposed Tariff Rates [3]	
Basic Service Charge	$ 250.00
Commodity Charge	
All Usage	$ 1.10283

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective May 1, 2007 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	47	$ 61.28	$ 64.63	$ 3.35	5.47%	1
2	Average Summer Use [1]	63	$ 78.84	$ 82.28	3.44	4.36%	2
3	125 Percent Average Use	79	$ 96.40	$ 99.92	3.52	3.65%	3
	Winter Season Bills						
4	75 Percent Average Use	44	$ 57.99	$ 61.32	3.34	5.75%	4
5	Average Winter Use [1]	59	$ 74.45	$ 77.87	3.42	4.59%	5
6	125 Percent Average Use	74	$ 90.91	$ 94.41	3.50	3.85%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 9.70
Commodity Charge	
All Usage	$ 1.09748

Proposed Tariff Rates [3]	
Basic Service Charge	$ 12.80
Commodity Charge	
All Usage	$ 1.10283

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective May 1, 2007 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	5,093	$ 5,949.39	$ 6,032.11	$ 82.71	1.39%	1
2	Average Summer Use [1]	6,791	$ 7,902.91	$ 8,003.20	100.29	1.27%	2
3	125 Percent Average Use	8,489	$ 9,856.42	$ 9,974.29	117.86	1.20%	3
	Winter Season Bills						
4	75 Percent Average Use	5,220	$ 6,095.51	$ 6,179.53	84.03	1.38%	4
5	Average Winter Use [1]	6,960	$ 8,097.34	$ 8,199.38	102.04	1.26%	5
6	125 Percent Average Use	8,700	$ 10,099.18	$ 10,219.22	120.05	1.19%	6

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 90.00
Commodity Charge	
All Usage	$ 1.15048

Proposed Tariff Rates [3]	
Basic Service Charge	$ 120.00
Commodity Charge	
All Usage	$ 1.16083

[1] Workpapers, Schedule H-2, Sheets 1-4.
[2] Rates effective May 1, 2007 including all adjustments.
[3] Schedule H-3, Sheets 1 - 3.

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-5 CLASS = RESIDENTIAL AREA = ARIZONA PERIOD = SUMMER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
0	0	0	168,759	168,759	0.00	3.30	4,939,100	0	0	0.00
1	68,554	68,554	68,554	237,314	0.11	4.65	4,870,545	4,870,545	4,939,100	7.71
2	214,312	282,866	107,156	344,470	0.44	6.74	4,763,389	9,526,779	9,809,645	15.31
3	752,867	1,035,733	250,956	595,425	1.62	11.66	4,512,434	13,537,302	14,573,035	22.75
4	1,245,252	2,280,986	311,313	906,738	3.56	17.75	4,201,121	16,804,483	19,085,469	29.80
5	1,645,582	3,926,568	329,116	1,235,855	6.13	24.20	3,872,004	19,360,022	23,286,589	36.35
6	2,070,541	5,997,109	345,090	1,580,945	9.36	30.95	3,526,914	21,161,485	27,158,594	42.40
7	2,453,632	8,450,741	350,519	1,931,464	13.19	37.81	3,176,395	22,234,767	30,685,508	47.90
8	2,819,751	11,270,492	352,469	2,283,933	17.59	44.71	2,823,926	22,591,411	33,861,903	52.86
9	2,514,042	13,784,534	279,338	2,563,271	21.52	50.18	2,544,588	22,901,295	36,685,830	57.27
10	2,898,078	16,682,613	289,808	2,853,078	26.04	55.86	2,254,781	22,547,805	39,230,418	61.24
11	3,203,528	19,886,141	291,230	3,144,308	31.05	61.56	1,963,551	21,599,057	41,485,198	64.76
12	2,890,299	22,776,440	240,858	3,385,167	35.56	66.27	1,722,692	20,672,309	43,448,749	67.83
13	2,782,216	25,558,656	214,017	3,599,183	39.90	70.46	1,508,676	19,612,785	45,171,441	70.52
14	1,962,138	27,520,794	140,153	3,739,336	42.96	73.21	1,368,523	19,159,324	46,680,117	72.87
15	2,444,815	29,965,608	162,988	3,902,324	46.78	76.40	1,205,535	18,083,032	48,048,640	75.01
16	2,309,769	32,275,378	144,361	4,046,684	50.39	79.22	1,061,175	16,978,798	49,254,176	76.89
17	2,161,681	34,437,059	127,158	4,173,842	53.76	81.71	934,017	15,878,292	50,315,351	78.55
18	1,970,234	36,407,293	109,457	4,283,299	56.84	83.86	824,560	14,842,075	51,249,368	80.01
19	1,817,229	38,224,522	95,644	4,378,943	59.67	85.73	728,916	13,849,406	52,073,928	81.29
20	1,109,872	39,334,394	55,494	4,434,437	61.41	86.82	673,422	13,468,450	52,802,844	82.43
25	6,879,217	46,213,611	295,839	4,730,275	72.15	92.61	377,584	9,439,590	55,653,201	86.88
30	3,856,399	50,070,010	134,865	4,865,141	78.17	95.25	242,718	7,281,552	57,351,562	89.53
35	2,550,561	52,620,571	75,600	4,940,741	82.15	96.73	167,118	5,849,131	58,469,702	91.28
40	1,687,846	54,308,418	43,544	4,984,285	84.78	97.58	123,574	4,942,951	59,251,368	92.50
45	1,246,282	55,554,700	28,492	5,012,777	86.73	98.14	95,082	4,278,680	59,833,379	93.41
50	926,798	56,481,498	18,978	5,031,755	88.18	98.51	76,104	3,805,197	60,286,695	94.12
55	723,501	57,204,999	13,411	5,045,166	89.31	98.77	62,693	3,448,113	60,653,111	94.69
60	595,001	57,800,000	10,076	5,055,242	90.23	98.97	52,617	3,157,030	60,957,030	95.16
65	547,469	58,347,469	8,520	5,063,762	91.09	99.14	44,097	2,866,305	61,213,774	95.56
70	418,225	58,765,693	6,005	5,069,767	91.74	99.25	38,092	2,666,459	61,432,152	95.90

SOUTHWEST GAS CORPORATION
BILL FREQUENCY ANALYSIS
TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-5 CLASS = RESIDENTIAL AREA = ARIZONA PERIOD = SUMMER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
75										
80	366,033	59,131,727	4,892	5,074,658	92.31	99.35	33,201	2,490,047	61,621,773	96.20
85	314,624	59,446,350	3,945	5,078,603	92.80	99.43	29,256	2,340,471	61,786,822	96.46
90	268,917	59,715,267	3,173	5,081,776	93.22	99.49	26,083	2,217,086	61,932,354	96.69
95	236,755	59,952,023	2,639	5,084,414	93.59	99.54	23,445	2,110,034	62,062,057	96.89
100	227,035	60,179,058	2,393	5,086,807	93.95	99.59	21,052	1,999,940	62,178,997	97.07
105	191,144	60,370,202	1,914	5,088,721	94.25	99.63	19,138	1,913,780	62,283,982	97.23
110	197,916	60,568,117	1,882	5,090,603	94.56	99.66	17,256	1,811,863	62,379,981	97.38
115	157,865	60,725,983	1,429	5,092,032	94.80	99.69	15,827	1,740,963	62,466,946	97.52
120	143,877	60,869,860	1,245	5,093,277	95.03	99.71	14,582	1,676,925	62,546,785	97.64
125	138,340	61,008,200	1,148	5,094,425	95.24	99.74	13,434	1,612,133	62,620,333	97.76
130	127,436	61,135,636	1,015	5,095,439	95.44	99.76	12,420	1,552,447	62,688,082	97.86
135	117,024	61,252,659	897	5,096,336	95.62	99.77	11,523	1,497,975	62,750,635	97.96
140	101,756	61,354,415	750	5,097,086	95.78	99.79	10,773	1,454,354	62,808,769	98.05
145	100,830	61,455,245	717	5,097,803	95.94	99.80	10,056	1,407,832	62,863,078	98.14
150	102,746	61,557,991	704	5,098,507	96.10	99.82	9,352	1,356,019	62,914,011	98.22
155	83,914	61,641,906	555	5,099,062	96.23	99.83	8,797	1,319,537	62,961,442	98.29
160	81,817	61,723,723	523	5,099,585	96.36	99.84	8,274	1,282,416	63,006,138	98.36
165	75,656	61,799,379	469	5,100,054	96.48	99.85	7,805	1,248,727	63,048,106	98.43
170	69,896	61,869,275	420	5,100,475	96.59	99.86	7,384	1,218,408	63,087,683	98.49
175	68,002	61,937,277	397	5,100,872	96.69	99.86	6,987	1,187,838	63,125,115	98.55
180	65,285	62,002,562	370	5,101,242	96.79	99.87	6,617	1,157,965	63,160,527	98.60
185	62,571	62,065,133	345	5,101,587	96.89	99.88	6,272	1,128,973	63,194,106	98.65
190	65,497	62,130,629	351	5,101,938	96.99	99.88	5,921	1,095,372	63,226,001	98.70
195	60,733	62,191,362	316	5,102,254	97.09	99.89	5,605	1,064,874	63,256,237	98.75
200	56,169	62,247,531	285	5,102,539	97.18	99.90	5,320	1,037,362	63,284,893	98.80
999,999	44,943	62,292,475	222	5,102,762	97.25	99.90	5,097	1,019,486	63,311,961	98.84
	1,763,270	64,055,745	5,097	5,107,859	100.00	100.00	0	0	64,055,745	100.00
TOTAL	64,055,745		5,107,859							
AVG. USE	12.5									

SCHEDULE H-5
SHEET 2 OF 20

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-5 CLASS = RESIDENTIAL AREA = ARIZONA PERIOD = WINTER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
0	0	0	71,964	71,964	0.00	1.39	5,118,207	0	0	0.00
1	25,507	25,507	25,507	97,471	0.01	1.88	5,092,700	5,092,700	5,118,207	2.27
2	53,897	79,404	26,948	124,420	0.04	2.40	5,065,751	10,131,503	10,210,907	4.54
3	149,047	228,451	49,682	174,102	0.10	3.35	5,016,069	15,048,207	15,276,658	6.79
4	237,350	465,802	59,338	233,440	0.21	4.50	4,956,731	19,826,925	20,292,727	9.02
5	209,331	675,132	41,866	275,306	0.30	5.30	4,914,865	24,574,326	25,249,458	11.22
6	260,829	935,962	43,472	318,777	0.42	6.14	4,871,394	29,228,362	30,164,323	13.41
7	549,210	1,485,171	78,459	397,236	0.66	7.65	4,792,935	33,550,546	35,035,717	15.57
8	667,975	2,153,146	83,497	480,733	0.96	9.26	4,709,438	37,675,506	39,828,652	17.70
9	884,524	3,037,670	98,280	579,013	1.35	11.16	4,611,158	41,500,420	44,538,090	19.79
10	1,031,312	4,068,982	103,131	682,144	1.81	13.14	4,508,027	45,080,266	49,149,248	21.84
11	956,060	5,025,042	86,915	769,059	2.23	14.82	4,421,112	48,632,232	53,657,275	23.85
12	1,473,075	6,498,118	122,756	891,815	2.89	17.18	4,298,356	51,580,269	58,078,387	25.81
13	1,340,265	7,838,383	103,097	994,913	3.48	19.17	4,195,258	54,538,359	62,376,742	27.72
14	1,641,508	9,479,891	117,251	1,112,163	4.21	21.43	4,078,008	57,092,110	66,572,001	29.59
15	566,819	10,046,709	37,788	1,149,951	4.47	22.16	4,040,220	60,603,299	70,650,009	31.40
16	2,042,036	12,088,746	127,627	1,277,578	5.37	24.62	3,912,593	62,601,483	74,690,228	33.20
17	1,959,449	14,048,195	115,262	1,392,840	6.24	26.84	3,797,331	64,554,627	78,602,821	34.93
18	2,152,609	16,200,804	119,589	1,512,429	7.20	29.14	3,677,742	66,199,348	82,400,152	36.62
19	1,099,955	17,300,759	57,892	1,570,322	7.69	30.26	3,619,849	68,777,135	86,077,894	38.26
20	2,296,000	19,596,759	114,800	1,685,122	8.71	32.47	3,505,049	70,100,984	89,697,743	39.87
25	10,072,374	29,669,133	434,221	2,119,343	13.19	40.83	3,070,828	76,770,707	106,439,840	47.31
30	11,219,716	40,888,849	397,531	2,516,874	18.17	48.49	2,673,297	80,198,912	121,087,761	53.82
35	10,290,610	51,179,459	308,243	2,825,117	22.75	54.43	2,365,054	82,776,898	133,956,357	59.54
40	10,668,055	61,847,515	279,679	3,104,796	27.49	59.82	2,085,375	83,415,010	145,262,524	64.56
45	10,727,382	72,574,897	249,088	3,353,884	32.26	64.62	1,836,287	82,632,932	155,207,828	68.98
50	11,240,515	83,815,412	233,630	3,587,514	37.25	69.12	1,602,657	80,132,865	163,948,277	72.87
55	11,391,371	95,206,783	214,136	3,801,649	42.31	73.25	1,388,522	76,368,683	171,575,466	76.26
60	10,804,701	106,011,484	184,976	3,986,625	47.12	76.81	1,203,546	72,212,758	178,224,242	79.21
65	10,286,765	116,298,249	162,300	4,148,925	51.69	79.94	1,041,246	67,681,004	183,979,252	81.77
70	10,129,608	126,427,857	148,179	4,297,104	56.19	82.79	893,067	62,514,696	188,942,553	83.97

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-5 CLASS = RESIDENTIAL AREA = ARIZONA PERIOD = WINTER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
75	9,441,352	135,869,209	128,469	4,425,573	60.39	85.27	764,598	57,344,861	193,214,070	85.87
80	8,422,196	144,291,404	107,353	4,532,925	64.13	87.34	657,246	52,579,649	196,871,053	87.50
85	7,651,537	151,942,941	91,966	4,624,891	67.53	89.11	565,280	48,048,766	199,991,708	88.89
90	7,434,396	159,377,337	84,114	4,709,006	70.83	90.73	481,165	43,304,864	202,682,201	90.08
95	6,432,891	165,810,228	68,833	4,777,839	73.69	92.06	412,332	39,171,562	204,981,790	91.10
100	5,524,613	171,334,841	56,145	4,833,984	76.15	93.14	356,187	35,618,727	206,953,567	91.98
105	5,441,273	176,776,114	52,589	4,886,573	78.57	94.15	303,598	31,877,819	208,653,933	92.73
110	4,479,884	181,255,998	41,212	4,927,784	80.56	94.94	262,387	28,862,530	210,118,528	93.39
115	3,845,312	185,101,310	33,826	4,961,610	82.27	95.60	228,561	26,284,483	211,385,793	93.95
120	3,608,082	188,709,392	30,444	4,992,054	83.87	96.18	198,117	23,774,044	212,483,435	94.44
125	2,984,368	191,693,759	24,118	5,016,172	85.20	96.65	173,999	21,749,823	213,443,582	94.86
130	2,793,095	194,486,854	21,710	5,037,883	86.44	97.07	152,288	19,797,503	214,284,358	95.24
135	2,295,064	196,781,918	17,189	5,055,072	87.46	97.40	135,099	18,238,424	215,020,343	95.56
140	2,177,963	198,959,882	15,721	5,070,793	88.43	97.70	119,378	16,712,967	215,672,849	95.85
145	2,002,459	200,962,341	13,924	5,084,717	89.32	97.97	105,454	15,290,844	216,253,185	96.11
150	1,568,248	202,530,589	10,527	5,095,244	90.01	98.17	94,927	14,239,086	216,769,675	96.34
155	1,531,443	204,062,032	9,958	5,105,201	90.69	98.36	84,970	13,170,309	217,232,341	96.55
160	1,332,588	205,394,620	8,382	5,113,583	91.29	98.52	76,588	12,254,076	217,648,696	96.73
165	1,154,884	206,549,504	7,039	5,120,622	91.80	98.66	69,549	11,475,546	218,025,050	96.90
170	1,045,759	207,595,263	6,191	5,126,813	92.26	98.78	63,358	10,770,854	218,366,117	97.05
175	924,359	208,519,622	5,319	5,132,132	92.68	98.88	58,039	10,156,829	218,676,450	97.19
180	894,787	209,414,408	4,999	5,137,131	93.07	98.98	53,040	9,547,285	218,961,693	97.32
185	754,929	210,169,338	4,103	5,141,234	93.41	99.06	48,937	9,053,343	219,222,681	97.43
190	755,691	210,925,029	3,997	5,145,231	93.74	99.13	44,940	8,538,557	219,463,586	97.54
195	656,536	211,581,565	3,380	5,148,611	94.04	99.20	41,560	8,104,234	219,685,799	97.64
200	585,707	212,167,272	2,940	5,151,551	94.30	99.26	38,620	7,724,078	219,891,350	97.73
999,999	12,833,098	225,000,370	38,620	5,190,171	100.00	100.00	0	0	225,000,370	100.00
TOTAL	225,000,370		5,190,171							
AVG. USE	43.4									

SCHEDULE H-5
SHEET 4 OF 20

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-6 CLASS = MULTI-FAMILY RESIDENTIAL AREA = ARIZONA PERIOD = SUMMER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
0	0	0	10,195	10,195	0.00	5.59	172,214	0	0	0.00
1	4,090	4,090	4,090	14,285	0.21	7.83	168,124	168,124	172,214	8.63
2	9,960	14,050	4,980	19,265	0.70	10.56	163,144	326,288	340,338	17.06
3	31,957	46,008	10,652	29,918	2.31	16.40	152,491	457,474	503,482	25.24
4	46,591	92,599	11,648	41,565	4.64	22.79	140,844	563,375	655,973	32.89
5	53,297	145,895	10,659	52,225	7.32	28.63	130,184	650,922	796,817	39.95
6	76,522	222,418	12,754	64,978	11.15	35.62	117,431	704,583	927,001	46.48
7	90,315	312,733	12,902	77,881	15.68	42.70	104,528	731,699	1,044,432	52.37
8	97,204	409,937	12,150	90,031	20.55	49.36	92,378	739,023	1,148,960	57.61
9	100,182	510,119	11,131	101,162	25.58	55.46	81,247	731,219	1,241,338	62.24
10	101,555	611,673	10,155	111,318	30.67	61.03	71,091	710,911	1,322,585	66.31
11	107,480	719,153	9,771	121,089	36.06	66.38	61,320	674,522	1,393,676	69.88
12	102,777	821,930	8,565	129,654	41.21	71.08	52,755	633,066	1,454,996	72.95
13	92,374	914,304	7,106	136,759	45.84	74.97	45,650	593,447	1,507,752	75.60
14	67,986	982,290	4,856	141,615	49.25	77.64	40,794	571,111	1,553,401	77.89
15	80,060	1,062,350	5,337	146,953	53.27	80.56	35,456	531,845	1,594,195	79.93
16	74,273	1,136,624	4,642	151,595	56.99	83.11	30,814	493,028	1,629,651	81.71
17	70,082	1,206,705	4,122	155,717	60.50	85.37	26,692	453,760	1,660,466	83.25
18	62,801	1,269,507	3,489	159,206	63.65	87.28	23,203	417,651	1,687,157	84.59
19	57,343	1,326,849	3,018	162,224	66.53	88.93	20,185	383,511	1,710,360	85.76
20	53,805	1,380,655	2,690	164,914	69.23	90.41	17,495	349,890	1,730,545	86.77
25	212,586	1,593,241	8,176	173,091	79.88	94.89	9,318	232,962	1,826,203	91.56
30	135,448	1,728,689	4,234	177,325	86.68	97.21	5,084	152,526	1,881,214	94.32
35	75,076	1,803,765	1,995	179,319	90.44	98.31	3,090	108,137	1,911,901	95.86
40	48,960	1,852,725	1,122	180,442	92.89	98.92	1,967	78,687	1,931,412	96.84
45	30,311	1,883,036	616	181,058	94.41	99.26	1,351	60,810	1,943,846	97.46
50	20,664	1,903,700	375	181,432	95.45	99.46	977	48,829	1,952,529	97.90
55	12,490	1,916,190	206	181,638	96.08	99.58	771	42,402	1,958,593	98.20
60	9,713	1,925,903	146	181,784	96.56	99.66	625	37,505	1,963,408	98.44
65	7,236	1,933,139	100	181,884	96.93	99.71	525	34,135	1,967,274	98.64
70	6,866	1,940,005	88	181,972	97.27	99.76	437	30,590	1,970,595	98.80

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-6 CLASS = MULTI-FAMILY RESIDENTIAL AREA = ARIZONA PERIOD = SUMMER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
75	5,570	1,945,575	67	182,039	97.55	99.80	370	27,777	1,973,352	98.94
80	3,424	1,948,999	43	182,082	97.72	99.82	327	26,177	1,975,176	99.03
85	3,815	1,952,814	45	182,127	97.91	99.85	282	23,982	1,976,796	99.12
90	3,152	1,955,966	35	182,162	98.07	99.86	247	22,214	1,978,180	99.18
95	2,144	1,958,110	23	182,185	98.18	99.88	224	21,306	1,979,416	99.25
100	1,667	1,959,777	17	182,201	98.26	99.89	208	20,762	1,980,539	99.30
105	1,344	1,961,121	13	182,214	98.33	99.89	195	20,461	1,981,582	99.36
110	3,337	1,964,458	30	182,245	98.50	99.91	164	18,091	1,982,549	99.40
115	1,469	1,965,927	13	182,257	98.57	99.92	152	17,452	1,983,379	99.45
120	1,063	1,966,990	9	182,266	98.62	99.92	143	17,152	1,984,142	99.48
125	1,225	1,968,215	10	182,276	98.69	99.93	133	16,640	1,984,855	99.52
130	1,525	1,969,740	12	182,288	98.76	99.93	121	15,778	1,985,518	99.55
135	1,736	1,971,476	13	182,300	98.85	99.94	109	14,663	1,986,139	99.58
140	1,241	1,972,717	9	182,309	98.91	99.95	100	13,974	1,986,691	99.61
145	715	1,973,432	5	182,314	98.95	99.95	95	13,764	1,987,196	99.64
150	890	1,974,322	6	182,320	98.99	99.95	89	13,358	1,987,680	99.66
155	612	1,974,934	4	182,324	99.02	99.95	85	13,195	1,988,129	99.68
160	1,261	1,976,195	8	182,332	99.09	99.96	77	12,364	1,988,559	99.71
165	818	1,977,013	5	182,337	99.13	99.96	72	11,942	1,988,955	99.73
170	1,009	1,978,022	6	182,342	99.18	99.96	67	11,307	1,989,329	99.74
175	519	1,978,541	3	182,345	99.20	99.97	64	11,125	1,989,666	99.76
180	714	1,979,255	4	182,349	99.24	99.97	60	10,736	1,989,991	99.78
185	1,100	1,980,355	6	182,355	99.29	99.97	54	9,951	1,990,306	99.79
190	944	1,981,299	5	182,360	99.34	99.97	49	9,287	1,990,586	99.81
195	773	1,982,072	4	182,364	99.38	99.98	45	8,769	1,990,841	99.82
200	594	1,982,666	3	182,367	99.41	99.98	42	8,405	1,991,071	99.83
999,999	11,771	1,994,437	42	182,409	100.00	100.00	0	0	1,994,437	100.00
TOTAL	1,994,437		182,409							
AVG. USE	10.9									

SCHEDULE H-5
SHEET 6 OF 20

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-6 CLASS = MULTI-FAMILY RESIDENTIAL AREA = ARIZONA PERIOD = WINTER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
0	0	0	5,311	5,311	0.00	2.82	182,842	0	0	0.00
1	2,382	2,382	2,377	7,688	0.05	4.09	180,465	180,465	182,846	4.05
2	4,639	7,020	2,315	10,003	0.16	5.32	178,150	356,300	363,320	8.05
3	9,458	16,478	3,146	13,149	0.37	6.99	175,004	525,013	541,491	12.00
4	17,637	34,115	4,396	17,545	0.76	9.32	170,608	682,433	716,549	15.88
5	21,302	55,417	4,253	21,797	1.23	11.58	166,356	831,779	887,196	19.66
6	24,920	80,337	4,145	25,942	1.78	13.79	162,211	973,266	1,053,604	23.34
7	36,571	116,909	5,216	31,157	2.59	16.56	156,996	1,098,969	1,215,877	26.94
8	30,275	147,184	3,775	34,932	3.26	18.57	153,221	1,225,764	1,372,948	30.42
9	54,342	201,526	6,028	40,961	4.46	21.77	147,192	1,324,731	1,526,257	33.81
10	46,347	247,873	4,623	45,584	5.49	24.23	142,569	1,425,689	1,673,562	37.08
11	69,466	317,340	6,305	51,889	7.03	27.58	136,264	1,498,908	1,816,247	40.24
12	81,421	398,760	6,774	58,663	8.83	31.18	129,490	1,553,880	1,952,641	43.26
13	101,629	500,390	7,795	66,458	11.09	35.32	121,695	1,582,032	2,082,421	46.14
14	90,663	591,052	6,465	72,923	13.09	38.76	115,230	1,613,220	2,204,272	48.84
15	91,432	682,484	6,084	79,007	15.12	41.99	109,146	1,637,192	2,319,676	51.39
16	71,874	754,358	4,480	83,487	16.71	44.37	104,666	1,674,653	2,429,011	53.82
17	96,297	850,654	5,654	89,141	18.85	47.38	99,012	1,683,206	2,533,860	56.14
18	90,245	940,900	5,002	94,142	20.85	50.04	94,011	1,692,191	2,633,090	58.34
19	101,010	1,041,910	5,305	99,447	23.08	52.85	88,706	1,685,408	2,727,317	60.42
20	102,076	1,143,986	5,093	104,540	25.35	55.56	83,613	1,672,262	2,816,248	62.39
25	481,022	1,625,008	20,510	125,050	36.00	66.46	63,103	1,577,584	3,202,591	70.95
30	447,621	2,072,628	15,673	140,723	45.92	74.79	47,430	1,422,899	3,495,527	77.44
35	421,677	2,494,305	12,505	153,228	55.26	81.44	34,925	1,222,388	3,716,693	82.34
40	344,105	2,838,410	8,836	162,064	62.89	86.13	26,089	1,043,566	3,881,976	86.01
45	259,272	3,097,682	5,881	167,945	68.63	89.26	20,208	909,382	4,007,064	88.78
50	245,829	3,343,512	5,013	172,958	74.08	91.92	15,195	759,752	4,103,263	90.91
55	180,232	3,523,743	3,331	176,289	78.07	93.69	11,864	652,501	4,176,244	92.53
60	156,186	3,679,929	2,638	178,927	81.53	95.10	9,226	553,564	4,233,494	93.79
65	127,546	3,807,475	1,982	180,909	84.36	96.15	7,244	470,869	4,278,344	94.79
70	105,750	3,913,225	1,523	182,432	86.70	96.96	5,721	400,488	4,313,712	95.57

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-6 CLASS = MULTI-FAMILY RESIDENTIAL AREA = ARIZONA PERIOD = WINTER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
75	88,312	4,001,537	1,184	183,616	88.65	97.59	4,537	340,271	4,341,808	96.19
80	69,423	4,070,960	878	184,494	90.19	98.06	3,659	292,698	4,363,658	96.68
85	59,050	4,130,010	703	185,197	91.50	98.43	2,956	251,276	4,381,286	97.07
90	45,696	4,175,706	513	185,710	92.51	98.70	2,443	219,881	4,395,587	97.38
95	42,064	4,217,770	446	186,156	93.45	98.94	1,997	189,686	4,407,456	97.65
100	37,774	4,255,544	381	186,538	94.28	99.14	1,615	161,542	4,417,086	97.86
105	27,466	4,283,010	264	186,801	94.89	99.28	1,352	141,941	4,424,951	98.04
110	20,859	4,303,869	191	186,992	95.35	99.38	1,161	127,735	4,431,604	98.18
115	15,454	4,319,323	135	187,127	95.70	99.45	1,026	117,978	4,437,301	98.31
120	18,174	4,337,497	152	187,279	96.10	99.54	874	104,859	4,442,356	98.42
125	13,273	4,350,770	107	187,386	96.39	99.59	767	95,884	4,446,654	98.52
130	12,167	4,362,937	94	187,480	96.66	99.64	673	87,521	4,450,458	98.60
135	10,506	4,373,443	78	187,558	96.89	99.68	595	80,361	4,453,804	98.67
140	10,049	4,383,492	72	187,630	97.12	99.72	523	73,251	4,456,743	98.74
145	6,593	4,390,085	46	187,675	97.26	99.75	478	69,269	4,459,354	98.80
150	6,653	4,396,738	44	187,720	97.41	99.77	433	65,003	4,461,741	98.85
155	3,971	4,400,709	26	187,745	97.50	99.78	408	63,189	4,463,898	98.90
160	4,592	4,405,301	29	187,774	97.60	99.80	379	60,656	4,465,957	98.94
165	4,226	4,409,527	26	187,800	97.69	99.81	353	58,297	4,467,824	98.99
170	3,365	4,412,892	20	187,820	97.77	99.82	333	56,691	4,469,583	99.02
175	2,604	4,415,496	15	187,834	97.83	99.83	319	55,770	4,471,266	99.06
180	3,021	4,418,517	17	187,851	97.89	99.84	302	54,336	4,472,853	99.10
185	2,754	4,421,271	15	187,866	97.95	99.85	287	53,090	4,474,361	99.13
190	1,503	4,422,774	8	187,874	97.99	99.85	279	53,027	4,475,801	99.16
195	2,512	4,425,286	13	187,887	98.04	99.86	266	51,902	4,477,188	99.19
200	1,981	4,427,267	10	187,897	98.09	99.86	256	51,261	4,478,528	99.22
999,999	86,355	4,513,622	256	188,153	100.00	100.00	0	0	4,513,622	100.00
TOTAL	4,513,622		188,153							
AVG. USE	24.0									

SCHEDULE H-5
SHEET 8 OF 20

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-10 CLASS = LOW INCOME RESIDENTIAL AREA = ARIZONA PERIOD = SUMMER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
0	0	0	3,281	3,281	0.00	2.13	150,642	0	0	0.00
1	2,061	2,061	2,061	5,342	0.11	3.47	148,581	148,581	150,642	8.17
2	5,730	7,791	2,865	8,207	0.42	5.33	145,716	291,432	299,223	16.23
3	19,582	27,373	6,527	14,734	1.48	9.57	139,189	417,566	444,939	24.14
4	36,012	63,385	9,003	23,737	3.44	15.42	130,186	520,743	584,128	31.69
5	48,643	112,028	9,729	33,466	6.08	21.74	120,457	602,286	714,314	38.75
6	60,782	172,810	10,130	43,596	9.37	28.32	110,327	661,960	834,771	45.28
7	70,245	243,055	10,035	53,631	13.18	34.84	100,292	702,042	945,097	51.27
8	82,696	325,751	10,337	63,968	17.67	41.56	89,955	719,638	1,045,389	56.71
9	84,658	410,409	9,406	73,375	22.26	47.67	80,548	724,935	1,135,344	61.59
10	74,335	484,744	7,433	80,808	26.29	52.50	73,115	731,149	1,215,892	65.95
11	104,566	589,309	9,506	90,314	31.97	58.67	63,609	699,698	1,289,007	69.92
12	93,891	683,201	7,824	98,138	37.06	63.76	55,785	669,415	1,352,616	73.37
13	91,193	774,394	7,015	105,153	42.01	68.32	48,770	634,007	1,408,401	76.40
14	86,931	861,325	6,209	111,363	46.72	72.35	42,560	595,846	1,457,170	79.04
15	77,017	938,341	5,134	116,497	50.90	75.69	37,426	561,389	1,499,731	81.35
16	56,033	994,375	3,502	119,999	53.94	77.96	33,924	542,782	1,537,157	83.38
17	74,757	1,069,132	4,397	124,397	57.99	80.82	29,526	501,948	1,571,081	85.22
18	67,942	1,137,074	3,775	128,171	61.68	83.27	25,752	463,533	1,600,607	86.82
19	61,497	1,198,570	3,237	131,408	65.02	85.37	22,515	427,789	1,626,359	88.22
20	60,296	1,258,866	3,015	134,423	68.29	87.33	19,500	390,008	1,648,874	89.44
25	221,701	1,480,567	9,374	143,797	80.31	93.42	10,126	253,149	1,733,717	94.04
30	132,648	1,613,215	4,636	148,433	87.51	96.43	5,490	164,699	1,777,914	96.44
35	90,964	1,704,179	2,682	151,115	92.44	98.18	2,808	98,272	1,802,451	97.77
40	44,352	1,748,531	1,126	152,242	94.85	98.91	1,681	67,259	1,815,790	98.50
45	29,499	1,778,029	665	152,907	96.45	99.34	1,016	45,738	1,823,768	98.93
50	16,773	1,794,802	340	153,247	97.36	99.56	676	33,799	1,828,601	99.19
55	14,466	1,809,268	264	153,511	98.14	99.73	412	22,644	1,831,912	99.37
60	6,912	1,816,180	115	153,626	98.52	99.81	297	17,815	1,833,995	99.48
65	4,782	1,820,962	73	153,699	98.78	99.85	224	14,540	1,835,502	99.56
70	3,905	1,824,867	55	153,755	98.99	99.89	168	11,779	1,836,645	99.63

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-10 CLASS = LOW INCOME RESIDENTIAL AREA = ARIZONA PERIOD = SUMMER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
75	2,257	1,827,124	30	153,784	99.11	99.91	139	10,393	1,837,517	99.67
80	2,099	1,829,223	27	153,811	99.22	99.93	112	8,948	1,838,171	99.71
85	1,583	1,830,806	19	153,830	99.31	99.94	93	7,909	1,838,715	99.74
90	1,322	1,832,128	15	153,845	99.38	99.95	78	7,038	1,839,166	99.76
95	1,111	1,833,239	12	153,857	99.44	99.96	66	6,300	1,839,539	99.78
100	1,268	1,834,507	13	153,870	99.51	99.97	53	5,345	1,839,852	99.80
105	615	1,835,122	6	153,875	99.54	99.97	48	4,989	1,840,111	99.81
110	967	1,836,089	9	153,884	99.60	99.97	39	4,247	1,840,336	99.83
115	673	1,836,762	6	153,890	99.63	99.98	33	3,757	1,840,519	99.84
120	707	1,837,469	6	153,896	99.67	99.98	27	3,208	1,840,677	99.85
125	611	1,838,080	5	153,901	99.70	99.99	22	2,723	1,840,803	99.85
130	0	1,838,080	0	153,901	99.70	99.99	22	2,832	1,840,912	99.86
135	134	1,838,214	1	153,902	99.71	99.99	21	2,807	1,841,021	99.86
140	416	1,838,630	3	153,905	99.73	99.99	18	2,496	1,841,126	99.87
145	145	1,838,775	1	153,906	99.74	99.99	17	2,441	1,841,216	99.87
150	149	1,838,924	1	153,907	99.75	99.99	16	2,376	1,841,300	99.88
155	152	1,839,076	1	153,908	99.76	99.99	15	2,302	1,841,378	99.88
160	314	1,839,390	2	153,910	99.78	99.99	13	2,059	1,841,449	99.89
165	491	1,839,881	3	153,913	99.80	99.99	10	1,634	1,841,515	99.89
170	338	1,840,219	2	153,915	99.82	99.99	8	1,346	1,841,565	99.89
175	173	1,840,392	1	153,916	99.83	100.00	7	1,213	1,841,605	99.90
180	177	1,840,569	1	153,917	99.84	100.00	6	1,069	1,841,638	99.90
185	367	1,840,936	2	153,919	99.86	100.00	4	732	1,841,668	99.90
190	0	1,840,936	0	153,919	99.86	100.00	4	752	1,841,688	99.90
195	193	1,841,129	1	153,920	99.87	100.00	3	579	1,841,708	99.90
200	0	1,841,129	0	153,920	99.87	100.00	3	594	1,841,723	99.90
999,999	2,394	1,843,523	3	153,923	100.00	100.00	0	0	1,843,523	100.00
TOTAL	1,843,523		153,923							
AVG. USE	12.0									

SCHEDULE H-5
SHEET 10 OF 20

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-10 CLASS = LOW INCOME RESIDENTIAL AREA = ARIZONA PERIOD = WINTER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
0	0	0	1,022	1,022	0.00	0.65	155,961	0	0	0.00
1	459	459	459	1,481	0.01	0.94	155,502	155,502	155,961	2.29
2	927	1,386	463	1,944	0.02	1.24	155,039	310,077	311,463	4.57
3	3,006	4,391	1,002	2,946	0.06	1.88	154,037	462,110	466,502	6.84
4	3,141	7,533	785	3,731	0.11	2.38	153,252	613,006	620,539	9.10
5	6,986	14,518	1,397	5,129	0.21	3.27	151,854	759,272	773,790	11.35
6	10,279	24,798	1,713	6,842	0.36	4.36	150,141	900,847	925,645	13.58
7	10,981	35,779	1,569	8,411	0.52	5.36	148,572	1,040,007	1,075,786	15.78
8	19,236	55,015	2,404	10,815	0.81	6.89	146,168	1,169,344	1,224,358	17.96
9	23,762	78,777	2,640	13,455	1.16	8.57	143,528	1,291,749	1,370,526	20.11
10	29,177	107,954	2,918	16,373	1.58	10.43	140,610	1,406,100	1,514,054	22.22
11	9,797	117,751	891	17,264	1.73	11.00	139,719	1,536,913	1,654,664	24.28
12	39,414	157,165	3,285	20,548	2.31	13.09	136,435	1,637,218	1,794,383	26.33
13	47,263	204,428	3,636	24,184	3.00	15.41	132,799	1,726,390	1,930,818	28.33
14	40,882	245,310	2,920	27,104	3.60	17.27	129,879	1,818,307	2,063,617	30.28
15	31,851	277,162	2,123	29,227	4.07	18.62	127,756	1,916,335	2,193,496	32.18
16	57,736	334,898	3,609	32,836	4.91	20.92	124,147	1,986,354	2,321,252	34.06
17	59,263	394,161	3,486	36,322	5.78	23.14	120,661	2,051,238	2,445,399	35.88
18	51,880	446,041	2,882	39,204	6.54	24.97	117,779	2,120,019	2,566,060	37.65
19	44,630	490,671	2,349	41,553	7.20	26.47	115,430	2,193,168	2,683,839	39.38
20	43,205	533,876	2,160	43,713	7.83	27.85	113,270	2,265,393	2,799,269	41.07
25	326,837	860,713	14,145	57,859	12.63	36.86	99,124	2,478,108	3,338,820	48.99
30	344,796	1,205,509	12,209	70,068	17.69	44.63	86,915	2,607,452	3,812,961	55.95
35	361,455	1,566,964	10,833	80,901	22.99	51.53	76,082	2,662,878	4,229,842	62.06
40	389,050	1,956,013	10,088	90,989	28.70	57.96	65,994	2,639,761	4,595,774	67.43
45	355,087	2,311,100	8,090	99,079	33.91	63.11	57,904	2,605,672	4,916,772	72.14
50	359,757	2,670,858	7,404	106,484	39.19	67.83	50,499	2,524,967	5,195,825	76.24
55	352,861	3,023,718	6,574	113,058	44.37	72.02	43,925	2,415,891	5,439,609	79.81
60	360,798	3,384,517	6,143	119,201	49.66	75.93	37,782	2,266,925	5,651,442	82.92
65	346,670	3,731,187	5,432	124,633	54.75	79.39	32,350	2,102,749	5,833,936	85.60
70	325,094	4,056,282	4,729	129,362	59.52	82.41	27,621	1,933,447	5,989,729	87.88

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-10 CLASS = LOW INCOME RESIDENTIAL AREA = ARIZONA PERIOD = WINTER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
75	327,574	4,383,856	4,432	133,795	64.32	85.23	23,188	1,739,126	6,122,982	89.84
80	280,445	4,664,301	3,566	137,361	68.44	87.50	19,622	1,569,761	6,234,062	91.47
85	265,280	4,929,581	3,178	140,539	72.33	89.53	16,444	1,397,714	6,327,295	92.84
90	224,329	5,153,910	2,535	143,074	75.62	91.14	13,909	1,251,819	6,405,729	93.99
95	227,130	5,381,040	2,421	145,495	78.95	92.68	11,488	1,091,336	6,472,376	94.97
100	183,455	5,564,495	1,855	147,351	81.65	93.86	9,632	963,229	6,527,724	95.78
105	160,340	5,724,835	1,543	148,894	84.00	94.85	8,089	849,366	6,574,201	96.46
110	155,056	5,879,891	1,424	150,317	86.27	95.75	6,666	733,226	6,613,116	97.03
115	120,782	6,000,673	1,060	151,377	88.05	96.43	5,606	644,665	6,645,338	97.50
120	112,373	6,113,046	945	152,322	89.69	97.03	4,661	559,341	6,672,386	97.90
125	99,373	6,212,419	801	153,123	91.15	97.54	3,860	482,492	6,694,910	98.23
130	86,455	6,298,874	669	153,792	92.42	97.97	3,191	414,812	6,713,686	98.51
135	64,217	6,363,091	479	154,271	93.36	98.27	2,712	366,094	6,729,185	98.73
140	57,921	6,421,012	417	154,688	94.21	98.54	2,295	321,339	6,742,351	98.93
145	58,598	6,479,611	407	155,094	95.07	98.80	1,889	273,848	6,753,459	99.09
150	46,006	6,525,616	308	155,403	95.75	98.99	1,580	237,064	6,762,680	99.23
155	34,638	6,560,254	225	155,627	96.26	99.14	1,356	210,148	6,770,402	99.34
160	37,446	6,597,700	236	155,863	96.81	99.29	1,120	179,237	6,776,937	99.43
165	30,467	6,628,168	185	156,048	97.25	99.40	935	154,340	6,782,508	99.52
170	25,085	6,653,253	148	156,196	97.62	99.50	787	133,842	6,787,096	99.58
175	20,453	6,673,706	117	156,313	97.92	99.57	670	117,246	6,790,952	99.64
180	18,561	6,692,267	103	156,416	98.19	99.64	567	101,996	6,794,263	99.69
185	13,205	6,705,472	72	156,488	98.39	99.68	495	91,584	6,797,056	99.73
190	16,010	6,721,481	84	156,572	98.62	99.74	411	78,018	6,799,499	99.77
195	14,518	6,735,999	75	156,647	98.83	99.79	336	65,527	6,801,526	99.80
200	8,745	6,744,744	44	156,691	98.96	99.81	292	58,464	6,803,208	99.82
999,999	70,705	6,815,449	292	156,983	100.00	100.00	0	0	6,815,449	100.00
TOTAL	6,815,449		156,983							
AVG. USE	43.4									

SCHEDULE H-5
SHEET 12 OF 20

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-11 CLASS = MULTI-FAMILY LOW INCOME RESIDENTIAL AREA = ARIZONA PERIOD = SUMMER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
0	0	0	784	784	0.00	5.78	12,776	0	0	0.00
1	309	309	309	1,093	0.20	8.06	12,467	12,467	12,776	8.09
2	450	759	225	1,318	0.48	9.72	12,242	24,484	25,243	15.99
3	1,759	2,518	586	1,905	1.59	14.05	11,655	34,966	37,485	23.74
4	2,466	4,984	616	2,521	3.16	18.59	11,039	44,156	49,140	31.12
5	4,024	9,008	805	3,326	5.71	24.53	10,234	51,171	60,179	38.11
6	4,953	13,961	825	4,151	8.84	30.61	9,409	56,453	70,413	44.60
7	5,742	19,703	820	4,972	12.48	36.66	8,588	60,119	79,822	50.55
8	6,515	26,218	814	5,786	16.61	42.67	7,774	62,192	88,410	55.99
9	7,240	33,458	804	6,590	21.19	48.60	6,970	62,727	96,184	60.92
10	7,396	40,854	740	7,330	25.87	54.06	6,230	62,300	103,154	65.33
11	8,514	49,369	774	8,104	31.27	59.76	5,456	60,015	109,384	69.28
12	8,319	57,688	693	8,797	36.54	64.88	4,763	57,152	114,840	72.73
13	6,367	64,055	490	9,287	40.57	68.49	4,273	55,547	119,603	75.75
14	7,971	72,026	569	9,856	45.62	72.69	3,704	51,850	123,876	78.46
15	6,968	78,994	465	10,321	50.03	76.11	3,239	48,585	127,579	80.80
16	6,438	85,431	402	10,723	54.11	79.08	2,837	45,387	130,818	82.85
17	6,295	91,726	370	11,094	58.09	81.81	2,466	41,928	133,655	84.65
18	6,133	97,859	341	11,434	61.98	84.32	2,126	38,262	136,121	86.21
19	5,393	103,252	284	11,718	65.39	86.42	1,842	34,994	138,247	87.56
20	4,903	108,155	245	11,963	68.50	88.23	1,597	31,933	140,089	88.72
25	20,253	128,408	800	12,763	81.33	94.13	797	19,913	148,321	93.94
30	11,575	139,983	378	13,141	88.66	96.91	419	12,556	152,538	96.61
35	7,155	147,137	196	13,337	93.19	98.36	223	7,801	154,939	98.13
40	2,974	150,112	74	13,411	95.07	98.90	149	5,946	156,058	98.84
45	2,745	152,857	61	13,472	96.81	99.35	88	3,961	156,818	99.32
50	1,870	154,727	36	13,508	97.99	99.61	52	2,616	157,343	99.65
55	846	155,573	17	13,524	98.53	99.74	36	1,953	157,526	99.77
60	402	155,975	7	13,532	98.79	99.79	28	1,690	157,665	99.86
65	634	156,609	10	13,542	99.19	99.87	18	1,152	157,761	99.92
70	477	157,086	7	13,550	99.49	99.92	10	731	157,817	99.95

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-11 CLASS = MULTI-FAMILY LOW INCOME RESIDENTIAL AREA = ARIZONA PERIOD = SUMMER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
75	220	157,306	3	13,553	99.63	99.95	7	549	157,855	99.98
80	155	157,461	2	13,555	99.73	99.96	5	419	157,880	99.99
85	165	157,626	2	13,557	99.83	99.98	3	267	157,893	100.00
90	267	157,893	3	13,560	100.00	100.00	0	0	157,893	100.00
95	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
100	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
105	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
110	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
115	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
120	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
125	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
130	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
135	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
140	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
145	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
150	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
155	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
160	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
165	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
170	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
175	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
180	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
185	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
190	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
195	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
200	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
999,999	0	157,893	0	13,560	100.00	100.00	0	0	157,893	100.00
TOTAL	157,893		13,560							
AVG. USE	11.6									

SCHEDULE H-5
SHEET 14 OF 20

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-11 CLASS = MULTI-FAMILY LOW INCOME RESIDENTIAL AREA = ARIZONA PERIOD = WINTER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
0	0	0	291	291	0.00	2.10	13,537	0	0	0.00
1	208	208	208	499	0.05	3.61	13,329	13,329	13,537	3.43
2	261	469	130	630	0.12	4.55	13,198	26,397	26,866	6.81
3	317	786	106	735	0.20	5.32	13,093	39,278	40,064	10.15
4	761	1,547	190	926	0.39	6.69	12,902	51,609	53,157	13.47
5	941	2,489	188	1,114	0.63	8.06	12,714	63,570	66,059	16.73
6	1,438	3,927	240	1,354	0.99	9.79	12,474	74,846	78,773	19.96
7	1,175	5,102	168	1,521	1.29	11.00	12,307	86,146	91,247	23.12
8	2,202	7,303	275	1,797	1.85	12.99	12,031	96,250	103,554	26.23
9	2,116	9,419	235	2,032	2.39	14.69	11,796	106,166	115,585	29.28
10	3,073	12,492	307	2,339	3.16	16.92	11,489	114,889	127,381	32.27
11	4,211	16,703	383	2,722	4.23	19.68	11,106	122,167	138,870	35.18
12	5,903	22,606	492	3,214	5.73	23.24	10,614	127,371	149,976	37.99
13	5,360	27,966	412	3,626	7.08	26.22	10,202	132,625	160,591	40.68
14	4,172	32,137	298	3,924	8.14	28.38	9,904	138,655	170,793	43.27
15	6,562	38,700	437	4,362	9.80	31.54	9,466	141,997	180,696	45.77
16	5,667	44,366	354	4,716	11.24	34.10	9,112	145,796	190,163	48.17
17	6,891	51,257	405	5,121	12.98	37.03	8,707	148,018	199,275	50.48
18	6,867	58,124	381	5,503	14.72	39.79	8,325	149,858	207,982	52.69
19	7,184	65,308	378	5,881	16.54	42.53	7,947	151,000	216,308	54.80
20	5,405	70,713	270	6,151	17.91	44.48	7,677	153,542	224,255	56.81
25	39,029	109,742	1,650	7,801	27.80	56.41	6,027	150,678	260,419	65.97
30	36,297	146,038	1,255	9,056	37.00	65.49	4,772	143,150	289,188	73.26
35	36,694	182,732	1,087	10,143	46.29	73.35	3,685	128,973	311,706	78.96
40	30,142	212,875	774	10,917	53.93	78.95	2,911	116,444	329,318	83.42
45	29,446	242,321	667	11,584	61.39	83.77	2,244	100,963	343,284	86.96
50	24,039	266,360	492	12,077	67.48	87.34	1,751	87,565	353,925	89.66
55	20,019	286,379	370	12,447	72.55	90.01	1,381	75,967	362,346	91.79
60	16,162	302,541	273	12,720	76.64	91.99	1,108	66,478	369,019	93.48
65	15,484	318,025	241	12,961	80.56	93.73	867	56,380	374,405	94.85
70	11,476	329,501	165	13,125	83.47	94.92	703	49,194	378,694	95.93

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-11 CLASS = MULTI-FAMILY LOW INCOME RESIDENTIAL AREA = ARIZONA PERIOD = WINTER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
75	10,039	339,540	134	13,260	86.01	95.89	568	42,624	382,164	96.81
80	10,553	350,093	135	13,395	88.69	96.87	433	34,647	384,740	97.46
85	6,576	356,669	79	13,474	90.35	97.44	354	30,079	386,748	97.97
90	6,415	363,084	73	13,547	91.98	97.97	281	25,265	388,349	98.38
95	4,765	367,849	51	13,598	93.19	98.34	230	21,805	389,654	98.71
100	4,221	372,070	43	13,642	94.25	98.65	186	18,643	390,713	98.98
105	3,188	375,258	31	13,673	95.06	98.88	155	16,310	391,568	99.19
110	3,996	379,254	37	13,710	96.07	99.14	118	13,014	392,268	99.37
115	2,364	381,618	21	13,731	96.67	99.30	97	11,181	392,799	99.51
120	2,951	384,569	25	13,756	97.42	99.48	72	8,660	393,229	99.61
125	1,717	386,286	14	13,770	97.86	99.58	58	7,262	393,548	99.70
130	1,027	387,313	8	13,778	98.12	99.64	50	6,514	393,827	99.77
135	1,988	389,301	15	13,793	98.62	99.75	35	4,727	394,028	99.82
140	1,104	390,405	8	13,801	98.90	99.80	27	3,780	394,185	99.86
145	713	391,118	5	13,806	99.08	99.84	22	3,190	394,308	99.89
150	587	391,705	4	13,810	99.23	99.87	18	2,700	394,405	99.91
155	762	392,467	5	13,815	99.42	99.91	13	2,014	394,481	99.93
160	313	392,780	2	13,817	99.50	99.92	11	1,760	394,540	99.95
165	489	393,269	3	13,820	99.62	99.94	8	1,319	394,588	99.96
170	335	393,604	2	13,822	99.71	99.96	6	1,021	394,625	99.97
175	0	393,604	0	13,822	99.71	99.96	6	1,051	394,655	99.98
180	359	393,963	2	13,824	99.80	99.97	4	720	394,683	99.98
185	182	394,145	1	13,825	99.85	99.98	3	554	394,699	99.99
190	186	394,331	1	13,826	99.89	99.99	2	377	394,708	99.99
195	0	394,331	0	13,826	99.89	99.99	2	387	394,718	99.99
200	0	394,331	0	13,826	99.89	99.99	2	397	394,728	99.99
999,999	419	394,750	2	13,828	100.00	100.00	0	0	394,750	100.00
TOTAL	394,750		13,828							
AVG. USE	28.5									

SCHEDULE H-5
SHEET 16 OF 20

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-15 CLASS = SPECIAL RESIDENTIAL AREA = ARIZONA PERIOD = SUMMER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
0	0	0	21	21	0.00	3.24	627	0	0	0.00
1	8	8	8	29	0.01	4.48	619	619	627	0.86
2	2	10	1	30	0.01	4.63	618	1,236	1,246	1.70
3	33	43	11	41	0.06	6.33	607	1,821	1,864	2.55
4	80	123	20	61	0.17	9.41	587	2,348	2,471	3.37
5	130	253	26	87	0.35	13.43	561	2,805	3,058	4.18
6	108	361	18	105	0.49	16.20	543	3,258	3,619	4.94
7	161	522	23	128	0.71	19.75	520	3,640	4,162	5.68
8	120	642	15	143	0.88	22.07	505	4,040	4,682	6.39
9	108	750	12	155	1.02	23.92	493	4,437	5,187	7.08
10	180	930	18	173	1.27	26.70	475	4,750	5,680	7.76
11	198	1,128	18	191	1.54	29.48	457	5,027	6,155	8.41
12	180	1,308	15	206	1.79	31.79	442	5,304	6,612	9.03
13	169	1,477	13	219	2.02	33.80	429	5,577	7,054	9.63
14	182	1,659	13	232	2.27	35.80	416	5,824	7,483	10.22
15	105	1,764	7	239	2.41	36.88	409	6,135	7,899	10.79
16	224	1,988	14	253	2.71	39.04	395	6,320	8,308	11.35
17	85	2,073	5	258	2.83	39.81	390	6,630	8,703	11.89
18	306	2,379	17	275	3.25	42.44	373	6,714	9,093	12.42
19	95	2,474	5	280	3.38	43.21	368	6,992	9,466	12.93
20	120	2,594	6	286	3.54	44.14	362	7,240	9,834	13.43
25	663	3,257	29	315	4.45	48.61	333	8,325	11,582	15.82
30	862	4,119	31	346	5.63	53.40	302	9,060	13,179	18.00
35	888	5,007	27	373	6.84	57.56	275	9,625	14,632	19.98
40	761	5,768	20	393	7.88	60.65	255	10,200	15,968	21.81
45	592	6,360	14	407	8.69	62.81	241	10,845	17,205	23.50
50	575	6,935	12	419	9.47	64.66	229	11,450	18,385	25.11
55	481	7,416	9	428	10.13	66.05	220	12,100	19,516	26.65
60	635	8,051	11	439	10.99	67.75	209	12,540	20,591	28.12
65	567	8,618	9	448	11.77	69.14	200	13,000	21,618	29.52
70	410	9,028	6	454	12.33	70.06	194	13,580	22,608	30.87

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-15 CLASS = SPECIAL RESIDENTIAL AREA = ARIZONA PERIOD = SUMMER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
75	360	9,388	5	459	12.82	70.83	189	14,175	23,563	32.18
80	702	10,090	9	468	13.78	72.22	180	14,400	24,490	33.44
85	1,155	11,245	14	482	15.36	74.38	166	14,110	25,355	34.63
90	178	11,423	2	484	15.60	74.69	164	14,760	26,183	35.76
95	834	12,257	9	493	16.74	76.08	155	14,725	26,982	36.85
100	392	12,649	4	497	17.27	76.70	151	15,100	27,749	37.90
105	309	12,958	3	500	17.70	77.16	148	15,540	28,498	38.92
110	535	13,493	5	505	18.43	77.93	143	15,730	29,223	39.91
115	339	13,832	3	508	18.89	78.40	140	16,100	29,932	40.88
120	591	14,423	5	513	19.70	79.17	135	16,200	30,623	41.82
125	124	14,547	1	514	19.87	79.32	134	16,750	31,297	42.74
130	254	14,801	2	516	20.21	79.63	132	17,160	31,961	43.65
135	533	15,334	4	520	20.94	80.25	128	17,280	32,614	44.54
140	415	15,749	3	523	21.51	80.71	125	17,500	33,249	45.41
145	426	16,175	3	526	22.09	81.17	122	17,690	33,865	46.25
150	292	16,467	2	528	22.49	81.48	120	18,000	34,467	47.07
155	302	16,769	2	530	22.90	81.79	118	18,290	35,059	47.88
160	316	17,085	2	532	23.33	82.10	116	18,560	35,645	48.68
165	977	18,062	6	538	24.67	83.02	110	18,150	36,212	49.45
170	504	18,566	3	541	25.35	83.49	107	18,190	36,756	50.20
175	349	18,915	2	543	25.83	83.80	105	18,375	37,290	50.92
180	354	19,269	2	545	26.31	84.10	103	18,540	37,809	51.63
185	548	19,817	3	548	27.06	84.57	100	18,500	38,317	52.33
190	0	19,817	0	548	27.06	84.57	100	19,000	38,817	53.01
195	385	20,202	2	550	27.59	84.88	98	19,110	39,312	53.69
200	593	20,795	3	553	28.40	85.34	95	19,000	39,795	54.35
999,999	52,431	73,226	95	648	100.00	100.00	0	0	73,226	100.00
TOTAL	73,226		648							
AVG. USE	113.0									

SCHEDULE H-5
SHEET 18 OF 20

SOUTHWEST GAS CORPORATION

BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-15 CLASS = SPECIAL RESIDENTIAL AREA = ARIZONA PERIOD = WINTER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
0	0	0	8	8	0.00	1.23	640	0	0	0.00
1	5	5	5	13	0.01	2.01	635	635	640	0.94
2	0	5	0	13	0.01	2.01	635	1,270	1,275	1.87
3	9	14	3	16	0.02	2.47	632	1,896	1,910	2.80
4	12	26	3	19	0.04	2.93	629	2,516	2,542	3.72
5	25	51	5	24	0.07	3.70	624	3,120	3,171	4.64
6	30	81	5	29	0.12	4.48	619	3,714	3,795	5.56
7	28	109	4	33	0.16	5.09	615	4,305	4,414	6.46
8	40	149	5	38	0.22	5.86	610	4,880	5,029	7.36
9	72	221	8	46	0.32	7.10	602	5,418	5,639	8.26
10	70	291	7	53	0.43	8.18	595	5,950	6,241	9.14
11	99	390	9	62	0.57	9.57	586	6,446	6,836	10.01
12	84	474	7	69	0.69	10.65	579	6,948	7,422	10.87
13	26	500	2	71	0.73	10.96	577	7,501	8,001	11.72
14	70	570	5	76	0.83	11.73	572	8,008	8,578	12.56
15	150	720	10	86	1.05	13.27	562	8,430	9,150	13.40
16	96	816	6	92	1.19	14.20	556	8,896	9,712	14.22
17	85	901	5	97	1.32	14.97	551	9,367	10,268	15.03
18	144	1,045	8	105	1.53	16.20	543	9,774	10,819	15.84
19	133	1,178	7	112	1.72	17.28	536	10,184	11,362	16.64
20	140	1,318	7	119	1.93	18.36	529	10,580	11,898	17.42
25	548	1,866	24	143	2.73	22.07	505	12,625	14,491	21.22
30	638	2,504	23	166	3.67	25.62	482	14,460	16,964	24.84
35	1,160	3,664	35	201	5.37	31.02	447	15,645	19,309	28.27
40	644	4,308	17	218	6.31	33.64	430	17,200	21,508	31.49
45	1,080	5,388	25	243	7.89	37.50	405	18,225	23,613	34.58
50	1,288	6,676	27	270	9.78	41.67	378	18,900	25,576	37.45
55	1,377	8,053	26	296	11.79	45.68	352	19,360	27,413	40.14
60	753	8,806	13	309	12.89	47.69	339	20,340	29,146	42.68
65	1,067	9,873	17	326	14.46	50.31	322	20,930	30,803	45.10
70	886	10,759	13	339	15.75	52.31	309	21,630	32,389	47.43

SOUTHWEST GAS CORPORATION

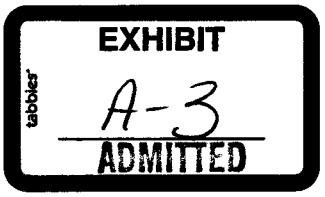
BILL FREQUENCY ANALYSIS

TEST YEAR AS ADJUSTED

RATE SCHEDULE = G-15 CLASS = SPECIAL RESIDENTIAL AREA = ARIZONA PERIOD = WINTER

INTERVAL UPPER LIMIT	THERMS IN INTERVAL	CUMULATIVE THERMS	BILLS IN INTERVAL	CUMULATIVE BILLS	CUMULATIVE USAGE PERCENT	CUMULATIVE BILLS PERCENT	BILLS PASSING INTERVAL UPPER LIMIT	THERMS FROM BILLS PASSING UPPER LIMIT	CONSOLIDATED THERMS	FACTOR PERCENT
75	1,170	11,929	16	355	17.47	54.78	293	21,975	33,904	49.64
80	1,250	13,179	16	371	19.30	57.25	277	22,160	35,339	51.75
85	1,414	14,593	17	388	21.37	59.88	260	22,100	36,693	53.73
90	1,585	16,178	18	406	23.69	62.65	242	21,780	37,958	55.58
95	1,496	17,674	16	422	25.88	65.12	226	21,470	39,144	57.32
100	1,560	19,234	16	438	28.16	67.59	210	21,000	40,234	58.91
105	1,030	20,264	10	448	29.67	69.14	200	21,000	41,264	60.42
110	1,081	21,345	10	458	31.25	70.68	190	20,900	42,245	61.86
115	1,125	22,470	10	468	32.90	72.22	180	20,700	43,170	63.21
120	1,410	23,880	12	480	34.97	74.07	168	20,160	44,040	64.49
125	859	24,739	7	487	36.22	75.15	161	20,125	44,864	65.69
130	1,021	25,760	8	495	37.72	76.39	153	19,890	45,650	66.84
135	801	26,561	6	501	38.89	77.31	147	19,845	46,406	67.95
140	827	27,388	6	507	40.10	78.24	141	19,740	47,128	69.01
145	1,289	28,677	9	516	41.99	79.63	132	19,140	47,817	70.02
150	595	29,272	4	520	42.86	80.25	128	19,200	48,472	70.98
155	616	29,888	4	524	43.76	80.86	124	19,220	49,108	71.91
160	1,107	30,995	7	531	45.38	81.94	117	18,720	49,715	72.80
165	491	31,486	3	534	46.10	82.41	114	18,810	50,296	73.65
170	1,009	32,495	6	540	47.58	83.33	108	18,360	50,855	74.46
175	1,210	33,705	7	547	49.35	84.41	101	17,675	51,380	75.23
180	356	34,061	2	549	49.87	84.72	99	17,820	51,881	75.97
185	552	34,613	3	552	50.68	85.19	96	17,760	52,373	76.69
190	753	35,366	4	556	51.78	85.80	92	17,480	52,846	77.38
195	969	36,335	5	561	53.20	86.57	87	16,965	53,300	78.04
200	986	37,321	5	566	54.65	87.35	82	16,400	53,721	78.66
999,999	30,973	68,294	82	648	100.00	100.00	0	0	68,294	100.00
TOTAL	68,294		648							
AVG. USE	105.4									

SCHEDULE H-5
SHEET 20 OF 20



IN THE MATTER OF
SOUTHWEST GAS CORPORATION
Docket No. G-01551A-07-___

PREPARED DIRECT TESTIMONY
OF
ROGER C. MONTGOMERY

ON BEHALF OF
SOUTHWEST GAS CORPORATION

August 31, 2007

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Of
Prepared Direct Testimony
Of
ROGER C. MONTGOMERY

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Southwest Gas Corporation
Docket No. G-01551A-07-___

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
Of
ROGER C. MONTGOMERY

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Roger C. Montgomery and 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 Vice President Pricing.

Q. 3 Does Appendix A summarize your educational background and business experience?

A. 3 Yes, it does.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 Yes. I have testified before the Arizona Corporation Commission (ACC or Commission), the California Public Utilities Commission, the Public Utilities Commission of Nevada, and the Federal Energy Regulatory Commission.

II. PURPOSE OF TESTIMONY

Q. 5 What is the purpose of your prepared direct testimony in this proceeding?

A. 5 The purpose of my testimony is to provide the Commission with a brief explanation of the significant challenges facing the Company in Arizona and to explain the broad

goals and objectives Southwest hopes to achieve in this general rate case (GRC) to help meet those challenges. Specifically, my testimony will:

(1) identify Southwest's witnesses and their subject area(s);

(2) support Southwest's application and need for increased rates and charges;

(3) summarize the financial and regulatory challenges Southwest faces; and

(4) discuss, from a policy perspective, Southwest's key proposals to address these challenges and why they should be approved by the Commission. Southwest's other witnesses will more fully describe Southwest's GRC and provide more specific detail concerning Southwest's proposals.

III. OTHER SOUTHWEST WITNESSES

Q. 6 Please identify Southwest's other witnesses in this GRC and their general subject or issue areas.

A. 6 Besides myself, Southwest sponsors the testimony of nine other witnesses:

(1) Robert Mashas - Overall deficiency/revenue requirement and various adjustments;

(2) Randi Aldridge - Cost of service and various adjustments;

(3) Laura Hobbs - Management Incentive Program (MIP) and Supplemental Executive Retirement

Plan (SERP);

(4) Theodore Wood - Capital structure, cost of debt, and overall rate of return;

(5) Frank Hanley - Cost of equity;

(6) Jamie Cattanach - Billing determinants and declining residential consumption per customer;

(7) Frank Maglietti - Class cost of service study and Purchased Gas Adjustment (PGA) mechanism;

(8) Ralph Miller - Revenue decoupling and energy efficiency; and

(9) A. Brooks Congdon - Rate design and regulatory/ratemaking mechanisms.

IV. OVERVIEW OF CURRENT AND LAST RATE CASE

Q. 7 Please provide a brief overview of Southwest's current GRC application.

A. 7 The current GRC is based on a test year for the 12 months ended April 30, 2007. Southwest's adjusted test year shows a deficiency of approximately $50.2 million and an earned return of only 6.68 percent. Southwest requests a capital structure consisting of 51 percent debt, four percent preferred equity, and 45 percent common equity, with a requested return on common equity (ROE) of 11.25 percent and an overall return on rate base of 9.45 percent. Mr. Robert Mashas and Ms. Randi Aldridge provide further details of the amount, reasons, and bases for the Company's revenue deficiency. The GRC also contains several proposals to modify the Company's rate

design and to employ specific regulatory mechanisms to address fixed cost recovery, declining residential consumption per customer and weather volatility.

Q. 8 How does the current GRC application compare to Southwest' previous GRC application (test year ended August 31, 2004).

A. 8 In Southwest's previous GRC, the Company's analysis indicated it was deficient by approximately $66.9 million and was earning only a 5.47 percent return on its investment in Arizona. In that proceeding, Southwest requested a hypothetical capital structure consisting of 53 percent debt, five percent preferred equity, and 42 percent common equity. Southwest recommended an ROE of 11.42 percent. Southwest also requested several rate design changes, including increases in residential basic service charges and a revenue decoupling mechanism to assist the Company in recovering its fixed cost of service in the face of declining residential consumption per customer and weather volatility.

Q. 9 What did the Commission decide in Southwest's last GRC?

A. 9 In its decision issued on February 23, 2006 (Decision No. 68487), the Commission granted Southwest approximately $49.3 million in rate relief effective March 1, 2006. However, with the exception of some moderate increases in basic service charges, including an increase of $1.70 in the residential basic service charge, the Commission did not adopt an overall rate design or a revenue decoupling

mechanism that would adequately address Southwest's inability to recover its fixed costs and provide a reasonable opportunity for Southwest to earn its authorized rate of return. The Commission also granted an ROE of only 9.50 percent on a 40 percent equity ratio.

Q. 10 How did the Commission's last GRC decision impact Southwest?

A. 10 The Company's earned rates of return in Arizona improved after the rate relief was in place for a full winter season. Southwest's earned returns for the 12-month periods ended March 31, 2006, September 30, 2006, and March 31, 2007, were 4.48 percent, 6.08 percent, and 7.85 percent, respectively. Southwest did not, however, earn its authorized return of 8.40 percent, and based on projected cost increases and continuing declines in customer usage, it will not earn the authorized return without further rate relief. As such, the Company filed this GRC.

Q. 11 How frequently does Southwest typically file GRCs in Arizona?

A. 11 Over the past decade or more, Southwest has filed a GRC with the Commission about every three years. For several reasons, filing a GRC much more often than every three years or so is not practicable. Despite the frequency of filing GRCs, Southwest was able to earn its authorized rate of return in only one year over the past decade or more. If Southwest were able to earn a rate of return

closer to the authorized rate of return, it could result in less frequent GRC applications, which Southwest believes its customers would welcome and the Commission would prefer.

V. MAJOR CHALLENGES FACING SOUTHWEST

Q. 12 What are the major challenges facing Southwest?

A. 12 In general, Southwest faces two major challenges. First, Southwest has been unable to earn its Commission-authorized return. Second, Southwest's authorized return is significantly below returns authorized for its peers in the industry and, more particularly, below the rates authorized for other energy utilities in Arizona.

VI. INABILITY TO EARN AUTHORIZED RATE OF RETURN

Q. 13 Please briefly summarize why Southwest has been unable to earn its authorized return?

A. 13 In general, there are three primary reasons Southwest has not earned its authorized return in Arizona. First, average usage by residential customers, who make up over 95 percent of the Company's customer base, continues to decline each year. If residential customers, on average, continue to use less natural gas each year, as has been the case for the past two decades, Southwest will not recover its fixed costs of providing utility service. Southwest's inability to earn its authorized return will continue unless and until this issue of declining residential consumption per customer is adequately addressed in the regulatory process. This problem is not

unique to Southwest; it is happening across the nation. There are several regulatory solutions to this problem, and several state regulatory commissions have approved various rate design or regulatory mechanisms to resolve the problem.

Second, the vagaries of weather in the desert southwest also plague Southwest and its customers. Weather volatility affects customers when it is colder-than-normal. In that situation, customers pay more than necessary for Southwest to recover its fixed costs (as long as fixed costs continue to be partially recovered through a commodity rate). Weather volatility also affects the Company. When weather is warmer-than-normal, fixed costs, those recovered through the commodity charge, are under-recovered, causing the Company financial distress. For example, during 2005 and 2006, weather was significantly warmer than normal. As a result, Southwest's earned return for 2005 and 2006 was substantially less than what was authorized by the Commission. Conversely, in some years, the weather has been colder-than-normal. The Company believes that removing weather from the general ratemaking equation will protect both Southwest and its customers.

Third, in the last several Arizona rate cases, a ratemaking theory was put into practice that Southwest believes is fundamentally flawed and unfair. It is the concept that if any program or service that the Company

performs benefits shareholders, then some portion of the costs for the program or service should be "shared". In the last Southwest Arizona GRC, this practice of "sharing" was even extended to programs imposed on the Company by the federal government. It is a long-standing and fundamental regulatory paradigm that a regulated utility should be allowed to recover all costs that are prudently incurred, are reasonable, and are necessary in providing utility service. Only those expenses or costs deemed to be imprudent or unreasonable should be disallowed. Southwest does not dispute the Commission's authority to disallow imprudent or unreasonable expenses. However, to "share" prudent, necessary, and reasonable expense merely because there is some benefit to shareholders is, in Southwest's view, confiscatory and amounts to nothing less than an explicit disallowance and erosion of Southwest's opportunity to realize its Commission-authorized return.

VII. NEED FOR A REASONABLE AND COMPARABLE RATE OF RETURN

Q. 14 Can you briefly elaborate on the need for the Commission to authorize a reasonable and comparable return to the Company on its investment in Arizona?

A. 14 Yes. As noted earlier in this testimony, in Southwest's last GRC, the Commission authorized an ROE of only 9.50 percent, which is significantly below what the Commission has authorized for other Arizona energy utilities and represents one of the lowest ROEs authorized by any state

regulatory commission in the nation in recent years. This is particularly troubling considering two of Southwest's credit ratings are just one step above "junk bond" status. Arizona is also one of the fastest growing states in the nation. Therefore, Southwest must compete with its peers in the utility industry for capital to fund this growth and to maintain and improve its natural gas system infrastructure.

The Company's inability to earn its authorized return is a major problem for Southwest's shareholders. It is also a major problem for customers if the authorized rate of return is not competitive in the financial marketplace and Southwest must obtain capital at less attractive (higher) rates. If the Commission approves an ROE for Southwest that is comparable to its peers, and also provides Southwest a reasonable opportunity to actually earn the return, the Company's financial condition would improve over time and help mitigate the need for future increases in base rates for customers.

Q. 15 Would Commission consideration and resolution of the challenges you previously identified eliminate Southwest management's need to effectively and efficiently run the business and serve customers?

A. 15 No, Southwest's management must still efficiently manage its workforce and pay close consideration to operating and capital costs to provide it a reasonable opportunity

to earn its authorized return. This is particularly true in a state like Arizona with growth rates still well above national averages. Nothing in Southwest's proposals guarantees the Company a specific return on its investment nor relieves management of its obligation and responsibility to serve its various constituencies. Southwest presents the Commission with a number of tools that should help it meet the substantial and multiple challenges of providing for the natural gas energy needs of Arizona.

Q. 16 Does this conclude your prepared direct testimony?

A. 16 Yes, it does.

SUMMARY OF QUALIFICATIONS
ROGER C. MONTGOMERY

I graduated from the University of Texas at El Paso in 1970 with a Bachelor of Business Administration degree. My principal area of concentration was in accounting. After graduation, I joined El Paso Natural Gas Company as a Technician in the Gas Marketing and Customer Relations department where my duties included preparation of gas sales and revenue analyses for rate and certificate filings with the Federal Energy Regulatory Commission ("FERC"). In 1974, I joined Northwest Pipeline as a Rate Analyst in the Rate department. In 1976, I joined Southwest as Rates Administrator in the Rates department. In 1982, I was promoted to Manager/Rates and in 1988 to Director/Rates, Certificates and Tariffs. In 1995, I assumed the position of Director/Rates and State Regulatory Affairs. In 1998, I was promoted to my current position where I am responsible for the activities of the Pricing and Tariffs, Revenue Requirements, and Federal Regulatory Affairs departments.

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
Docket No. G-01551A-07-0504

PREPARED REBUTTAL TESTIMONY
OF
ROGER C. MONTGOMERY

ON BEHALF OF
SOUTHWEST GAS CORPORATION

May 9, 2008

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rebuttal Testimony
of
Roger C. Montgomery

Q. 1 Please state your name and business address.

A. 1 My name is Roger C. Montgomery. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150.

Q. 2 Are you the same Roger C. Montgomery who sponsored direct testimony on behalf of Southwest Gas Corporation (Southwest or the Company) in this proceeding?

A. 2 Yes, I am.

Q. 3 What is the purpose of your prepared rebuttal testimony?

A. 3 The purpose of my testimony is to stress the importance to Southwest of coming out this proceeding with a rate design or regulatory mechanism that adequately addresses the financial implications of declining average residential usage and weather volatility.

Q. 4 Please elaborate.

A. 4 In my prepared direct testimony, I identified Southwest's inability to recover its fixed costs and earn the rate of return authorized by the Commission as one of the Company's primary problems and greatest challenges. I further identified three factors as the primary reasons for Southwest's inability to earn the Commission authorized rate of return. Two of the factors I

identified were declining average usage by residential customers and Southwest's sensitivity to variations in weather. In Southwest's last general rate case, the Arizona Corporation Commission (Commission) stated that "We recognize that Southwest Gas is facing increased financial pressure due to declining usage on a per customer basis. . . ."[1] Notwithstanding this finding, Staff and RUCO failed to present proposals in their direct testimonies that adequately address the financial pressure caused by declining average residential usage and weather volatility.

Q. 5 What proposals did the Company present as part of its direct testimony to address declining usage and weather sensitivity?

A. 5 In its direct testimony, Southwest proposed a variety of new rate design and regulatory mechanisms that were designed to decouple revenues from sales volumes. These proposals included a revenue decoupling adjustment provision (RDAP) to address declining average usage, a weather normalization adjustment provision (WNAP) to address adverse effects of weather volatility for both customers and shareholders, and a volumetric rate design that includes a flat commodity rate, but which, for accounting purposes, has a declining block rate for non-gas charges and an inverted block rate for purchased gas

[1] Decision 68487, p. 33, lns. 26-28.

cost. Southwest's volumetric rate design is based upon the rate design methodology currently authorized for Laclede Gas Company, a natural gas distribution company (LCD) serving over 630,000 customers in Missouri and one of the companies in the proxy group of eight LDCs selected by Southwest witness Frank Hanley.

Q. 6 Did Staff or RUCO support the Company's proposals in their direct testimony?

A. 6 No. Although proposing a higher basic service charge, both Staff and RUCO rejected the Company's RDAP, WNAP and volumetric rate design proposals. Southwest witnesses Ralph Miller and Brooks Congdon provide rebuttal testimony on Staff's and RUCO's rejection of these proposals.

Q. 7 Did any of the intervening parties support the Company's proposals in their direct testimony?

A. 7 Yes. The Southwest Energy Efficiency Project (SWEEP) and Arizona Investment Council (AIC) both sponsored testimony supporting at least one of the proposals presented by the Company.

Q. 8 If the Commission accepts Staff's and RUCO's recommendations to reject the Company's proposals, are there any other ways the Commission could mitigate the financial pressure due to declining average residential usage and weather volatility?

A. 8 Yes. One way would be for the Commission to use updated numbers for residential usage. Southwest's currently

effective residential rates are based on average annual usage of 347 therms. Southwest's test year ended April 30, 2007 had weather normalized average annual residential customer usage of 332 therms. For the twelve months ended March 31, 2008, the Company has calculated that average annual residential usage has dropped from 332 therms to 319 therms. Southwest witness James Cattanach provides rebuttal testimony on the continuing decline in average residential usage that is being experienced by the Company. Southwest witness Brooks Congdon provides rebuttal testimony quantifying that the financial impact of the decline in residential average usage from 332 therms to 319 therms is approximately $6.3 million. The Commission could utilize this known and measurable change in average residential usage to calculate the revenue deficiency and to design residential rates in this proceeding.

Another way would be for the Commission to make an upward adjustment in the authorized rate of return on common equity capital that the Commission authorizes in this proceeding, as discussed in more detail in the rebuttal testimony of Southwest witness Theodore Wood. Either of these alternatives would allow the Commission to mitigate the financial impact declining residential use per customer has on the Company's ability to earn its Commission authorized rate of return.

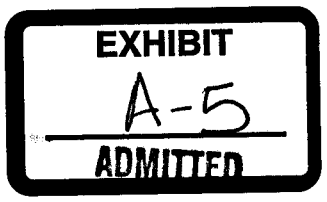
Q. 9 Why is Southwest so resolute about finding a solution to

the financial impact that declining residential usage and weather volatility has had on its ability to earn the Commission authorized rate of return?

A. 9 Absent affirmative corrective action by the Commission in this proceeding, the moment rates from this proceeding take effect, the Company will already have a revenue deficiency of approximately $6.3 million, assuming average residential usage does not decline further between March 2008 and the date that new rates in this proceeding become effective. Accordingly, Southwest implores the Commission to carefully weigh and consider the evidence in this proceeding and approve the RDAP, WNAP, or Southwest's volumetric rate design, or any combination of these proposals so that Southwest will be put on the path to improved financial stability, and have a reasonable opportunity to earn its Commission authorized rate of return.

Q. 10 Does this conclude your prepared rebuttal testimony?

A. 10 Yes, it does.



IN THE MATTER OF

SOUTHWEST GAS CORPORATION

Docket No. G-01551A-07-0504

PREPARED REBUTTAL TESTIMONY

OF

WILLIAM N. MOODY

ON BEHALF OF

SOUTHWEST GAS CORPORATION

May 9, 2008

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of
Prepared Rebuttal Testimony
of
WILLIAM N. MOODY

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BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rebuttal Testimony
of
WILLIAM N. MOODY

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is William N. Moody. 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 Company) as the Vice President / Gas Resources.

Q. 3 Did you provide direct testimony in this proceeding on behalf of Southwest?

A. 3 No.

Q. 4 Please state your educational background and business experience.

A. 4 A summary of my educational background and business experience is attached hereto as Appendix A.

Q. 5 Have you previously testified before any regulatory commissions?

A. 5 Yes. I have testified before the Arizona Corporation Commission (Commission or ACC) and the Public Utilities Commission of Nevada (PUCN).

Q. 6 What is the purpose of your prefiled rebuttal testimony?

A. 6 The purpose of my prefiled rebuttal testimony is to

respond to specific aspects of the direct testimony of Stephen L. Thumb and Rita R. Beale, witnesses for the Arizona Corporation Commission's Utilities Division Staff (Staff), pertaining to natural gas procurement.

Q. 7 Please summarize your rebuttal testimony.

A. 7 My rebuttal testimony will address the 15 recommendations made in the below-mentioned testimony of Staff. They include:

(1) Southwest should continue seeking access to storage capacity, particularly market-area storage capacity.

(2) Southwest should increase the documentation requirements for its transportation-only (T-1) customers.

(3) Southwest should make its Daily Forecasting Accuracy Improvement Task Force a permanent entity. Southwest's policies should also require ongoing validation and back-testing of its daily load forecast, along with its required frequency.

(4) Until the point that market-area storage becomes a reality in Arizona, it is recommended that the ACC develop and implement policies that would promote the sharing of gas supplies among the major users of interstate pipeline capacity in Arizona during extreme conditions, including gas LDCs and electric utilities.

(5) While Southwest has taken efforts to diversify its future pipeline capacity portfolio, it is recommended that Southwest carefully track the likelihood of liquefied natural gas (LNG) imports entering the Company's gas

market and consider gaining access to such supplies, in an effort to diversify its gas supplies and reduce its dependence on the San Juan basin.

(6) Consolidate all strategies, policies, and procedures into a minimal number of documents with sufficient detail such that new employees could read and immediately perform the bulk of their work.

(7) Clarify the Arizona Price Stability Program (APSP) supply element by documenting required timing and volumes for the next one to two years forward. If there is uncertainty, then windows of time and ranges of volume or duration can be established instead.

(8) Clarify the precise nature of the APSP strategy. The precise strategy should be recognized and declared in Company policies and procedures to guide employees and decision makers, as well as the ACC's oversight.

(9) Designate the *Arizona Dispatch Guidelines* as the buyers' limits and authorization to execute and meet the forecasted daily demand requirement in Company policies and procedures.

(10) Company policies regarding the 'unbuying' of gas, as well as the reasons for the policies, should be reevaluated, and then explicitly documented in official Company policies and procedures.

(11) Ensure all confirmations with gas suppliers include deal transaction dates.

(12) Ensure all confirmations with suppliers include dates of

the internal approval next to the signature authorization.

(13) Considerably shorten the time lapse between deal execution and deal confirmation with gas supplier.

(14) Include a list of attendees present during the solicitation and purchase of the APSP fixed price gas supply element (as well as during selection and approval of the index gas supply element) to ensure independence, proper monitoring, and to improve the quality of the audit trail.

(15) Update any old master supply agreements that cap the buyers' liquidated damages at 50 cents per MMBtu into supply agreements that are based on true up to actual market during non-performance.

II. STAFF RECOMMENDATIONS ACCEPTED BY SOUTHWEST

Q. 8 Are there recommendations that witnesses Stephen L. Thumb and Rita R. Beale have made that Southwest can accept and implement without discussion?

A. 8 Yes. If approved by the Commission, Southwest would implement the following recommendations as soon as practicable within 60 days of an order in this case: Recommendations numbered 1, 3, 4, 7, 8, 10, 11, 12, 13, and 14.

III. DOCUMENTATION AND REQUIREMENTS FOR ITS TRANSPORTATION-ONLY (T-1) CUSTOMERS

Q. 9 Do you have comments regarding recommendation number 2, that Southwest should increase the documentation and

requirements for its transportation-only (T-1) customers?

A. 9 Yes. First, I would like to scope the documentation that is referred to in this statement. In his prefiled direct testimony on Page 17, Mr. Thumb suggests that Southwest require detailed documentation of both supply contracts and interstate capacity contracts for transportation-only customers.

Q. 10 What is the current process to track transportation customers' capacity rights?

A. 10 Southwest works diligently with the upstream pipeline (El Paso Natural Gas Company or El Paso), the transportation customers, and where applicable, their supplier agents to document and confirm all upstream capacity rights. Southwest's Key Accounts Management (KAM) Department maintains a documented procedure for acquiring and updating this information on a quarterly basis. KAM and Southwest's Planning Department personnel together work closely with El Paso to determine rights that have been secured by and assigned to transportation customers. Southwest's Arizona Gas Tariff clearly establishes that transportation customers are responsible for any upstream charges or penalties occasioned by their actions and Southwest's billing system includes those costs in transportation-only customer bills.

Q. 11 Can you summarize Southwest's position on this issue?

A. 11 Southwest believes its existing practice of quarterly verification of customer interstate capacity contracts is

an efficient and effective method of collecting the necessary information to ensure allocations of charges and penalties incurred by Southwest as a point operator are accurate and should not be modified.

IV. ACCESSING LNG SUPPLIES

Q. 12 Please comment on Staff's recommendation number 5, that the Company carefully track the likelihood of LNG imports entering the Southwest market and consider gaining access to such supplies.

A. 12 Southwest has commented in past proceedings on the developing nature of the western LNG market and supplies and agrees it should continue to monitor the progress and likelihood of LNG imports entering Southwest's Arizona gas market. However, at this time, there is continuing uncertainty about the regularity and reliability of supplies that may be available from this source. Issues of price competition with international markets and the timing of production area liquefaction facilities remain, at best, cloudy.

Q. 13 How do you propose that Arizona customers participate in these developing supplies?

A. 13 In the short term, 1 to 3 years, this participation should be indirect. In other words, if and when LNG flows into the western gas market, it will simply increase the available supplies to the market and become indirectly available through displacement or reduced demand on traditional producing basins. As the LNG

market matures with pricing and reliability in full view, then the direct acquisition of this supply for diversity should be reviewed and considered.

V. COMPANY POLICIES AND PROCEDURES

Q. 14 What recommendations will you specifically discuss in this section of testimony?

A. 14 I would like to comment on recommendations 6 and 9. Each of these recommendations revolves around documentation of the policies and procedures used when purchasing gas for the customer portfolio.

Q. 15 Please discuss your views of recommendation 6 to consolidate all strategies, policies, and procedures into a minimal number of documents with sufficient detail such that new employees could read and immediately perform the bulk of their work.

A. 15 In Exhibit SLT-2 on Page 3-17, Mr. Thumb notes as curious and implies criticism of the fact that Southwest policies, strategies, and procedures are grouped in the annual documentation filed with the Commission (Annual Gas Procurement Plan), rather than in some other consolidated form. Southwest believes that is a logical and convenient place and format for such documentation. It is easily and readily accessible to Staff and Southwest personnel. The Commission has never found this practice to be deficient.

Q. 16 Do you agree that this form of documentation is sufficient to guide a new employee in their task to

develop and execute their portion of the portfolio process each day?

A. 16 No. Although I agree that quality documentation is important for consistency, controls, and ongoing compliance with established policies and procedures, such a goal as stated in the recommendation is unrealistic. The complexity of the work that must be accomplished by both Planning Department and Gas Purchases Department personnel and the institutional knowledge of interstate pipeline and market area matters that must attend this work is such that no new employee should be expected, nor would any new employee be allowed, to attempt to perform the "bulk of their work" from a procedural document.

Q. 17 Recommendation 9 states that Southwest should "Designate the *Arizona Dispatch Guidelines* as the buyers' limits and authorization to execute and meet the forecasted daily demand requirement in company policies and procedures". Please discuss Southwest's position on this issue.

A. 17 Southwest believes that Mr. Thumb has mistakenly viewed a monthly internal worksheet titled "Arizona Dispatch Guidelines", prepared by Planning Department staff, as a document which designates gas buyers' "limits and authorization to execute" in meeting daily demand requirements in accordance with Company policies and procedures. The referenced monthly document does not serve such a purpose and was never designed to do so. It is no more than a listing of firm supply contracts,

detailing volumes and prices, allowing Planning Department and Gas Purchase Department personnel to compare and confirm that each of their respective data systems have available contract data correctly entered.

Q. 18 Does a document exist that accomplishes the intent of Mr. Thumb's recommendation?

A. 18 Yes. A more detailed procedural document for Planning Department and Gas Purchasing Department personnel, titled "DEPARTMENT AND STAFF RESPONSIBILITIES-PORTFOLIO SELECTION PROCEDURES" exists today. Among other things, it includes an itemization of many things that a buyer must review and consider in arranging supply for a daily demand. This document has been supplied to the Commission in the past and was also provided in this docket in response to Staff Data Request 4.25. (Attached is Rebuttal Exhibit No.__(WNM-1))

VI. LIQUIDATED DAMAGES IN SUPPLY CONTRACTS

Q. 19 Recommendation 15 calls for Southwest to update any old master supply agreements that cap the buyers' liquidated damages at 50 cents per MMBtu into supply agreements that are based on true-up to actual market during non-performance. Has Southwest completed a review of all Arizona master supply contracts?

A. 19 Yes.

Q. 20 Please discuss the results of this effort.

A. 20 Southwest's "old master supply agreements", other than NAESB standard format contracts, which are solely based

upon market/contract differentials, provide for liquidated damages equal to the greater of $0.50 or the market/contract price differential. Southwest finds no contract modifications are necessary to comply with Staff's recommendation.

Q. 21 Does this conclude your prepared rebuttal testimony?

A. 21 Yes, it does.

SUMMARY OF QUALIFICATIONS
WILLIAM N. MOODY

Experience

Southwest Gas Corporation — **Las Vegas, Nevada**

Vice President/Gas Resources — **05/06/04 to present**
Director/Gas Supply — **01/27/03 to 05/06/04**

Direct the negotiation and administration of all gas purchase contracts, spot purchase activities, and capacity and transportation agreements. Direct the planning and execution of the annual gas portfolios for each regulatory jurisdiction. Also, direct medium to long term interstate infrastructure planning, gas scheduling activities, gas control functions, gas system support staff for the Company.

Director/Customer Relations/
Southern Nevada Division — **11/98 to 01/03**

Directed the Customer Service, Meter Reading, Customer Assistance/Call Center functions for the Las Vegas and Bullhead City Districts.

Director/Corporate Development — **09/96 to 11/98**

Responsible for new business development activities. Oversaw preparation of financial feasibility of potential acquisitions or projects; conducted due diligence activities; prepared recommendations for senior management.

Director/Facilities and Resource Development — **12/93 to 09/96**

Responsible for conducting operations analysis and benchmarking activities focused on productivity enhancement and measurement. Conducted new subsidiary development and direct business plan preparation.

Manager/Administration/
Central Arizona Division — **10/91 to 12/93**

Responsible for management of central support functions for Division Operations including: Warehouse, Transportation/Auto Shop, Division Accounting, Risk Management, Materials Management, and Facilities departments.

Management Development Program **04/91 to 10/91**

Participated in comprehensive training program that required training and short-term participation in every department in the Company.

Director/Planning and Financial Services **05/89 to 04/91**

Directed the annual budget and multi-year planning process for the corporation. Produced long-term earnings and cash forecasts for use with bond rating agencies, appropriate public utilities commissions, and industry financial analysts.

Manager/Administrator/Budget **03/85 to 05/89**

Developed and conducted the corporate annual budget. Developed new corporate Budget Department as an independent function.

Cost Analyst/Rate Department **05/81 to 03/85**

Responsible for collecting, analyzing, and preparing information for all regulatory filings with the Arizona, California, and Nevada public utilities commissions and the Federal Energy Regulatory Commission. This included cost analysis, forecasting, and written testimony. Provided testimony at commission proceedings as an expert witness.

Gas Accountant/Accounting Department **11/80 to 05/81**

Conducted allocations and prepared monthly journal entries to the corporate general ledger for gas cost by rate jurisdiction.

Accountant/Accounting Department **10/79 to 11/80**

Calculated unitized cost of property units for all capital plant.

Education

University of Nevada, Reno **05/1978**

Bachelor of Science degree in Business Administration with a major in Accounting.

DEPARTMENT AND STAFF RESPONSIBILITIES
PORTFOLIO SELECTION PROCEDURES

Solicitation of Firm Term Bids

1. Gas Purchases and Transportation (GPT) will consult with Gas Resources Planning to identify input variables required by the computer model or other analyses to be used in the upcoming portfolio evaluation process.

2. In consideration of Gas Resources Planning modeling and other analytical needs, requisite non-modeled contractual details, and concerns for respondent understandability, GPT will fashion a bid solicitation designed to maximize the quantity, quality, and diversity of proposals received and Southwest's ability to effectively evaluate such proposals.

3. The firm term bid solicitation will request index-based supply pricing.

4. Gas Resources Planning will attempt to evaluate all responsive term proposals received. The primary tool used for evaluating the proposals is a computer-based optimization modeling program. When a proposal cannot be modeled as submitted, it will be evaluated using other available tools. In cases where a proposal is submitted with attributes that cannot be entered into the model a surrogate is used that conforms to the parameters outlined in the bid solicitation guidelines, subject to any model design limitations.

5. GPT will seek supplier clarification on proposals that appear incomplete, unclear, internally inconsistent, or not within the scope of the solicitation. Proposals that cannot be clarified sufficiently for evaluation will be removed from further consideration. Gas Resources Planning and GPT will maintain appropriate documentation as to the reason(s) any proposal is removed from evaluation.

6. Fixed-price proposals for the portfolio will be requested as part of the Nevada Volatility Mitigation Program (VMP) and Arizona Price Stability Program (APSP), apart from this firm term bid solicitation. Similar programs may be conducted for other rate jurisdictions as deemed appropriate by management.

   The VMP and APSP will involve periodic solicitations for various future purchase periods. GPT and Gas Resources Planning will jointly decide the exact dates for issuing the

solicitations. The fixed-price solicitation and requested responses will be briefer and narrower in scope than

Southwest's general firm term bid solicitation. The structure of the solicitation will be tailored to minimize evaluation time and acceptance response time for Southwest, and also allow for respondent suppliers to minimize risk, therefore encouraging participation. GPT will create a bid request that is applicable to each specific fixed-price solicitation and distribute the request to suppliers. The bid request will identify market areas, receipt locations and purchase periods, as well as setting forth the bid and response date and time deadlines.

Results from each fixed price bid solicitation will be reviewed jointly by GPT and Gas Resources Planning to confirm that all bids are appropriate to the solicitation and entered into the records correctly. Multiple suppliers will be contacted to provide up to the minute price quotes for final selection of the requested supplies.

Evaluation of Firm Term Supplies

1. Preparation for Evaluation

(a) Evaluation Engineers from Gas Resources Planning will create a new model set-up for the rate jurisdictions that require models. Space will be reserved in the model for existing and future fixed-price contract commitments. The minimum daily quantities will be dependent on each rate jurisdiction's needs. However, the quantity may be revised at anytime during the analysis to reflect changing market conditions and experienced management judgment.

(b) Electronic bid forms will be held in a database as created by an interactive bid program.

(c) Evaluation Engineers review bids for clarity and convert price statements into modeling equation coefficients. All bids that appear incomplete, unclear or internally inconsistent will be returned to GPT for clarification, as noted above. Any proposal that cannot be clarified sufficiently for evaluation will be removed from further consideration.

(d) All bids accepted for consideration will be sorted by rate jurisdiction, term and type to facilitate modeling.

(e) Special cases will receive appropriate treatment.

2. At this point, all offers or surrogates are presented and the iterative selection and negotiation process can begin to identify and secure the best cost portfolio considering price, reliability, and resource mix.

3. Modeling will identify the lowest cost portfolio components from the available bids, based upon portfolio requirements.

   (a) Demand forecasts developed by the Demand Planning department will be used in the modeling with minor exceptions as deemed necessary to meet supply reliability goals.
   (b) Monthly price levels for modeling will be based upon forward market conditions with adjustments necessary for specific location or seasonal decision support.

4. Bids will be authorized for inclusion in the portfolio based upon model results and qualitative consideration with and without negotiated improvement. At such time as a bid is authorized, GPT will contact the supplier to confirm purchase and/or negotiate specific provisions prior to confirming. All firm supply arrangements are authorized with approval of executive management.

5. Supplies already contracted and bids authorized during the evaluation process will be converted to "existing" status as the iterative selection process continues.

Monthly/Daily Spot Purchases

1. Monthly spot gas (typically baseload for one month) purchase requirements for each jurisdiction will be determined by GPT based on economic, contractual, and operational considerations prior to the first of each month. Based on these considerations and the forecasted demand requirements, GPT will determine if monthly baseload spot gas is applicable for the next month. If so, a bid solicitation will be sent to suppliers and results will be reviewed in conjunction with observation of monthly supplies posted as available on the Intercontinental Exchange (ICE) electronic trading platform. Supply selections, if any, may be made from either the bids received or ICE postings with a representative from Gas Resources Planning as an independent observer and participant in the process. Bids received and bids selected (or ICE purchases acquired) will be recorded for each applicable

jurisdiction. This process may be repeated on an as needed basis depending upon shifting economic, contractual, and operational considerations.

2. Daily spot gas purchase requirements for each jurisdiction will be determined by GPT daily, based on economic, contractual, and operational considerations, as set forth below.

Daily Spot Purchase and Nomination Procedures

The following constitutes the general procedure for GPT in acquiring and nominating daily supplies. These steps are followed after the previously detailed firm term supplies, firm fixed-price supplies, and monthly spot purchases have been contracted and are available for nomination.

1. Survey current spot market prices.

2. Review daily system demand forecast, as available, from Central Gas Dispatch.

3. Review pipeline imbalance activity to determine if a deviation from Central Gas Dispatch's daily system demand forecast is necessary or desired to counteract any imbalance trends.

4. Determine if any further deviation from Central Gas Dispatch's daily system demand forecast is necessary to accommodate any requests or demands for action communicated from upstream pipelines or to comply with pipeline balancing tariffs.

5. Review available upstream pipeline capacity availability for the flow day for which volumes are being purchased.

6. Review past nomination activity and results.

   (a) Review most recent pipeline scheduling reports to identify any instances of nonperformance on nominated supplies.

   (b) In cases of nonperformance, identify the cause of the nonperformance.

   (c) Determine if it is necessary or desirable to have the involved supplier re-nominate the shortfall.

   (d) Contact supplier if re-nomination has been deemed desirable.

(e) Contact Central Gas Dispatch scheduler to verbally advise of intent to re-nominate supplies.

(f) Enter re-nominations into internal nomination systems.

(g) Review pipeline reports for results of any prior re-nomination attempts.

(h) If re-nomination efforts were partially unsuccessful, repeat Steps 6(c) through 6(g), as appropriate.

7. Determine estimated daily spot gas requirement in light of the preceding steps.

8. Gather market intelligence by receiving calls from and making calls to prospective suppliers and monitoring electronic messaging, internet trading platform(s), and other industry pricing information to determine daily price parameters available in the marketplace.

9. Monitor market price fluctuations throughout the daily trading period and modify offer acceptance threshold based on these market fluctuations.

10. Review available firm term, firm fixed-price, and monthly spot supplies/prices and determine what, if any, nomination changes from prior day should be made in consideration of opportunities to flex firm term contract volumes up or down based on prevailing spot market prices.

11. Modify daily spot purchase volume target arrived at in Step 7 based on price observations made in Steps 8, 9, and 10.

12. Enter daily nomination information in internal systems and advise respective system Central Gas Dispatch scheduler of its availability.

13. Print daily spot gas confirmation letters, review for accuracy, and sign them.

14. Provide signed daily spot gas confirmation letters to administrator for faxing to respective suppliers.

15. Review any confirmation letters independently sent by supply representatives for accuracy, and follow up with supplier on any perceived errors.

IN THE MATTER OF

SOUTHWEST GAS CORPORATION

Docket No. G-01551A-07-0504

PREPARED REJOINDER TESTIMONY

OF

WILLIAM N. MOODY

ON BEHALF OF

SOUTHWEST GAS CORPORATION

June 9, 2008

Southwest Gas Corporation
Docket No. G-01551A-07-0504

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Prepared Rejoinder Testimony
Of
WILLIAM N. MOODY

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BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rejoinder Testimony
of
WILLIAM N. MOODY

INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is William N. Moody. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150.

Q. 2 Are you the same William N. Moody that sponsored rebuttal testimony on behalf of Southwest Gas Corporation (Southwest or Company)?

A. 2 Yes, I am.

Q. 3 Do you have any corrections to your rebuttal testimony?

A. 3 Yes. I agree with Staff witness Rita R. Beale's surrebuttal assertion that I misattributed all of the fifteen Staff recommendations to Staff witness Stephen L. Thumb in my rebuttal testimony. I further agree with clarification beginning on page 1, line 23 through page 2, line 3.

Q. 4 What is the purpose of your prepared rejoinder testimony?

A. 4 I am responding to the surrebuttal testimony of the Arizona Corporation Commission Utilities Division Staff (Staff) witnesses Mr. Thumb and Ms. Beale.

Q. 5 Please comment on Mr. Thumb's surrebuttal testimony.

A. 5 Southwest believes that there is no remaining disagreement with the two issues mentioned in Mr. Thumb's surrebuttal testimony as previously rejected, Recommendations #2 and #5. Specifically regarding recommendation #2, Southwest has a quarterly review process for T-1 contracts and will continue in this process into the future. Southwest accepts Mr. Thumb's explanation of the current status of recommendation #5.

Q. 6 Did Southwest agree to any of the recommendations contained in Ms. Beale's direct testimony?

A. 6 Yes. As indicated in my rebuttal testimony, Southwest agreed with eight of the ten recommendations made by Ms. Beale. However, the Company disagreed with two of Ms. Beale's recommendations. The issues that Southwest accepted are referenced in Ms. Beale's surrebuttal testimony under Section II entitled "SUMMARY OF SOUTHWEST'S SURREBUTTAL TESTIMONY". However, Southwest still disagrees with two of Ms. Beale's recommendations.

SARBANES-OXLEY COMPLIANCE

Q. 7 Before discussing the two recommendations Southwest is rejecting, are there any other matters you would like to address?

A. 7 Yes. In her surrebuttal testimony, Ms. Beale implies that Sarbanes-Oxley requires gas procurement

documentation and that Southwest is somehow deficient in this area.

First, the Sarbanes-Oxley Act of 2002 (Sarbanes-Oxley), requires management assessment of internal controls over financial reporting, not "...complete sets of internal policies and procedures reviewed and authorized by the Board of Directors". Furthermore, Company management, not the Board of Directors, is responsible to ensure that these controls are in place and operating effectively such that the failure of one or more controls does not result in a material error in the financial statements. The role of the Board of Directors, specifically the Audit Committee, is to ensure management has evaluated the effectiveness of its internal controls over financial reporting and that an audit of those controls is performed by an independent public accounting firm. The Board (Audit Committee) does not authorize and approve internal controls or as stated in Ms. Beale's terminology, "internal policies and procedures".

Q. 8 Is Southwest Sarbanes-Oxley compliant?

A. 8 Yes. Southwest has been under Sarbanes-Oxley review for four years and has received a clean opinion from the independent auditing firm, Pricewaterhouse-Coopers, finding no material weaknesses in the Company's internal controls for each of these years.

INDUSTRY BEST PRACTICES

Q. 9 Ms. Beale also implies in her surrebuttal testimony that the Company is deficient in meeting Industry Best Practices. Has the Commission reviewed Southwest for best practices in gas supply activities in the recent past?

A. 9 Yes. Southwest's gas supply and procurement practices were reviewed in the last general rate case (Docket No. G-01551A-04-0876). Staff's review resulted in a number of recommendations, including the preparation of a benchmarking study of Southwest's natural gas procurement practice. The benchmarking study is attached as Rejoinder Exhibit No.__(WNM-1). This comprehensive review did not find that Southwest policies and procedures for gas procurement where outside of best practices for the industry. Southwest has fully complied with all of Staff's recommended changes in policies and procedures. Staff's Report dated August 22, 2006, on Southwest's compliance is attached as Rejoinder Exhibit No.__(WNM-2).

RECOMMENDATIONS 6 AND 9

Q. 10 After reviewing Ms. Beale's surrebuttal testimony, have you changed your opinion regarding the two recommendations Southwest previously disagreed with?

A. 10 No, I have not. Ms. Beale's recommendations that Southwest continues to believe unnecessary are:

(6) Consolidate all strategies, policies, and

procedures into a minimal number of documents; and

(9) Designate the *Arizona Dispatch Guidelines* as the buyers' limits and authorization to execute and meet the forecasted daily demand requirement in Company policies and procedures.

Q. 11 Why does Southwest believe implementing these recommendations is unnecessary?

A. 11 Southwest's policies and procedures are well documented in an appropriate manner in the pertinent Southwest publications. A regrouping of this documentation will produce minimal, if any, improvement in accessing these documents by Gas Supply personnel. The *Arizona Dispatch Guidelines* is not an appropriate document to utilize for buyers' limits and authorization. Southwest currently uses a system generated report from our Gas Transaction System to produce a daily/monthly economic dispatch list of available contracts. In addition, "Gas Day" provides a system generated daily load forecast multiple times a day to identify load limits. This information is used today as Ms. Beale suggests the *Arizona Dispatch Guidelines* document would be used.

Q. 12 Does that conclude your prepared rejoinder testimony?

A. 12 Yes, it does.

Southwest Gas Corporation

Natural Gas Procurement Practices and Benchmarking Study

July 2006

Natural Gas Procurement Practices and Benchmarking Study
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Natural Gas Procurement Practices and Benchmarking Study
Prepared for Southwest Gas Corporation
By Ralph E. Miller
July 5, 2006

Introduction and Overview

This report is a review of the gas acquisition practices of Southwest Gas Corporation (Southwest). The Arizona Corporation Commission expressed an interest in this topic in the hearings on Southwest's recent Arizona general rate case, Docket No. G-01551A-04-0876, and in Decision No. 68487 (issued February 23, 2006) it directed Southwest to continue to cooperate with the Commission Staff in Staff's investigation of this topic. Southwest requested the preparation of this report in response to the Commission's interest in this subject, and in furtherance of its cooperation with Staff's continuing investigation of this matter.

The author of this report is Ralph E. Miller. Mr. Miller is a recognized independent expert on natural gas supply, acquisition, and commodity purchasing, and he has been active in this field for more than 25 years. During this period he has reviewed the gas supply arrangements of more than 15 different gas utilities in numerous regulatory proceedings in seven states, and he continues to testify regularly on this subject in three state regulatory jurisdictions. Appendix A to this report contains a more detailed description of his expert qualifications in this area.

Southwest distributes natural gas to 1.6 million customers in Arizona, Nevada, and California. Southwest's total annual throughput in 2005 was approximately 249 million Dekatherms or Dth. This total includes 104 million Dth sold by Southwest to end-users connected to its distribution systems, and a further 145 million Dth that Southwest delivered to customers who purchased their gas supplies from vendors other than Southwest itself. These total system throughput quantities include sales and transportation deliveries to all customer classes including large commercial and special procurement customers.

Southwest's Arizona service territory encompasses central and southern Arizona, which includes the Phoenix and Tucson metropolitan areas. In 2005, Southwest sold 66 million Dth of natural gas to 877,000 end-use customers in Arizona. Southwest's Arizona sales were 63% of Southwest's total gas sales to end-use customers in all three states where Southwest provides gas distribution service.

This principal focus of this report is a review of Southwest's commodity gas procurement practices for its Arizona service territory. Commodity gas procurement is one of three major aspects of the gas supply activities typically conducted by a gas distribution utility, sometimes known as a "local distribution company" or LDC, and more recently in some states as a natural gas distribution company or NGDC.

The two other major aspects of a typical LDC's gas supply activities are load forecasting and capacity acquisition. To provide a proper context for the review of Southwest's commodity gas acquisition practices, this report begins with an overview of Southwest's load forecasting and capacity acquisition for its Arizona service territory. This overview is a description of the load forecasts that Southwest has prepared and the gas supply capacity that Southwest has acquired. It is not intended as an evaluation of the quality of the load forecasts or an assessment of the adequacy or cost of Southwest's portfolio of capacity resources.

Annual planning -- Southwest plans and manages its commodity gas procurement on an annual basis, with each annual period running from November of the current year through October of the following year. The use of an annual gas supply planning period is a standard practice.

In the gas industry, annual planning periods typically begin either in November or in April. November is the start of the winter heating season. April is the start of the "summer" season when utilities having access to seasonal storage resources typically begin their storage injections.

Load Forecasts

Load forecasting is important for commodity gas procurement because an LDC cannot make appropriate gas purchasing decisions unless it knows how much gas it is likely to need, and when it is likely to need that gas delivered.

A complete load forecast generally includes the following components:

- Annual, seasonal, and monthly loads under normal weather conditions

  Commodity gas procurement often involves advance purchase commitments for part of the gas supply that a utility expects to purchase under normal weather conditions. A forecast of the normal weather purchase quantities is needed to establish appropriate levels of advance purchase and hedging commitments.

- Design day, design week, and design winter season loads

  A utility needs to project the loads it is likely to experience under design weather conditions so that it can acquire sufficient gas supply capacity to serve those loads. The utility should also plan its commodity gas procurement to assure a sufficient and reliable supply of gas available for delivery under these design weather conditions. As an adjunct to its development of projected design condition loads, a utility should from time to time review its determination of the design weather conditions on which the design loads are based. Although changes in the range of likely weather conditions occur only slowly and are difficult to measure, a utility should not ignore the possibilities for change.

- Maximum and minimum daily loads that may occur in each calendar month

  The maximum daily load that may occur in any calendar month is the design daily load for that calendar month, and a utility needs to establish it for the same reason that it establishes an annual design day load. The minimum daily load in each calendar month determines the maximum quantity of gas that a utility can appropriately schedule for baseload delivery every day of that month. This maximum baseload quantity also limits a utility's advance commodity purchase commitments.

- No-notice and swing requirements

  For Southwest, as for other gas utilities, daily loads depend upon the weather, especially during the winter heating season. Weather forecasts are never perfectly accurate, and daily loads are also subject to other random influences. A utility must therefore arrange its gas supply activities to accommodate the variance between its actual load on a given day and the load that the utility forecasted when it made it gas purchases and supply nominations on the preceding day. That variance is typically accommodated through the use of a no-notice supply. The utility also needs swing supplies to accommodate differences from one day to the next in the forecasted load level, so that it can schedule or "nominate" its daily supplies to match its forecasted daily loads.

Southwest prepares a comprehensive load forecast analysis annually. The load forecast document includes the first three of the four components identified above: normal weather projected loads; design condition loads; and minimum and maximum daily loads in each calendar month. Table 1 shows data from Southwest's most recently completed forecast for its 2006/2007 gas year.

Southwest's swing requirements in each calendar month are simply the difference between the maximum and minimum daily loads for that month, and they are implicitly included in the load forecast. These swing requirements are the range within which Southwest must be prepared to schedule or nominate its daily gas supplies in each calendar month.

As this discussion indicates, Southwest's load forecasting process is complete and comprehensive, and it provides all of the requisite information for Southwest to have an informed commodity gas procurement policy. As noted in the introduction, this report makes no attempt to evaluate the methods that Southwest uses to prepare its load forecast analyses, or to comment on the quality (as opposed to the scope) of the results.

Capacity Acquisition

Southwest maintains a separate portfolio of capacity resources for its Arizona service territory. The shape of this portfolio is determined largely by one overriding factual

consideration - at present, all of Southwest's Arizona city gates are connected only to the interstate pipeline facilities of El Paso Natural Gas Company (El Paso, or EPNG), and for most (if not all) of those city gates it would be extremely difficult and expensive to establish connections to other pipelines or sources of gas supply. Southwest's portfolio of capacity resources for its Arizona service territory therefore consists entirely of services provided by El Paso. Southwest has sufficient firm transportation (FT) capacity on El Paso to serve the Arizona design day load indicated in Table 1.

The shape of Southwest's capacity portfolio is further restricted by the relatively narrow range of services provided by El Paso, which does not offer any market-area storage services. Southwest's capacity portfolio for Arizona therefore consists entirely of FT on El Paso from the San Juan and Permian basin gas production areas. Some storage services are available in the production area, but they would not add to or substitute for FT capacity on El Paso, because Southwest would still need FT capacity from the production area to deliver any storage withdrawals, and that capacity could be used equally well to deliver gas supplies that Southwest purchased in the production area. Southwest could perhaps use production-area storage as an adjunct to its commodity supply arrangements, as discussed below; but it is not at this time a relevant capacity resource for Arizona.

Southwest continually reviews the availability of alternative methods for delivering firm gas supplies to Southwest's Arizona city gates. As is appropriate, Southwest analyzes these possibilities to determine whether it could use these new resources to supplement or perhaps replace some of its El Paso FT capacity. The consideration of alternative capacity resources is an important aspect of Southwest's gas supply planning, but it has no direct impact on Southwest's procurement of commodity gas supplies unless and until Southwest is able to acquire some alternative capacity on an economical basis.

Southwest is participating in a proposed Transwestern project that would include the construction of a new lateral from Transwestern's mainline to the Phoenix metropolitan area. If this project is built, service would not begin until the fall of 2008 at the earliest. The Transwestern capacity would provide Southwest with an alternative to El Paso for part of its Arizona load.

Southwest's Commodity Gas Procurement

Southwest maintains a separate portfolio of commodity gas purchases for its Arizona service territory. The shape of this portfolio is illustrated in Table 2, which is a chart showing Southwest's planned Arizona Supply-Demand Balance for the 2005/2006 gas year. Southwest's portfolio for its Arizona commodity purchases has five major components.

- **Fixed price purchases** for the Arizona Price Stability Program (APSP)

  The APSP is designed to help stabilize the gas costs for Southwest's "core customer" residential and small commercial gas sales load. In the past,

Southwest has implemented the APSP with fixed price gas purchase contracts having terms ranging up to 12 months. These fixed price contracts have been baseload contracts with must-take provisions. Southwest's fixed price purchases for the APSP were 50% of Southwest's forecasted core customer load of 59 Bcf for the 2005/2006 gas year. Fixed price purchases for the APSP were approximately 61% of Southwest's actual total purchases for the 2004/2005 gas year.

- Term contracts for **firm baseload supplies** — winter season

  Southwest also purchases some baseload supplies at prices reflecting current gas market conditions for first-of-the-month purchases. During the winter season, Southwest uses firm contracts with terms up to five months in length to ensure that these supplies will be available. Pricing is index-based. Some of the term contracts for baseload supplies also have limited monthly swing capabilities. Southwest's monthly baseload purchases under its winter season term contracts were approximately 4% of Southwest's total purchases in the 2004/2005 gas year.

- Term contracts for **peaking supplies** — winter season

  As indicated in Table 1, there is a very wide range between the highest daily load that may occur in a winter month and the lowest daily load in that same month. Southwest cannot make baseload purchases for more gas than the lowest daily load that may occur during the month, because baseload purchases flow at a constant daily rate for the entire month, but Southwest must still be prepared to serve the highest daily load. To obtain the needed flexibility in its daily purchase quantities, Southwest obtains contracts that allow it to adjust its purchase quantities on a daily basis. The supplies purchased under these contracts are called "peaking supplies." As indicated graphically in Table 2, Southwest relies on its peaking supplies for more than half of the maximum daily load that it prepares to serve in each winter month.

  Southwest's contracts for peaking supplies are firm contracts for the winter months. Under each contract, Southwest has the right to nominate a purchase quantity from zero up to the maximum contract quantity on each day. Some of the peaking supplies are shown in Table 2 as "Late Cycle Peaking" because they are purchased under contracts that allow Southwest to adjust its daily nomination after the gas day has begun. These "intra-day" nominations enable Southwest to respond to weather and other load changes as they occur, even within a single gas day.

  Southwest's contracts for peaking supplies have index-based commodity charges, often accompanied by demand or inventory charges to support the swing features.

For the 2004/2005 gas year, Southwest used its peaking contracts for approximately 16% of its total commodity purchases. The commodity volume of Southwest's peaking supplies is much smaller than the commodity volume of Southwest's APSP and other baseload supplies (64%, as noted above), despite Southwest's reliance on peaking supplies for more than half of its daily supply availability, because the actual load on most days is much closer to the minimum load served with baseload contracts than it is to the maximum daily load that Southwest is prepared to serve. Southwest therefore uses its peaking contracts at a low load factor, whereas the baseload contracts are — by definition — used at a 100% load factor in each month.

- Monthly **baseload supplies** purchased at current (**spot**) prices — summer

  During the summer, Southwest purchases some baseload supplies at current market prices (in addition to the fixed price purchases in the APSP) under one-month contracts. These monthly baseload purchases are included in the "Spot" supply category in the chart in Table 2. Southwest's baseload supplies in the summer months were approximately 11% of Southwest's total purchases in the 2004/2005 gas year.

- Daily **spot purchases** for swing supplies — summer

  During the summer, when daily load variations are not so large as in the winter months, Southwest matches its daily supply to its daily loads by making daily purchases in the spot market. Southwest makes some of these purchases at negotiated (fixed) prices, and some at index-based prices. Daily spot purchases were about 8% of Southwest's total purchases in the 2004/2005 gas year.

Term Structure of Southwest's Portfolio

Southwest obtains term contracts for all of the commodity gas supplies that it purchases during the winter season, but it relies on monthly and daily purchases in the spot market for about half of the gas it purchases during the summer season. These arrangements are consistent with the practice of other LDCs. A useful report of the purchasing practices of other LDCs is the American Gas Association (AGA) annual survey of the winter season gas commodity purchasing arrangements used by its members. The AGA published its report of the 2005 survey on July 19, 2005 as Energy Analysis report EA 2005-01, "LDC Supply Portfolio Management during the 2004-2005 Winter Heating Season" (*2005 AGA Survey*). This report is attached as Appendix B.

In the *2005 AGA Survey,* slightly more than half the respondents indicated that they did not obtain any of their gas supplies for the peak month using monthly or daily contracts, which indicates that reliance on term contracts (more than one month) is the standard industry practice for the winter season. The *2005 AGA Survey* did not collect data on the term structure of commodity purchase arrangements for the summer season, but a

reduced reliance on term contracts for summer purchases is typical of LDCs with which the author is familiar.

Baseload and Daily Purchases

Southwest's reliance on extensive use of peaking supplies (in winter) and daily spot purchases (in summer) is atypical, but it is a direct and necessary consequence of Southwest's portfolio of capacity resources. Most LDCs use storage withdrawals as the primary "swing" supply in the winter, and they do not require large day-to-day variations in their purchase quantities. In summer, they achieve the same stability of daily purchase quantities by swinging their storage injections up on days when loads are relatively low, and swinging injections down on days when loads are higher. Southwest cannot use this portfolio strategy because currently there are no operating natural gas storage facilities serving Southwest's Arizona market area.[1]

Southwest could purchase production-area storage. If Southwest did so, it could reduce its use of peaking supplies in winter and daily purchases in summer, and instead increase its baseload purchases during the summer. Southwest's total winter purchase quantity would decrease, because storage withdrawals would replace some of the purchases, and Southwest's total summer purchases would increase despite the reduction in daily spot purchases. Southwest has analyzed production-area storage proposals in the past, and it has found them to be uneconomic because the price of the storage service exceeds the commodity cost savings that it would have permitted. Most other LDCs have market-area storage, and it provides the added benefit of reduced pipeline transportation capacity costs that Southwest cannot achieve with production-area storage, as explained in the discussion of Southwest's capacity.

Pricing Arrangements for Baseload Purchases

Baseload purchases are purchases that flow at a constant daily rate for an entire month. Southwest, like other gas utilities, makes some baseload purchases on a monthly basis. Southwest also makes some baseload purchases under contracts that extend for more than one month. Contracts that extend for two or more months, up to 12 months, can be called intermediate-term baseload purchases, and they are a staple of Southwest's APSP. Baseload purchases extending for terms longer than one year are long-term purchases. Southwest does not generally make long-term baseload purchases, but Southwest does make intermediate-term baseload purchases at fixed prices for the APSP, with the gas to be delivered as far as 24 months into the future.[2]

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[1] While several Arizona market-area storage projects have been proposed, including two projects from El Paso, none have successfully been developed. Southwest continues to review storage and other infrastructure projects in Arizona for inclusion in its mix of resources.

[2] For example, Southwest might purchase gas in the summer of 2006 for delivery during the winter months December 2007 through February 2008. The term length of such a contract would be only three months, so it would be an intermediate-term contract, but the delivery dates would be approximately 18 months after the contract was negotiated.

Several different pricing arrangements are available for baseload purchases. One method is for Southwest to establish a fixed purchase price with the seller.

A second method is for Southwest to establish a "basis" component of the total price with the seller, and then add the NYMEX component of the total price reflecting the current NYMEX price for the applicable futures contract. The "basis" component of the total price is the difference between the price at Henry Hub in Louisiana, which is the location where physical volumes purchased under NYMEX futures contracts are actually delivered, and the location at which Southwest wishes to make its actual purchase. Basis differentials thus represent the local market conditions that affect the price of gas at specific locations where gas is purchased. Most gas purchase transactions are priced by combining a basis differential with a NYMEX component, either explicitly or implicitly.

If Southwest and the seller fix the NYMEX component of the total price at the same time they agree on the basis, the purchase becomes, in effect, a fixed price purchase. Alternatively, the parties can agree that the NYMEX component will be the settlement price on the last day the applicable month's NYMEX futures contract is traded, or they can establish some other formula for setting the NYMEX component of the total price. A variation on this arrangement is to complete the purchase with a fixed basis and a floating NYMEX component, but allow Southwest to "trigger" the NYMEX component at any time on the basis of the NYMEX price of the applicable month's futures contract at the time of the triggering.

A third major pricing method is index-based pricing. With index-based pricing, Southwest and the seller would agree that the purchase price will be based on a specific published index for first-of-the-month purchases at a specific location, such as the Bondad receipt point on El Paso in the San Juan basin production area. The actual purchase price could be agreed to be the published index, or it could be the index plus or minus a relatively small amount (typically up to a few cents per Dth) agreed upon in the purchase negotiations or obtained as a result of a competitive solicitation by Southwest for index-based bids.

Southwest uses all three of these major pricing methods, making some of its baseload purchases under each method. Some use of fixed prices or NYMEX-based pricing methods is important because these methods provide greater flexibility and an opportunity for Southwest to diversify the times at which its prices -- and especially their NYMEX component -- are established. When Southwest makes an index-based purchase, it must accept a price that is not yet known at the time Southwest commits to the purchase, and the index price that is eventually published will represent gas market conditions on the last trading day or during the last few days of the month prior to the one when the gas flows. The *2005 AGA Survey* indicates that index-based pricing is the principal pricing arrangement used by LDCs for monthly purchases. Southwest's reliance on fixed price contracts for most of its baseload purchases is a direct consequence of the relatively large size of the APSP, which is discussed below as an aspect of Southwest's price risk management arrangements.

In procuring baseload commodity gas supplies, it is important for the utility to engage in a competitive process, and Southwest does so. Southwest uses bid solicitations to obtain the best (*i.e.,* lowest) basis for its fixed price purchases, including those under the APSP. Southwest uses informal solicitations or the Intercontinental Exchange (ICE) trading platform to obtain NYMEX-based or index-based contracts for its monthly purchases. These procurement methods are consistent with the practices of other gas utilities.

Pricing Arrangements for Swing and Daily Spot Purchases

A swing purchase is a purchase contract covering one or more months, but with a contractual right for Southwest to nominate or change the purchase quantity on a daily basis. Southwest calls its swing purchases "peaking supplies," and that is the rubric under which they have been identified as part of Southwest's portfolio for its winter season purchases.

A daily purchase is a purchase of gas supplies to be delivered on a single day, or sometimes for more than one day but less than an entire calendar month. The difference between a swing purchase and a daily purchase is that the swing purchase contract is arranged in advance, whereas a daily purchase is arranged on an *ad hoc* basis when Southwest is ready to purchase the gas, typically the day ahead of the day the gas is to be delivered.

Two pricing arrangements are available for daily purchases -- fixed prices, and index-based prices. They are similar to the fixed price and index-based pricing arrangements for baseload purchases. The only important difference is that index-based prices for daily purchases are related to a published index of daily gas transaction prices, whereas the index-based prices for baseload purchases are related to published indexes of first-of-the-month prices. NYMEX-based pricing is not available for daily purchases because the NYMEX trades gas futures contracts only for baseload monthly purchases.

Southwest uses both of the available pricing methods for its daily purchases, sometimes negotiating a set or fixed price, and sometimes purchasing at an index-based price. This practice is consistent with the practices of other gas utilities.

The commodity pricing arrangement for swing purchases is generally index-based. Fixed price arrangements are not generally available because a swing purchase contract is, in effect, an option -- but not an obligation -- for Southwest to purchase gas on any day of the month or months covered by the swing purchase contract. If the price were fixed in advance, Southwest would exercise its option to nominate the full purchase quantity on days when the market price exceeded the contract price, causing a loss for the seller. On days when the market price was less than the swing contract fixed price, Southwest would not nominate any swing contract purchases, and would instead make a daily purchase in the market. The use of index-based pricing assures

that Southwest will each day pay a price bearing some relationship to the market value of the gas that it nominates for purchase under the swing contract.

Southwest obtains swing purchase contracts sufficient to provide the daily supplies that it will need during the winter season, to ensure that these swing supplies are available when and as needed, especially on cold days. As explained above, this arrangement is consistent with the practice of other gas utilities. Swing purchase contracts often involve modest demand charges to compensate the seller for standing ready to provide the full contract quantity every day of the contract term, even though the seller has no assurance that it will actually sell any gas because Southwest can choose to nominate zero purchases every day. Swing contracts may also have small commodity price premiums above the published index for any quantities actually nominated. Southwest uses solicitations to obtain the best available terms -- lowest demand charges, and smallest commodity price premiums -- for its swing purchase contracts. The use of solicitations is consistent with the practice of other gas utilities.

Price Risk Management and the Arizona Price Stability Program

Price risk management is an attempt to avoid the unexpectedly high purchased gas costs that occur when gas prices reach unexpected heights. Price risk management necessarily involves some costs, because there is no "free lunch" in the market for natural gas. The most common way of "paying" for price risk management is by sacrificing some of the opportunity to benefit from unexpected gas price decreases. Price risk management is not -- and cannot be -- a strategy to achieve uniformly lower gas costs under all market conditions, because there is no such magic strategy.

Southwest manages its gas price risks by purchasing approximately half of its projected normal weather requirements under fixed price contracts with prices established (*i.e.*, fixed or set) up to 24 months in advance of the time Southwest receives the gas. Southwest thus avoids the risk of unexpected gas price increases on half of its purchases, because the prices for those purchases are fixed -- and therefore known -- in advance. But this arrangement also sacrifices the opportunity to gain from any unexpected gas price decreases on those same fixed price purchases. The effect of this fixed price purchase program is therefore to provide some stability for Southwest's purchased gas costs, and the fixed price purchase program is aptly called the Arizona Price Stability Program, or APSP.

As noted above, price stabilization does not achieve uniformly lower gas costs. But it does tend to reduce gas costs in a rising gas market. The price that Southwest pays for its fixed price purchases reflects the gas market conditions at the time the fixed price contract was established, which is (on average) about 12 months before the gas is received. In a rising gas market, prices from last year are lower than current prices, and a price stability program thus achieves lower purchased gas costs. But in a falling market, a price stability program tends to yield higher prices, because the benefit of the falling prices cannot immediately affect the supplies already purchased in advance of delivery under fixed price contracts.

The evaluation of Southwest's APSP involves three principal issues. The first is the size of the program, which for Southwest is approximately half of its projected total normal weather requirements. The second is Southwest's decision to fix the prices of some gas purchases in advance of delivery, rather than use other possible price risk management strategies. The third is Southwest's use of fixed price purchase contracts as the instruments for fixing the price of the purchases included in the APSP.

Size of the APSP -- Southwest's use of price protection for 50% of its projected annual purchases is towards the high end of the spectrum of typical commodity purchasing practices. A more typical strategy is to obtain price protection (using fixed price purchases, financial instruments, or a combination) for approximately 50% of the planned normal weather flowing gas purchases in the winter season, with less price protection (often none) for gas purchased in the summer season. Fixed price purchase programs that apply only or primarily to the winter season are common in Maryland, Michigan, and Pennsylvania, and only in Michigan is the fixed price purchase target typically set as high as 50% of projected normal weather purchases in the winter season. The *2005 AGA Survey* reports that fewer than half of the respondents used fixed prices for any of their purchases under long-term or mid-term contracts, and only one-fourth used fixed prices for at least 25% of their mid-term contract purchases. On the other hand, the same survey also indicated that 70% of the respondents used financial instruments to hedge some of their purchases for the 2004-2005 winter season, and almost half of all the respondents hedged up to 50% of their winter purchases.

The relatively large size of Southwest's APSP reflects Southwest's atypical commodity supply situation, which is in turn a direct consequence of Southwest's lack of seasonal gas storage resources in its gas supply portfolio. Other gas utilities automatically obtain greater pricing diversity than Southwest because their commodity purchases are spread more evenly throughout the year than Southwest's purchases. They obtain this diversity by purchasing part of their winter delivery requirements in the summer months and injecting those summer purchases into seasonal storage. Seasonal storage also improves price stability for supplies used during the winter season, because the cost of gas in storage is established at the time it is injected and therefore known before the winter season begins. Southwest's purchases, in contrast, are concentrated in the winter season because they must match Southwest's seasonal load pattern. Southwest's extensive use of fixed price purchases, in both the summer and winter, helps to offset the absence of storage resources.

Alternative price risk management strategies -- Southwest's use of fixed price purchase arrangements is not the only possible way to manage price risk. The principal alternative is the purchase of call options. The holder of a call option has the right -- but not the obligation -- to purchase gas at the "strike price" of the option. The advantage of a call option is that the holder can benefit from any unexpected gas price decreases, whereas the holder of a fixed price purchase arrangement is obligated to purchase gas at the price fixed in advance, even if market prices decline between the time the price is

fixed and the time the gas is to be delivered. The disadvantage of a call option is that it involves an up-front (and non-refundable) cost to purchase the option itself.

When an LDC uses call options for risk management, it typically uses them to protect against large, and therefore unlikely, gas price increases. It is therefore common for most of an LDC's call options to expire without being exercised, but that does not mean that the LDC's initial purchase of its call options was unwarranted.

An alternative way to offset the cost of purchasing a call option is to write (*i.e.,* sell) a "put" option. A put option obligates the writer to purchase gas at the specified strike price if the holder of the option chooses to exercise it, but the writer of the option has no right to demand that gas. The combination of a put option and a call option is called a gas price "collar." For example, if the NYMEX futures price for gas to be delivered in February 2008 is $10.00 per Dth, an LDC could purchase a call option with a strike price of $11.50 and write a put option with a strike price of $9.00 per Dth. The LDC would end up paying the market price if it remained in the range between $9.00 and $11.50 per Dth; but it would exercise its call option and pay only $11.50 if the market price rose above that level; and it would be obligated to purchase at $9.00 if the market price fell below that level. The LDC's purchase price would be collared in the range from $9.00 to $11.50 per Dth.

When the cost of a call is completely offset by the proceeds from the sale of a put, it is called a "costless collar." Costless collars are typically asymmetric relative to prevailing market prices and, as a result, they require the consumer to bear more upside price risk than the potential benefit from falling prices. For example, if the NYMEX futures price for gas to be delivered in January was $12.00 per Dth, a costless collar may result in a range of $11.50 to $15.00. The LDC could participate in falling prices up to $0.50 per Dth but would be exposed to price increases up to $3.00 per Dth. Under present gas market conditions, collars that are reasonably symmetric around the current NYMEX futures price still require a cash outlay by the LDC, because the price (cost) of the call option exceeds the sales price received by the LDC for the put option. Even with an asymmetric collar, like the asymmetric example in the preceding paragraph (with the put option strike price closer to the current NYMEX futures price than the call option strike price), reasonably structured collars tend to involve an up-front purchase cost.

The opinion of the author is that an LDC should use fixed price purchase arrangements as the foundation for its price risk management program. The use of call options or collars is not necessary. If an LDC uses them, it should only be as a relatively small supplement to a fixed price purchase program. The only advantage of a call option is that it preserves the opportunity to benefit from gas price decreases. But if an LDC does not have any fixed price contracts, then it will obtain the benefit of any gas price decreases on 100% of its purchases. Sacrificing part of this benefit by entering into some fixed price purchase arrangements is the least painful way to pay for protection against the risk of gas price increases, and in the author's view it is far better than incurring an out-of-pocket cost for protection. On the other hand, if an LDC already has fixed the prices for a substantial portion of its projected purchases, then it has obtained

its upside price protection by trading away the opportunity to benefit from any price decreases on those purchases. If further protection against upward price movements on an even larger fraction of the projected purchases is desired, such protection may justify the use of call options.

The author is not aware of any compilations or reports of the extent to which gas utilities use call options or collars (as opposed to fixed price purchase arrangements) for price risk management. In the author's experience, LDCs that use call options or collars do so for only a relatively small fraction of their projected purchases, typically around 10% or less. All of the LDCs that obtain price protection for as much as one-fourth of their winter purchases use fixed price purchase arrangements as their primary price risk management strategy.

Price risk management tools, and the use of financial instruments instead of fixed price purchase contracts -- Fixed price purchase contracts are not the only way for an LDC to establish fixed price gas purchase arrangements. Alternatives include various financial instruments that hedge future purchase prices in ways that enable Southwest to achieve the same result as it would with a fixed price gas purchase contract. For example, some financial intermediaries and other gas market participants will "sell" the to-be-published index price for some future month (such as February 2008) at a specified purchase location (such as the Bondad receipt point on El Paso in the San Juan basin production area) for a fixed price. If Southwest purchases this "swap" as a hedge against a future gas purchase, it has the same effect as entering into a fixed price contract now for delivery of the gas in the specified future month. Southwest pays the published index price for its actual purchase, but it receives the same published index price from its swap arrangement and pays the fixed price that it obtained when it first entered into the swap transaction.

Another alternative is the use of NYMEX futures contracts as hedges. Instead of purchasing the gas that it actually plans to receive in a future month, Southwest can purchase a NYMEX futures contract for the delivery of a corresponding quantity of gas at Henry Hub in Louisiana, which is the physical delivery point associated with all NYMEX gas futures contracts. Then, when Southwest purchases the gas that it actually plans to receive, typically in the week or two before the month when the gas is to be delivered, Southwest sells the NYMEX contract at the same time. Southwest's net cost from the two transactions is the cost of its actual purchase, less the sales price of the NYMEX on the same day as Southwest's actual purchase, plus the price at which Southwest originally purchased the NYMEX futures contract. The difference between the first two of these three components is the so-called "basis" for the location where Southwest actually purchases its gas (relative to Henry Hub), so Southwest's total cost for the purchase is the original cost of the NYMEX futures contract plus the current basis at Southwest's actual purchase location, typically in the Permian or San Juan basin gas production areas. The NYMEX futures contract is a good hedge against this purchase price because the basis differentials for the Permian and San Juan basin production area receipt points are subject to much less market price fluctuation than the NYMEX itself, so the purchase of a NYMEX futures contract removes most of the price

risk from the future purchase of gas even in the Permian or San Juan basins. To "perfect" the hedging arrangement, Southwest could use a "basis swap" to lock in the basis differential between the NYMEX contract and the market area, in this case the Permian or San Juan basin. The basis swap protects against a basis blowout where prices in the purchase area rise much more than the NYMEX contract. A good example occurred during the winter of 2000-2001, when gas prices at the California border were significantly more volatile than at the Henry Hub.

Southwest is considering the use of financial instruments such as NYMEX futures contracts and swaps instead of fixed price purchase contracts for at least part of the APSP. If Southwest makes this change, the price hedging arrangements for the APSP would be divorced from the commodity purchases being hedged, and the commodity purchases for the APSP volumes would be moved into one or more of the other categories of Southwest's commodity purchases. A change in this direction is consistent with the practices being adopted by some of the more forward-looking LDCs at this time. The *2005 AGA Survey* indicated that slightly more than one-fourth of the respondents used swaps and slightly less than one-fourth used NYMEX futures contracts as hedges for some of their 2004-2005 winter purchases. These figures probably overstate the use of hedges to achieve the equivalent of fixed price purchases because some LDCs may have responded affirmatively as using both swaps and NYMEX futures, and some of the respondents may have been using swaps for purposes other than achieving the equivalent of fixed price purchases.

In the author's experience, several LDCs have within the past two years adopted or proposed plans to use financial instruments rather than fixed price gas purchase contracts to hedge their future purchases and achieve the equivalent of fixed price purchases. The author has generally supported these proposals in the proceedings in which they have been presented.

Financial instruments have two advantages over fixed price gas purchase contracts as price hedges. The first is that a fixed price gas purchase contract can only be used to purchase baseload supplies that flow at a uniform daily rate throughout the delivery month. Financial instruments, in contrast, can also be used to hedge swing or peaking supplies, because the hedging arrangements are divorced from the actual gas purchase contract. Of course, the financial instrument hedges only the first-of-the-month price, and the LDC is still subject to the risk of daily price fluctuations during the month.

The second advantage of using financial instruments is that it can help to reduce the risk of counter-party default. With a fixed price gas purchase contract, Southwest is dependent upon the survival and eventual performance of the seller. If Southwest uses NYMEX futures contracts for its hedges, then the counter-party bearing the performance risk is the NYMEX itself, which is most likely a safer arrangement than a fixed price gas purchase contract. Even with a swap, Southwest probably has the opportunity to be more selective about the identity of the counter-party than with a fixed price gas purchase contract.

Summary and Conclusion

Southwest's purchasing practices are generally consistent with the practices of well-managed gas utilities. Southwest employs a variety of different gas purchase contract term lengths, contract "shapes," pricing arrangements, and risk management tools for its commodity gas purchases. Some of Southwest's purchases are for terms as short as one day, others for terms as long as 12 months. Some of the purchases with terms of one or more months are baseload purchase contracts; others have swing provisions for Southwest's peaking supplies.

Southwest uses a competitive bidding process to secure fixed price and term contracts. Term supplies are obtained through an annual solicitation process which encourages the participation of a broad base of suppliers. Fixed price purchases for the APSP are acquired on a periodic basis, generally every four to six weeks, through a competitive bidding process. Southwest secures spot supplies through informal solicitations via the telephone or electronic medium (like email or instant messaging) or the ICE trading platform. All of these procurement methods are consistent with the practices of other gas utilities.

Southwest manages gas price risks through its APSP. In the APSP, Southwest purchases half of its commodity supplies under fixed price arrangements established at least a month in advance of the delivery date for the gas, and it arranges some of its fixed price purchases as much as 24 months in advance of delivery. Southwest's use of a price risk management strategy is consistent with the practice of most other gas utilities, but not all utilities make such extensive use of fixed price contracts. The large size of Southwest's APSP relative to other gas utilities is due to the lack of storage resources in Southwest's portfolio. Production-area storage would not benefit Southwest operationally, and at present there are no market-area storage facilities available to serve Arizona.

In the future, Southwest may wish to expand its APSP to include the use of financial instruments along with fixed price contracts. Some common instruments include price swaps, put and call options, NYMEX future contracts, and basis swaps. The use of these instruments, in a properly structured risk management program, may help Southwest to further reduce the short-term price volatility in its supply portfolio.

The other half of Southwest's purchases use pricing arrangements that reflect current gas market conditions at the time the gas is delivered. Southwest negotiates the prices for some of those current purchases, and it uses index-based pricing for other purchases. Southwest determines the relative importance of each of these different constituents of its commodity gas portfolio to match the loads that it serves at the best cost available within the constraints of the portfolio of pipeline transportation resources that Southwest uses to bring its commodity gas purchases to its Arizona city gates.

Table 1 - Projected Normal Weather Loads, November 2006 – October 2007
Southwest Gas Corporation, Arizona Service Area
(Volumes in Dekatherms (Dth))

	Projected Monthly and Seasonal Loads	Projected Average Daily Load	Projected Maximum Daily Load (Design Day)	Projected Minimum Daily Load	Projected Minimum as Percent of Average	Swing Requirement (Maximum Load Less Minimum)
November 2006	6,053,105	201,770	382,778	162,082	80%	220,696
December	9,847,886	317,674	604,204	165,948	52%	438,256
January 2007	9,571,375	308,754	627,248	166,964	54%	460,284
February	7,558,226	269,937	579,790	166,721	62%	413,069
March	6,601,901	212,965	441,730	166,094	78%	275,636
April	4,724,456	157,482	246,814	146,531	93%	100,283
May	3,749,076	120,938	162,059	119,678	99%	42,381
June	3,243,596	108,120	109,386	108,068	100%	1,318
July	2,991,128	96,488	96,488	96,488	100%	0
August	2,981,239	96,169	96,191	96,169	100%	22
September	3,021,000	100,700	101,002	100,700	100%	302
October	3,866,051	124,711	226,950	117,155	94%	109,795
Annual total	64,209,039	175,915	627,248			
Winter season total (November – March)	39,632,493	262,467	627,248		63%	

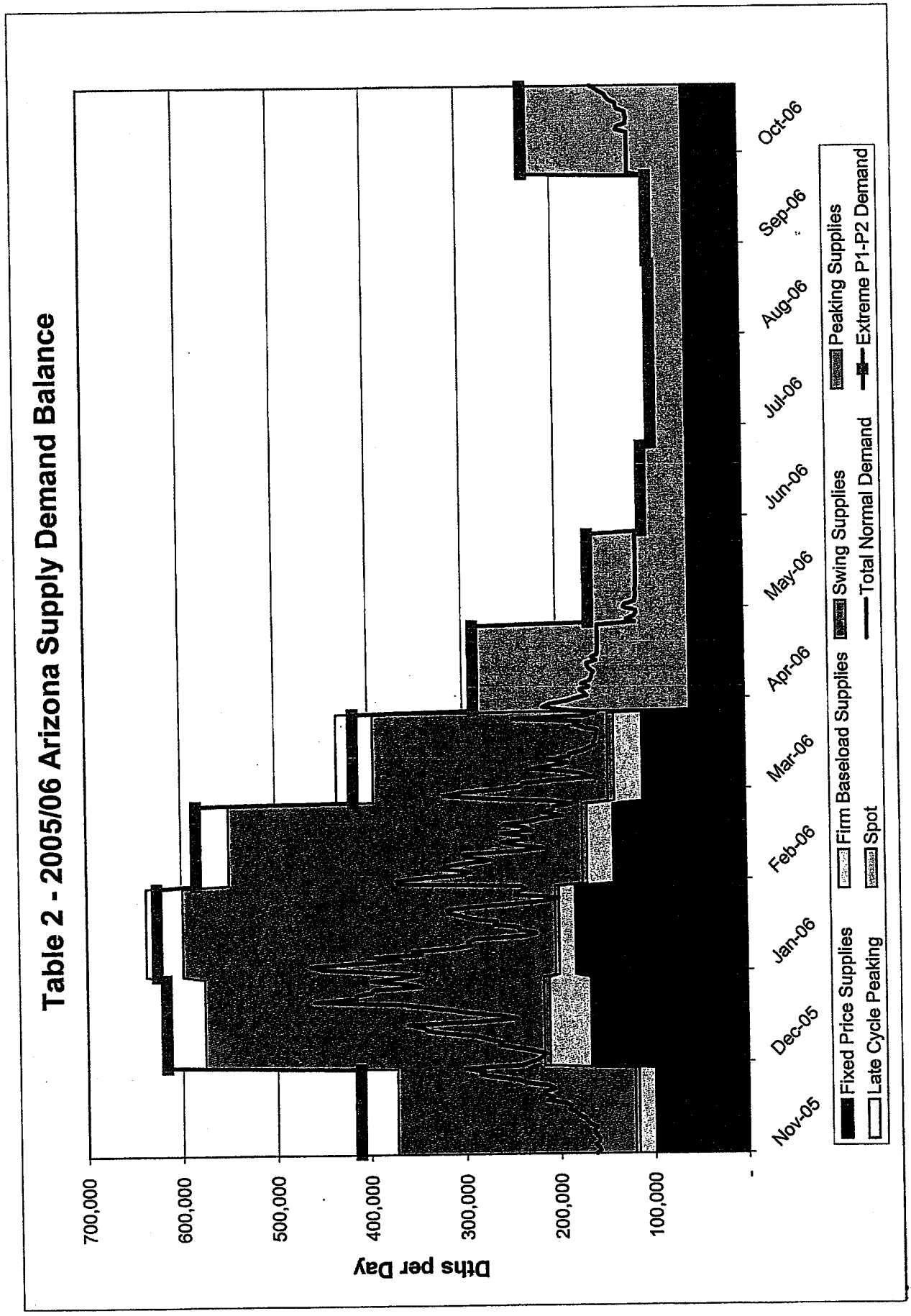
Table 2 - 2005/06 Arizona Supply Demand Balance
Dths per Day
700,000
600,000
500,000
400,000
300,000
200,000
100,000
-
Nov-05
Dec-05
Jan-06
Feb-06
Mar-06
Apr-06
May-06
Jun-06
Jul-06
Aug-06
Sep-06
Oct-06
Fixed Price Supplies
Firm Baseload Supplies
Swing Supplies
Peaking Supplies
Late Cycle Peaking
Spot
Total Normal Demand
Extreme P1-P2 Demand

Qualifications of Ralph E. Miller

Ralph E. Miller is an independent consulting economist who works in the fields of regulatory economics, industrial organization, and public policy towards business. He has more than 30 years of consulting experience in the public utility and energy sectors of the economy, and several additional years in government and on the faculty of a major university. He specializes in energy supply and demand analysis, especially natural gas supply and distribution; antitrust and market structure analysis, including the introduction of competition into previously regulated areas; public utility ratemaking, especially gas and electric utility cost allocation and rate design; and the economics of regulation. He is the author of several published reports and papers in these areas.

During the past 30 years, Mr. Miller has presented expert testimony in more than 300 public utility rate cases and other proceedings before the FERC and other federal agencies, U.S. District Court and state courts, and more than two dozen state regulatory commissions. Over the years, he has addressed almost all the aspects of gas and electric utility regulation, including rate of return, accounting and revenue requirements, rate design and cost of service, electric fuel and purchased gas cost recovery, industry structure and the role of competition, incentive ratemaking and other types of innovative rate designs, gas and electric supply planning and power plant licensing, productivity and efficiency, and the determination of marginal, incremental, and avoidable costs.

Mr. Miller has more than 25 years of experience in gas procurement analysis. He has reviewed the gas supply planning and/or gas cost recovery arrangements of more than 15 gas distribution companies (LDCs) in numerous regulatory proceedings in seven states, and he has extensive experience in gas pipeline cases at the FERC.

Mr. Miller has been an independent consultant for twenty years. He also has ten years of experience as president or vice president of two different consulting firms specializing in public utility and energy matters. Before that, he spent three years in the federal government, where he was employed in positions at the Federal Power Commission (now the Federal Energy Regulatory Commission, or FERC), the Antitrust Division of the U.S. Department of Justice, and the Federal Energy Administration (now part of the U.S. Department of Energy, or DOE). He was on the faculty of the University of California for three years, where he taught economics courses at both the graduate and undergraduate levels.

Mr. Miller did his undergraduate work at Harvard College, where he received the A. B. degree *summa cum laude* in mathematics in 1961, and he was elected to Phi Beta Kappa. He then went on to graduate work in economics at Harvard, where he received a Master's degree in 1963. He continued his graduate studies there until 1966, and he completed all of the course requirements for the Ph.D. degree, but not a doctoral dissertation.

Mr. Miller has been working on gas supply planning and purchased gas cost recovery cases since prior to 1980, and he has concentrated his attention on these areas since 1990. Beginning in 1981, he analyzed the way Southern Union Gas Company acquired gas supplies for its New Mexico distribution system, and he testified on aspects of this subject in U.S. District Court in 1982.

At the FERC, he reviewed requests by three interstate pipelines for recovery of take-or-pay buyout and contract reformation costs under Order No. 500. He has also testified in many pipeline rate proceedings and two pipeline gas inventory charge proceedings, and he reviewed the gas supply restructuring plans proposed by two pipelines as part of their Order 636 compliance. He also reviewed the implementation of Order 637 by two pipelines.

At the state level, he (along with one or more colleagues) has performed many management/performance audits of the gas purchasing practices and policies of gas distribution companies in Ohio, and the reports on these audits were submitted to the Public Utilities Commission of Ohio (PUCO). The companies that he has audited include three of the major LDCs in Ohio.

In Michigan, he has reviewed and testified on the gas supply plans and gas cost recovery (GCR) reconciliations of Consumers Energy Company and Michigan Consolidated Gas Company in each year since 1988, except for the three years when their GCR clauses were suspended. He has also reviewed and testified on many of the gas supply plans and GCR reconciliations of the other LDCs in Michigan during this period.

In New Jersey, he participated in the levelized gas adjustment clause (LGAC) proceedings as a consultant to the Ratepayer Advocate (or its predecessor, the Public Advocate) for ten years. He reviewed the LGAC filings and gas supply planning of each of the four New Jersey LDCs at least once during this period. He also participated extensively in the consideration of gas cost recovery issues in the unbundling proceedings and base rate cases of the New Jersey LDCs.

In Maryland, Mr. Miller has for more than 25 years been reviewing the gas supply planning and gas purchases of several Maryland utilities, including Baltimore Gas and Electric Company and Washington Gas Light Company, in a variety of proceedings. Other states in which he has done similar work include Pennsylvania, Nevada, and Utah.

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LDC SUPPLY PORTFOLIO MANAGEMENT DURING THE 2004 - 2005 WINTER HEATING SEASON

I. Introduction

As with the prior winter, the issue for consumers and local distribution companies (LDCs) purchasing natural gas during the 2004-2005 winter heating season (WHS) was not its availability but its cost. With supply and demand relationships in the market remaining tight, most pressure on commodity prices was upward pressure. In fact, to begin the winter heating season the NYMEX close (October 27, 2004) for November 2004 futures contracts was $3.17 per MMBtu higher than the November close one year earlier.

Even with that backdrop, natural gas supplies remained relatively strong throughout the 2004-2005 winter. A review of gas supply sources shows that underground storage exceeded the five-year average for inventories at winter's end, domestic production appeared to sustain itself and LNG was in the process of setting another annual record for imports (now accounting for about three percent of available supply). Still, market prices (at $6.00-7.00 per MMBtu and more) seem to point to high level issues for the longer-term regarding natural gas supply -- and questions emerge. For example, if increasing gas supply and infrastructure in the form of LNG (or even pipeline gas from Alaska) is viewed as a positive element for mitigating price volatility and possibly the absolute price level for gas consumers, how can the infrastructure be developed without long-term commitments to support such projects? Are purchasing practices beginning to demonstrate changes in contracting terms or lengths and are more companies using financial or other instruments to protect gas consumers from market price fluctuations?

This analysis describes critical elements of the 2004-2005 WHS and reports the results of the *Winter Heating Season Performance Survey*, which was conducted under the guidance of the AGA Gas Transportation and Supply Operations (GTSO) Task Force. Data for this report were acquired by surveying AGA member local distribution companies and concentrate on defining peak-day and peak-month supply practices, as well as certain regulatory and market hedging practices.

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This year, responses (whole and part) were received from 54 LDCs with service territories in 30 states. Ten of the companies have service territories west of the Mississippi River, while the balance of the companies that responded are located in the east. The sample companies had an aggregate peak-day sendout of 43,391,052 Dekatherms (Dth), acknowledging that the peak-day did not occur on the same calendar day for each company. However, these same companies planned for an aggregate peak-day of 54,200,554 Dth, meaning only 80 percent of the planned peak volume for sendout was actually required during the 2004-2005 WHS. This is the second year in a row that the sample company actual peak-day sendout was only 80 percent of the design peak-day for the companies supplying responses to the winter heating season survey.

A list of companies returning surveys for this year's study is shown in Appendix A. The purpose of the survey is to document some gas delivery system operations during the past winter season and to provide insights into gas supply trends and procurement portfolio management. *The aggregated data presented in this report is in no way to be interpreted as establishing standards or best practices for gas supply management.* It is instead a snapshot of supply practices. In some cases, the report compares survey results for the 2004-2005 winter heating season with those reported in prior years. *It should be noted, however, that the compared samples are not identical and the data are not normalized in order to compensate for sample differences, weather or other factors.*

II. Executive Summary

The foundation for this report comes from survey responses submitted by 54 AGA member LDCs (compared to 43 one year ago). These companies had a non-coincident peak-day sendout of 43 million Dth and an average peak-day sendout of 803,538 Dth per company. The 54 companies reporting represent about 45 percent of the gas delivered by all AGA member companies during an annual period. Results of the winter heating season survey are generally presented as counts of companies that fit into percentage based categories (1-25 %, 26-50 %, and so forth) of supply volumes. The intent of this report is to document the data as a snapshot of current supply behavior by large purchasers of natural gas, in this case LDCs.

Weather

- Each month of the 2004-2005 winter heating season was warmer-than-normal, with the exception of March 2005, which was 5.1 percent colder-than-normal. For the period October 2, 2004 - April 2, 2005, heating degree day totals were 6.0 percent fewer-than-normal and thus the winter was warmer-than-normal on average for the nation as a whole.

- A view of heating degree days by region yields similar results. Only New England was colder-than-normal (1.2 percent), while every other region of the country was warmer for the 2004-2005 winter heating season. The central portion of the country was warmest when compared to normal for the cumulative winter heating season.

- For the country as a whole, temperature conditions were 6.0 percent warmer-than-normal and compares to the prior winter heating season (October 2003 – March 2004) when conditions were nearly the same – 5.0 percent warmer-than-normal.

Gas Supply Portfolios

LDCs build and manage a portfolio of supply, storage and transportation services, which include a diverse set of contractual arrangements to meet anticipated peak-day and peak-month gas requirements. For the 2004-2005 winter, sample companies planned for over 54 million Dth of required peak-day gas throughput but only 80 percent of that volume was actually required.

- It should be no surprise that purchases moved by firm transportation provided much of the gas to consumers for the peak-day and peak-month. Fifty-three of 54 companies indicated that firm supplies were a part of their gas supply portfolio, including 29 companies that showed between 26-50 percent of their required peak-day volumes coming from firm supplies.

- Forty-six companies indicated that up to 50 percent of peak-day supplies originated from pipeline or other storage, while 34 companies also noted that up to 25 percent of the deliveries arriving at their citygate on a peak-day were earmarked for transportation customers on their system.

- Long-term agreements, defined as one year or longer, were used by 37 of 52 of companies within their peak-day gas supply portfolio (compared to 29 of 41 companies the previous year) and accounted for more than 50 percent of purchased gas for 15 companies on a peak-day (compared to 10 companies the previous year). Mid-term (more than one month, less than one year) agreements were utilized more often than one-month and daily agreements for 2004-2005 peak-day purchases.

- As a general statement, comparing 2004-2005 data to that collected two years ago (2002-2003 winter heating season with 65 companies responding to the survey), daily and monthly contract terms are less prevalent today than two years ago among the survey participants. This may be because recent daily pricing has been high relative to history. It may also be, however, that companies and Public Utility Commissions are becoming more comfortable with longer-term supply agreements as a part of a supply portfolio, remembering that a long-term deal today may be two years not 10 or 15 as in the past.

- When asked to describe the distribution of gas supply purchases among suppliers -- independent marketers, producers and producer marketing affiliates more than any other classes of supply aggregators, were cited by those responding to the winter heating season survey.

Supply Pricing Mechanisms and Hedging Issues

Several factors play a role in the market pricing of natural gas and of transportation services, including weather, storage levels, end-use demand, financial markets and various operational issues. When asked to identify the tools most effective to manage supply and price risk, survey respondents pointed to daily swing contracts, storage and LNG, weather-based calls and options, asset managers, fixed pricing and advanced purchases at fixed prices.

- When examining the purchase practices of companies during the past winter heating season, it is clear that first-of-the-month index pricing dominates the market for long- and mid-term supply agreements. However, this year's survey sample included references to fixed price, daily and other NYMEX-based arrangements.

- For long-term supplies (one year or more), 30 of 49 companies responding used first-of-the-month (FOM) pricing for a portion of their supplies, including 27 companies that used FOM for 51-100 percent of long-term gas purchases. Thirteen companies utilized some form of fixed long-term pricing.

- Mid-term purchases (more than one month, less than one year) were reported by 39 companies to most often be tied to FOM indices for significant volumes of gas. In addition, fixed-price (20 companies) and daily mechanisms (13 companies) were part of the mid-term pricing basket.

- Seventy percent of the companies responding indicated use of financial instruments to hedge at least a portion of their supply purchases. Even though this percentage is identical to last year, three years earlier only 55 percent of the companies responding had indicated the same. For this past winter, twenty-one of 37 companies providing data hedged up to 50 percent of their gas supply purchases during the winter.

- In addition, options (23 companies), fixed-price contracts (18 companies), swaps (16 companies) and futures (11 companies) were most often sited as financial tools used to hedge a portion of gas volumes delivered on a peak-day. This balance is similar to that of last year. The use of financial tools may be understated in this report inasmuch as some volumes delivered to LDCs from marketers and other suppliers are hedged by the third-party rather than the LDC or customer and may have been excluded from the LDC hedging calculation.

- On the physical side, in preparation for the 2004-2005 WHS 47 companies reported using storage as a primary hedging tool. Twenty-nine of those companies hedged between 26-50 percent of winter heating season supplies using underground storage compared to 22 companies last year. Several companies noted that storage (as a physical hedge) is the only hedge they employ, choosing not to use financial instruments at all.

- Companies use a portfolio of timed hedges to balance their approach to strategic price planning. When asked about the timing of hedging strategies, 25 of 38 companies (66 percent) responding indicated that they employ a six-month and less strategy for a portion of their hedges. Thirty-five of 38 companies utilized a 7-12 month strategy for a portion of their hedges, while 19 companies hedged forward for more than 12 months.

- Only seven survey respondents indicated that they used weather derivatives during the 2004-2005 winter heating season. This compares to six companies in 2003-2004 and eight companies during 2002-2003.

- When asked about their own regulatory environment, 37 of the companies responding to the question indicated that financial losses and gains were treated equally within their hedging plans. Only three noted that losses and gains were treated unequally.

- When asked about the relative ease of acquiring hedging products for 6-month or less hedges, thirty-eight companies saw current markets as less difficult or the same as the year before. Thirty-two companies said the same of hedges more than six months in duration. Very few companies indicated market conditions to be more difficult to operate within. This compares to last year's survey when up to a third of the companies viewed markets as more difficult to operate within.

- The majority of companies reported that acquiring financial hedges or implementing a strategy was no more or less difficult than the prior year. Thirty-one of the 54 companies responding indicated that for the 2005-2006 winter heating season they planned to hedge the same as this past winter heating season, eleven companies plan to hedge even more.

Gas Storage

Production and market area storage are key tools for efficiently managing LDC gas supply and transportation portfolios. However, it should be noted that storage practices are no longer dictated only by local utility requirements to serve winter peaking loads. Storage services now support natural gas parking, loaning, balancing and other commercial arbitrage opportunities that take place at market hubs and citygates.

- Forty-nine of 54 companies answering the question indicated that weather-induced demand compelled the respondents to utilize storage services. However, respondents also singled out no-notice requirements (42 companies), pipeline operational flow orders (20 companies), "must turn" provisions (35 companies) and arbitrage opportunities (18 companies) as reasons to maintain storage services within their gas supply portfolio during the 2004-2005 winter heating season.

- Must turn provisions may be in place for some storage contracts as a way to maintain facility integrity through an optimal pattern of injection and withdrawal in a storage field. During the 2004-2005 winter heating season, storage inventories were consistently higher than the prior five-year average. As a result, thirty-five of 54 companies (65 percent) singled out must turn provisions as influencing their use of storage this past winter – eighteen percent more than the prior winter.

- Forty-five of 54 companies used first-of-the-month index pricing to purchase gas for injection into storage with 20 of those companies indicating that 76-100 percent of gas into storage was based on FOM prices. Twenty-one of 54 companies (39 percent) used fixed-price schedules for some portion of their storage purchases – up from fourteen companies (33 percent) the year before. Twenty-five companies indicated that they purchased stored gas in the daily market compared to 18 companies the prior year. A majority of those 25 companies (15) acquired less than 25 percent of storage purchases in the daily market.

- Twenty-five companies indicated that they were actually constructing or examining the potential for physically adding underground storage, while 13 were considering peak shaving facility expansion during the next five years.

- For the nation as a whole, working gas inventories at the end of March 2005 were significantly higher than inventories from one-year prior (by 215 Bcf) and pointed to less gas required for net storage injections during the 2005 refill season.

LDC Transportation and Capacity Issues

Transportation-only customers have assumed a higher profile among all customers served by LDCs. Managing pipeline capacity efficiently is a challenge for many LDC's and can involve the release of capacity to the secondary transportation market.

- From April 2004 to March 2005, 20-26 of the companies (varying with the month) released between one and 25 percent of their pipeline capacity on a monthly basis to the secondary market, when that capacity was not needed to serve LDC customers. As many as 14 companies released between 26 and 50 percent of their capacity during the summer of 2004 compared to only 5 companies in the sample one year prior.

- Although not as active as two years prior when gas storage was under more stress, some operational flow orders (OFO) were issued during the 2004-2005 winter heating season. Twenty-two companies indicated impacts from OFOs. The median number of OFOs issued was 3 with a median duration of 3.5 days.

III. Weather

The 2004-2005 WHS started remarkably similar to the prior winter heating season as shown below in Table 1. For the October-December WHS kick-off, monthly heating degree days were fewer than normal in both years, resulting in warmer-than-normal cumulative conditions entering January. However, while January and February 2004 quickly turned colder-than-normal, January and February 2005 remained decisively warmer and, in fact, February was 10 percent warmer-than-normal for the nation as a whole.

Cumulative heating degree day totals eventually settled at 6.0 percent warmer-than-normal for the 2004-2005 WHS, even after a much colder-than-normal March, while the prior year winter heating season totals for temperature were 5.0 percent warmer-than-normal. For the 27-week period October 2, 2004 to April 2, 2005, only 10 weeks registered colder-than-normal conditions, on a national basis, with four of those weeks coming in March 2005. By winter's end and like the year before, only New England had seen greater heating degree day totals than normal (1.2 percent colder).

TABLE 1

MONTHLY COMPARISON OF NATIONAL HEATING DEGREE DATA
OCTOBER 2003 – MARCH 2005

MONTH	PERCENT CHANGE FROM NORMAL			
	2003 – 2004		2004 – 2005	
October	11.0%	Warmer	13.2%	Warmer
November	10.5%	Warmer	10.2%	Warmer
December	6.8%	Warmer	4.1%	Warmer
January	4.3%	Colder	6.5%	Warmer
February	2.2%	Colder	10.0%	Warmer
March	18.2%	Warmer	5.1%	Colder
TOTAL	5.0%	Warmer	6.0%	Warmer

Source: U.S. Department of Commerce, National Oceanic and Atmospheric Administration.

IV. Gas Supply Portfolios

LDCs build and manage a portfolio of supply, storage and transportation services to meet expected peak-day, peak-month and seasonal gas delivery requirements. The 1992 FERC Pipeline Restructuring rule (Order No. 636) increased competition in the interstate transportation market but introduced new risks to the process of acquiring natural gas and required pipeline capacity. In today's business environment, gas portfolio managers continually attempt to strike a balance between their need to minimize gas-acquisition risks and their obligation to provide reliable service at the lowest possible cost.

Given the reality of significant deviations from normal weather patterns (warm and cold), volatility in commodity prices and regulatory scrutiny of costs to consumers, local gas utility exposure to hindsight for gas supply practices has increased. Also, in some cases, the unbundling of gas sales and transportation services at the retail level have further prompted many LDCs to reassess the quantity of gas supplies they must contract for and at what cost.

Table 2 and Figure 1 illustrate the diversity of gas supply sources available to LDCs. It should be no surprise that purchases moved by firm transportation provided much of the gas to consumers for the peak-day and peak-month. Fifty-three of 54 companies indicated that firm supplies were a part of their gas supply portfolio, including 29 companies that showed between 26-50 percent of their required peak-day volumes coming from firm supplies. An additional eight companies showed 51-75 percent of peak-day supplies to be firm. But other categories of gas supply for peak-day deliveries are also important to the sample of companies.

For example, 34 companies out of 54 indicated that up to 25 percent of their citygate peak-day supplies were earmarked for transportation customers and 43 companies indicated that up to 50 percent of peak-day supplies originated from pipeline or other storage. Eighteen companies indicated on-system storage as a supply source, also. Citygate purchases, local production and LNG or propane-air also provided up to 25 percent of peak-day supplies for 23, 8 and 19 companies out of 54, respectively. The visual impact of Figure 1 demonstrates that very few companies source a supply portfolio with all of their eggs in one basket. The table and figure show that the largest number of companies tend to employ a multiple supply source strategy in increments often amounting to 50 percent or less of their total supply package.

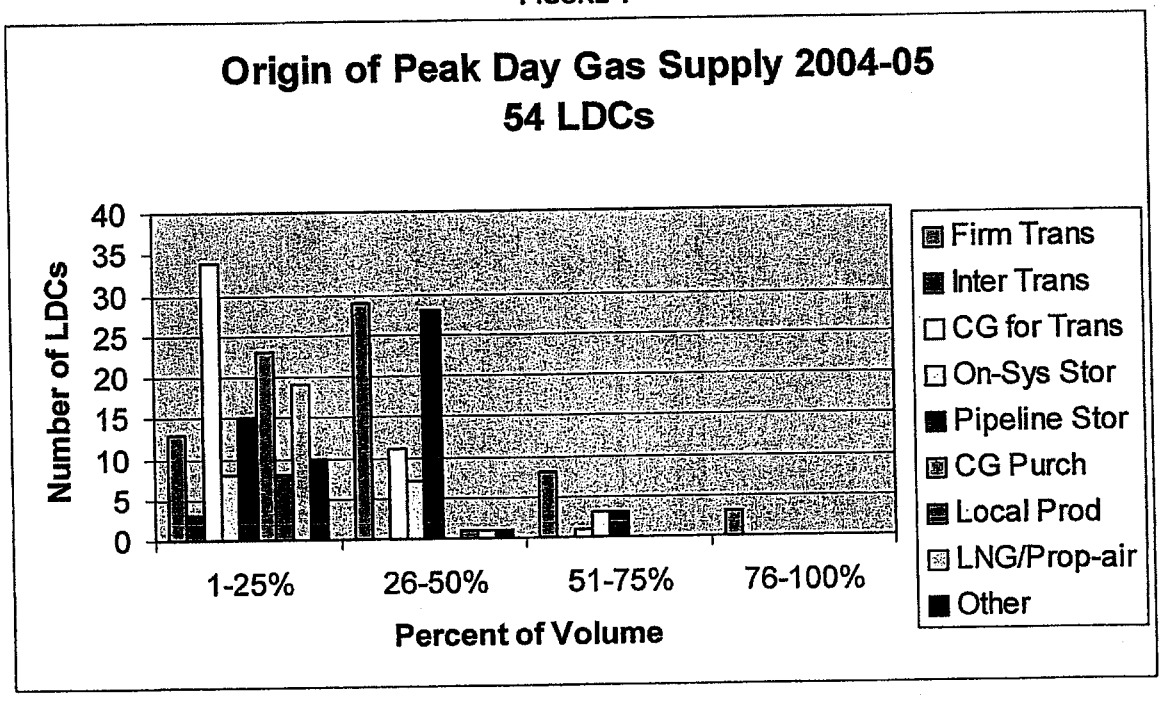
TABLE 2

ORIGIN OF LDC GAS SUPPLY
2004-2005 WINTER HEATING SEASON
(NUMBER OF COMPANIES)

PERCENT GAS SUPPLY	PURCHASES VIA FIRM TRANS	PURCHASES VIA INTERRUPTIBLE TRANS	CITYGATE SUPPLIES FOR TRANS CUSTOMERS	ON-SYSTEM STORAGE	PIPELINE OR OTHER STORAGE	CITYGATE PURCHASES	LOCAL PRODUCTION	LNG PROPANE-AIR	OTHER
PEAK-DAY									
1 – 25	13	3	34	8	15	23	8	19	10
26 – 50	29	0	11	7	28	0	1	1	1
51 – 75	8	0	1	3	3	0	0	0	0
76 – 100	3	0	0	0	0	0	0	0	0
0	1	51	8	36	8	31	45	34	43
PEAK-MONTH									
1 – 25	7	2	22	7	30	19	6	15	4
26 – 50	22	0	19	8	13	0	2	0	2
51 – 75	15	0	0	2	1	0	0	0	0
76 – 100	5	0	0	0	0	0	0	0	0
0	1	48	8	33	6	31	42	35	44

Source: 2004-05 AGA LDC Winter Heating Season Performance Survey.

FIGURE 1



According to Table 2, peak-month supplies were also heavily weighted toward purchases via firm transportation. Like peak-day supplies, peak-month supplies tended to be supplemented with pipeline and on-system storage, citygate purchases, citygate deliveries for transportation customers, LNG or propane-air and even some local production.

The diverse set of contractual arrangements that LDCs use to procure their gas supplies includes long-term, mid-term, monthly, and daily agreements. A mix of contracts allows the LDC to balance between competing needs, such as the obligation to serve its customers as the supplier of last resort and the need to maximize efficiency while minimizing costs. In many cases, longer-term contracts contribute to baseload obligations, while shorter-term contracts allow companies to respond to market changes. In the past, survey results reflected a transition toward shorter-term and spot contracts to meet peak requirements, which has been consistent with demands from consumers, regulators and the market, in order to pursue least cost options. However, recent developments in market volatility, particularly as they apply to natural gas acquisition prices is resulting in a reexamination by consumers and regulators of supply acquisition contracting with less emphasis on absolute least cost and more emphasis on price stability. Stability may mean a trend toward longer-term contracting and some argue that longer-term contracting will be necessary to underpin new supply sources in the future.

As a general observation, comparing 2004-2005 data to that collected two years ago (2002-2003 winter heating season with 65 companies responding to the survey), daily and monthly contract terms are less prevalent today than two years ago among the survey participants. This may be because recent daily pricing has been high relative to history. It may also be, however, that companies and Public Utility Commissions are becoming more comfortable with longer-term supply agreements as a part of a supply portfolio, remembering that a long-term deal today may be two years not 10 or 15.

Table 3 shows that long-term agreements, defined as one year or longer, were used by 37 of 52 companies (answering the question) and accounted for more than 50 percent of purchased gas for 15 companies on a peak-day. Last year's results produced only 10 companies that used long-term deals for more than 50 percent of their purchased gas on the peak-day. Mid-term (more than one month, less than one year) were utilized more often than one-month or daily agreements for peak-day purchases, also. This makes sense in an environment where daily gas prices tended to be high compared to recent history and many fluctuations in price were upward. In contrast, for peak-month gas purchases, 32 companies utilized mid-term agreements for between 26 and 100 percent of gas supplies, while 23 companies acquired the same range of supplies through long-term contracts. Monthly and daily agreements were used to some extent by 22 and 26 companies, respectively, for peak-month supplies – but like peak-day arrangements tended to be for 25 percent or less of volumes.

TABLE 3

CONTRACT TERMS FOR GAS PURCHASED
2004-2005 WINTER HEATING SEASON
(NUMBER OF COMPANIES)

Percent Contracted	Long-Term	Mid-Term	Monthly	Daily
PEAK-DAY				
1 – 25	15	10	13	12
26 – 50	7	9	8	9
51 – 75	7	9	2	3
76 – 100	8	13	1	1
0	15	11	28	27
PEAK-MONTH				
1 – 25	14	8	11	20
26 – 50	8	12	7	3
51 – 75	6	5	2	3
76 – 100	9	15	2	0
0	13	10	28	25

Source: 2004-05 AGA LDC Winter Heating Season Performance Survey.

When asked to describe the distribution of gas supply purchases among suppliers, 37 LDCs identified independent marketers as suppliers with producers (31 companies), producer marketing affiliates (29 companies) and pipeline marketing affiliates (9) providing the balance of gas supplies to LDCs. Table 4 also shows that LDC-owned production and purchases directly from pipelines played a very small role in supplying LDC customers with natural gas.

TABLE 4

PERCENT PEAK-DAY GAS DISTRIBUTED AMONG SUPPLY PROVIDERS
2004-2005 WINTER HEATING SEASON
(NUMBER OF COMPANIES)

Percent Peak-Day Gas Supply	Producer	LDC-Owned Production	Producer Marketing Affiliate	Pipeline	Pipeline Marketing Affiliate	Independent Marketer	Other
1 – 25	9	1	7	0	8	11	7
26 – 50	9	1	8	0	0	17	1
51 – 75	9	0	9	0	1	6	2
76 - 100	4	0	5	0	0	3	6
0	21	50	23	52	43	15	36

Source: 2004-05 AGA LDC Winter Heating Season Performance Survey.

V. Supply Pricing Mechanisms and Hedging

Pricing Mechanisms

Many factors play a role in the market pricing of the gas commodity and of transportation services, including weather, storage levels, end-use demand, pipeline capacity, operational issues, and functioning financial markets. Such market factors impact LDCs and other gas suppliers making it difficult for all players to plan. In order to deal with the inherent uncertainty of the market, supply planners use a portfolio approach to pricing gas supplies just as they use a portfolio approach for supply providers and transportation options. That said, when examining the purchase practices of companies during the past several winter heating seasons, it is clear that first-of-the-month (FOM) index pricing dominates the market for the largest portion of long- and mid-term supply agreements. Table 5 examines more closely the balance of pricing mechanisms among survey respondents during the 2004-2005 winter heating season. Figures 2-5 compare pricing mechanisms from this year's survey participants with last year's sample of companies.

Table 5 and Figure 2 show that for long-term supplies (one year or more agreement) 30 of 49 companies answering the question used first-of-the-month pricing for a portion of their supplies, including 27 companies that used FOM for 51-100 percent of long-term gas purchases. Thirteen companies utilized some form of fixed pricing for a portion of their long-term arrangements, which is interesting because two years ago when the survey included 65 respondents the number of companies citing fixed deals was only 10. A smaller number included daily, average-of-the-last-three-days and NYMEX based pricing mechanisms for small volumes within their gas supply portfolio. For those companies referencing fixed price mechanisms for gas supply, only five indicated that the arrangements lasted for more than two years. All others were of less duration. Using a scale of 1-10 %, 11-20 %, 21-30 % and so forth, the largest number of companies described their fixed-price deals as 11-20 percent of their supply portfolio.

Comparing Figures 2 and 3 (2004-2005 and 2003-2004, respectively) indicates that for the winter heating season just past there was slightly less diversity in pricing mechanisms for small volumes of gas but general agreement that the largest number of companies purchased the largest volumes of their supply using FOM pricing.

TABLE 5

GAS SUPPLY PRICING MECHANISMS 2004-2005
(NUMBER OF COMPANIES)

PERCENT GAS SUPPLY PURCHASED	FIRST-OF-THE-MONTH INDEX	WEEKLY	FIXED	DAILY	AVERAGE LAST 3 DAYS	NYMEX	OTHER
LONG-TERM							
ONE YEAR OR GREATER							
1 – 25	0	0	5	4	2	3	0
26 – 50	3	0	1	4	0	1	3
51 – 75	10	0	4	0	2	2	1
76 – 100	17	0	3	0	0	2	5
0	19	49	36	41	45	41	40
MID-TERM							
GREATER THAN ONE MONTH, LESS THAN ONE YEAR							
1 – 25	6	0	8	4	0	4	1
26 – 50	9	0	5	5	0	3	1
51 – 75	10	0	3	2	0	2	0
76 – 100	14	0	4	2	0	8	0
0	13	52	32	39	52	35	50
SHORT-TERM							
ONE MONTH OR LESS							
1 – 25	8	0	9	11	0	3	2
26 – 50	8	0	5	6	0	3	0
51 – 75	14	0	3	8	1	5	0
76 – 100	10	0	2	10	0	1	2
0	13	53	34	18	52	41	49

Source: 2004-05 AGA LDC Winter Heating Season Performance Survey.

FIGURE 2

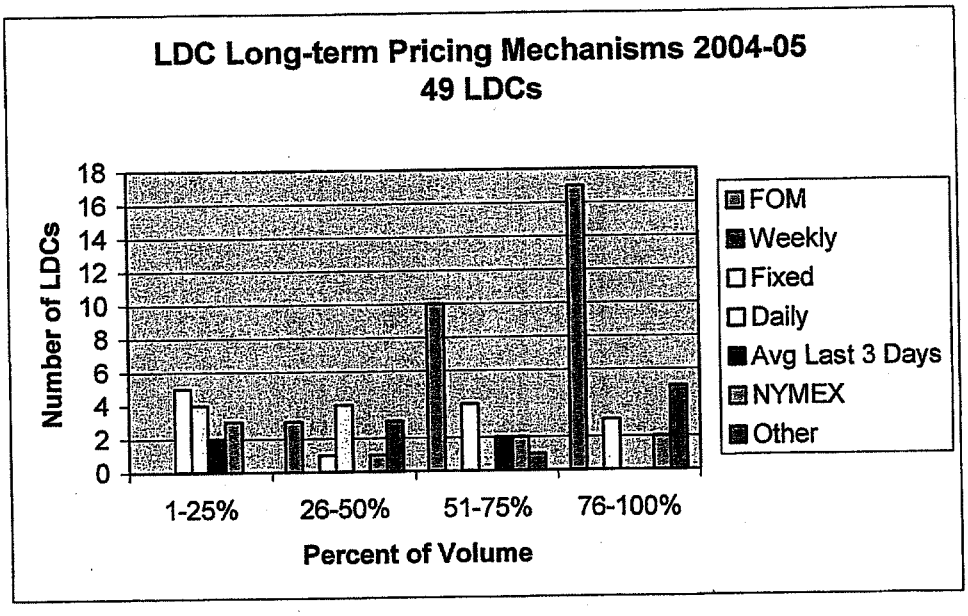
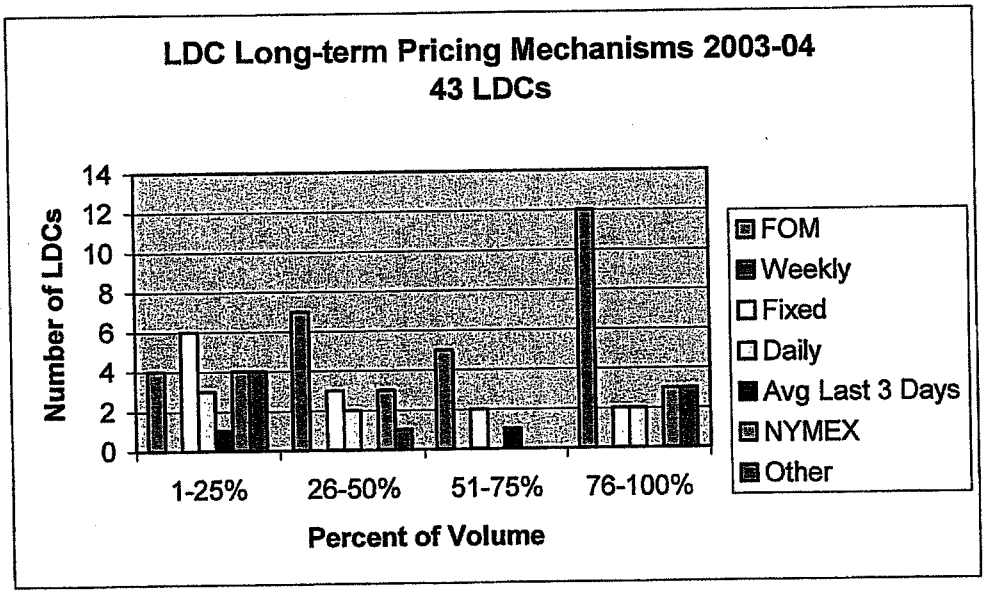


FIGURE 3



Mid-term purchases (more than one month, less than one year) were reported by companies to most often be tied to FOM indices for almost any volume of gas during the past two winter heating seasons, as shown in Figures 4 and 5. In addition, fixed-price, NYMEX and daily mechanisms were used to a greater extent for mid-term purchases than in the case of long-term purchases. Twenty companies reported using fixed pricing mechanisms for mid-term purchases compared to 13 companies for long-term and 13 used daily prices for mid-term purchases compared to eight for long-term purchases, which makes sense. In a volatile gas market, trading partners are more likely to limit

the term of pricing arrangements because local utilities are encouraged by regulators to be in a position to capture lower gas prices when the market swings down, while suppliers are interested in capturing the high end of the market. However, there appears to be a growing undercurrent of concern among some gas market players that first-of-the-month indices are *over* relied upon and that index pricing of such large volumes of gas may need to change in the future. That could only happen if market players were willing to do so and regulatory support was forthcoming.

FIGURE 4

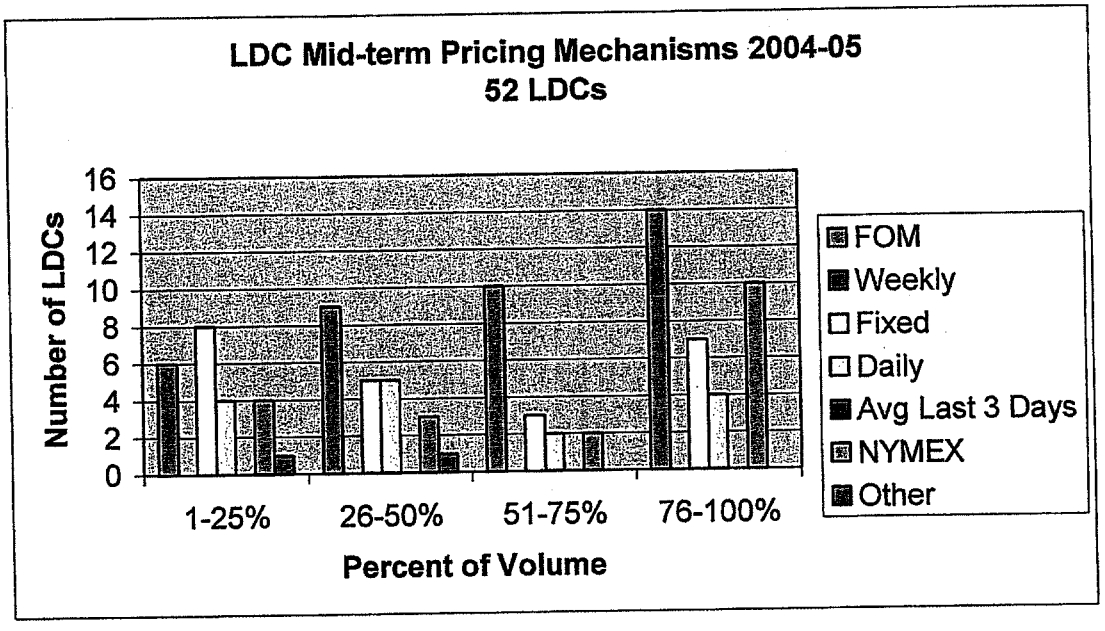
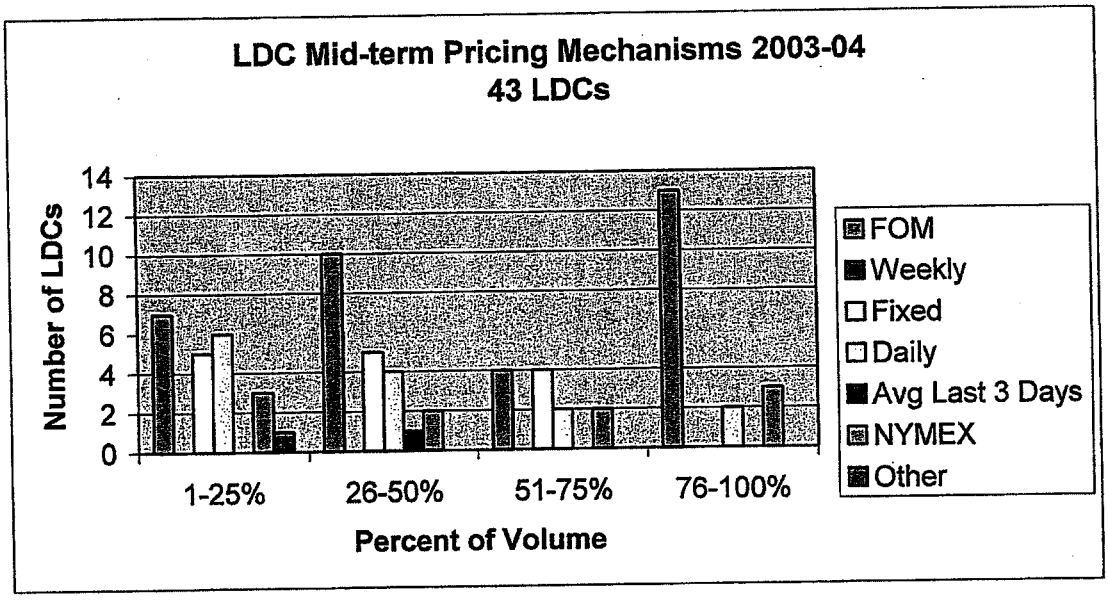


FIGURE 5



As expected, short-term purchases (one month or less) depended more heavily on daily pricing mechanisms but, also, were tied to first-of-the-month, fixed and NYMEX indices (see Table 5). It should be noted that LDCs build gas supply portfolios and pricing strategies based on prior and anticipated experiences. Even state regulatory approved pricing mechanisms can appear favorable one year and less attractive another. Flexibility and constructive review of policies, rather than second-guessing, can effect positive impacts on bringing natural gas and services to customers at the lowest possible cost.

Hedging Mechanisms

Market developments during the 1990s have expanded gas supply options, transportation capacity trading and the use of financial instruments. Today, industry players use futures contracts and other tools to offset the risk of commodity price movements. These financial instruments, which to some extent include fixed-price gas purchase contracts, futures, and options, allow gas supply portfolio managers to hedge or lock in a portion of the gas cost component of gas supplies. This is achieved particularly when the level of risk required and the rewards or benefits of managing the risk are properly balanced by the company, consumers and regulatory bodies.

Seventy percent of the companies responding to the AGA WHS survey said they used financial instruments to hedge a portion of their gas supply purchases during the 2004-2005 winter. That number is identical to the percentage last year and compares to 45 of 65 LDCs (69 percent) answering the question in the 2002-2003 survey and 55 percent in the 2001-2002 survey (remembering that the sample companies and sample size were different each year). For this past winter, twenty-one of 37 companies providing data hedged up to 50 percent of their gas supply purchases during the winter. Options (23 companies), fixed-price contracts (18 companies), swaps (16 companies) and futures (11 companies) were most often sited as financial tools used to hedge a portion of gas volumes delivered on a peak-day. This balance is similar to that of last year. The use of financial tools may be understated in this report inasmuch as some volumes delivered to LDCs from marketers and other suppliers are hedged by the third-party rather than the LDC or customer and may have been excluded from the LDC hedging calculation.

Only seven companies indicated that they used weather derivatives during the 2004-2005 winter heating season. This compares to six companies in 2003-2004 and eight companies in the 2002-2003 survey.

When asked about the timing of hedging strategies, 25 of 38 companies (66 percent) responding indicated that they employ a six-month and less strategy for a portion of their hedges. Thirty-five of 38 companies utilized a 7-12 month strategy for a portion of their hedges, while 19 companies hedged forward for more than 12 months. Of course, a single company may use one or all strategies simultaneously. The majority of companies also reported that acquiring financial hedges or implementing a strategy was no more or less difficult than the prior year. Thirty-one of the 54 companies responding indicated that for the 2005-2006 winter heating season they planned to hedge the same as this past winter heating season. Eleven companies plan to hedge even more of their purchased gas volumes. Thirteen of the companies reported that Public Utility Commissions were more receptive to hedging strategies than in the past, while 31 indicated PUC receptivity to be the same compared to last year.

On the physical side, companies view gas delivered to storage during the summer refill season as a price hedge against potential winter run-ups. In preparation for the 2004-2005 WHS, 47 companies reported using storage as a primary hedging tool. Twenty-nine of those companies hedged between 26-50 percent of winter heating season supplies using underground storage compared to 22 companies last year. Several companies noted that storage (as a physical hedge) is the only hedge they employ choosing not to use financial instruments at all.

When asked about their own regulatory environment, 37 of the companies responding to the question indicated that financial losses and gains were treated equally within their hedging plans. Only three noted that losses and gains were treated unequally. When asked about the relative ease of acquiring hedging products for 6-month or less hedges, thirty-eight companies saw current markets as less difficult

or the same as the year before. Thirty-two companies said the same of hedges more than six months in duration. Very few companies indicated market conditions to be more difficult to operate within. This compares to last year's survey when up to a third of the companies viewed markets as more difficult to operate within.

Motivations behind hedging programs are varied among survey respondents. For some jurisdictions there are no formal standing plans. In some cases, however, companies are permitted to enter into fixed price deals well ahead of the delivery season (up to 2.5 years ahead) for a portion of their monthly requirements. Timing of a contract reflects historical price trends and demonstrates a desire to maintain diversity among market-based prices within a supply portfolio. In other cases, LDCs may be required to hedge portions of future gas supplies and those hedges must be in place by predetermined dates. Accelerating or slowing down the process occurs based on evaluation of market fundamentals. Variations on these themes are many and are shaped to fit the relationship between local distribution company, regulators and market conditions in a given area.

VI. Gas Storage

As noted earlier, LDCs are concerned with managing gas supply and transportation portfolios efficiently to reduce costs. Producing area and market area storage can help LDCs to meet such goals. The use of storage facilities helps LDCs to meet short-term swing opportunities, as well as, to satisfy peaking needs.

Table 6 shows storage levels as estimated by the Energy Information Administration for January-April 2005 compared to the same period in 2004. For the nation as a whole, working gas inventories during the January-April 2003 period were tested, eventually falling to 642 Bcf in total (a historic low). This occurred during a winter that was only 1.4 percent colder than normal nationally.

In contrast, the lowest volume of gas in storage for early 2004 was 372 Bcf higher than the previous year and the lowest point for storage inventories in 2005 was another 215 Bcf higher. This is consistent with the fact that the past two winter heating seasons were five and six percent warmer-than-normal, respectively. All of the additional gas in storage at the end of the 2003-2004 WHS was located in the Consuming Region East and Producing Region. By the first week in April 2005, higher inventories of natural gas in underground storage were distributed in all three regions of the U.S. and were more than 25 percent ahead of the prior five-year average and 20 percent ahead of the previous year.

Forty-nine companies answering the question indicated that weather-induced demand compelled the respondents to utilize storage services. However, respondents also singled out no-notice requirements (42 companies) and pipeline operational flow orders (20 companies) as reasons to maintain storage services within their gas supply portfolio. Thirty-five and 18 companies, respectively, also stated that both contractual "must turn" provisions and arbitrage opportunities influenced their storage decisions during the 2004-2005 WHS.

TABLE 6

AMERICAN GAS STORAGE SURVEY

WORKING GAS IN STORAGE

	2004 (Bcf)					2005 (Bcf)			
	Total	Prod	East	West		Total	Prod	East	West
Jan02	2567	753	1495	319		2698	802	1536	360
	2414	709	1412	293	Jan07	2610	783	1494	333
	2258	683	1297	278		2500	755	1438	307
	2063	633	1163	267		2270	692	1290	288
	1827	575	1009	243		2082	648	1155	279
Feb06	1603	512	880	211	Feb04	1906	599	1043	264
	1431	456	788	187		1808	576	984	248
	1267	406	689	172		1720	564	921	235
	1171	379	630	162		1613	571	838	224
Mar05	1143	376	619	148	Mar04	1474	523	737	214
	1097	371	575	151		1379	507	659	213
	1032	372	507	153		1290	487	592	211
	1014	380	474	160		1239	486	548	205
Apr02	1034	395	477	162	Apr01	1249	497	546	206
	1049	411	473	165		1293	521	562	210
	1077	423	483	171		1343	538	591	214
	1155	449	531	175		1416	558	636	222

Source: Energy Information Administration

For the previous year, only 20 of 43 companies (47 percent) noted must turn provisions as significant influences on their storage withdrawal strategy during the winter. Must turn provisions may be in place for some storage contracts as a way to maintain facility integrity through an optimal pattern of injection and withdrawal in a storage field. As such, once gas is stored portions must be removed within a scheduled cycle in order to manage the geologic nature of the reservoir properly. During the 2004-2005 winter heating season, storage inventories were consistently higher than the prior five-year average and, therefore, companies may have been faced with a need to cycle gas out of storage to meet the must turn provisions of their contract. As noted above, thirty-five of 54 companies (65 percent) singled out must turn provisions as influencing their use of storage this past winter – eighteen percent more than the prior winter.

Many influences were cited regarding decisions for storage injections during the Spring-Summer refill season in 2004. Price considerations were noted by 38 companies and were up from only 22 companies the year prior (2003). In addition, 46 companies sited operational issues as influencing storage injection patterns in 2004. Regulatory plans and mandates were reported by 21 companies, while 44 cited additional supply considerations as influencing storage injections.

TABLE 7

PRICING MECHANISMS FOR GAS
INJECTED INTO UNDERGROUND STORAGE
2004
(NUMBER OF COMPANIES)

Percent Underground Storage Purchases	First-Of-The-Month Index	Weekly	Fixed	Daily	Average Last 3 Days	NYMEX	Other
1 – 25	5	0	11	15	1	3	0
26 – 50	8	0	6	6	0	3	2
51 – 75	12	0	3	2	1	3	0
76 – 100	20	0	1	2	0	2	1
0	7	52	31	27	50	41	49

Source: 2004-05 AGA LDC Winter Heating Season Performance Survey.

FIGURE 6

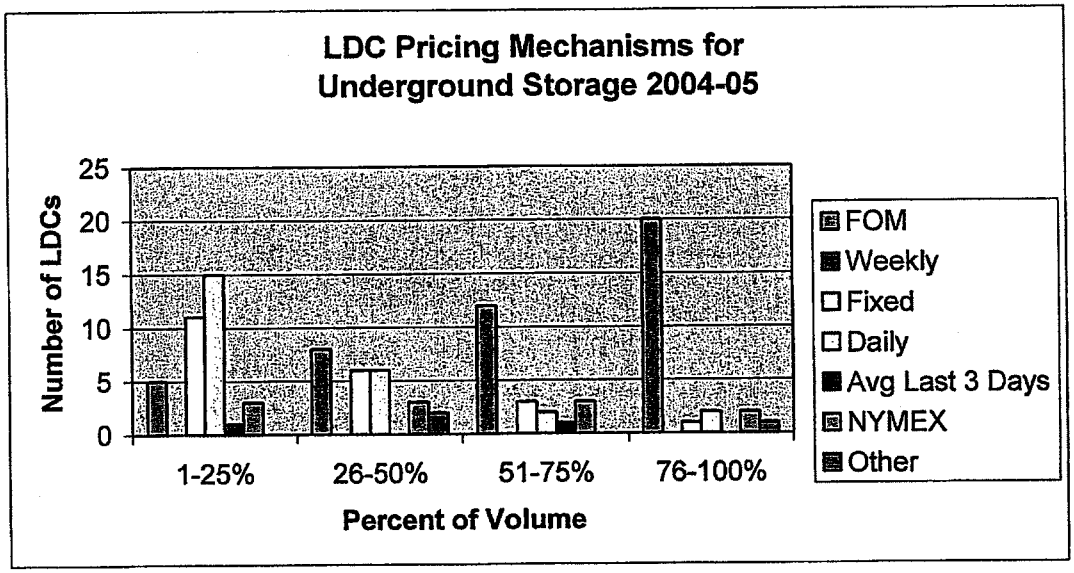


Figure 7

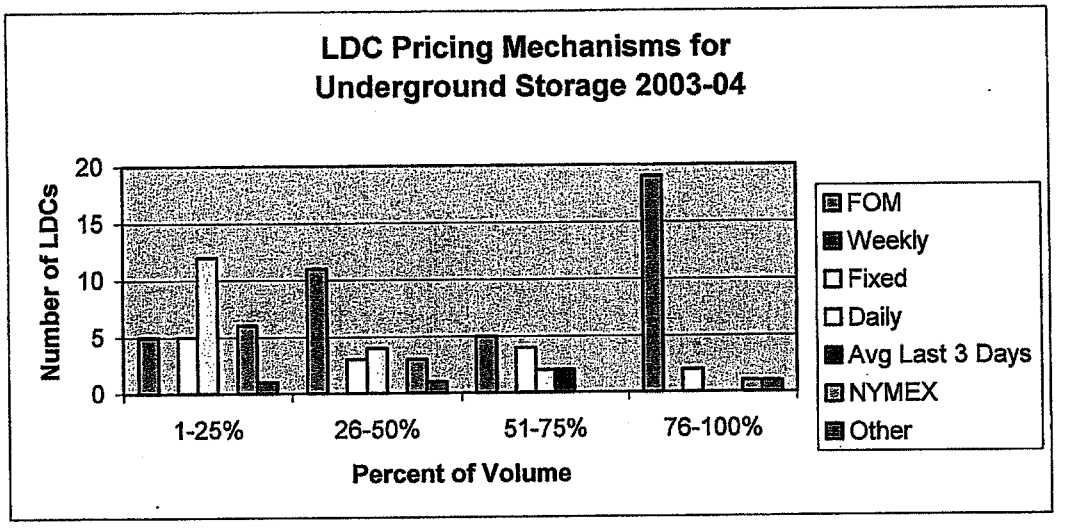


Table 7 and Figure 6 show that most gas purchases for storage injections during 2004 (preparing for the 2004-2005 winter heating season) were made based on *first-of-the-month* indices, although fixed price and daily priced gas was also prevalent for small volumes of gas destined for underground storage. The same is reflected in Figure 7 for the refill period in 2003. For 2004, twenty companies indicated that more than 75 percent of the supplies purchased for storage injections were FOM priced. Fixed schedules accounted for some storage volumes injected by 21 companies reporting, while daily pricing applied to 25 of the surveyed companies (compared to 18 companies in 2003). Generally, daily pricing was applied to 1-25 percent of gas purchased for underground storage, although four companies in 2004 indicated that between 51-100 percent of their stored gas was purchased on a daily basis.

Twenty-five companies indicated that they were examining options to build underground storage additions during the next five years or currently constructing expansions, while 13 companies were considering additions or expansions of peak-shaving facilities. Regarding contracted storage capacity, 10 companies plan to increase underground storage for the 2005-2006 winter heating season, while 33 companies reported plans to keep the same capacity as this past year.

VII. LDC Transportation and Capacity Issues

Transportation only customers have assumed a higher profile among all customers served by LDCs. As has been stated before, planning for transportation capacity and supply, in general, is ultimately held hostage to weather, economic activity and other factors that influence gas consumption. Managing pipeline capacity efficiently is a challenge for LDC's and can involve the release of capacity to the secondary transportation market, if events allow it to be so.

Table 8 takes a brief view of this issue. Companies were asked to identify the percentage of pipeline capacity held by the LDC and released to the secondary market by month from April 2004 to March 2005. In general, several elements can be noted by examining the table. First, most companies release no capacity or less than 25 percent of their capacity throughout the year. During the summer months, however, additional companies with capacity to release may have up to 50 percent of their capacity available to the secondary market. This makes sense, assuming that LDCs are less likely to have large blocks of excess capacity during the winter heating season months in order to meet seasonal heating loads.

The second item is that most capacity sales to the secondary market were for less than 25 percent of the LDC capacity portfolio. From April 2004 to March 2005, 20-26 of the 50 companies answering the question released between one and 25 percent of their pipeline capacity on a monthly basis to the secondary market, when that capacity was not needed to serve LDC customers. As many as 5 companies released up to 50 percent of their capacity during the winter of 2004-2005, which can be attributed to the warmer-than-normal conditions throughout the country for most of that period.

Regarding system operations, 22 of 53 companies (42 percent) in the 2004-2005 AGA Winter Heating Season Survey indicated that they had been impacted by the issuance of operational flow orders during the past WHS. That compares to 48 of 65 companies (74 percent) during the 2002-2003 WHS and 51 percent during the 2003-2004 winter. For those companies during 2004-2005, the median number of OFOs issued was 3. Duration for the orders ranged from one day to 45 days, however, the median duration was 3.5 days.

TABLE 8

PERCENT LDC PIPELINE CAPACITY RELEASED
2004-2005 WINTER HEATING SEASON
(NUMBER OF COMPANIES)

	2004							2004		2005		
Percent Pipeline Capacity Released	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
0	16	13	13	15	14	13	14	18	21	21	21	20
1 – 25	24	24	23	20	22	22	24	26	23	24	23	25
26 – 50	9	12	13	14	13	14	10	5	5	4	5	3
51 – 75	0	0	0	0	0	0	1	0	0	0	0	1
76 - 100	1	1	1	1	1	1	2	1	1	1	1	2

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APPENDIX A

2004-2005 WINTER HEATING SEASON SURVEY PARTICIPANTS

AGL Resources
Ameren Corporation

Baltimore Gas & Electric Co.

Chattanooga Gas Company
Cinergy Corp.
Citizens Gas and Coke Utility
Clearwater Gas System, City of
Con Edison Co. of New York
Connecticut Natural Gas
Consumers Energy

Dominion – East Ohio Gas
Dominion Gas Delivery
DT Energy – Michcon

Equitable Resources

Hope Gas, Inc.

Indiana Gas Company
Intermountain Gas Company

KeySpan Energy Delivery-Long Island
KeySpan Energy Delivery-New England
KeySpan Energy Delivery-New York

LaClede Gas Company
Louisville Gas & Electric Company

MDU Resources Group, Inc.
Memphis Light Gas & Water
Mobile Gas Service Corp.
Mountaineer Gas Service Corp.

National Fuel Gas Distribution Co.
New Jersey Natural Gas
Niagara Mohawk Power Corp.
NICOR Gas
North Shore Gas Company
Northern States Power Company (Xcel Energy)
Northwest Natural Gas Company

PECO Energy
Peoples Gas Light & Coke Company
Peoples Gas System
Piedmont Natural Gas Co.
PNM Gas Services (Public Service of NM)
Public Service Co. of Colorado (Xcel Energy)
Puget Sound Energy

Questar Gas Company

Roanoke Gas Co.

San Antonio Public Service Board, City of
SEMCO Energy
Southern Connecticut Gas Company
Southern Indiana Gas & Electric Company
Southwest Gas Corporation

UGI Utilities

Vectren
Vermont Gas Systems, Inc.
Virginia Natural Gas, Inc.

Washington Gas Light Company
Wisconsin Public Service Company

Yankee Gas Services Co.

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ORIGINAL

30

MEMORANDUM

TO: Docket Control

FROM: Ernest G. Johnson
Director
Utilities Division

DATE: August 22, 2006

RE: STAFF REPORT ON SOUTHWEST GAS CORPORATION COMPLIANCE MATTERS RELATED TO ITS 2005 RATE PROCEEDING (DOCKET NO. G-01551A-04-0876)

Attached is the Staff Report for compliance matters related to its 2005 rate proceeding.

EGJ:BGG:red

Originator: Bob Gray

Attachment: Original and Thirteen Copies

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Docket No. G-01551A-04-0876

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STAFF REPORT
UTILITIES DIVISION
ARIZONA CORPORATION COMMISSION

SOUTHWEST GAS COMPLIANCE MATTERS RELATED TO ITS 2005 RATE PROCEEDING

DOCKET NO. G-01551A-04-0876

AUGUST 22, 2006

STAFF ACKNOWLEDGMENT

The Staff Report for Southwest Gas Compliance Matters Related to Its 2005 Rate Proceeding, Docket No. G-01551A-04-0876, was the responsibility of the Staff members listed below.

Robert Gray
Senior Economist

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Southwest Gas Corporation
Docket No. G-01551A-04-0876
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Introduction

On February 23, 2006, the Commission issued an order in Southwest Gas Corporation's ("Southwest") rate proceeding before the Arizona Corporation Commission ("Commission") in Docket No. G-01551A-04-0876. The order discusses a number of matters that require further actions by Southwest and discussions with Staff, followed by a report from Staff to the Commission. Specifically, ordering paragraphs on page 68 of the order state:

> "Southwest shall initiate discussions with Staff, within 60 days of this Decision, regarding stock ownership issues discussed herein, and to continue to cooperate with Staff regarding other procurement issues, including issues pertaining to El Paso and construction and ownership of laterals on the Company's system." (lines 18-21)
>
> "Staff shall file within 180 days of the effective date of this Decision, as a compliance item in this docket, a report or reports regarding stock ownership issues, procurement practices, benchmarking, and El Paso laterals issues discussed above." (lines 22-24)

Southwest did initiate discussions with Staff within 60 days of the decision, and this document is Staff's report to the Commission, as required within 180 days of the decision (by August 22, 2006). In this Staff Report, there is a brief discussion of each issue identified in the order for Staff to report on. In general, Staff believes that Southwest's efforts to comply with Decision No. 68487's requirements are consistent with the order.

Procurement Practices

During the rate proceeding, Staff recommended a number of changes regarding Southwest's procurement practices, including separating the contract award group from the invoice approval authority, eliminating the use of cell phones in term bidding and negotiating activities, and having a neutral party observe these activities. Southwest agreed to implement these changes during the rate proceeding.

On April 24, 2006, Southwest filed a letter in the rate case docket. The letter states that Southwest has completed making changes to implement the recommendations discussed above regarding procurement practices. Southwest has provided Staff with additional information, including internal memos, work orders, organizational charts and other information, documenting the changes Southwest agreed to make during the rate proceeding. Further, Staff anticipates making a future site visit to observe Southwest's acquisition practices, during which Staff could visually verify implementation of these changes.

Benchmarking Study

Southwest hired Ralph Miller, a consultant, to conduct a benchmarking study of Southwest's gas procurement practices. The report discusses various aspects of Southwest's procurement policies and procedures and compares them to industry practices. Areas covered by the review include load forecasting, capacity acquisition, and commodity procurement. The report includes discussion of an American Gas Association ("AGA") study on gas portfolio management during the 2004-2005 winter season by AGA members.

Southwest has an annual planning period which runs from November through December each year, a common industry practice according to the report. The report notes that Southwest's load forecast is comprehensive, including major components such as:

- Annual, seasonal, and monthly loads under normal weather conditions.
- Design day, design week, and design winter season loads.
- Maximum and minimum daily loads that may occur in each calendar month.

The report indicates that no-notice and swing requirements (used to meet short term fluctuations in customer demand for natural gas) are implicitly included in the components identified above. The report concludes that Southwest's load forecasting process is complete and comprehensive and provides the information needed for Southwest's gas procurement activities. The report notes that it does not address the specific methods Southwest uses to prepare its load forecast or the quality of the load forecast.

Regarding capacity acquisition, the report notes that Southwest's overriding consideration is that its Arizona city gates are connected only to the El Paso Natural Gas interstate pipeline system, and for most if not all city gates, it would be difficult and expensive to connect to another pipeline. The report does note the prospect of the Transwestern Pipeline Phoenix Project entering the Phoenix market in 2008. The report indicates that Southwest's capacity portfolio is further restricted by the limited services offered by El Paso and the lack of market area natural gas storage in Arizona. The report states that Southwest continuously reviews alternative options for gas delivery to Arizona, but notes that the consideration of alternative delivery options does not impact the actual procurement of gas supplies until such time as Southwest actually acquires alternative capacity.

The report discusses five components of Southwest's commodity purchase portfolio, including fixed price purchases, term contracts for firm baseload supplies in the winter season, term contracts for peaking supplies in the winter season, monthly baseload supplies at current spot prices in the summer season, and daily spot purchases for swing supplies in the summer season.

The report also compares a number of characteristics of Southwest's gas procurement activities to the results of the AGA's study of local distribution company ("LDC") practices during the 2004-2005 winter season. The report indicates that Southwest's structure of its term

contracts is consistent with other LDCs. Southwest relies on peaking supplies and daily spot purchases much more than most other LDCs, but this is a necessary result given the lack of market area storage (storage in the areas where natural gas is consumed) in Arizona. The report indicates that Southwest has considered acquiring production area storage (storage where natural gas is produced) but found it to be uneconomic. The report discusses Southwest's use of intermediate term baseload purchases of one to twelve months, with such purchases being made either on the basis of a fixed purchase price, a use of a basis differential with a NYMEX component, and via index pricing. The report also talks about Southwest's use of swing and daily spot purchases. Southwest makes daily purchases using a combination of fixed pricing and index pricing, a common LDC practice.

The report also contains a section that deals with Southwest's price risk management efforts, which Southwest refers to as its Arizona Price Stability Program ("APSP"). The report indicates Southwest manages its price risk by acquiring approximately half of its gas supplies through fixed price contracts with prices established up to 24 months in advance. The report evaluates three aspects of the APSP, including the size of the program, alternative price risk management strategies, and the use of financial instruments instead of fixed price purchase contracts. The report states that Southwest's APSP is large but reflective of the unusual supply situation Southwest faces, given the lack of market area storage which many LDCs around the country have access to. The report indicates that Southwest's extensive use of fixed price contracts helps offset the lack of market area storage.

The report indicates that the other option for Southwest to manage price risk is for Southwest to acquire call options, which would allow Southwest to acquire gas at the strike price of the option or alternatives including puts and collars. The report discusses the pros and cons of these options before concluding that such options should generally only be a relatively small supplement to a fixed price purchase program and notes that LDCs the author is aware of only use such options for a small part of their portfolio.

The report then discusses the use of other financial instruments such as swaps and NYMEX futures contracts as other options to acquire natural gas at a fixed price. The report notes that Southwest has been looking into using such financial instruments, and this is consistent with movement by a number of LDCs around the country to make greater use of financial instruments. The report notes benefits from use of these financial instruments including the ability to hedge some swing or peaking supplies and the reduction in risk of a counter-party defaulting.

Attached to Southwest's report are a number of items, including several tables showing loads and demands, qualifications of the consultant, and the AGA's report on LDC Supply Portfolio Management During the 2004-2005 Winter Heating Season. Southwest also attached a document providing an overview of Southwest's financial hedging policy and processes for its gas supply portfolio. This overview document included five sections dealing with policy, governance structure, processes and controls, the hedge capture and control system, and the code of ethics.

The report summarizes with a number of conclusions about Southwest's gas procurement activities, including:

- Southwest's purchasing practices are generally consistent with practices of well-managed gas utilities.
- Southwest's use of a competitive bidding process to secure fixed price and term contracts, acquisition of fixed price purchases on a periodic basis, and use of informal solicitations to acquire spot purchases are consistent with the practices of other gas utilities.
- Southwest's APSP relies more heavily on fixed price purchases to hedge approximately half of its natural gas supplies. This reliance on fixed price purchases is greater than a typical gas utility due to the lack of natural gas storage facilities in the market area to assist in Southwest's hedging efforts.
- Southwest acquires the other half of its gas supplies using pricing arrangements that reflect current market conditions, including use of negotiated prices and index pricing.

Review of Gas Portfolio Evaluation Software

In the rate proceeding, Staff recommended that Southwest review its gas portfolio evaluation software. Southwest's July 7, 2006 report contains a discussion of Southwest's portfolio evaluation software review.

For many years Southwest has used a software package known as UPLAN-G, owned and developed by LCG Consulting. This software is used by Southwest to determine a least cost mix of resource contracts, taking into account a variety of factors including forecasted demand, available interstate resources, and contract pricing.

Southwest identified three groups of available software, including macroeconomic models, transactional models, and optimization and dispatch models. Macroeconomic software models flows of natural gas on a regional basis on the basis of supply, demand, price, and available infrastructure facilities. Transactional software enables an LDC to track transactions related to the purchase, transportation, and sale of natural gas. Southwest concluded that macroeconomic and transactional software would not enable Southwest to effectively optimize its portfolio of supply resources, due to the nature of these kinds of software.

Optimization and dispatch models enable an LDC to optimize its selection of resources. Southwest indicated that two optimization and dispatch models are currently available in the natural gas industry, UPLAN-G, which Southwest currently uses, and a software program named Sendout. Southwest states that a review of Sendout did not identify any functionality that would be gained by Southwest that would warrant switching from its current modeling software. Southwest indicated that it will continue to evaluate developments in modeling software and will inform Commission Staff of developments in this area.

Stock Ownership Issues

Southwest's Code of Business Conduct and Ethics currently contains a list of statements of things that Southwest considers to be in conflict with an employee's duties and contrary to Company policy. One of these statements says: "Holding any substantial stock or other financial interest in any competitor, supplier, contractor, or vendor or other organization with which an employee is engaged in a business relationship. If there is any question as to whether the interest is substantial, you should seek advice from the General Counsel."

In the rate proceeding, Staff expressed a concern with the lack of clarity regarding potential ownership of stock or other financial interests in counterparties, and Staff recommended that Southwest preclude stock ownership or other financial interest with any supplier or class of suppliers with which they do business. In early July Southwest provided Staff with a draft document providing a more clear definition of what Southwest viewed as being "substantial." In essence, this draft document indicated that if a Southwest employee owned more than 1 percent of the equity in a counterparty, that would be considered substantial.

Staff has had several follow-up discussions with Southwest regarding this issue. Staff has expressed concern that one percent of some counterparties, such as a major natural gas producer/marketer, could be a very large amount of money, while also recognizing that Southwest has a number of other policies and procedures in place that provide checks and balances on an employee possibly conducting procurement activities in a manner that would be inconsistent with Southwest or ratepayers' interests.

Southwest provided Staff with additional documentation regarding the Company's efforts to develop its stock ownership definition and how it fits within Southwest's overall controls and procedures.

In developing its stock ownership definition and related documents, Southwest cites a number of steps Southwest took, including:

- A review of the policies, procedures, and controls of the gas procurement and purchasing departments.
- A review of the Codes of Ethics and Business Conduct including the Conflict of Interest Policies of Unisource Energy Corporation and Arizona Public Service Company. Southwest found that its policies are similar to the policies of those companies.
- Via Southwest's Assistant General Counsel, Southwest queried approximately 30 other companies at a recent American Gas Association Legal Committee meeting, and none of the other companies' representatives indicated they had stock ownership restrictions beyond their code of ethics and business conduct.
- Development of a stock ownership disclosure form in addition to Southwest's existing conflicts of interest form that is distributed to all employees.

Regarding Southwest's gas procurement department, Southwest identifies a number of policies and procedures which help ensure that Southwest employees are not conducting themselves in a manner that could favor an entity they had a financial interest in, including:

- Southwest's strong motivation to buy the lowest price natural gas supplies due to competitive pressures.
- Periodic regulatory reviews of Southwest's purchasing practices.
- Use of a blind bid selection process for fixed price and first of the month purchases where the person awarding the contract does not know the identity of the supplier.
- For daily spot or term portfolio purchases, Southwest only purchases from the lowest priced qualified bidder.
- Solicitations are sent out to a standard list of suppliers by the department secretary, not the gas buyer and a neutral party observes the solicitation process.
- Periodic external and internal audits.
- Requiring employees to sign conflict of interest forms.

Southwest indicates that the purchasing department has similar controls to the gas procurement department. Southwest has not completed the process of designing its stock ownership policy and related materials, and Southwest has agreed to provide Staff with such further materials and documents when they are completed. Southwest has also agreed to have further discussions with Staff on these issues as necessary.

El Paso Lateral Issues

In the rate proceeding Staff had put forth a recommendation that Southwest should construct its own laterals (rather than having El Paso construct them) unless there is a compelling reason to do otherwise. Most of Southwest's load is served off of El Paso's lateral system in Arizona and proposals by El Paso in its on-going rate proceeding at the Federal Energy Regulatory Commission ("FERC") would make it difficult if not impossible for Southwest to access service from another pipeline or storage service provider for these loads. This recommendation came from Staff's on-going concern about El Paso's use of its lateral system as one of several means to stifle competition from potential third party storage and/or pipeline developers in Arizona. To the extent laterals are owned by Arizona entities, rather than El Paso, Arizona entities such as Southwest may be able to lessen the effects of such anti-competitive behavior. Staff has had discussions with Southwest and believes that Southwest and Staff have similar views on the issue of laterals.

Options available to Southwest to meet new or growing demand for natural gas in Arizona include construction of new laterals, expansion of existing laterals, and/or acquisition of existing laterals from El Paso. Southwest has acquired laterals from El Paso in the past, including 2001 acquisitions of the Buckeye, Rainbow Valley, Parker, and Elfrida laterals. Southwest has indicated that another factor influencing its possible acquisition of laterals is El Paso's positioning of itself in the Arizona market and that at times Southwest would like to acquire laterals from El Paso, but El Paso may not be interested in such transactions for a variety

of reasons. Southwest weighs a variety of factors related to a possible acquisition from El Paso, including:

- The need for additional capacity.
- Bypass potential of Southwest's core customers.
- Potential higher delivery pressure benefits.
- Ability to access other supplies.
- El Paso's current limitations on Southwest's use of the lateral.
- Possible reductions in needed Southwest facility expansions on its distribution system.
- Reduced need for additional interconnects with El Paso.
- Benefits from acquisition of rights-of-way.

If Southwest makes a preliminary determination that an acquisition is cost-effective, it undertakes a detailed Acquisition Review Plan. The plan involves an analysis of pipeline capacity, original design and materials, installation records and practices, operational and maintenance records, compliance and safety issues, rights-of-way, environmental issues, modifications required for acquisition, and a final cost-benefit analysis. Southwest would then consider the totality of these issues and make a decision.

Staff understands and agrees with Southwest's approach to weigh all of these various factors when considering an acquisition from El Paso or other options and supports Southwest conducting a thorough evaluation of its alternatives. Staff still supports a policy of encouraging Southwest to own infrastructure rather than having El Paso construct, operate, and own infrastructure, while recognizing that Southwest, subject to the unique circumstances present in certain cases, may choose to not own or construct infrastructure sometimes and that such decisions may be in the best interests of Arizona ratepayers' long term interests. Staff and Southwest also discussed having further discussions in the future regarding Southwest's planning and actions to meet its current and future infrastructure needs.

Conclusions

Staff believes that Southwest's efforts in the areas described in this report are consistent with the requirements of Decision No. 68487 for Southwest to work with Staff on these issues, subject to further discussions and efforts as discussed herein. Some areas of interest in this report, including gas procurement related matters and El Paso lateral issues are matters of on-going interest as circumstances continue to develop in Southwest's Arizona service territory and across the region, and therefore Staff anticipates continued, on-going discussions with Southwest regarding these matters.

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
Docket No. G-01551A-07-___

PREPARED DIRECT TESTIMONY
OF
LAURA LOPEZ HOBBS

ON BEHALF OF
SOUTHWEST GAS CORPORATION

August 31, 2007

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Of
LAURA LOPEZ HOBBS

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BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
Of
LAURA LOPEZ HOBBS

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Laura Lopez Hobbs. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150-0002.

Q. 2 By whom and in what capacity are you employed?

A. 2 I am employed by Southwest Gas Corporation (Southwest or the Company) as Director of Human Resources.

Q. 3 Please summarize your educational background and professional experience.

A. 3 My background and experience are reflected in Appendix A to my direct testimony.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 Yes. I have previously testified before the Public Utilities Commission of Nevada (PUCN).

Q. 5 What is the purpose of your direct testimony in this proceeding?

A. 5 The purpose of my direct testimony is to support the test year expenses associated with Southwest's Supplemental Executive Retirement Plan (SERP) and the Management Incentive Program (MIP) as part of the Company's total

compensation package for management/executive employees (Total Compensation). The Company's Total Compensation is prudent and reasonable; therefore, the Commission should not disallow portions of the MIP costs or the SERP costs in this proceeding.

II. REASONABLENESS OF EXECUTIVE TOTAL COMPENSATION

Q. 6 Can you explain the Company's philosophy with regard to compensation of its management/executive employees?

A. 6 The Company's management compensation and benefits package is designed to attract, retain and motivate skilled management for the organization. In addition, the compensation package is intended to be reasonable, competitive, internally equitable and tied to performance.

Q. 7 How can the Company demonstrate that SERP and MIP are reasonable components of the Total Compensation Package?

A. 7 SEC executive compensation rules provide the ability to compare the Company's Total Compensation with that of other utilities within its geographical area. To make the comparison, the Company utilized the most recent publicly available proxy statements of the other major western energy utilities ("Proxy Peer Group"). Southwest compared its five highest paid employees' Total Compensation, which includes Base Salary, Bonus, Other, Restricted Stock Awards, Options Awards, Non-Equity Incentive Plan, Long Term Incentive Payout and All Other Compensation, to the five highest paid employees of each

Proxy Peer Group company.

Q. 8 Describe the Proxy Peer Group used in this proceeding?

A. 8 The Proxy Peer Group consists of all major utility companies in Arizona, California, Nevada, Oregon, Utah and Washington. The Proxy Peer Group is identified on Exhibit No.__(LLH-1) and is ranked by total compensation for the five highest paid employees (from highest to lowest); Southwest is included to show its ranking amongst its peer utilities.

Q. 9 Describe the Company's findings as a result of its analysis of the Proxy Peer Group.

A. 9 The Company compared the compensation for the five highest paid employees across the Proxy Peer Group with that of Southwest. (Exhibit No.__(LLH-1)). Although only 2 of the 13 companies listed in the Proxy Peer Group serve more customers per employee than Southwest, only 2 companies rank below Southwest in terms of total compensation - Northwest Natural and Portland General Electric, both of which rank well below Southwest in number of customers served and number of customers served per employee. These comparisons demonstrate that not only are management/executive employees at the Company compensated within a reasonable range, they are well below a majority of their peers.

Q. 10 Do other utilities in the Company's Proxy Peer Group offer incentive plans to their employees?

A. 10 Virtually all other utilities in the Proxy Peer Group

have incentive plans, including programs like the SERP and the MIP. Southwest must offer this compensation as part of its overall compensation package in order to remain competitive in the marketplace.

Q. 11 Briefly summarize the purpose of the SERP and the MIP.

A. 11 In general, these plans are offered to Southwest's senior management/executive employees to attract highly qualified individuals to manage and run the Company and to ensure their retention for the benefit of customers and shareholders. The Total Compensation package, including the MIP and the SERP, is crucial for the Company to remain competitive in attracting and maintaining quality management employees. If Southwest does not provide a Total Compensation package which includes a competitive collection of benefits, the chances of attracting and retaining a highly-skilled, well-motivated workforce is greatly reduced and ultimately increases costs and decreases service levels to customers.

Q. 12 Why is the MIP an important component of Southwest's management/executive compensation package?

A. 12 The Company's MIP provides variable compensation to management/executive employees for the achievement of specific goals and benchmarks important to both the short-term and long-term success of the Company. Forty (40) percent of the total award earned under the MIP is paid in cash immediately following the financial close

of the most recent calendar year. The remaining sixty (60) percent is awarded through the issuance of performance shares. These performance shares vest three years in the future. The longer-term performance shares act as a retention tool while aligning the interests of management/executive employees, shareholders and customers for continued financial and customer-oriented performance.

Q. 13 Why is the SERP an important component of Southwest's executive compensation program?

A. 13 The SERP compensates an officer for the limitations on compensation and the exclusion of deferred compensation in the basic (qualified) retirement plan (BRP) provided to other employees of the Company. The SERP is an unqualified plan and, as such, payments are not guaranteed (i.e., participants are general creditors of the corporation). Some form of SERP benefit is common in the utility industry.

Q. 14 How does the Company's executive compensation compare to the Proxy Peer Group?

A. 14 The difference is most evident in the compensation per customer amount. In Exhibit No.__(LLH-1) Southwest demonstrates that the total compensation per customer for the five highest paid Southwest executives is $2.47. Only one company in the Proxy Peer Group has lower total compensation per customer for the five highest paid executives. Yet, only one other company ranks higher in

productivity based on the number of customers served per employee.

Q. 15 Can the Company provide an example of the cost of executive compensation for other Arizona utilities?

A. 15 An analysis of Unisource and Pinnacle West data reveals a compensation per customer cost of $7.38 and $13.05, respectively.

Q. 16 Should the Commission include the MIP and SERP expenses in the cost of service in this proceeding?

A. 16 Yes. As demonstrated herein, Southwest's Total Compensation package, which includes the MIP and SERP as essential components, is prudent and reasonable. Virtually all other utilities in the proxy groups have MIP and SERP plans. As such, it is critical that Southwest continue its MIP and SERP plans to be competitive with its peers. Southwest ranks near the top in the customer-to-employee ratio (productivity) and near the bottom in management/executive compensation dollars per customer (reasonable). Therefore, a disallowance of part or all of the MIP or SERP would have a punitive effect on a compensation package that is already well below the market. Such a result is unfair and inequitable. Southwest concludes that the recovery of its MIP and SERP expense in this proceeding is appropriate not only because it is a normal, on-going, and necessary expense, but it is inherently reasonable when its Total Compensation package is measured against

other southwest regional utilities.

Q. 17 Does this conclude your prepared direct testimony?

A. 17 Yes, it does.

SUMMARY OF QUALIFICATIONS
LAURA LOPEZ HOBBS

I graduated from the University of Nevada - Las Vegas (UNLV) in 1981 with a Bachelor of Science degree in Business Administration and a Master degree in Business Administration from UNLV in 1990.

From 1981 to 1984, I was employed by Valley Bank of Nevada in various positions in the trust and audit departments.

In 1984, I began my career with Southwest as a Human Resource Analyst in the Human Resource Department. In 1987, I was promoted to Benefits Administrator. I was primarily responsible for day-to-day administrations of the various employee benefit plans, including medical, dental, and 401(k) employee investment plans, and development and distribution of employee benefits statements.

In 1989, I was promoted to Investor Relations Specialist and transferred to the Investor Relations Department. In 1993, I was promoted to Manager of Investor Relations, with managerial responsibility for Investor Relations and Shareholder Services Departments for Southwest. While in these positions, I was responsible for primary contact with the financial community, including institutional shareholders, portfolio managers, and specialists with the New York Stock Exchange. Further responsibilities included developing shareholder

communications, including annual and quarterly reports, as well as presentations and analyses for financial analysts, compliance with regulatory reporting and disclosure requirements, and being a member of the National Investor Relations Institute.

In January 2001, I was promoted to Senior Manager of Corporate Human Resources. My responsibilities included directing and managing executive, exempt, and nonexempt employee compensation programs; reviewing compensation trends throughout relevant industries and initiating action to ensure Company compensation programs are competitive and cost-effective; and all employment functions. These employment functions included employee relations; staffing; and equal employment opportunity (EEO) matters. I also managed the development and integrity of the Human Resources information systems. I continued to direct the Shareholder Services Department, which includes transfer agent and stock registration activities, annual meetings, proxy solicitation, and administration of the Dividend Reinvestment and Stock Purchase Plan.

In 2005, I was promoted to my present position as Director/Corporate Human Resources. In addition to the responsibilities mentioned above, I am responsible for the consistency of employee benefits programs throughout the Company. The Benefits Department identifies benefit program requirements and regulations, establishes and

tracks benefit budgets and is responsible for administering employee welfare, investment and retirement plans.

In addition, the Benefits and Compensation Departments work together to build employee awareness of total compensation which encompasses cash compensation and benefits.

Comparison of Major Western Energy Utilities' Executive Compensation per Customer and Number of Customers Served per Employee

Utility/(Stock Symbol)	Total Compensation of the Five Highest Paid Executives (000)	Number of Customers Served (000)	Number of Employees	Number of Customers Served per Employee	Executive Compensation per Customer
Sempra Energy (SRE)	$ 28,047	7,823	14,061	556	$ 3.59
Southern California Edison (EIX)	25,336	4,812	16,139	298	5.26
Pacific Gas & Electric (PCG)	15,071	9,252	20,400	453	1.63
Pinnacle West (PNW)	13,730	1,075	7,400	145	12.77
Questar (STR)	9,291	851	2,188	389	10.92
Sierra Pacific (SRP)	8,284	1,314	3,212	409	6.30
Avista (AVA)	7,321	650	1,995	326	11.26
PNM Resources (PNM)	6,980	1,191	3,294	362	5.86
Puget Sound (PSD)	5,994	1,752	2,400	730	3.42
Unisource (UNS)	4,650	631	1,732	364	7.37
Southwest Gas (SWX)	**4,410**	**1,784**	**2,525**	**707**	**2.47**
Northwest Natural (NWN)	3,997	637	1,211	526	6.27
Portland General (POR)	3,429	793	2,635	301	4.32

Exhibit No.___(LLH-1)
Sheet 1 of 1

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
Docket No. G-01551A-07-0504

PREPARED REBUTTAL TESTIMONY
OF
LAURA LOPEZ HOBBS

ON BEHALF OF
SOUTHWEST GAS CORPORATION

May 9, 2008

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Of
LAURA LOPEZ HOBBS

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Rebuttal Exhibit No.__(LLH-1)

Rebuttal Exhibit No.__(LLH-2)

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rebuttal Testimony
of
Laura Lopez Hobbs

I. INTRODUCTION

Q. 1 Please state your name, business address, and position.

A. 1 My name is Laura Lopez Hobbs. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150-0002. I am employed by Southwest Gas Corporation (Southwest or the Company) as Vice President of Human Resources.

Q. 2 Did you sponsor direct testimony on behalf of Southwest in this proceeding?

A. 2 Yes.

Q. 3 What is the purpose of your prepared rebuttal testimony?

A. 3 The purpose of my prepared rebuttal testimony is to respond to the direct testimony presented by Mr. Ralph Smith, witness for the Arizona Corporation Commission (ACC) Utilities Division Staff (Staff), and Mr. Rodney Moore, witness for the Residential Utility Consumer Office (RUCO), regarding their recommendations and comments concerning the Company's Management Incentive Program (MIP), other stock-based compensation, and its Supplemental Executive Retirement Plan (SERP) expenses.

II. SOUTHWEST'S POSITION ON INCENTIVE PAYMENTS

Q. 4 Why does Southwest believe it should be allowed cost

recovery of incentive payments?

A. 4 As discussed in my prefiled direct testimony, Southwest's incentive payments are calculated and paid to qualified employees based on reliability, safety, cost-efficiency and customer satisfaction targets directly related to the provision of natural gas service. In order to ensure customers receive the most reliable and cost-effective gas service, Southwest must attract, retain and motivate a skilled and highly competent work force capable of meeting and even exceeding customer expectations. My analysis of compensation in the utility industry proxy groups demonstrates that annual variable pay, in addition to base pay, is standard in the industry. Base salary plus annual variable pay is defined as total compensation for the Company's qualified employees. Southwest's total executive compensation is much less than the market average and is reasonable, as shown in Exhibit No.__(LLH-1) of my prepared direct testimony. The fact that Southwest's executive compensation per customer is much lower than that of the other major western energy utilities, including Pinnacle West and Unisource, was given no weight by Staff and RUCO. As such, it is appropriate for customers to bear these costs as they do other reasonable costs of service.

III. STAFF'S AND RUCO'S RECOMMENDATIONS REGARDING THE COMPANY'S MIP EXPENSES

Q. 5 Do Staff and RUCO make any recommendations regarding the

Company's MIP?

A. 5 Yes. In their direct testimony, both Staff witness, Mr. Smith, and RUCO witness, Mr. Moore, recommend a 50/50 sharing as "a reasonable balancing of the interests between ratepayers and shareholders." See Smith Direct, page 26 and Moore Direct, page 29.

Q. 6 Do you agree with Staff's and RUCO's adjustments related to the MIP?

A. 6 No, I do not. The sharing concept relating to the Company's MIP expense is premised upon a false assumption that the program is an additional cost to customers. To the contrary, I believe the information the Company provided demonstrates that the MIP expense results in savings to customers. The program provides a valuable management tool to promote additional cost savings, to promote financial health, to motivate individual employees, to encourage groups of employees to work together to impact specific goals, and to aid in the retention of the higher-performing individuals. Each of these benefits is ultimately passed on to customers. The goals or targets of the current MIP are also heavily weighted toward providing benefits to customers. Identifying which of the goals is a greater benefit to whom in deciding cost recovery is irrelevant. Penalizing the Company for utilizing an employee program that reduces costs to customers, promotes increased safety, provides increased customer services, reduces other costs

and increases the financial soundness of the Company is unreasonable and bad policy. Furthermore, Staff and RUCO's "sharing" recommendation essentially encourages the Company to eliminate management incentive compensation as a component of total compensation, which would negate any benefits that are currently being received by customers as a result of the at-risk structure of the incentive compensation.

IV. SOUTHWEST'S STOCK-BASED INCENTIVE EXPENSES

Q. 7 Does Staff make any recommendations regarding Southwest stock-based incentive expenses?

A. 7 Yes. Staff witness Mr. Smith at page 36 of his direct testimony recommends the removal of the Company's stock option compensation expense allocated for Arizona cost recovery.

Q. 8 Do you agree with Staff witness Mr. Smith's contention at page 34 of his direct testimony that a stock-based incentive program provides an incentive for an employee to perform "in a manner that could negatively affect the Company's provision of safe, reliable utility service at a reasonable rate"?

A. 8 No. Southwest takes issue with Mr. Smith's insinuation that Southwest management would perform in a manner that could negatively affect the Company's provision of safe, reliable utility service. As discussed earlier in my prepared rebuttal testimony, Southwest's MIP uses five measures to determine the short-term and long-term

payouts to qualified employees. The customer satisfaction and customer-to-employee ratios both serve as counter balances for return on equity measures. Management clearly has no incentive to cut corners on customer safety expenditures or reduce staff, such that customer satisfaction suffers.

V. STAFF'S AND RUCO'S RECOMMENDATIONS REGARDING THE COMPANY'S SERP EXPENSES

Q. 9 Do Staff and RUCO make any recommendations concerning the Company's SERP expenses in this proceeding?

A. 9 Both Staff and RUCO are recommending the disallowance of 100 percent of the Company's SERP expenses.

Q. 10 Do you agree with Mr. Moore's statement at page 30 of his direct testimony that providing the SERP to officers of the Company is an unnecessary cost of providing natural gas service?

A. 10 No, I believe that such a program is a necessary cost of providing service because it is part of the Company's overall executive compensation, which neither RUCO nor Staff has deemed unreasonable. As Staff witness Mr. Smith recognizes, companies provide SERP benefits to attract and retain qualified employees. RUCO witness, Mr. Moore asserts that because executives are "fairly compensated for their work" and are "provided with a wide array of benefits including medical plan, dental plan, life insurance, long term disability, paid absence time

and a retirement plan" that no other cost of benefits should be borne by the customer.[1]

Q. 11 Is the payout under the Company's SERP guaranteed to qualified employees?

A. 11 No. The SERP is an unqualified plan and, as such, payments are not guaranteed (i.e., participants are general creditors of the corporation). Benefits from the qualified retirement plan for a vested, 30 year employee typically equal 50 percent of the employee's final salary. The SERP only makes up the difference between the benefits from the qualified plan. Benefits from the SERP, when added to the benefits received under the basic retirement plan, will equal 60 percent of annual compensation for senior executives, and 50 percent of annual compensation for all others.

Q. 12 Are SERP benefits standard in the natural gas industry?

A. 12 Yes. Contrary to both Staff's and RUCO's testimony, each of the proxy groups used in my analysis of total executive compensation provides such a plan. Furthermore, contrary to both Staff witness Mr. Smith's and RUCO witness Mr. Moore's assertion that SERP is not a necessary cost of providing natural gas service, Mr. Moore could not identify a single gas or electric utility that offers a qualified defined benefit pension plan, but that does not provide officers with a supplemental

[1] Moore Direct at page 30.

executive retirement plan.[2] (See RUCO response to Southwest Data Request 2.5, Rebuttal Exhibit No.__(LLH-1)) Mr. Moore also could not identify a single gas or electric utility that does not provide officers with a supplemental executive retirement plan, regardless of whether the company offers a qualified defined benefit pension plan.[3] (See RUCO response to Southwest Data Request 2.6, Rebuttal Exhibit No.__(LLH-2)) Mr. Smith's and Mr. Moore's assertion that SERP is not a necessary cost of doing business as a utility is inconsistent with the reality that such plans are a standard imprint of natural gas utility executive compensation.

Q. 13 Please summarize your prepared rebuttal testimony.

A. 13 Southwest has proven that the Company's total executive compensation expenses are prudently managed and reasonable. Neither Staff nor RUCO have offered testimony that the Company's total executive compensation is unreasonable. As such, it is appropriate for the Company to be permitted to recover these costs as they do other reasonable costs of service. MIP, stock-based compensation, and SERP are key components of Southwest's prudently managed total executive compensation expense and are vital to the Company's attraction and retention

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[2] Mr. Smith simply made no attempt to conduct such an investigation. See Staff response to Southwest Data Request 2.40.

[3] Mr. Smith simply made no attempt to conduct such an investigation. See Staff response to Southwest Data Request 2.41.

of highly-skilled employees, which ultimately benefits customers.

Q. 14 Does this conclude your prepared rebuttal testimony?

A. 14 Yes, it does.

SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-07-0504

RESIDENTIAL UTILITY CONSUMER OFFICE'S ("RUCO")
RESPONSE TO SOUTHWEST GAS CORPORATION'S
SECOND SET OF DATA REQUESTS

2.5 Please identify all gas or electric utilities that you are aware of that offer a qualified defined benefit pension plan, but that does not provide officers with a supplemental executive retirement plan.

Response: Rodney L. Moore

I am not aware of any.

SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-07-0504

RESIDENTIAL UTILITY CONSUMER OFFICE'S ("RUCO")
RESPONSE TO SOUTHWEST GAS CORPORATION'S
SECOND SET OF DATA REQUESTS

2.6 Please identify all gas or electric utilities that you are aware of that do not provide officers with a supplemental executive retirement plan, regardless of whether they offer a qualified defined benefit pension plan.

Response: Rodney L. Moore

I am not aware of any.

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
Docket No. G-01551A-07-0504

PREPARED REJOINDER TESTIMONY
OF
LAURA LOPEZ HOBBS

ON BEHALF OF
SOUTHWEST GAS CORPORATION

June 9, 2008

Southwest Gas Corporation
Docket No. G-01551A-07-0504

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Of
LAURA LOPEZ HOBBS

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Southwest Gas Corporation
Docket No. G-01551A-07-0504

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rejoinder Testimony
Of
LAURA LOPEZ HOBBS

INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Laura Lopez Hobbs. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150.

Q. 2 Did you sponsor direct and rebuttal testimony on behalf of Southwest Gas Corporation (Southwest or Company) in this proceeding?

A. 2 Yes.

Q. 3 What is the purpose of your rejoinder testimony?

A. 3 The purpose of my rejoinder testimony is to respond to aspects of the surrebuttal testimony presented by Ralph Smith, witness for the Arizona Corporation Commission Utilities Division Staff (Staff) regarding his recommendations and comments concerning the Company's executive compensation expenses.

Q. 4 Please summarize the specific issues your rejoinder testimony will address.

A. 4 My rejoinder testimony will address certain comments made by Mr. Smith in his surrebuttal testimony concerning the Company's Management Incentive Program (MIP), other stock-based compensation and

Supplemental Executive Retirement Plan (SERP) expenses.

MIP

Q. 5 Mr. Smith's testimony states that "SWG's employee salaries have continued to increase each year. Thus the MIP is an additional expense." Do you agree with this assertion?

Q. 5 No. I believe that Mr. Smith's assertion is flawed because the MIP is not an additional expense, but a reasonable necessary expense in order for Southwest to remain competitive and be able to attract, retain and motivate management employees. In 1994, Southwest contracted with the Wyatt Company (Wyatt) to conduct a study of management compensation. The study reviewed all compensation and benefit plans for 174 executives, managers and supervisors. Based upon this review, it was evident that the Company's total compensation was below market. Therefore, in order to be able to compete in the marketplace for the attraction and retention of qualified management-level employees, Southwest implemented its MIP in 1995. Rather than significantly increasing guaranteed base pay, management increased total compensation by adding a risk-based performance component that would pay only if certain measures were met. As such, Mr. Smith's assertion that the MIP is an additional expense is inaccurate.

Q. 6 Do you believe it is appropriate for the Commission to treat all utilities under its jurisdiction the same with respect to the equal sharing of utility incentive compensation expense?

A. 6 No. Although the Commission has previously ordered the equal sharing of utility incentive compensation for Southwest as well as other utilities, the Company believes that its situation is distinguishable from other Arizona utilities and thus, merits different treatment. Southwest has demonstrated in this proceeding that its total compensation expenses are conservative and reasonable, especially when compared to the Company's peers. See Hobbs Direct Testimony at pages, 3, 5-6. As a multi-jurisdictional utility, Southwest allocates the cost of executive compensation across a greater number of customers thereby significantly reducing the cost to Arizona customers. As such, the 50/50 sharing allocation is, in essence, punitive for Southwest since, unlike other Arizona utilities, its executive compensation expenses are already divided among three states.

Q. 7 Is Mr. Smith's contention that the Company's MIP expense in the current rate case is 76 percent higher than in its prior rate case correct?

A. 7 No, it is not. Mr. Smith appears to base his analysis on inaccurate data. Southwest's MIP expenses are actually lower in the current proceeding

than in the last rate case. For further explanation, please see the rejoinder testimony of Southwest witness Randi Aldridge.

STOCK-BASED COMPENSATION

Q. 8 Why should the Company's stock-based compensation be allowed?

A. 8 As stated in my previous testimony, Southwest's total executive compensation is reasonable and conservative when measured against its peer group. Because the Company has demonstrated the reasonableness of its total executive compensation, I believe that stock-based incentive compensation should be allowed. Rather than disputing the reasonableness of such compensation, Mr. Smith's surrebuttal testimony merely reiterates his allegation that stock-based compensation could "potentially" incent Company employees to cut corners in order to enhance earnings. While acknowledging that there is no evidence that Southwest's management is performing in a manner that could negatively affect its quality of service, Mr. Smith continues to base his argument on the disallowance rationale in the most recent APS and UNS rate cases.

However, Southwest's controls make it highly unlikely that one person within a business unit of Southwest could exert such control and influence over budget decisions that the person's conduct could

dramatically impact the stock price. And to the extent that any one person could significantly impact the amount of money expended on maintenance or other costs which affect the quality of service, the probability that such reductions in expenditures actually impact the stock price is virtually non-existent. There are numerous factors that impact stock price, and to suggest that the Company or any individual can manipulate the stock price by simply reducing expenditures is illogical. In addition, to the extent that the quality of service is reduced, customer satisfaction is likely to decline. Any such decline in customer satisfaction will directly impact the incentive pay, including stock, received through the MIP. The employees receiving stock-based compensation are the same employees that are eligible for the MIP, and any cost cutting measures that affect customer satisfaction will directly impact that employee's incentive pay.

Further, as explained in my prefiled direct testimony, the Company's stock-based incentive plans are paid out over a period of three years, which is designed to be incentive to retain employees. With the stock-based incentive plans being staggered over a three year period, even if an employee could hypothetically impact the stock price in the short term there is really no incentive to do so because

the employee is not fully vested with his/her stock-based compensation. As such, Mr. Smith's argument regarding stock-based compensation is without merit.

SERP

Q. 9 Why should the Company's SERP expense be allowed?

A. 9 As Southwest has demonstrated, the Company's SERP expenses are a necessary cost of providing safe, efficient, and reliable service. In fact, both Staff and RUCO have acknowledged that every gas or electric utility of which they are aware, offers such a program. See Residential Utility Consumer Office's (RUCO) Response to SWG DR 2-5 and 2-6; Staff's Response to SWG DR 2-40 and 2-41, attached hereto. Without such a program, Southwest would be at a significant disadvantage in the competition for and the retention of qualified individuals.

Q. 10 Does this conclude your prepared rejoinder testimony?

A. 10 Yes, it does.

SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-07-0504

RESIDENTIAL UTILITY CONSUMER OFFICE'S ("RUCO")
RESPONSE TO SOUTHWEST GAS CORPORATION'S
SECOND SET OF DATA REQUESTS

2.5 Please identify all gas or electric utilities that you are aware of that offer a qualified defined benefit pension plan, but that does not provide officers with a supplemental executive retirement plan.

Response: Rodney L. Moore

I am not aware of any.

SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-07-0504

RESIDENTIAL UTILITY CONSUMER OFFICE'S ("RUCO")
RESPONSE TO SOUTHWEST GAS CORPORATION'S
SECOND SET OF DATA REQUESTS

2.6 Please identify all gas or electric utilities that you are aware of that do not provide officers with a supplemental executive retirement plan, regardless of whether they offer a qualified defined benefit pension plan.

Response: Rodney L. Moore

I am not aware of any.

applicable to all other employees it may do so at the expense of its shareholders. However, it is not reasonable to place this additional burden on ratepayers.

A utility's SERP expense was also disallowed in the Commission's recent decision in the rate case involving UNS Gas, Inc. See Decision No. 70011 (dated 11-27-07) at pages 27-29. Notably, at page 28 of that Decision, the Commission stated:

> **... the issue is not whether UNS may provide compensation to select executives in excess of the retirement limits allowed by the IRS, but whether ratepayers should be saddled with costs of executive benefits that exceed the treatment allowed for all other employees. If the Company chooses to do so, shareholders rather than ratepayers should be responsible for the retirement benefits afforded only to those executives. We see no reason to depart from the rational on this issue in the most recent Southwest Gas rate case [See also Arizona Public Service Co., Decision No. 69663, at 27 (June 28, 2007), wherein SERP costs were excluded in their entirety.], and we therefore adopt the recommendations of Staff and RUCO and disallow the requested SERP costs.**
>
> **Consequently, Mr. Smith has recommended an adjustment related to SWG's SERP expense specifically to remove SWG's expense for the SERP, which is shown on Schedule C-5 and reduces O&M expense by $1.625 million.**

40) Please identify all gas or electric utilities that you are aware of that offer a qualified defined benefit pension plan, but that do not provide officers with a supplemental executive retirement plan.

Answer: The number and/or specific identity of other gas or electric utilities that may have offered a qualified defined benefit pension plan, but that do not provide officers with a supplemental executive retirement plan, did not appear to be a consideration used by the Commission in Decision No. 68487 (February 23, 2006), in Southwest's last rate case, or in Decision No. 70011 (November 27, 2007), in the recent UNS Gas rate case, Docket No. G-04204-06-0463 et al, wherein the Commission disallowed Southwest's and UNSG's SERP expense, respectively, so Mr. Smith did not attempt to conduct such research.

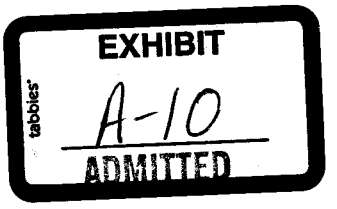
41) Please identify all gas or electric utilities that you are aware of that do not provide officers with a supplemental executive retirement plan, regardless of whether they offer a qualified defined benefit pension plan.

Answer: The number and/or specific identity of other gas or electric utilities that may not have provided officers with a supplemental executive retirement plan, did not appear to be a consideration used by the Commission in Decision No. 68487 (February 23, 2006), in

Southwest's last rate case, or in Decision No. 70011 (November 27, 2007), in the recent UNS Gas rate case, Docket No. G-04204-06-0463 et al, wherein the Commission disallowed Southwest's and UNSG's SERP expense, respectively, so Mr. Smith did not attempt to conduct such research.

42) Please produce copies of all responses, formal and informal, provided by Staff in response to data requests from any other party to this proceeding in the above-captioned docket.

Answer: None to date.



IN THE MATTER OF
SOUTHWEST GAS CORPORATION
Docket No. G-01551A-07-___

PREPARED DIRECT TESTIMONY
OF
RANDI L. ALDRIDGE

ON BEHALF OF
SOUTHWEST GAS CORPORATION

August 31, 2007

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Of
Prepared Direct Testimony
Of
RANDI L. ALDRIDGE

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Appendix A - Summary of Qualifications of James L. Cattanach

Exhibit No.___(RLA-1)

Exhibit No.___(RLA-2)

Southwest Gas Corporation
Docket No. G-01551A-07-___

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
Of
RANDI L. ALDRIDGE

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Randi L. Aldridge. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150.

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 Supervisor/Revenue Requirements.

Q. 3 Please describe Appendix A.

A. 3 Appendix A describes my educational and business background.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 Yes, I testified before the Arizona Corporation Commission (ACC or the Commission), 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 First, I describe the Company's natural gas operations. Then I explain how the Company determines whether costs are assigned directly to one or more ratemaking jurisdictions or allocated to all rate jurisdictions,

along with a description of the allocation methodologies Southwest uses to allocate common costs. Next, I explain the rate case adjustments that I am sponsoring.

Finally, I describe how the Company has complied with the Commission's directive in Southwest's last general rate case to: 1) address how Southwest and its customers benefit from the activities of the American Gas Association (AGA); and 2) provide a detailed explanation of the duties that are associated with "sales, marketing, or promotional activities" of certain employees and offer a reasonable allocation of wage expense consistent with those duties.

II. DESCRIPTION OF NATURAL GAS UTILITY OPERATIONS

Q. 6 Please describe Southwest's natural gas operations.

A. 6 Southwest is primarily a natural gas local distribution company, providing service to over 1.7 million customers in three states. At the end of the test year, Southwest served over 945,000 customers in Arizona, or nearly 54 percent of its total customer base. Southwest has eight (8) ratemaking jurisdictions subject to the regulation of the ACC, the PUCN, the CPUC, and the Federal Energy Regulatory Commission (FERC). These eight ratemaking jurisdictions are as follows: Arizona, Southern Nevada, Northern Nevada, Southern California, Northern California, South Lake Tahoe, Paiute Pipeline Company (Paiute) and Southwest Gas Transmission Company (SGTC).

Southwest's operations are divided geographically

into five (5) operating divisions: Southern California, Northern Nevada, Southern Nevada, Central Arizona, and Southern Arizona. Each division operates independently of the others and may include portions of multiple ratemaking jurisdictions. All divisions are supported by Corporate staff.

III. JURISDICTIONAL COST RESPONSIBILITY AND ALLOCATIONS

Q. 7 Briefly describe how costs associated with Southwest's natural gas operations are treated in this rate application.

A. 7 Both operating and capital costs are incurred at the division level and 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 may be charged to one or more rate jurisdictions if the cost/activity was incurred on its behalf (i.e., "Corporate Direct" costs). Corporate costs that are beneficial to all of the Company's rate jurisdictions, or where the effort of tracking the jurisdictional allocation of the costs is burdensome and not cost justified, are allocated to all rate jurisdictions (i.e. "common" or "System Allocable" costs).

Q. 8 What do System Allocable costs consist of?

A. 8 System Allocable costs are primarily corporate administrative and general (A&G) expenses, and the costs associated with intangible plant (primarily software)

and general plant used to support the corporate administrative staff.

Q. 9 How does the Company allocate these common costs to Paiute and SGTC?

A. 9 System Allocable A&G expenses (except Account 924, Property Insurance) are first allocated to Paiute and SGTC using the Modified Massachusetts Formula (MMF), a FERC-authorized methodology that is calculated on Schedule C-1, Sheet 18. Property Insurance is allocated using an insurable property factor (Workpapers Schedule C-2). Paiute is also charged a rental fee for its use of System Allocable intangible and general plant.

System Allocable costs that are allocated and charged to Paiute are transferred to and recorded on Paiute's books monthly. Consequently, System Allocable A&G expenses shown on Southwest's books are net of the allocations to Paiute.

For this rate application, the MMF, the insurable property factor, and the Paiute rental charge were recalculated using end of test year data. The resulting pro forma adjustment is presented in Adjustment No. 12, which is discussed in more detail later in my testimony.

Q. 10 After System Allocable costs are allocated to Paiute and SGTC, how are the remaining costs allocated to Southwest's retail ratemaking jurisdictions?

A. 10 Property Insurance costs are allocated to each retail ratemaking jurisdiction using the same insurable

property factor discussed previously, and the remaining System Allocable costs are allocated using the 4-Factor allocation methodology as described below.

Q. 11 Please describe the 4-Factor Allocation Methodology.

A. 11 The 4-Factor is based on the average of four equally-weighted components: (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 17 provides the development of the 4-Factor allocation percentages for the test year.

IV. RATE CASE ADJUSTMENTS

A. Adjustment No. 3 - Labor

Q. 12 Please explain the adjustments you are supporting, starting with Adjustment No. 3, Labor.

A. 12 Adjustment No. 3 annualizes the labor and related labor loadings of Arizona and Corporate Staff employees employed by the Company at April 30, 2007.

The labor and labor loading annualization adjustment includes three 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 beginning prior to April 30, 2007. Secondly, it annualizes labor loadings at the end of the test year and applies those costs to the employees on Southwest's

payroll at the end of the test year. Finally, the labor adjustment reflects the actual three percent general wage increase effective June 25, 2007, an estimated three percent general wage increase to be effective in June 2008, along with additional wage increases as a result of within-grade movement during the twelve months subsequent to the end of the test year (i.e., through April 2008).

Q. 13 Why is it appropriate to adjust labor expense for the 2007 and 2008 wage increases and within-grade movement?

A. 13 Under current Commission guidelines for processing major rate applications, it is expected that the hearing in this proceeding will not be conducted before June 2008. Historically, the Company has granted general wage increases effective each June after being approved by the Company's Board of Directors in May. Therefore, the year 2007 wage increase is known and measurable, and the 2008 wage increase and post-test year within-grade wage increases will be known and measurable prior to the hearing in this proceeding. As such, Staff and other interveners will have an opportunity to verify and quantify the 2008 wage increase and post-test year within grade movement.

Q. 14 Does this post-test year adjustment violate the matching principle?

A. 14 No. This adjustment only applies to employees on the payroll at April 30, 2007, the end of the test year. It

does not apply to any employees hired after April 30, 2007 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 serve. 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 six percent more than the wages in effect at the end of the test year.

Q. 15 Have previous Commission rulings in the Company's rate applications addressed this adjustment?

A. 15 Yes. The Commission has consistently allowed Southwest's post test year wage increases. Most recently, in Decision No. 68487, the Commission found that the "…wage increase should be allowed because it is a known and measurable expense that is being incurred by the Company on a going-forward basis. Because the post-test year wage increase has been applied only to employees who were employed during the test year, there is no resulting mismatch of revenue and expenses."

Q. 16 Please describe the labor loading process.

A. 16 Pensions, benefits and payroll taxes are accumulated at the corporate level. These costs are then distributed amongst the various jurisdictions through a labor loading process. The labor loading rate is adjusted at the beginning of each year, based on budgeted pensions,

benefits, and payroll taxes and expected employee levels. The labor loading process applies the labor loading rate to each labor dollar, assigning an appropriate amount of pensions, benefits, and payroll taxes to each account to which labor has been charged.

Q 17 How were labor loadings for Arizona and Corporate Staff employees annualized?

A. 17 For benefits with premiums or regular monthly payments, I used the amount recorded in April 2007 times twelve months to more accurately reflect current expenses. If there were thirteen payments during the test year for any item, the extra payment was removed. For pensions, post employment benefits other than pension (PBOP), and supplemental executive retirement plan (SERP), Southwest's uses the most recent actuarial studies as the basis for the labor loading annualization. The Company removes certain costs in the Miscellaneous Benefits account from the cost of service, such as costs related to service awards, employee events, and employee recognition, consistent with prior Commission decisions. In addition, payroll taxes and indirect time were adjusted for the impact of annualizing payroll and overtime. For remaining costs in Account 926, recorded test year costs were used as the basis for the annualization.

There are two methods used to allocate labor loading costs to Arizona. First, the cost of pensions, PBOP,

SERP, 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 adjusted cost divided by the average number of total Company employees during the test year. The cost per employee was multiplied by the number of jurisdictional employees at the end of the test year to determine the amount allocated to Arizona for ratemaking purposes.

Q. 18 Once the annualized labor and labor loadings were calculated, how was the adjustment determined?

A. 18 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 80 percent of Arizona direct labor and loadings were charged to operations and maintenance (O&M) accounts. Therefore, 80 percent of the annualized Arizona direct labor and loadings were assigned to operations and maintenance accounts. The difference between the annualized labor and loadings assigned to the O&M accounts and recorded labor and loadings is the adjustment for that account. As approximately 80 percent of the annualized Arizona direct labor and loadings were assigned to O&M, the remaining 20 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 loadings to determine the adjustment required.

B. Adjustment No. 4 - Customer Billing

Q. 19 Please explain Adjustment No. 4, Customer Billing.

A. 19 Adjustment No. 4 annualizes costs associated with the customer billing function, such as bill stock, toner, envelopes, and postage, to account for the difference between recorded and annualized bills.

This annualization also takes into account the recent increase in postage of two cents per piece of first class mail, which was effective May 14, 2007. Southwest applied this increase to the annualized number of bills. Such an adjustment is consistent with Southwest's proposal in its most recent general rate case, which was approved by the Commission.

C. Adjustment No. 5 - Miscellaneous Adjustments

Q. 20 Please explain Adjustment No. 5, Miscellaneous Adjustments.

A. 20 Adjustment No. 5 identifies a number of items recorded during the test year for which Southwest is not requesting recovery in this proceeding. The amounts removed from the cost of service are summarized by account in Schedule C-2, Adjustment No. 5, and the supporting workpapers categorize the transactions removed by type of cost.

D. Adjustment No. 6 - Vehicle Compensation

Q. 21 Please explain Adjustment No. 6, Vehicle Compensation.

A. 21 Adjustment No. 6 removes the cost of Company vehicles related to personal use from test year expenses. This adjustment is consistent with Southwest's proposal in its most recent general rate case, which was approved by the Commission.

E. Adjustment No. 7 - Out-Of-Period Expenses

Q. 22 Please explain Adjustment No. 7, Out-of-Period Expenses.

A. 22 Adjustment No. 7, Out-of-Period Expenses, adjusts test year expenses for payments made to two vendors.

The payments made to the first vendor were charged to the Southern Nevada jurisdiction in error during the test year, but the correcting journal entry moving these charges to the Arizona jurisdiction was made subsequent to the end of the test year. This adjustment adds the correcting journal entry to test year expenses.

A reclassification journal entry was made during the test year for payments made to a second vendor, reducing test year expenses to correct an error for an expense that was incurred prior to the test year. This adjustment reverses the reclassification journal entry.

Q. 23 Which transactions were reviewed for the Out-of-Period Expenses adjustment?

A. 23 All Arizona jurisdictional expenses exceeding $50,000 were evaluated to determine whether an adjustment was necessary. This adjustment is consistent with Southwest's proposal in its most recent general rate

case, which was approved by the Commission.

F. Adjustment No. 11 - AGA Dues

Q. 24 Explain Adjustment No. 11, AGA Dues.

A. 24 Adjustment No. 11 removes the portion of the Company's dues to the AGA identified as promotional or lobbying in nature. This adjustment is consistent with previous Commission decisions not allowing the recovery of the promotional and lobbying portion of the Company's AGA dues.

Q. 25 What is AGA?

A. 25 AGA is a trade and professional organization representing 200 natural gas utilities. AGA focuses on the collection, use, and dissemination of natural gas-related information.

Q. 26 In Decision No. 68487, the Commission directed Southwest to provide more information about the functions of AGA, and how AGA's activities benefit the Company and its customers. Are you the witness who is sponsoring testimony responsive to the Commission's directive?

A. 26 Yes. This topic is discussed later in my testimony in the "Compliance Items" section.

G. Adjustment No. 12 - Paiute/SGTC Allocation

Q. 27 Please explain Adjustment No. 12, Paiute/SGTC Allocation, which you previously referred in your response to Question No. 10.

A. 27 Adjustment No. 12 annualizes the System Allocable A&G amounts allocated to Paiute through the MMF allocation

methodology, and the insurable property factor, and the rent revenue that Southwest receives from Paiute for the test year ended April 30, 2007. The supporting workpapers to Adjustment No. 12 show the detailed calculations needed to derive the Paiute rent expense and insurable property factor at April 30, 2007. This adjustment is consistent with the methodology approved by the Commission in the Company's last several rate cases.

The annualized MMF allocation factors are also used in the pro forma adjustments that impact System Allocable A&G costs, in order to allocate a portion of the adjustment to Paiute and SGTC before calculating the portion that is allocated to Arizona.

H. Adjustment No. 13 - Rate Case Expense

Q. 28 Please explain Adjustment No. 13, Rate Case Expense.

A. 28 The Company estimated the incremental costs that would be incurred to prepare and 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. This adjustment is consistent with Southwest's proposal in its most recent general rate case, which was approved by the Commission.

I. Adjustment No. 14 - Depreciation and Amortization Expense

Q. 29 Please explain Adjustment No. 14, Depreciation and Amortization Expense.

A. 29 Adjustment No. 14 annualizes depreciation and amortization expense based on plant in service at April 30, 2007, using currently approved depreciation rates. The annualization also includes the depreciation and amortization related to the plant adjustments made in Adjustment No. 17, which is discussed in detail later in my testimony.

Q. 30 Please explain why an adjustment is necessary to annualize depreciation and amortization expense for the test year.

A. 30 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 test year 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 customers for assets removed/retired from service, depreciation and amortization must be annualized based on end of test year plant balances, as adjusted. This adjustment accomplishes those objectives, and is consistent with the methodology approved by the Commission in the Company's last several rate cases.

J. Adjustment No. 15 - Property Tax

Q. 31 Please explain Adjustment No. 15, Property Tax.

A. 31 Adjustment No. 15 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 April 30, 2007, adding materials and supplies, and subtracting transportation equipment and land rights. The estimated full cash value is then multiplied by the 2008 assessment rate of 23 percent to determine the assessed value. The assessed value is then multiplied by the estimated property tax rate of 11.52 percent to determine the annualized property tax expense.

Q. 32 Why is Southwest proposing to use the statutory assessment rate for 2008 in its property tax annualization, rather than the assessment rate applicable for 2007?

A. 32 Based on recent changes in Arizona law, Southwest based its property tax calculation on a known and measurable

change that will be applicable when rates from this proceeding go into effect in 2008. Utilizing the 2008 assessment rate is consistent with the methodology approved by the Commission in Southwest's last general rate case.

K. Adjustment No. 16 - Interest on Customer Deposits

Q. 33 Please explain Adjustment No. 16, Interest on Customer Deposits.

A. 33 Adjustment No. 16 synchronizes interest expense on customer deposits with the amount of customer deposits used as a rate base reduction. Consistent with prior Commission decisions, interest expense is treated as an above-the-line expense.

L. Adjustment No. 17 - Completed Construction not Classified

Q. 34 Describe Adjustment No. 17, Completed Construction not Classified (CCNC).

A. 34 Adjustment No. 17 comprises two parts. First, an adjustment was made to gas plant for plant serving customers but not recorded in Account 101 - Gas Plant in Service (GPIS) at the end of the test year. Second, an adjustment was made to System Allocable Intangible Plant to better match cost recovery of these projects (primarily software) to the plant that will be amortized during the period that rates from this proceeding will be in effect.

The gas plant included in this adjustment reflects construction expenditures made before the end of the

test year. No expenditures for tangible plant incurred after April 30, 2007 are included in the adjustment. The tangible plant represented by these expenditures (i.e., CCNC) 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 entering the required information into the Company's computer systems.

The CCNC 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 CCNC included in the adjustment are: 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 CCNC 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. 35 Please explain the portion of the CCNC adjustment made

to System Allocable miscellaneous intangible plant.

A. 35 Most of the items in System Allocable miscellaneous intangible plant (Account 303) are software projects with a three-year amortization period. This amortization period is roughly equivalent to the Company's Arizona rate case cycle. Absent an adjustment, customers may end up double-paying for certain projects, and never paying for other projects through rates. To ameliorate this phenomenon, the Company proposes an adjustment to remove all projects with an amortization period expiring December 31, 2007 or earlier from rate base, and adding estimated amounts for projects to be closed to plant prior to December 31, 2007 to rate base. This is a conservative adjustment because many small software projects spend a relatively short time in Construction Work in Progress before being transferred to plant. Consequently, between the date this rate case was prepared and the end of 2007, more projects may close to plant than was indicated by the estimated balances when this rate case was prepared. Furthermore, the amounts estimated by the Company can be verified prior to the hearing in this rate case.

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.

The CCNC adjustment is equitable to both the Company and its customers, and was approved by the Commission in Southwest's last general rate case.

V. COMPLIANCE ITEMS

A. Sales, Marketing, and Promotional Activities

Q. 36 In Southwest's last general rate case, the Commission disallowed 10 percent of the compensation of certain employees in the Service Planning and Key Accounts Management (KAM) departments based on a belief that some portion of the employees' duties related to the "sales, marketing, and promotional activities" of natural gas. In making the disallowance, the Commission relied on outdated job descriptions. The Commission directed the Company to provide detailed information regarding the duties of the Service Planning and KAM employees in its next rate case to determine if any disallowance is appropriate. Has the Company provided updated job descriptions?

A. 36 Yes. Attached as Exhibit No. ____(RLA-1) are the current job descriptions for the Southwest's Service Planning and KAM employees referred to above.

Q. 37 What are the duties of Southwest's Service Planning and KAM employees?

A. 37 These groups are primarily responsible for the coordination and installation of new services. Service Planning focuses on residential and commercial

customers. KAM focuses on Southwest's largest customers.

The Service Planning and KAM employees concentrate on the following activities, which are further detailed in the attached job descriptions:

- Ensuring Southwest's system expands in a cost-effective manner, while ensuring that existing customers are not harmed by customer growth;
- Maintaining and improving service quality and customer satisfaction; and
- Ensuring that the Company's infrastructure is used in the most efficient manner, which reduces the average cost for all customers since the Company's infrastructure costs are primarily fixed.

Q. 38 Why did Southwest update job descriptions in the Service Planning and Key Account Management (KAM) departments over the last several years?

A. 38 The natural gas market has changed substantially over the past ten years. Recognizing the demands of its customers are individually unique, Southwest shifted the priorities of its Service Planning and KAM employees to reflect the changes in the market and tailored the duties and responsibilities of these employees to more suitably meet the needs of new and existing customers. Because customers now demand that natural gas be available in their homes and for commercial use, the Company no longer finds it necessary to market and promote the use of natural gas in the same manner as it

did in the past. As part of the change in the marketplace and the Company's priorities, Southwest eliminated the "sales, marketing, and promotional activities" responsibilities. The current job descriptions reflect these market changes.

Q. 39 What is a reasonable allocation of compensation consistent with the job duties attached to your testimony?

A. 39 Southwest's Service Planning and KAM employees do not perform "marketing" or "sales" functions. All of the job duties of these employees provide clear benefits to customers. Southwest believes that the compensation for the Service Planning and KAM positions are just and reasonable and should be included in rates with no disallowance.

B. AGA Activities

Q. 40 You discussed the AGA in your testimony describing Adjustment No. 11. Why are you including additional information about AGA in this proceeding?

A. 40 In Decision No. 68487, the Commission directed Southwest to describe the various functions of the AGA, and how the AGA's activities provide benefits to the Company and its customers.

Q. 41 What are some of the AGA activities that benefit its member utilities and their customers?

A. 41 The AGA provides a number of services and programs benefiting its individual members. The AGA serves as a

leader of research and programs for the natural gas industry. The AGA's ability to concentrate its efforts solely on the natural gas industry allows individual gas utilities, such as Southwest, to focus on regional service and business issues while remaining abreast of industry trends through its AGA membership. Southwest can then implement the programs or research developed by the AGA to help maximize its business efficiencies. The benefits of the AGA's latest research and programs concern the areas of new equipment, service and technical processes, natural gas supply trends, and newly identified business processes.

Moreover, when a utility experiences a problem unique to the natural gas sector, the AGA serves as an intermediary for the exchange of approaches and solutions through direct information exchanges, such as e-mail, message boards, and telephone. Other informational exchanges include newsletters, magazines, and workshops/seminars on topics specific to the natural gas sector.

In addition, the AGA's Codes of Standards publications serve as a precise, accurate and uniform source for technical matters. This concentration of resources and information saves the Company a considerable amount of time and money, because it has direct access to a network of information exchanges. Of course, customers are the ultimate beneficiary of the

savings.

A good example is the AGA's sponsorship and publication of ANZI Z380.1, Guide for Gas Transmission and Distribution Piping, which this Commission has relied upon in its own rulemaking. See Arizona Administrative Code 14-5-202(R).

The AGA also develops and implements public information campaigns. The campaigns directly target specific markets and media to inform the public about the gas industry's operations and utility and regulatory activities. The nationwide campaigns and partnerships advance important issues to the public, such as safety, pricing, the environment, the availability of low income assistance programs, and the "Call Before You Dig" program.

The AGA benefits Southwest and its customers by increasing Southwest's efficiencies which reduces the amount of time and money the Company must spend conducting its own research, continuing education, and outreach.

Q. 42 Please describe the various AGA functions?

A. 42 Exhibit No. ___(RLA-2) provides a list and description of the AGA's functions as listed in the March 2005 Annual Audit report to the National Association of Regulatory Utility Commissioners (NARUC).

Q. 43 Does the AGA provide a cost savings analysis for benefits to the Company and its Arizona customers?

A. 43 Yes. In 2006, the AGA's programs, services and advocacy efforts provided its members with $479 million in outright savings or avoided costs. The AGA collected under $18 million in membership dues which resulted in more than a $27 return on every $1 in paid AGA dues.

Q. 44 Is Southwest requesting recovery for the AGA's marketing and lobbying activities?

Q. 44 No. In accordance with previous Commission decisions Southwest is not requesting the recovery of dues associated with marketing and lobbying activities.

Q. 45 Does this conclude your prepared direct testimony?

A. 45 Yes, it does.

SUMMARY OF QUALIFICATIONS
RANDI L. ALDRIDGE

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 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, in July 2003 I was promoted to Senior Specialist, and in May 2007 I was promoted to my present position. In my present position, I am responsible for supervising the activities of junior-level staff, as well as the preparation of general rate case filings for state and federal jurisdictions, the research, preparation, and presentation of various regulatory and financial analyses, studies, and reports, as well as other special projects.

I have attended numerous training and technical conferences related to utility ratemaking, regulatory, and accounting issues.

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 since 2003.

SOUTHWEST GAS CORPORATION
ARIZONA
JOB DESCRIPTION TABLE OF CONTENTS

Department	Job Title	Job Code
Service Planning	Utilization Engineer	ENG0002017
Service Planning	Service Planner	SP00002059
Service Planning	Sr Service Planner	SP00002060
Service Planning	Director/Service Planning/CAZ	SP00002062
Service Planning	Manager/Service Planning/SAZ	SP00002065
Service Planning	Manager/Service Planning/CAZ	SP00002067
Service Planning	Supervisor/Service Planning	SP00002068
Service Planning	Supervisor/Industrial Service Planning	SP00002012
Key Account Managment (KAM)	Supervisor	GS00002038
Key Account Managment (KAM)	Manager	GS00002054
Key Account Managment (KAM)	Senior Manager	GS00002044
Key Account Managment (KAM)	Industrial Gas Engineer	GS00002060

TITLE: **Energy Utilization Engineer**
JOB CODE: ENG0002017
DIVISION:
DEPARTMENT: Service Planning
DATE: August 19, 1987

APPROVED BY:_____ **DATE**_____
(For Sr. Evaluation Committee)

POSITION OVERVIEW

The incumbent is an individual contributor involved in energy services, engineering support, customer relations, trade relations and strategy & planning for a division of Southwest Gas Corporation.

POSITION DIMENSIONS

The incumbent does not have accountability for people or budgets.

NATURE AND SCOPE

The Energy Utilization Engineer reports to the Manager/Service Planning or Supervisor/Service Planning along with:

Note: This position involves the activities listed below. The activities in **bold** type are the most critical for this job. The activities marked with an asterisk (*) are those on which the incumbent spends the most time. (Asterisk may be added by supervisor for each incumbent.)

Customer Relations

The incumbent is personally responsible to:

Work with customer to determine technical needs and specifications
Advise customers on gas products and availability

The incumbent, with others, is responsible to:

Participate in customer business meetings as consultant/advisor
Assure continuing relationships with key customers
Investigate and settle customer complaints

The incumbent assists others to:

Establish and maintain contact with top management of important customers
Advise dealers and distributors of programs

Strategy, Planning And Execution

The incumbent assists others to:

Energy Utilization Engineer
ENG0002017

Implement plans for assigned market sectors
Keep abreast of industry strategies and tactics
Analyze legislation impacting company products or services

Trade Relations

The incumbent is personally responsible to:

Make presentations to trade allies or prospective customers

The incumbent, with others, is responsible to:

Represent the company at association meetings

The incumbent assists others to:

Formulate and implement plans for trade association activities

MISCELLANEOUS ACTIVITIES

The incumbent is personally responsible to:

Design HVAC systems for residential applications
Build and maintain relationships with manufacturers, distributors, dealers and builders
Provide customers and/or colleagues with technical information on products/services
Keep abreast of technology or other changes within the industry
Keep up-to-date on tariffs and regulations

The incumbent assists others to:

Achieve assigned margin goals
Establish budgets and goals
Keep up-to-date on government regulations impacting company products or services
Develop company displays for trade shows

OTHER REQUIREMENTS

There are standardized methods and procedures that determine how this job is performed. This position requires 3 to 4 years of relevant work experience.

In this job, the incumbent must be able to influence customers and government officials. The incumbent also frequently exchanges information with suppliers and infrequently with top management, senior management, department heads of units outside of marketing and outside consultants.

TITLE:	**Service Planner**
JOB CODE:	SP00002059
DIVISION:	All Divisions
DEPARTMENT:	Service Planning
DATE:	September 15, 2005

APPROVED BY:_____ **DATE**_____
(For Sr. Evaluation Committee)

POSITION OVERVIEW

The incumbent is an individual contributor as a Service Planner involved in Service Planning, Customer Relations, Trade Relations and Strategy for a division of Southwest Gas. The Service Planner may require assistance and general direction.

POSITION DIMENSIONS

The incumbent does not have accountability for people or budgets.

NATURE AND SCOPE

The Service Planner reports to the Supervisor/Service Planning or Manager/Service Planning along with Senior Service Planners. Job is limited in size, scope or complexity in negotiating contracts and projects.

Note: This position involves the activities listed below. The activities underlined or in **bold-faced** type are the most critical for this job. The activities marked with an asterisk (*) are those on which the incumbent spends the most time. (Asterisk may be added by supervisor for each incumbent.)

Service Planning Strategy and Execution

The incumbent is personally responsible and may need assistance to:

* **Build and maintain relationships with developers, builders and trade allies**
  Advise customers on gas products and availability
  Coordinate new business processes and contractual information requirements
  Work with customers to determine technical needs and specifications
* **Investigate, review and resolve issues to ensure customer satisfaction**
  Participate in customer business meetings as consultant/advisor
  Establish programs to educate customers
* **Interpret, apply and communicate tariffs to main/service extensions**

Service Planner
SP00002059

Ensure timely coordination of installation of natural gas facilities
Negotiate contracts/special agreements
Prepare studies and analyses
Make presentations to trade allies or potential customers
Participate in relevant trade associations
Keep up-to-date on government regulations impacting company products/ services
Keep abreast of technology or other changes within the industry.
Implement demand-side management programs
Provide customers and/or colleagues with technical information on products/ services
Provide Service Planning support material/demonstration equipment to distributors, dealers and customers

OTHER REQUIREMENTS

There are clear precedents and practices which the incumbent uses as guidelines to determine how this job is performed. A Bachelor's degree is preferred, plus 1-3 years of relevant work experience or equivalent experience.

In this job, the incumbent must be able to influence department heads of units outside of Service Planning, outside consultants, customers, and government officials. The incumbent also frequently exchanges information with suppliers and infrequently with top management and senior management.

TITLE:	**Senior Service Planner**
JOB CODE:	SP00002060
DIVISION:	All Divisions
DEPARTMENT:	Service Planning
DATE:	September 15, 2005

APPROVED BY:_____ **DATE**_____
(For Sr. Evaluation Committee)

POSITION OVERVIEW

The incumbent is an individual contributor as a Senior Service Planner involved in Service Planning, Customer Relations, Trade Relations and Strategy for a division of Southwest Gas. The Senior Service Planner may require assistance and general direction.

POSITION DIMENSIONS

The incumbent does not have accountability for people or budgets.

NATURE AND SCOPE

The Senior Service Planner reports to the Supervisor/Service Planning or Manager/Service Planning along with Service Planners.

Note: This position involves the activities listed below. The activities underlined or in **bold-faced** type are the most critical for this job. The activities marked with an asterisk (*) are those on which the incumbent spends the most time. (Asterisk may be added by supervisor for each incumbent.)

Service Planning Strategy and Execution

The incumbent is personally responsible and may need assistance to:

* **Build and maintain relationships with developers, builders and trade allies**
  Advise customers on gas products and availability
  Coordinate new business processes and contractual information requirements
  Work with customers to determine technical needs and specifications
* **Investigate, review and resolve issues to ensure customer satisfaction**
  Participate in customer business meetings as consultant/advisor
  Establish programs to educate customers
* **Interpret, apply and communicate tariffs to main/service extensions**

Senior Service Planner
SP00002060

Ensure timely coordination of installation of natural gas facilities
Negotiate contracts/special agreements
Prepare studies and analyses
Make presentations to trade allies or potential customers
Participate in relevant trade associations
Keep up-to-date on government regulations impacting company products/ services
Keep abreast of technology or other changes within the industry.
Implement demand-side management programs
Provide customers and/or colleagues with technical information on products/ services
Provide Service Planning support material/demonstration equipment to distributors, dealers and customers

OTHER REQUIREMENTS

There are clear precedents and practices which the incumbent uses as guidelines to determine how this job is performed. This position requires a Bachelor's degree plus 1-5 years of relevant work experience, or equivalent experience.

In this job, the incumbent must be able to influence department heads of units outside of Service Planning, outside consultants, customers, and government officials. The incumbent also frequently exchanges information with suppliers and infrequently with top management and senior management.

TITLE: **Director/Service Planning/CAZ**
JOB CODE: SP00002062
DIVISION: Central Arizona Division
DEPARTMENT: Service Planning
DATE: May 18, 2006

APPROVED BY:_____ **DATE:**_____
(For Sr. Evaluation Committee)

POSITION OVERVIEW

This position is provides strategic leadership and direction for Service Planning, Communications and Consumer Affair activities within the division.

POSITION DIMENSIONS

Budget Accountable For:	$5 – 10 million
Personnel Managed	11 - 15 Exempt Employees
	2 - 4 Non-Exempt Employees

This job has three levels reporting to it.

NATURE AND SCOPE

The Director/Service Planning reports to the Division Vice President along with General Manager/Operations, Director/Administration, Director/Division Support and Manager/Human Resources. Reporting to the incumbent are Manager/ Service Planning, Manager Communications, and Administrator/Consumer Affairs.

Note: This position involves the activities listed below. The activities in **bold**-faced type are the most critical for this job. The activities marked with an asterisk (*) are those on which the incumbent spends the most time. (Asterisks may be added by supervisor for each incumbent.)

Service Planning Strategy and Execution

The incumbent directs others who:

* **Manage the building and maintaining of relationships with developers, builders and trade allies**
* **Oversee those who advise customers on gas products and availability**
* **Coordinate new business processes and contractual information requirements**
  Work with customers to determine technical needs and specifications
* Participate in customer business meetings as consultant/advisor
  Interpret, apply and communicate tariffs to main/service extensions
  Ensure timely coordination of installation of natural gas facilities
* Negotiate contracts/special agreements

Director/Service Planning
SP00002062

Prepare studies and analyses
Represent the company in civic organizations

The incumbent is personally responsible to:

* **Develop strategies that enhance ability to serve growth areas**
* **Facilitate communication between Service Planning, General Managers and the division Vice President**

Communications

The incumbent directs others who:

* Represent the Company in dealings with the media
* **Propose, plan, execute and evaluate internal and external communication activities, programs and strategies**
* Manage division locally placed advertising
* **Develop communications programs relative to regulatory filings and other company actions**
* Maintain liaison with local and state agencies

The incumbent is personally responsible to:

* **Ensure division communications proactively meet needs of constituencies**

Consumer Affairs

The incumbent directs others who:

* **Create, support and enhance public, private, and non-profit sector relationships**
* **Administer Philanthropic and Civic giving**
* Facilitate employee volunteerism programs
* Serve as advocates for the division Low-Income Community Outreach programs
* Promote supplier diversity programs

The incumbent is personally responsible to:

* **Ensure consistency and accountability of Philanthropic and Civic programs**
* **Develop division strategy enhancing image with Consumer Affairs constituent groups**

Miscellaneous

The incumbent is personally responsible to:

* **Provide leadership to achieve departmental goals**

Director/Service Planning
SP00002062

* **Assure performance against codes, regulations and company standards in areas of responsibility**
* **Develop and implement strategic initiatives**
* Communicate corporate policy
* Provide oversight of budget and expenditures
* Maintain liaison with other departments of the organization
* Represent the company in ways that will enhance its image in the public and business sectors

OTHER REQUIREMENTS

There are broad precedents and practices which the incumbent uses as guidelines to determine how this job is performed. This position requires 7-10 years of relevant work experience. A Bachelor's degree is preferred.

In this job, the incumbent must be able to influence department heads, suppliers, outside consultants, customers, and government officials. The incumbent also frequently exchanges information with department heads, governmental officials and senior management.

TITLE:	**Manager/Service Planning/SA**
JOB CODE:	SP00002065
DIVISION:	Southern Arizona
DEPARTMENT:	Service Planning
DATE:	September 15, 2005

APPROVED BY:_____ **DATE**_____
(For Sr. Evaluation Committee)

POSITION OVERVIEW

The incumbent is concerned with Managing and Directing Service Planning related activities.

POSITION DIMENSIONS

Budget Accountable For:	$1.5 - $3.0 Million
Personnel Managed:	6 - 25 Exempt Employees 6 - 10 Nonexempt Employees

NATURE AND SCOPE

The Manager/Service Planning reports to the Director/Service Planning.

Note: This position involves the activities listed below. The activities underlined or in **bold-faced type** are the most critical for this job. The activities marked with an asterisk (*) are those on which the incumbent spends the most time. (Asterisk may be added by supervisor for each incumbent.)

Service Planning Strategy and Execution

The incumbent directs others who:

* **Build and maintain relationships with developers, builders and trade allies**
  Advise customers on gas products and availability
* **Coordinate new business processes and contractual information requirements**
  Work with customers to determine technical needs and specifications
* **Investigate, review and resolve issues to ensure satisfactory customer satisfaction**
* Participate in customer business meetings as consultant/advisor
  Establish programs to educate customers
  Interpret, apply and communicate tariffs to main/service extensions
  Ensure timely coordination of installation of natural gas facilities
* Negotiate contracts/special agreements

Manager/Service Planning/SA
SP00002065

Prepare studies and analyses
Make presentations to trade allies or potential customers
* Participate in relevant trade associations
Keep up-to-date on government regulations impacting company products/ services
Keep abreast of technology or other changes within the industry
Implement demand-side management programs
Provide customers and/or colleagues with technical information on products/ services
Provide Service Planning support material/demonstration equipment to distributors, dealers and customers

The incumbent is personally responsible to:

Ensure adequate and timely coordination of services
Interpret and apply tariffs to main and service extensions
Keep up-to-date on tariffs and regulations
Represent the company in civic organizations
Keep up-to-date on government regulations impacting company products or services
Keep abreast of technology or other changes within the industry

The incumbent assists others to:

Establish and maintain relationships with government and regulatory agencies

OTHER REQUIREMENTS

There are clear precedents and practices which the incumbent uses as guidelines to determine how this job is performed. This position requires a Bachelor's degree plus 8-10 years of relevant work experience, or equivalent experience.

In this job, the incumbent must be able to influence department heads of units outside of Service Planning, outside consultants, customers, and government officials. The incumbent also frequently exchanges information with suppliers and infrequently with top management and senior management.

TITLE:	**Manager/Service Planning/CAZ**
JOB CODE:	SP00002067
DIVISION:	Central Arizona
DEPARTMENT:	Service Planning
DATE:	September 15, 2006

APPROVED BY:_____ **DATE**_____
(For Sr. Evaluation Committee)

POSITION OVERVIEW

The incumbent directs Service Planning related activities including indirect oversight of Service Planning activities within the divisions New Business department. The incumbent also has indirect responsibility for Service Planning activities directly reporting to the division New Business Department.

POSITION DIMENSIONS

Budget Accountable For:	$1.5 - $3.0 Million
Personnel Managed:	6 - 8 Exempt Employees 1 - 3 Nonexempt Employees

NATURE AND SCOPE

The Manager/Service Planning is responsible for providing strategic direction for service planning activity for a division and reports to the Director/Service Planning, along with Manager Communications, Administrator/Consumer Affairs and an administrative secretary. Reporting to this position are Service Planning Supervisors.

Note: This position involves the activities listed below. The activities in **bold**-faced type are the most critical for this job. The activities marked with an asterisk (*) are those on which the incumbent spends the most time. (Asterisk may be added by supervisor for each incumbent.)

Service Planning Strategy and Execution

The incumbent directs others who:

* **Build and maintain relationships with developers, builders and trade allies Advise customers on gas products and availability**
* **Maintain liaison with developers and builders during design and construction phases**
* **Coordinate new business processes and contractual information requirements Work with customers to determine technical needs and specifications**

Manager/Service Planning/CAZ
SP00002067

* **Investigate, review and resolve issues to ensure customer satisfaction**
* Participate in customer business meetings as consultant/advisor
  Establish programs to educate customers
  Interpret, apply and communicate tariffs to main/service extensions
  Ensure timely coordination of installation of natural gas facilities
* Negotiate contracts/special agreements
  Prepare studies and analyses
  Make presentations to trade allies or potential customers
* Participate in relevant trade associations
  Keep up-to-date on government regulations impacting company products/ services
  Keep abreast of technology or other changes within the industry
  Implement demand-side management programs
  Provide customers and/or colleagues with technical information on products/ services
  Provide Service Planning support material/demonstration equipment to distributors, dealers and customers

The incumbent is personally responsible to:

* **Develop strategic direction for service planning activity with developers and builders**
* **Implement strategic service planning initiatives within a division**
  Ensure adequate and timely coordination of services
  Interpret and apply tariffs to main and service extensions
  Keep up-to-date on tariffs and regulations
  Represent the company in civic organizations
  Keep up-to-date on government regulations impacting company products or services
  Keep abreast of technology or other changes within the industry

The incumbent assists others to:

Establish and maintain relationships with government and regulatory agencies

Miscellaneous

The incumbent is personally responsible to:

* **Provide leadership to achieve departmental goals**
* Communicate corporate policy
* Provide oversight of budget and expenditures
* Maintain liaison with other departments of the organization

OTHER REQUIREMENTS

Manager/Service Planning/CAZ
SP00002067

There are clear precedents and practices which the incumbent uses as guidelines to determine how this job is performed. This position requires 5 to 7 years of relevant work experience. A Bachelors Degree is preferred.

In this job, the incumbent must be able to influence department heads of units outside of Service Planning, outside consultants, customers, and government officials. The incumbent also frequently exchanges information with suppliers and infrequently with top management and senior management.

TITLE: **Supervisor/Service Planning**
JOB CODE: SP00002068
DIVISION: All Divisions
DEPARTMENT: Service Planning
DATE: September 15, 2005

APPROVED BY:_____ **DATE**_____
(For Sr. Evaluation Committee)

POSITION OVERVIEW

The incumbent is concerned with Supervising and Directing Service Planning related activities.

POSITION DIMENSIONS

Personnel Managed: 3 - 10 Exempt Employees
1 - 5 Nonexempt Employees

NATURE AND SCOPE

The Supervisor/Service Planning reports to the Manager/Service Planning or District Manager along with other supervisors. Reporting to the incumbent are Project Managers and Project Specialists.

Note: This position involves the activities listed below. The activities underlined or in **bold-faced** type are the most critical for this job. The activities marked with an asterisk (*) are those on which the incumbent spends the most time. (Asterisk may be added by supervisor for each incumbent.)

Service Planning Strategy and Execution

The incumbent is personally responsible to supervise others who:

* **Build and maintain relationships with developers, builders and trade allies**
  Advise customers on gas products and availability
* **Coordinate new business processes and contractual information requirements**
  Work with customers to determine technical needs and specifications
* **Investigate, review and resolve issues to ensure satisfactory customer satisfaction**
* Participate in customer business meetings as consultant/advisor
  Establish programs to educate customers

Supervisor/Service Planning
SP00002013

Interpret, apply and communicate tariffs to main/service extensions
* Ensure timely coordination of installation of natural gas facilities
* **Negotiate contracts/special agreements**

Prepare studies and analyses
Make presentations to trade allies or potential customers
Participate in relevant trade associations
Keep up-to-date on government regulations impacting company products/ services
Keep abreast of technology or other changes within the industry
Implement demand-side management programs
Provide customers and/or colleagues with technical information on products/ services
Provide Service Planning support material/demonstration equipment to distributors, dealers and customers

The incumbent is personally responsible to:

Ensure adequate and timely coordination of services
Interpret and apply tariffs to main and service extensions
Keep up-to-date on tariffs and regulations
Represent the company in civic organizations
Keep up-to-date on government regulations impacting company products or services
Keep abreast of technology or other changes within the industry

The incumbent assists others to:

Establish and maintain relationships with government and regulatory agencies

OTHER REQUIREMENTS

There are clear precedents and practices which the incumbent uses as guidelines to determine how this job is performed. This position requires a Bachelor's degree plus 5-6 years of relevant work experience, or equivalent experience.

In this job, the incumbent must be able to influence department heads of units outside of Service Planning, outside consultants, customers, and government officials. The incumbent also frequently exchanges information with suppliers and infrequently with top management and senior management.

TITLE:	**Supervisor/Industrial Service Planning**
JOB CODE:	SP00002012
DIVISION:	Division
DEPARTMENT:	Service Planning
DATE:	June 26, 2003

APPROVED BY:_____ **DATE:**_____
(For Sr. Evaluation Committee)

POSITION OVERVIEW

This position has supervisory responsibility for service planning activities in the Commercial, Industrial and Agricultural market sectors for a division of Southwest Gas Corporation. This includes technical support for the above market sectors and for demand side management activities throughout the division, including the outlying districts.

POSITION DIMENSIONS

Budget Accountable for:	$300,000 - $1,500,000
Personnel Managed:	3 – 10 Exempt Employees
	1 – 5 Non- Exempt Employees

This job has 2 subordinate levels reporting to it.

NATURE AND SCOPE

The Supervisor/Industrial Service Planning reports to the Manager/Service Planning along with other Supervisors/Service Planning, the Management Assistant and the Service Planning Representatives.

Note: This position involves the activities listed below. The activities in **bold** are the most critical for this job. The activities marked with an asterisk (*) are those in which the incumbent spends the most time. (Asterisks may be added by the supervisor for each incumbent.)

The incumbent directs others who:

Coordinate the new business process for commercial, industrial and agricultural customers
Complete customer specific feasibility studies on alternative gas technologies like cogeneration, natural gas cooling, water pumping
Collaborate with individual customers and Energy Services to establish and monitor new product introduction and prototype testing for alternative gas technologies
Identify, evaluate and pursue opportunities with multi-family, commercial, industrial and agricultural customers

Educate architects, consulting engineers and end-use customers about the benefits of natural gas technologies for commercial, industrial and agricultural applications
Manage the implementation of cost-effective Demand Side Management programs within the Division

The incumbent is personally responsible to:

Manage service planning and technical personnel to ensure the provision of high quality, efficient and cost effective service to new and existing commercial, industrial and agricultural customers
Develop and implement an integrated technical service planning plan for the Division
Evaluate the economic feasibility of capital intensive new business projects and present the results to senior management for approval
Train Service Planning personnel on the effective use of business analysis tools used to evaluate new business projects
Establish efficient communications between Division Service Planning and Key Account Management personnel to ensure the effective pursuit of service planning opportunities with large, at risk customers
Facilitate communications between the company and economic development authorities to optimize natural gas utilization by new, incoming customers

The incumbent, with others, is responsible to:

Develop and implement cost effective strategies designed to meet the company's market sector specific service planning goals
Collaborate with Energy Services to identify and develop targeted programs for the commercial, industrial and agricultural market sectors
Formulate cost effective new business practices
Evaluate the company's competitive position on an ongoing basis to ensure the effectiveness of its programs
Develop economic and service planning forecasts
Manage the contact management program to ensure its effective use
Hire and train service planning and technical personnel

OTHER REQUIREMENTS

There are clear precedents and practices that the incumbent uses to determine how this job is performed. This position requires 3 to 5 years of relevant work experience, plus a bachelor's degree in Engineering.

The incumbent frequently exchanges information with senior management, department heads outside of the incumbent's functional area, outside consultants and customers.

TITLE: **Supervisor/Key Account Management**
JOB CODE: GS00002038
DIVISION: Corporate
DEPARTMENT: Key Account Management
DATE 6/7/2000

APPROVED BY:_____ **DATE:**_____
(For Sr. Evaluation Committee)

POSITION OVERVIEW

The Supervisor/Key Account Management supervises and conducts the negotiation and administration of natural gas services for the company's large volume customers. Large volume customers include those customers which: are served under transportation rate schedules; require negotiated contract terms and rates in that they have the ability to physically bypass the company's services or use alternate fuels; consume in excess of 500 therms per day on average; or, are classified as industrial, gas engine, agricultural or electric generation. Large volume customers may require specific supply arrangements or the construction of significant pipeline facilities.

POSITION DIMENSIONS

Budget Accountable for: This incumbent does not have accountability for budgets. The annual margin from large volume customers under the control of the Supervisor ranges from $ to approximately $ million per year.

Personnel Managed: Direct- 1-3 Exempt Employees

This job has one (1) subordinate level reporting to it.

NATURE AND SCOPE

The Supervisor/Key Account Management reports to the Manager/Key Account Management, along with two other Supervisors/Key Account Management and either a Supervisor/Contract Administration or an Analyst/Key Account Management.

Reporting directly to incumbent are the Industrial Gas Engineers (IGEs).

Note: This position involves the activities listed below. The activities in **bold** type are the most critical for this job. The activities marked with an asterisk (*) are those on which the incumbent spends the most time. (Asterisk may be added by supervisor for each incumbent.)

The incumbent is personally responsible to:

* **Supervise IGE's negotiations and administrative activities with agricultural, gas engine large commercial, cogeneration, electric generation and industrial customers which qualify for transportation/optional sales/special contract service, or are not (or cannot) be served with standard rate schedules, or consume in excess of 500 therms per day on average.**
* **Coordinate and administer the implementation of the company's large volume customer programs and support activities.**
* **Coordinate margin/rate studies with Rates Department.**
* **Supervise the company's Strategic Accounts Program for large volume customers.**
* **Communicate to management market opportunities and problem areas**
* **Negotiate contract conditions and rates with Key Account Management Department customers.**
* **Maintain contact and working relationships with Key Account Management Department customers.**
* **Identify customers with bypass potential.**
* **Maintain up-to-date customer information file.**
* **Coordinate Division Engineering studies.**
* **Explain transportation imbalance management to customers.**
* **Coordinate studies regarding transmission and distribution capacity for large volume customers with upstream pipelines, corporate staff and division Sales and Engineering Departments.**
* **Coordinate, prepare and review draft service agreements and other binding documents to provide the necessary service to large volume customers and adequate protection for the Company.**
  Initiate and develop market opportunities.
* **Perform the activities related to the Strategic Accounts program.**
* **Coordinate the development of gas supply required for large volume customers.**
* Prepare alternate fuel studies.
* Prepare economic and sales forecasts.
* Explain the company's transportation policy and procedure to IGEs and customers.
  Advise customers of tariff provisions.
  Keep abreast of state, federal and upstream pipeline tariffs/regulations affecting large volume customers.
  Ensure Key Account Management Department customers are informed of state and federal regulations.
  Ensure Key Account Management Department customers are kept abreast of company filings.
  Develop plans and procedures to identify market opportunities. Keep up-to-date with system gas supply purchase issues. Coordinate activities between IGEs and customers regarding transportation issues.
  Coordinate with Energy Services or Service Planning to develop and maintain relationships with market/trade allies.
  Provide monthly report of activities for manager.
  Prepare quarterly news letter for distribution to large volume customers.

The incumbent, with others, is responsible to:

* **Prepare and participate in training and development of IGEs. Determine information required and prepare documentation and material for customer rate/margin analysis.**

* **Determine information required and prepare studies of distribution and/or transmission capacity studies for customers**
* Maintain a complete data base on each customer in this market **segment.**
* **Determine market and specific customer requirements and appropriate corporate action.**
  Determine validity, negotiate and resolve billing disputes between customers and the Company.
  Establish and assure continuing relationships with top management of Key Account customers, using the Corporation's Strategic Accounts Program.
  Implement and administer the company's gas procurement service Determine validity, negotiate and resolve billing disputes between customers and the Company.
* Ensure adequate and timely coordination of Company services for large volume customers. Identify emerging Transportation/Contract sales problems. Review analyses of competitive customer offerings vs. company programs to meet customer requirements. Recommend changes in tariff provisions. Prepare economic and sales forecasts.
  Monitor and analyze competition and provide recommendations for corporate response.
  Assemble and process data and information necessary to expedite rate applications.
  Conduct market analysis research/evaluation and recommend specific activities based on analysis.
  Coordinate activity with appropriate Division and corporate Staff personnel.
  Provide IGEs with training and support programs and activities necessary to negotiate service agreements with sophisticated customers.
  Ensure timely and accurate filings of commission ordered reports.
  Maintain and cultivate contacts with trade allies, architects and engineers to improve the environment for installing natural gas equipment.
  Meet with architects and engineers to ensure that all opportunities to specify gas equipment are identified and create a gas-friendly environment.

The incumbent assists others to:

* **Analyze trends to determine profitable opportunities.**
* **Coordinate the execution of approved service agreements and other binding documents between large volume customers, IGEs and corporate Staff.**
  Determine cost-effectiveness of support activities and programs. Establish programs to educate customers.
  Determine impact of competitive forces in the marketplace. Develop short-term and long-term plans for Key Account Management Department activity.
  Develop PC programs and systems for department functions.

Additional Activities

Ensure that all regulatory filings regarding large volume customer contracts are complete, accurate and filed in a timely manner.
Attend and participate in various conferences related to natural gas regulations.
Analyze legislation impacting activities with large volume customers.
Prepare responses to data requests during proceedings.

OTHER REQUIREMENTS

There are established precedents and practices which the incumbent uses as guidelines to determine how this job is performed. This position requires four to six years of experience.

College degree required with technical discipline preferred or equivalent work experience. The incumbent must, be able to establish working relationships with others not under the incumbent's supervision.

The incumbent frequently exchanges information with department heads of other company activities such as Rates, Demand Planning, Gas STET, Central Gas Dispatch, Legal, Energy Services, Accounting, and Division Service Planning and Operations, outside consultants, trade associates, and infrequently with senior management or shareholders.

Approximate percentage of time spent performing various duties.

JOB DUTIES	APPROXIMATE % TIME PERFORMED
Supervisory	20%
Market Studies & Plans	5%
Technical Knowledge	5%
Department & Commission Interaction	5%
Rate Analysis	5%
Administration	10%
Customer Interaction	50%

TITLE: **Manager/Key Account Management**
JOB CODE: GS00002054
DIVISION: Corporate
DEPARTMENT: Key Account Management
DATE: 9/27/2006

APPROVED BY:_____ **DATE:**_____
(For Sr. Evaluation Committee)

POSITION OVERVIEW

The Manager/Key Account Management manages the negotiation and administration of natural gas services for the company's large volume customers. Large volume customers include those customers which: are served under transportation rate schedules; require negotiated contract terms and rates in that they have the ability to physically bypass the company's services or use alternate fuels; consume in excess of 500 therms per day on average; or, are classified as industrial, gas engine, agricultural or electric generation. Large volume customers may require specific supply arrangements or the construction of significant pipeline facilities. This position is also responsible for Special Assignments as identified and required from time to time, to meet corporate needs.

POSITION DIMENSIONS

Budget Accountable for: $1,200,000+

Personnel Managed: 4 Exempt Employees

Personnel Supervised: 11 Total Employees
9 Exempt Employees
2 Non-Exempt Employees

This job has four subordinate levels reporting to it.

NATURE AND SCOPE

The Manager/Key Account Management reports to the Director/Key Account management. Reporting to the incumbent are three Supervisors/Key Account Management and the Supervisor/Contract Administration or the Analyst/Key Account Management.

Note: This position involves the activities listed below. The activities in **bold** type are the most critical for this job. The activities marked with an asterisk (*) are those on which the incumbent spends the most time. (Asterisk may be added by supervisor for each incumbent.)

The incumbent manages others who:

* **Negotiate, administer and coordinate natural gas service planning and transportation service to large volume customers.**
* **Negotiate and administer Southwest's transportation and special contract policies and pricing.**
* **Negotiate agreements and gas prices with customers to ensure maximum margin to company while maintaining existing or acquiring new gas load.**
* **Coordinate and administer the corporation's large volume customer programs and support activities.**
* **Assist and support Supervisor/Key Account Management and Industrial Gas Engineers (IGEs) with customer contact in agricultural, commercial, industrial, and electric generation sectors which require transportation/special contracts or are not (or cannot) be served with standard rate schedules, or consume in excess of 500 therms per day on average.**
* **Coordinate margin/rate studies with Rates Department.**
* **Provide Supervisor/Key Account Management and IGEs with training and support necessary to negotiate service agreements with sophisticated customers.**
* **Implement and administer the company's gas procurement service.**
* **Develop records and methodology to initiate timely action for all key dates in customer agreements; e.g., termination, rate changes, anniversary dates etc. Analyze trends to determine profitable opportunities.**
* Maintain a complete data base on each customer for which Key Account Management is responsible.
  Conduct research/evaluation and recommend specific activities based on analysis.
  Coordinate studies regarding transmission and distribution capacity for large volume customers with pipeline suppliers, corporate staff and division Service Planning and Engineering departments.
  Coordinate the development of gas supply required for large volume customers.
  Prepare draft service agreements, consult with Legal Department regarding transportation contracts and special contracts.
  Monitor and analyze competitor activities and provide recommendations for corporate response.
  Develop plans and procedures to identify opportunities.
  Maintain communication with operating divisions on customers with alternative fuel capabilities and/or gas bypass opportunities.
  Advise affected departments and IGEs of compliance requirements ordered by Commissions on transportation/contract matters.
  Assemble and process data/information necessary to prepare exhibits for Commission filings.
  Ensure timely and accurate filings of Commission-ordered reports.
  Assemble and process data and information necessary to expedite rate applications.
  Prepare exhibits and testimony for transportation/contract matters.
  Develop PC programs and systems for department functions.
  Research other utilities' transportation policies and agreements to stay current on regional and national transportation/contract service planning issues.

Identify emerging transportation/contract service planning problems. Maintain and cultivate contacts with trade allies, architects and engineers to improve the environment for installing natural gas equipment.
Maintain files for all Key Account Management Department customer contracts/agreements --active, pending and inactive.
Maintain database and files of all corporate gas contracts/agreements --active, pending and inactive.
Maintain database and design reports used in conjunction with the Strategic Accounts Program for division Service Planning Departments and Key Account Management.
Design and provide quarterly reports used by management in recommending IGE incentives.
Prepare customer agreements, exhibits and correspondence.
Provide reports and data sheets for transmittal to divisions and staff department.
Use GoldMine to transmit important notices to customers through GoldMine on short notice.
Provide clerical/secretarial backup to Director/Manager and departments in general.

The incumbent is personally responsible to:

* **Develop and implement programs to ensure that transportation and special contracts' activities achieve company goals and objectives.**
* **Establish and maintain communications with other corporate staff and Division Service Planning and Engineering Departments focusing on large volume customers and transportation/contract issues affecting the company.**
Implement and administer the company's gas procurement service.
* Establish and maintain policies, procedures and records regarding corporate transportation and large volume customer contract activities.
* Develop programs and procedures for contract service planning, service and/or transportation in conjunction with the operating divisions.
Provide the director and officers with recommendations on corporate strategy/policy regarding transportation and special contracts.
Ensure company compliance regarding all matters contained in company tariffs for transportation/contracts.
* Direct the administration and maintenance of all large volume customer agreements (preparation, files, compliance, special conditions, etc.).
* Direct the development and administrating of the customer contact management/database information files.
Determine project scope, contract amount and completion time line of outside consultants.

The incumbent, with others, is responsible to:

Develop short-term and long-term plans for Key Account Management department activity.
* Prepare tariff revisions on tariff/contract service planning matters.
Establish service planning goals for IGEs.
Monitor and analyze impact of alternative fuel prices.

Perform energy cost comparisons of current alternative fuel prices and assess trends.

The incumbent assists others to:

* **Ensure corporate compliance with Commission decisions regarding transportation/contract service planning matters.**
* **Establish and maintain communication with other departments at systems and operating divisions to ensure tariffs reflect current operation procedures.**
* **Develop tariffs which are consistent with regulatory, legal and corporate requirements for all jurisdictions.**
  Provide expert testimony to regulatory Commissions and legislative bodies on transportation/contract service planning matters.
  Maintain working knowledge of legal requirements for application of tariffs and agreements.
  Advise affected departments of compliance requirements ordered by Commissions.
  Review and analyze competitors' rate structures for consideration in developing future rate design proposals. Initiate and develop data/information necessary to prepare testimony and exhibits for Commission filings regarding regulatory matters.
  Prepare exhibits and responses to data requests (interrogatories) from parties outside of the company.

Additional Activities

Provide monthly report of department activities to management.
Represent the corporation in outside industry/trade organizations.
Testify before regulatory commissions and legislative bodies.
Maintain working relationship with regulatory commission staffs regarding transportation and contract matters.

OTHER REQUIREMENTS

There are broad precedents and practices which the incumbent uses as guidelines to determine how this job is performed. This position requires 8 to 10 years of relevant work experience. The incumbent frequently exchanges information with senior management and department heads of the following departments: Rates, Demand Planning, Gas Resource Management, Central Gas Dispatch, Staff Engineering, State and Federal Regulatory Affairs, Legal, Energy Services, Accounting and Division Service Planning and Operations.

TITLE: **Senior Manager/Key Account Management**
JOB CODE: GS00002044
DIVISION: Corporate
DEPARTMENT: Key Account Management
DATE APPROVED: March 7, 2003

APPROVED BY:_____ **DATE:**_____
(For Sr. Evaluation Committee)

POSITION OVERVIEW

The incumbent is accountable for the negotiation and administration of all transportation contracts and anti-bypass contracts and other special contracts, such as special purchase agreements and optional sales agreements for all customers of the corporation that exceed 50 MMBtu/d of usage to ensure that such agreements are in compliance with the terms of the tariff and meet the goals of the Company. The incumbent is also responsible for the development of programs that target key account segments to improve margin for the Company and improve efficiencies and effectiveness of the Key Account Management Department.

POSITION DIMENSIONS

Department budget accountable for:	$2,000,000 - $4,000,000
Personnel supervised:	12 Exempt
	3 Non-exempt

NATURE AND SCOPE

The Senior Manager/Key Account Management reports to the Vice President/Gas Resources and Energy Services, as does the Director/Gas Supply. Reporting directly to the position are the Manager/Key Account Management, one Supervisor/Key Account Management, and one Administrative Secretary.

Note: This position involves the activities listed below. The activities in **bold** are the most critical for this job. The activities marked with an asterisk (*) are those in which the incumbent spends the most time. (Asterisks may be added by supervisor for each incumbent)

The incumbent is personally responsible to:

* **Manage the negotiation and preparation of all gas transportation agreements with customers whose usage exceeds 50 MMBtu/d to ensure adequate return on investments for the Company, and compliance with the respective state tariffs;**
* **Manage and coordinate the administration of all customer transportation agreements and related agreements to ensure performance under these legal instruments;**

* **Manage the preparation and negotiation of all amendments to customer gas transportation agreements, special procurement agreements and optional fuel agreements;**
* **Provide guidance and oversight for the development and the implementation of programs for large customers to ensure such programs are in compliance with the respective state tariff and meet corporate goals;**
* **Analyze customers' transportation options and develop anti-bypass strategies that meet corporate goals;**
* **Negotiate all large generator contracts to provide compliance with the respective state's tariff and to ensure adequate return on investment for the corporation;**
* **Retain, train, and develop industrial gas engineers who the effectively represent the Company with large customers;**
* **Provide guidance, experienced insight and leadership to the department and others on contractual and financial issues related to large customers;**
* **Represent the Company with respect to large customers and related tariff issues in regulatory proceedings and/or settlement negotiations;**
* **Participate in contract litigation and regulatory issues, including preparation of discovery, depositions, analysis, and testifying as necessary;**
  Ensure compliance with Federal and State regulations;
  Establish and maintain close business relationships with the Company's largest customers, primarily electric generators;
  Stay abreast of changing market conditions that affect large customers;
  Act as the primary contact with both internal and external auditors on matters relating to contracting, administration of contracts, and compliance with corporate policy and procedures.

The incumbent manages other who:

* **Provide administration of customer gas transportation agreements, special procurement agreements, and optional sales agreements;**
* **Negotiate with customers for the installation of new equipment to provide additional margin for the corporation;**
* **Provide energy surveys to customers with recommendations for new gas field equipment;**
* **Negotiate anti-bypass agreements to provide maximum available benefit to the Company;**
* Analyze and develop marketing programs for the large customers that provide for improved profit for the Company;
* **Develop and maintain solid business relationships with large customers.**

The incumbent, with others, is responsible to:

Analyze industry trends and changes which may require changes in corporate strategy for large customers and make policy recommendations to ensure corporate objectives are met;
Review Company policies, procedures, and information systems as they relate to KAM business and make recommendations to senior management.

OTHER REQUIREMENTS

There are established precedents and practices that the incumbent uses as guidelines to determine the basis for how this job is performed. This position requires a bachelor's degree or equivalent, with a minimum of 10 years work experience.

The incumbent frequently exchanges information with other departments outside of Key Account Management, outside consultants, regulatory agencies having jurisdiction, and the Company's largest customers.

TITLE: **Industrial Gas Engineer**
JOB CODE: GS00002060
DIVISION:
DEPARTMENT: Key Account Management
DATE: January 1993

APPROVED BY: _____ **DATE:**
(For Sr. Evaluation Committee)

POSITION OVERVIEW

This position is directly involved with the negotiation, administration, and regulatory activities for key account customers. Key account customers are large customers who require transportation service, optional alternate fuel rates or other special investment, supply or anti-bypass contracts.

POSITION DIMENSIONS

The incumbent does not have accountability for personnel or budgets.

NATURE AND SCOPE

The Industrial Gas Engineer is a staff position, located in the division, which reports to the Supervisor/Key Account Management.

Note: This position involves the activities listed below. The activities in **bold** type are the most critical for this job. The activities marked with an asterisk (*) are those on which the incumbent spends the most time. (Asterisk may be added by supervisor for each incumbent.)

The incumbent is personally responsible to:

* **Negotiate contracts and rates with large customers which: (a) require transportation service; (b) have alternate fuel capability; (c) have the potential to bypass; or (d) require a special contract due to the investment or supply arrangement**
* **Maintain close contact and working relationships with key account customers**
* **Maintain up-to-date alternate fuel and energy price information**
* **Maintain up-to-date knowledge on upstream interstate pipeline rates and tariffs**
* **Prepare fuel and energy studies and analysis and develop proposals for transportation, optional and anti-bypass rates and service**
* **Identify customers with bypass potential**
* **Maintain up-to-date customer information file**
* **Initiate and develop market opportunities and develop plans to remain competitive**
* **Perform the activities related to the Strategic Accounts program**

Industrial Gas Engineer
GS00002060

* **Maintain communications with key account customers with respect to tariff provisions and state and federal regulations**
* **Administer Title Assignment and/or Capacity Release programs**
* **Ensure key account customers are kept informed of company filings**
* **Explain transportation imbalance management to customers**
* **Determine market and specific customer requirements and appropriate corporate action**
* **Identify opportunities to increase the corporate margin for key account customers**
* **Ensure that service agreements and other binding documents are executed between key account customers and the division vice president**
* Coordinate Division Engineering studies for key account customers
* Coordinate meetings with division management and the management of key account customers using the Corporation's Strategic Accounts Program
* Ensure adequate and timely coordination of company services for key account customers

Prepare alternate fuel studies
Prepare economic and sales forecasts

The incumbent assists others to:

* **Resolve billing disputes between key account customers and the company**
* **Ensure satisfactory customer service to key account customers**
* **Explain Company's transportation policy and procedure to division customers who may qualify for this tariff**
* Determine impact of competitive forces in the marketplace

Explain Company's transportation and alternate fuel rate policy and procedure to Commission Staff members

Additional Activities

Inform division management of key account activities

OTHER REQUIREMENTS

There are established precedents and practices which the incumbent uses as guidelines to determine how this job is performed. This position requires 3 to 4 years of relevant work experience. College degree required with engineering discipline preferred or equivalent work experience. The incumbent must be able to establish working relationships with others not under the incumbent's supervision.

The incumbent frequently exchanges information with department heads of other company activities (such as Division Engineering, Division Service Planning, Division Technical Services, Division Customer Service, Division Accounting and Division Legal), outside consultants, and trade associates.

AMERICAN GAS ASSOCIATION

Definitions of Functional Cost Centers
For the Year Ended December 31, 2007

Advertisement manages the development and placement of advertisements in national print and electronic media.

Corporate Affairs provides opportunities for interaction between member companies and the financial community. The focus is to promote interest in the investment opportunities in the industry.

General and Administrative includes:

1. Office of the President provides senior management guidance for all AGA activities.
2. Human Resources develops and administers employee programs and provides office and personnel services.
3. Finance and Administration develops and administers financial accounting and treasury services and maintains computer services capability.

General Counsel provides legal counsel to the Association.

Industry Finance and Administration develops and implements programs in such areas as accounting, human resources, and risk management for member companies.

Operations and Engineering Management develops and implements programs and practices to meet the operational, safety, and engineering needs of the industry.

Policy, Planning, and Regulatory Affairs includes:

1. Policy & Analysis identifies the need for and conducts energy analyses and modeling efforts in the areas of gas supply and demand, economics, and the environment.
2. Regulatory Affairs provides members with information on FERC and state regulatory developments; prepares testimony, comments, and filings regarding regulatory activities.

Public Affairs provides members with information on legislative development; prepares testimony, comments, and filings regarding legislative activities, lobbies on behalf of the industry. It also includes Communications, which develops informational material for member companies and consumers and coordinates all media activity.

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
Docket No. G-01551A-07-0504

PREPARED REBUTTAL TESTIMONY
OF
RANDI L. ALDRIDGE

ON BEHALF OF
SOUTHWEST GAS CORPORATION

May 9, 2008

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Of
Prepared Rebuttal Testimony
Of
RANDI L. ALDRIDGE

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Rebuttal Exhibit No.__(RLA-1)

Rebuttal Exhibit No.__(RLA-2)

Southwest Gas Corporation
Docket No. G-01551A-07-0504

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rebuttal Testimony
Of
Randi L. Aldridge

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Randi L. Aldridge. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150.

Q. 2 Did you sponsor direct testimony on behalf of Southwest Gas Corporation (Southwest or the Company) in this proceeding?

A. 2 Yes, I did.

Q. 3 What is the purpose of your prefiled written rebuttal testimony?

A. 3 The purpose of my rebuttal testimony is to respond to specific aspects of the direct testimony presented by Mr. Ralph C. Smith, witness for the Arizona Corporation Commission Utilities Division Staff (Staff), and Mr. Rodney L. Moore, witness for the Residential Utility Consumer Office (RUCO), regarding their recommendations for ratemaking treatment of intangible plant and certain operating expense items.

Q. 4 Did you prepare exhibits to support your rebuttal testimony?

A. 4 Yes. I prepared the exhibits identified as Rebuttal

Exhibit No.__(RLA-1) and Rebuttal Exhibit No.__(RLA-2).

Q. 5 Please summarize your rebuttal testimony.

A. 5 My rebuttal testimony will address Staff and/or RUCO's adjustments related to the following issues:

- Labor Annualization: RUCO's proposal to exclude the 2008 wage increase.
- Uncollectibles: RUCO's proposal to normalize uncollectibles expense based on a 3-year average.
- AGA Dues: Staff's proposal to exclude 40 percent of AGA dues from the cost of service.
- Employee Recognition: RUCO's proposal to exclude certain expenses from the cost of service.
- Miscellaneous Expenses: RUCO's proposal to exclude certain expenses from the cost of service.
- Intangible Plant: RUCO and Staff's adjustment to update intangible plant through December 31, 2007.
- A&G Error Correction: RUCO's acknowledgement of a $300,000 error to A&G.

II. LABOR ANNUALIZATION

Q. 6 Did the Company propose a post-test year wage increase in its Labor Annualization pro forma adjustment?

A. 6 Yes. The Company proposed to increase wages by three percent in 2008 for those employees who were employed by Southwest at the end of the test year.

Q. 7 Is this a similar adjustment to the 2005 wage increase adjustment that Southwest proposed and the Commission accepted in Southwest's 2004 general rate case?

A. 7 Yes. The Commission agreed that this adjustment "...should be allowed because it is a known and measurable expense that is being incurred by the Company on a going-forward basis. Because the post-test year wage increase has been applied only to employees who were employed during the test year, there is no mismatch of revenues and expenses." (D.68487, p 13, Lns 1-4)

Q. 8 Does RUCO's concern that this adjustment results in a mismatch apply in this case?

A. 8 No. Similar to the 2005 wage increase adjustment, Southwest's proposed 2008 wage increase only applies to those employees employed by Southwest at the end of the test year so that the matching principle is not violated. This adjustment is also more reflective of costs that will be incurred by the Company when the rates set by the Commission from this proceeding will be effective.

Q. 9 What is the Commission's history of allowing post-test year adjustments for Southwest?

A. 9 The Commission has historically allowed certain post-test year adjustments in prior Southwest rate cases, as long as the matching principle is not violated. Examples of permissible post-test year adjustments include: wage increases for test year employees, completed construction not classified on non revenue-producing plant, and rate case expense. Staff witness Ralph C. Smith makes reference to post-test year

adjustments and the care that the Commission must take regarding post-test year adjustments on page 6 of his direct testimony, wherein he states: "Any adjustments that reach beyond the end of the historic test year must be very carefully considered before being adopted." This observation is consistent with prior Commission orders that have allowed appropriate post-test year adjustments that do not violate the matching principle, like a post-test year wage increase for test year employees.

III. UNCOLLECTIBLES EXPENSE

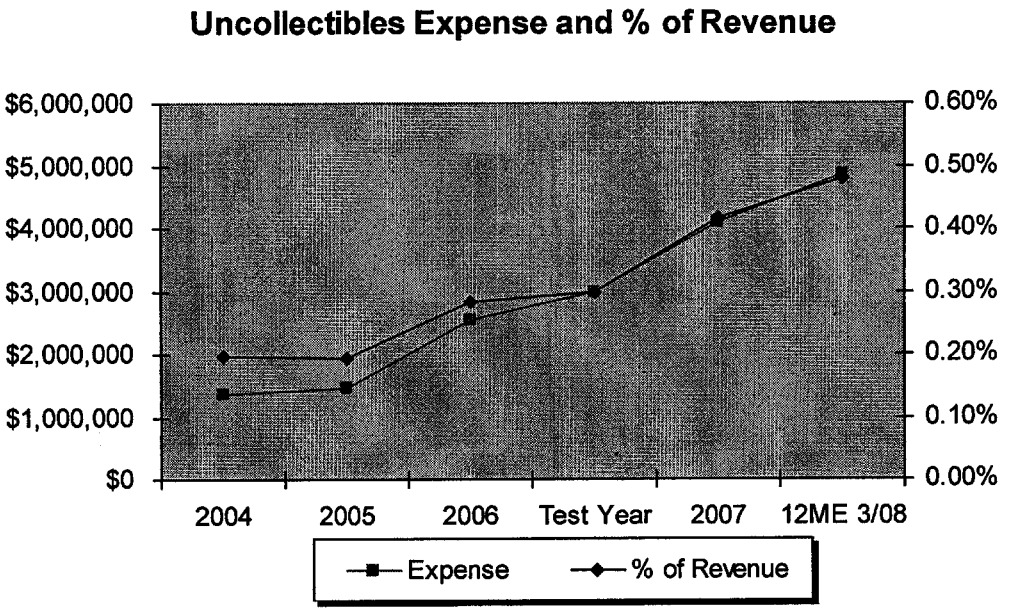
Q. 10 RUCO proposed to normalize uncollectibles expense based on a three-year average, since uncollectibles expense tends to be volatile. Did Southwest consider normalizing uncollectibles expense, rather than using the test year amount recorded for uncollectibles expense?

A. 10 Yes.

Q. 11 Why did Southwest use the test year expense for uncollectibles, rather than normalizing using a historical average?

A. 11 Southwest analyzed historical uncollectibles expense, as well as the current and historical level of write-offs. Uncollectibles expense has increased steadily from 2004 to the present. At the time the rate case was filed, it was apparent that uncollectibles expense for 2007 would continue to trend upward. The following graph

illustrates uncollectibles expense and uncollectibles as a percentage of total revenue over the time period 2004-2007 and the twelve months ended March 2008:



As illustrated in the graph, uncollectibles expense continues to trend upward. Based upon this historical trend and the continued impact that the slow economy and high energy costs are expected to have on ongoing uncollectibles expense, a historical average of test year uncollectibles expense would result in a clear under recovery of uncollectibles expense during the period of time that rates set by the Commission in this proceeding are effective. Southwest believes that test year uncollectibles expense more appropriately reflects expected ongoing uncollectibles expenses during the rate effective period. Staff applied similar logic with respect to several of its adjustments. Specifically,

Staff recommends that the end of year balance for customer advances and customer deposits be used for ratemaking purposes because "the average balance is not representative of the conditions at the end of the test year, or on a going-forward basis." (Smith Direct, pp. 14 and 18.)

Q. 12 Should Staff's analysis of customer advances and customer deposits also be applied to uncollectibles expense?

A. 12 Yes. As with customer advances and customer deposits, the average historical ratio of uncollectibles expense to revenues is not representative of the conditions at the end of the test year, or on a going-forward basis. For this reason, Southwest proposes that the Commission apply Staff's proposal consistently, to customer deposits, customer advances, and uncollectibles expense.

IV. AGA DUES

Q. 13 What is Staff's proposal regarding AGA dues?

A. 13 Staff proposes to disallow 40 percent of AGA dues from cost recovery.

Q. 14 What is Staff's basis for this proposed disallowance?

A. 14 Staff relies heavily on outdated National Association of Regulatory Commissioners (NARUC) sponsored audits of AGA expenditures and the ratemaking treatment in selected states outside of Arizona for AGA dues.

Q. 15 Does NARUC continue to sponsor audits of AGA expenditures?

A. 15 No. For many years, NARUC had a Committee on Association Oversight that conducted an audit on AGA. However, NARUC discontinued the audit a few years ago as that body determined it was no longer necessary. The last NARUC-sponsored audit was dated March 2005, and the audit period ended December 31, 2002.

Q. 16 Staff witness Ralph C. Smith discusses a Florida Public Service Commission (FPSC) Staff memorandum at length, which provided justification for a 40 percent disallowance for a utility in Florida in 2003 and included a related attachment, and attached the audit reports from June 2001 and December 2000 (for years ended 1999 and 1998) to his testimony. Do you have any comments on Staff's reliance on these items?

A. 16 Yes. First, these attachments are outdated and reflect the activities of AGA nearly a decade ago. Second, as Southwest noted in response to Staff data request STF-10-7, AGA eliminated promotional expenditures in 2000. The latest report available to the FPSC at the time of its memo was 1999 data (which was the subject of the June 2001 audit report), which included promotional expenditures that AGA no longer incurs. Third, Staff provides no current information supporting the disallowance of a portion of any category other than advertising and lobbying. The outdated attachments relied upon by Staff that are included with Mr. Smith's testimony have no value or relevance in this proceeding.

Q. 17 Are you providing information regarding AGA in your rebuttal testimony?

A. 17 Yes. Southwest received additional information directly from AGA, including a description of AGA written in the form of testimony from the AGA's Chief Financial Officer, AGA's mission statement, and AGA's committee structure. This additional support for Southwest's request for AGA dues was provided as a supplemental response to Staff data request STF-12-1, and is attached as Rebuttal Exhibit No.__(RLA-1).

Q. 18 What was Southwest's pro forma adjustment to AGA dues, which removed the advertising and lobbying portion, based on?

A. 18 The pro forma adjustment proposed by Southwest was based on the AGA's 2007 budget, which was provided by the Company to Staff in response to Staff data request STF-6-52 (which is contrary to Staff's assertion that Southwest did not provide the percentages relating to AGA's functions [Smith direct, page 40]). I have also attached the AGA 2007 budget, which illustrates the percentages of AGA activities related to each function as Rebuttal Exhibit No.__(RLA-2).

Q. 19 How do you respond to Staff's assertion that Southwest failed to demonstrate that a 96.61 percent recovery of AGA dues is appropriate?

A. 19 My direct testimony provided an abundance of examples of how AGA's activities provide benefits to the Company and

its customers (see Aldridge direct, pages 12 and 21-24). Furthermore, as noted by the AGA itself, AGA's efforts provide member benefits of $479 million of savings or avoided costs, in comparison with $18 million in total membership dues, which is information available on the AGA's website. Southwest has no reason to doubt the AGA's assertion. Staff made a broad assertion that the AGA activities would be subject to disallowance if they were conducted directly by the utility. However, Staff failed to specifically identify a single activity that Southwest has not already removed and would be disallowed if it conducted the activity directly. Despite Staff's broad assertions, Southwest provided an abundance of information regarding AGA functions and customer benefits. Accordingly, Southwest's pro forma adjustment removing 3.39 percent of AGA dues from cost recovery is appropriate.

V. EMPLOYEE RECOGNITION EXPENSE

Q. 20 RUCO proposes to remove $54,154 of employee recognition expenses from the cost of service. What does RUCO base its disallowance on?

A. 20 RUCO stated that it believes it is inappropriate to burden customers with expenses related to certain items.

Q. 21 Please describe the Company's employee recognition programs that comprise this expense item.

A. 21 There are four programs:

(1) Line Location Recognition Program: recognizes each

technician for every 2,500 consecutive Blue Stake requests completed without an error or mislocate.

(2) Meter Reading Recognition Program: recognizes employees who have performed their meter reading duties in an outstanding manner.

(3) Safety Awards: recognizes employees who drive a vehicle on a daily basis who complete a full calendar year without a preventable accident, and recognizes each employee in a department that completes a full calendar year without a lost time preventable injury.

(4) Trip Reduction Program: The Trip Reduction Program (TRP) ordinance is ***mandated*** for all employers in Maricopa County with 50 or more employees at a single work site (A.R.S. 49-581 et. seq.). The Company also agreed to be part of the Ozone Program and receive trip reduction credit for its participation.

Q. 22 What goals do these programs accomplish?

A. 22 The goal of the first three programs is to reduce the overall cost of service, along with improving safety and productivity. The Company recognizes that by providing modest awards to encourage employees to demonstrate a commitment to performing their job at the highest level can reduce overall costs. Customers are the primary beneficiaries of a reduced cost of service due to Southwest's efforts in preventing accidents and

injuries, and reducing errors that cause additional work or compromise safety. Southwest participates in the TRP to comply with a county ordinance, and as a good corporate citizen to improve the environment in which the Company operates.

Q. 23 Do you agree with RUCO's assessment that the expenses related to these four programs should be disallowed?

A. 23 No. As explained above, these programs offer very modest rewards to employees whose performance is extraordinary, or participate in programs which improve air quality. Southwest's customers and the community at large benefit from employees who are motivated and rewarded for performing their job safely, efficiently, and with a higher than expected quality. In addition, the TRP is a program mandated by Maricopa County and the community benefits from Southwest's participation. It is unclear why RUCO would propose to disallow the expenses related to complying with a county ordinance. Furthermore, RUCO has not found these expenditures to be excessive or imprudent. Therefore, these programs should be allowed in rates.

VI. MISCELLANEOUS EXPENSES

Q. 24 RUCO proposes to disallow a number of expenses which it terms "inappropriate or unnecessary". What is your response to this adjustment?

A. 24 Southwest disagrees with RUCO as to whether the expenses are appropriate for cost recovery.

Q. 25 Can you provide additional testimony supporting the appropriateness of these costs?

A. 25 Yes.

(1) Gift Certificates: The gift certificates that RUCO identified in this adjustment were for the Meter Reading Recognition Program, Trip Reduction Program, and Safety Awards Program. RUCO already removed the total costs incurred for these programs in its Employee Recognition Expense adjustment, which I discussed and rebutted earlier. Therefore, removing $18,230 of costs again in the Miscellaneous Expenses adjustment is a proposal to disallow these costs twice, which is clearly inappropriate.

(2) Office Refreshments: It is not unreasonable for a company to provide convenient onsite access to coffee, tea, and water in order to improve the productivity and morale of employees. Productive employees help Southwest keep its customer-to-employee ratio low, which benefits customers through a lower cost of service.

(3) Meals offered during meetings: Southwest often requires that certain employees be present for meetings outside of normal business hours. Alternatively, some meetings or work situations may offer a break that is insufficient in length for employees to obtain a meal off-site. When appropriate, the Company offers meals to employees

who attend such meetings or are included in certain work situations. The meals that Southwest did not remove from the cost of service were offered to keep employees present during non-working hours at the Company's convenience to improve productivity. The majority of these employees are exempt (not eligible for overtime), and covering a meal for them occasionally is far cheaper than hiring additional employees to compensate for the inability to hold meetings only during business hours with no meals offered. Also, the Company offers continuing professional education (CPE) luncheons twice a month to its accountants who have licenses or professional certifications and need CPE credits, which is less expensive than sending employees to off-site seminars or conferences to obtain the required CPE credits.

(4) Off-site meetings: rather than own and maintain the facilities needed for certain kinds of meetings, it is more economical to hold them offsite. Many hotels and other locations maintain the kinds of facilities that are suitable for Southwest's occasional needs.

Q. 26 Did Southwest agree to remove additional items that RUCO identified during its audit?

A. 26 Yes. In response to request RUCO-5-1, Southwest agreed to withdraw its request to recover $13,904 in operating

expenses.

Q. 27 Did RUCO raise a reasonable doubt as to whether the remaining costs are appropriate for cost recovery?

A. 27 No. There are several additional items that RUCO proposes to remove. Examples include: safety kits, photography and photo processing used for communications or recordkeeping, a payment to a builder to refund an overpayment, offsite meetings (in addition to those RUCO identified specifically), and a leadership conference. Other than the $13,904 that Southwest identified above, the remaining items are prudent and necessary business expenses that are properly included in rates.

VII. MISCELLANEOUS INTANGIBLE PLANT

Q. 28 Please explain Southwest's pro forma adjustment to miscellaneous intangible plant.

A. 28 Since the majority of these items are software projects with a three year amortization period, Southwest made a post-test year adjustment to remove all items with an amortization expiring December 31, 2007 or earlier, and to add the items estimated to close to plant during that same time period. The purpose of this adjustment was to better match the Company's request related to intangible plant to those projects that will be amortized during the time rates from this proceeding are effective.

Q. 29 Did Southwest provide updates to its estimates during the discovery process?

A. 29 Yes. In response to Staff data requests STF-6-49 and

STF-11-4, Southwest provided the actual projects that closed to plant after the test year and through December 31, 2007.

Q. 30. How did RUCO address the update of intangible plant?

A. 30 RUCO fully updated intangible plant as of December 31, 2007. RUCO's adjustment reflects an appropriate match and comports with the spirit of Southwest's pro forma adjustment, which removed all projects that expired by December 31, 2007 and added all projects closed by December 31, 2007.

Q. 31 Why do you disagree with Staff's adjustment?

A. 31 Since Staff did not include all intangible plant projects closed prior to December 31, 2007 in its adjustment, it results in a mismatch of ratemaking elements.

Q. 32 Does the Company agree with RUCO's adjustment?

A. 32 Yes. For the reasons stated above, the Company agrees with RUCO and the Commission should adopt RUCO's adjustment to intangible plant.

VIII. A&G ERROR CORRECTION

Q. 33 In RUCO's Operating Adjustment No. 2, RUCO made a conforming adjustment of $283,664. Can you provide some additional background regarding this adjustment to A&G expenses?

A. 33 Yes. There was a $300,000 credit that was erroneously booked to Account 923, Outside Services, during the test year. This credit should have been charged to Injuries

and Damages, Account 925. The reason there was such a large deficiency impact is that the test year amount for Account 923 was understated by $300,000. Whereas, the injuries and damages component of Account 925 was based on a 10-year average and was 4-factored. As such, this correction had a much smaller impact on Account 925. Southwest wants to clarify that this adjustment results in a $300,000 increase to Account 923 and a $16,336 decrease to Account 925.

Q. 34 Does this conclude your prepared rebuttal testimony?

A. 34 Yes, it does.

TESTIMONY OF KEVIN M. HARDARDT

OF THE AMERICAN GAS ASSOCIATION

ON THE BENEFITS OF AGA MEMBERSHIP

Attachment A
STF-12-1 Supplemental

FOR THE ARIZONA CORPORATION COMMISSION

Q. Would you please state your name and address?

A. My name is Kevin M. Hardardt, 400 North Capitol Street, N.W., Washington, D.C.

Q. By whom are you employed and in what position?

A. I am the Chief Financial & Administrative Officer for the American Gas Association (AGA).

Q. What is the purpose of your testimony today?

A. I am here to explain and illustrate how membership in AGA provides a direct and substantial benefit to a member company's customers -- specifically, how, through a variety of policies and programs, AGA aids member companies in improving the quality and reducing the cost of gas service. Membership in AGA helps the member company, provide the best service to the customer at a lower cost.

Q. What will be the structure of your testimony today?

A. First, I will briefly discuss the purposes and organization of AGA. Then I will highlight some of the benefits accruing to a member company's customers as a result of its membership in AGA. Specifically, I will discuss a few activities in each of AGA's major functional areas and illustrate how a member company's customers benefit -- either directly or indirectly -- from each. I also will show how, if a member company were to seek to obtain, by its sole efforts, even a few of the benefits AGA provides, the cost might

quickly exceed the total dues payment of a member company to AGA. As discussed below, the projects AGA performs and the availability of various materials are significant. In addition, I have included three Schedules that will be described below.

Q. Would you begin then by briefly describing the purposes and organization of AGA?

A. Yes. AGA is a national trade association comprising 200 distribution companies serving 64 million customers. As such, it exists to fulfill the needs of the local natural gas distribution companies and thereby improve the industry's ability to better serve its customers. Schedule 1 provides an elaboration of AGA's mission. Schedule 2 shows AGA's current committee organization. Schedule 3 shows AGA's expense breakdown by functional areas for 2008.

Q. Would you briefly describe the information shown on Schedule 2?

A. Yes. The Chairman, First and Second Vice-Chairmen and the Immediate Past-Chairman are top officials of member companies, and, together with our President, are the senior officers of AGA. The Board of Directors, who are top executives of member companies, establishes AGA's policies and actively controls the programs, projects, activities and budget of the Association. Reporting to the Board of Directors are various committees. Each committee is composed of employees of member companies of various sizes and from various parts of the country, and each committee has a "charter" that focuses its efforts on a specific functional area of a gas company's operations. Member company employees serve on the approximately 50 committees and their subcommittees and task forces. In addition, through AGA's functional area contact lists, other employees also regularly receive materials and information of special interest to their functional areas. It is

through the work and with the guidance of these committees that many of AGA's activities are undertaken.

Q. How does a member company and its customers benefit from participation in AGA?

A. AGA serves a member company and its customers in two general ways: the first is by helping them improve their local programs, practices, and procedures in all areas of their operation. In this regard, AGA provides hundreds of forums and other vehicles through which a member company's employees can exchange information with their peers in other companies in order to better serve its customers. These face-to-face exchanges include committee meetings, workshops, seminars, and other forums. In addition, AGA provides program "clearinghouse" services in a number of areas including customer relations, educational services, and training and development. Through such clearinghouses, AGA maintains information on successful programs conducted by member companies and makes this information available to other companies upon request.

The second way AGA serves a member company and its customers is by doing things collectively or at the national level that the utility could not do or could not do cost-effectively on its own. Just one example of the hundreds of projects is the Gas Engineers Operating Practices manuals that have been made available to member companies. These practice manuals convey the latest engineering information in such areas as distribution, utilization, transmission, measurement and supply. It has been estimated that each of the twelve volumes of these practice manuals would cost a utility between $275,000 to $300,000 per manual to produce on its own.

All of these activities are directed at the same goal --to improve the efficiency and effectiveness of member companies in all areas of operation without having them incur

unnecessary "learning curve" costs. If AGA did not exist, solid business practice would call for creation of such an organization.

Q. Would you please describe the type of activities conducted in some of the functional areas, emphasizing how these activities benefit -- either directly or indirectly -- a member company's customers?

A. Yes. The following are some relatively recent examples of AGA's operating and engineering activities -- activities that include literally hundreds of projects to improve the safety, efficiency and productivity of member companies' engineering and operating functions. For example:

(1) The safety record of natural gas utilities is outstanding and it keeps getting better. To help improve the safety of the natural gas delivery system, on December 5-6, 2007, AGA hosted a Safety Leadership Summit for its members to come together and discuss the state of the natural gas industry in four critical areas of safety:

1. Employee Safety
2. Utility Contractor Safety
3. Pipeline Safety
4. Public Safety

Officers, executives and managers from AGA member companies listened to outstanding presentations from industry leaders and various guest speakers, including Secretary of US Department of Labor, Elaine L. Chao and Admiral Frank L. "Skip" Bowman (USN Retired), President of Nuclear Energy Institute. The Summit participants exchanged ideas and experiences through roundtable discussions on all aspects of safety.

(2) AGA publishes the Gas Piping Technology Committee (GPTC) Guide. The Guide is prepared by safety experts from gas distribution and transmission companies, federal and state regulatory agencies, manufacturers and industry consultants.

(3) The Operating Section helped initiate a campaign to increase awareness among contractors and excavators about the damage that can be done to buried pipeline mains as a result of their activities. AGA is a supporting sponsor of this National Program known as the "Common Ground Alliance." Two out of three reportable incidents on these mains are a result of third party excavators. Most incidents occurred because the utility was not notified that work was about to be done or given the opportunity to mark the line. As a result of this effort, we have raised the public awareness of the importance of damage prevention programs and provided a forum for states to better address this issue. We continue to work to improve communication with excavators and reduce these incidents which are costly in terms of injuries and repair expenses and are avoidable.

(4) AGA has taken the lead in developing easy-to-use personal computer software to deal with a variety of operating/engineering issues faced by gas companies. The cost of these programs to members is minimal in relation to the hours of effort they save. So far, programs have been developed in the following areas: (1) Gas Measurement - performs orifice flow and super compressibility calculations; (2) Gas Properties – using the most recent versions of AGA Report No. 10, Speed of Sound in Natural Gas and AGA Report No. 8, Compressibility Factors of Natural Gas, this software calculates natural gas speed of sound, critical flow coefficient and other thermodynamic properties.

(5) AGA updates "Report No. 3, Orifice Metering of Natural Gas." This Report is standard reference in gas contracts. Because of the higher unit cost of gas at the city gate and wellhead, improved measurement accuracy will be of a great economic importance to gas consumers.

(6) AGA's Plastic Materials Committee evaluates the use of plastic materials and new fabrication techniques for gas piping systems. This Committee publishes the AGA Plastic Pipe Manual for Gas Services, which includes the latest information on plastic materials, piping components, and design as well as installation procedures covered under today's codes and standards for natural gas distribution piping systems. Through the use of this information, member companies can more quickly, confidently and safely move to increase the use of more cost-effective plastic materials.

(7) The AGA Best Practices Program for Gas Distribution is an effort to identify procedures of superior performing gas industry companies and innovative work practices that can be used to improve participants' operations. It focuses on improving the safety and efficiency of gas distribution system construction, maintenance, operation and inspection. This committee makes available information regarding a number of operational improvements in areas such as street repairs, safer trenchless technology and automated dispatching. Our members have documented millions of dollars in savings from participation in this program. These savings translate to lower costs for the customer.

(8) We develop a large number of manuals and textbooks that are essential in day-to-day operation of gas utilities. An excellent example is the Gas Engineering and Operating

Practices Services. This 11 book services has become the authoritative work on gas utility engineering.

(9) AGA's Operating Section Continues to provide support to its members who seek industry information on a variety of operations and engineering issues. The SOS Program is a resource for AGA members who have the need to query others on a particular subject. The SOS program is a simple and effective way for members to better understand how others are addressing a particular issue/challenge.

Recent SOS requests include member-initiated surveys on the following topics:

- Oversight and quality checks on contractors that perform locating services
- Security metrics
- Excavation and backfill practices around transmission lines
- 3rd party damage claims
- Gas odorization practices
- Budget practices used for forecasting operations & maintenance workload
- Elevated delivery pressure
- Right of Way acquisition

These are just a few of the many operating and engineering-related projects that benefit a member company and its customers. While in most areas the benefits to consumers in terms of efficiency and lower costs can not easily be quantified in specific dollar amounts, taken together they represent very significant cost benefits to the consumers.

Q. Would you please highlight AGA's financial and administrative activities and how they benefit a member company's customers?

A. Yes. The following are some relatively recent examples of AGA's financial and administrative activities.

(1) AGA sponsors topical workshops on cutting-edge issues facing our member companies. This past year we sponsored a seminar on Accounting for Derivatives, which focused on accounting for the new rules and their applications as they specifically effect the utility industry.

(2) The Accounting Principles Committee works extensively with the Financial Accounting Standards Board and the Securities and Exchange Commission to ensure that new accounting standards or information requests are sound and not unnecessarily burdensome. Over the past two years, numerous responses have been filed with these organizations on their proposals, and have been instrumental in the positions adopted.

(3) Through AGA's Risk Management Committee, member companies are provided with confidential insurance surveys that are beneficial in negotiating insurance coverages, premiums and deductibles. Membership also provides utilities the opportunity to meet with committees representing insurance companies to resolve mutual problems. In addition, AGA was instrumental in forming a utility mutual insurance company that provides competition to the commercial insurance markets, resulting in broader coverage and more competitive premiums. Most member companies' insurance coverage is with this mutual insurance company. Premium savings to companies range up to 20 percent over insurance from other

sources.

(4) In the customer activities area, AGA's Data Source is the utility industry's premier tool for benchmarking customer service programs. Subjects covered include call centers, energy assistance programs, billing and meter reading. A powerful online search engine and analytical tools enable member to retrieve data efficiently, thereby increasing employee productivity.

(5) Through AGA's Rate Committee, and its rate seminars, member company representatives are able to learn of successful programs undertaken by other gas utilities, for example, in the areas of innovative rate design. This information, in turn, can translate into reduced gas costs and load retention, both of which help reduce consumers' gas costs.

(6) Our Rate Committee has developed and maintains an excellent rate fundamentals training course and textbook that is used by many member companies and regulatory agencies in their training programs; the Accounting Services Committee has developed a training program on public utility accounting.

(7) AGA has many programs that assist companies in labor negotiations, collective bargaining agreements and employee benefits. AGA publishes regular collective bargaining reports, which assist member companies in reducing their labor costs. AGA also provides corporate and employee salary and benefit information which is helpful in identifying trends and implementing adjustments. This helps to control

costs.

These are just a few examples. In addition, we develop a range of financial and administrative manuals and reference documents. These are widely used in almost every gas utility. Although the cost to a member company for this information is small, if a member company were to develop this information on its own, the cost could be in the tens of thousands of dollars.

Q. What is the function of the General Counsel's Office?

A. The Office of General Counsel provides legal counsel to AGA. A significant responsibility of AGA's legal staff is to assist member company attorneys in more effectively performing their duties, thereby reducing their companies' cost of service. For example, AGA offers litigation alerts, forums and workshops. Antitrust Compliance Programs, assistance to members in potentially precedent-setting litigation, and analyses and legal summaries. The AGA Legal Committee sponsors Legal Forum, the preeminent legal program for attorneys at gas utilities. Continuing legal education credit is available for attorneys that participate in AGA's legal programs.

Q. Would you please highlight AGA's Policy and Planning activities and explain how they benefit a member company's customers?

A. Yes. AGA's Planning and Planning activities provide an important and timely information service to a member company. For example:

(1) A vast array of data about all aspects of the natural gas industry is collected and compiled in ready-reference form. Among these publications are **GAS FACTS**, and Heating/Cooling Degree-Day Statistics.

(2) AGA also undertakes a wide range of analyses on environmental, financial, gas supply, gas demand, consumer cost, capital requirements, resource efficiency and other issues facing the gas industry. These analyses are of great value in assisting a member company and other decision-makers in resolving the country's current energy problems and in establishing public policies that will be in the nation's best interest.

Q. Would you please describe AGA's Public Affairs program and discuss the benefits to a member company's customers of these activities?

A. AGA has in place a program to monitor federal legislative activities and to discuss with members of Congress and their staff the regulated gas industry's views on these activities. While the subject matter AGA monitors is broad, all of AGA's legislative positions have either a direct or indirect benefit to gas utility customers.

AGA also has been among the leaders in advocating for increased funding of the Low Income Home Energy Assistance Program by the federal government -- a program that is essential in reducing the financial burden of those on low and fixed incomes as they provide themselves with needed basic energy services. And, with the increasing help of many other consumer-oriented organizations, AGA continues to work to ensure the maintenance of adequate funding for the Program. Indeed, AGA's efforts have been a contributing factor in restoring the amounts that were proposed to be cut from the program the last several years.

Another important issue on which AGA has lobbied is the budget authorizations and allocations for the Department of Energy's research and development programs. DOE's R&D budget has been drastically reduced in recent years. We believe, however, that gas-related programs have suffered unjustifiably large cutbacks compared with projects for other forms of energy -- especially in light of the present and future importance of gas to the nation and the substantial benefits these programs could provide U.S. gas consumers.

These are a few examples. The point is that AGA's government relations efforts play a key role in protecting the interests of a member company and its customers from proposed legislation that inadvertently or otherwise could have serious impacts on gas supply and cost of gas service.

Q. Is the work of the AGA government relations program primarily devoted to lobbying?

A. No. AGA's involvement in federal government lobbying is a small part of the program. For example, AGA frequently comments on regulations proposed by a great number of executive branch agencies such as EPA, departments such as DOE, and independent agencies such as the FERC and DOT to communicate the interests of the gas industry and its customers, much as companies do individually before the FERC in rulemaking proceedings.

Reviewing and commenting on the economic and other impacts of the many regulations affecting the gas industry is an important aspect of AGA's governmental relations' work. Such efforts reduce the operating costs of member companies and thus are of direct benefit to consumers who must ultimately pay the costs of compliance with these regulations.

Q. Are government relations' activities or oversight by groups or associations, such as AGA, needed by and beneficial to natural gas distribution companies?

A. Yes, with government at the federal level continuing to be involved in matters such as safety, clean air and water, funding of energy research, and conservation of energy, there continues to be a need for the regulated gas companies to be aware of proposed actions and their potential economic and other impacts in a timely manner and for the industry to have its collective views made known to the federal decisionmakers. The only way the governmental process can arrive at balanced results is for all interested groups to express their views. AGA is the most efficient way through which the views of its member companies on gas industry matters collectively can be communicated, complementing individual companies' own communications. It is important to note, however, that communication between AGA and federal agencies is not just one way. Federal agencies look to AGA when there is a need to get a special notice to gas utilities quickly. On many occasions, we have provided this service to the Consumer Products Safety Commission (CPSC), the Environmental Protection Agency, and the National Transportation Safety Board. For example, CPSC asked AGA to help them get information to gas utility customers about the proper venting of vented gas heaters. AGA developed an extensive information package on this issue and distributed this package to each of our member companies, urging them to incorporate information from it in their customer communications programs.

Q. Would you summarize your testimony about the benefits to a member company's customers of membership in AGA?

A. The benefits of almost all of AGA's activities either directly or indirectly are realized by the customers of AGA's members. I have briefly highlighted a few of AGA's activities and attempted to show how a member company's consumers benefit from them. AGA's website www.aga.org contains additional information about AGA and its programs to benefit members and their customers.

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04/22/2008 3:16 PM

AGA Vision and Mission Statement

Attachment B
STF-12-1 Supplemental

VISION STATEMENT

AGA's vision is to be the most effective and influential energy trade association in the United States while providing clear value to its membership.

MISSION STATEMENT

The American Gas Association represents companies delivering natural gas to customers to help meet their energy needs. AGA members are committed to delivering natural gas safely, reliably and cost-effectively in an environmentally responsible way. AGA advocates the interests of its members and their customers, and provides information and services promoting efficient demand and supply growth and operational excellence in the safe, reliable and efficient delivery of natural gas.

To further this mission, AGA:

1. Encourages, facilitates, and assists members in sharing information designed to achieve operational excellence by improving their safety, security, reliability, efficiency, and environmental and other performance metrics;

2. Assists members in managing and responding to customer energy needs, regulatory trends, natural gas markets, capital markets and emerging technologies;

3. Collects, analyzes and disseminates data on a timely basis to policy makers and the public about energy utilities and the natural gas industry;

4. Focuses on the advocacy of natural gas issues that are priorities for the membership and that are achievable in a cost-effective way;

5. Serves as a voice on behalf of the energy utility industry and promotes natural gas demand growth by emphasizing before a variety of audiences the energy efficiency, environmental and other benefits of natural gas and promotes natural gas supply growth by advocating public policies favorable to increased supplies and lower prices to customers; and

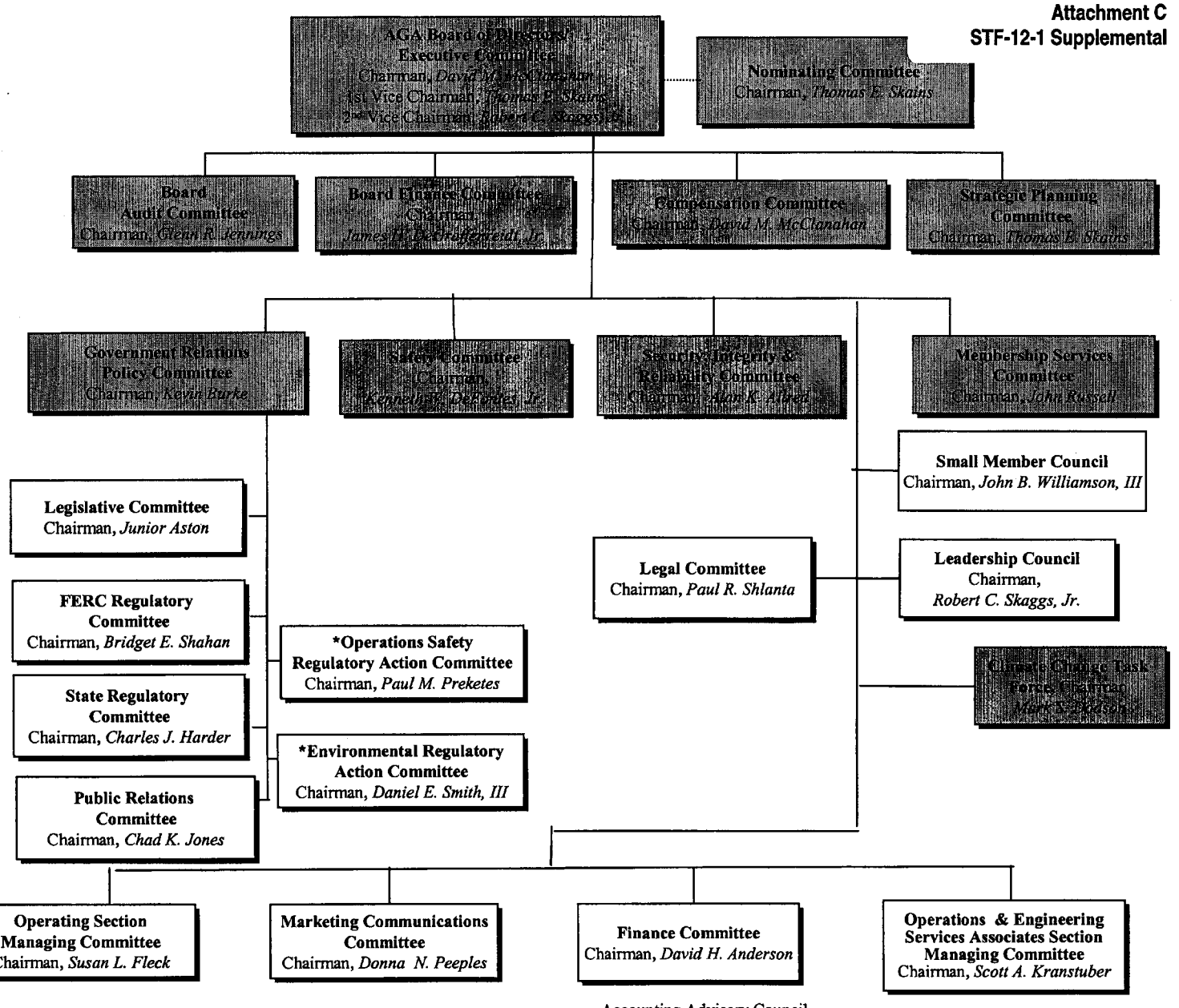
6. Delivers measurable value to AGA members.

Approved September 19, 2006

AGA Committee Structure

(Shaded Committees are Board-level)

Attachment C
STF-12-1 Supplemental



Building Energy Codes & Stds.
Corrosion Control
Distribution Construction & Maintenance
Distribution & Transmission Engineering
Distribution Measurement
Environmental Matters
Executive Committee
Gas Control
Natural Gas Security
Plastic Materials
Safety & Occupational Health
Supplemental Gas
Transmission Measurement
Underground Storage
Utility & Customer Field Services

Accounting Advisory Council
Accounting Principles
Accounting Services
Compensation & Benefits
Customer Service
Human Resources Policy
Internal Audit
Labor Relations
Rate
Risk Management
Taxation
Technology Advisory Council

*Regulatory Action committees also report to the Operating Section Managing Committee

January 2008

AMERICAN GAS ASSOCIATION
2007 BUDGET

STF-6-52

	$ 2007 ALLOCATION	% 2007 ALLOCATION
Advertising	$345,000	1.39%
Corporate Affairs	$2,099,000	8.44%
General & Administrative	$4,665,000	18.77%
General Counsel	$1,016,000	4.09%
Industry Finance & Administrative Programs	$1,283,000	5.16%
Operations & Engineering Management	$5,993,000	24.11%
Policy, Planning & Regulatory Affairs	$3,669,000	14.76%
Public Affairs	$5,790,000	23.29%
Total Budget	$24,860,000	100.00%

Note:
AGA estimates that lobbying expenses, as defined under IRC Section 162, will account for 2% of member dues in 2007.

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
Docket No. G-01551A-07-0504

PREPARED REJOINDER TESTIMONY
OF
RANDI L. ALDRIDGE

ON BEHALF OF
SOUTHWEST GAS CORPORATION

June 9, 2008

Southwest Gas Corporation
Docket No. G-01551A-07-0504

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Of
Prepared Rejoinder Testimony
Of
RANDI L. ALDRIDGE

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Rejoinder Exhibit No.__(RLA-2)	
Rejoinder Exhibit No.__(RLA-3)	

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rejoinder Testimony
Of
Randi L. Aldridge

INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Randi L. Aldridge. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150.

Q. 2 Are you the same Randi L. Aldridge who sponsored direct and rebuttal testimony on behalf of Southwest Gas Corporation (Southwest or the Company) in this proceeding?

A. 2 Yes, I am.

Q. 3 What is the purpose of your prepared rejoinder testimony?

A. 3 The purpose of my rejoinder testimony is to respond to specific aspects of the surrebuttal testimony presented by Mr. Ralph C. Smith, witness for the Arizona Corporation Commission Utilities Division Staff (Staff), and Mr. Rodney L. Moore, witness for the Residential Utility Consumer Office (RUCO), regarding their recommendations for ratemaking treatment of certain rate base and operating expense items.

Q. 4 Did you prepare exhibits to support your rejoinder testimony?

A. 4 Yes. I prepared the exhibits identified as Rejoinder Exhibit No.__(RLA-1) through Rejoinder Exhibit No.__(RLA-3).

Q. 5 Please summarize your rejoinder testimony.

A. 5 My rejoinder testimony will address the following:

(1) RUCO's proposal to exclude the Company's 2008 wage increase.

(2) Staff's proposal to exclude a portion of the Company's AGA dues.

(3) RUCO's proposal to exclude a portion of the Company's employee recognition expenses.

(4) RUCO's proposal to exclude a portion of the Company's miscellaneous general expenses.

(5) The Company's position regarding Staff's proposal on customer advances and customer deposits, as a result of RUCO's withdrawal of its proposed adjustment on the Company's uncollectibles expense.

(6) Staff's incorrect assertion that Southwest's MIP costs in this rate case are 76 percent higher than the last rate case.

2008 WAGE INCREASE

Q. 6 Has RUCO's position regarding the Company's proposal to include the 2008 wage increase in the cost of service changed since its direct testimony?

A. 6 No.

Q. 7 Do you have additional evidence to support the appropriateness of a three percent wage increase for

2008?

A. 7 Yes. In addition to the discussion in my rebuttal testimony at pages 2 and 3, which shows that the adjustment does not violate the matching principle and was prepared consistent with the methodology the Commission approved in the Company's last general rate case, Southwest's proposed 2008 wage increase is known and measurable. Attached as Rejoinder Exhibit No. __(RLA-1) is the Company's announcement to employees that Southwest's Board of Directors has approved salary increases to be effective June 23, 2008. The actual wage increase is identical to the estimated wage increase the Company proposed in its filing - three percent. Furthermore, Staff has not opposed the Company's request for the 2008 wage increase. For these reasons, the Commission should accept the Company's entire labor annualization adjustment as filed.

AGA DUES

Q. 8 Staff maintains that the final NARUC audit report and the Florida Cities Gas decisions should be considered by the Commission in determining the appropriate percentage of AGA dues that should be disallowed from operating expenses (Smith surrebuttal, page 33). Do either of these documents provide evidence to support Staff's position that AGA's cost for its Public Affairs and Corporate Affairs departments be disallowed in their entirety, and that 50 percent of AGA's General Counsel

and Corporate Secretary functions be disallowed?

A. 8 No. Neither of these documents contain evidence supporting Staff's proposal to disallow amounts related to the Public Affairs, Corporate Affairs, General Counsel and Corporate Secretary functions.

Q. 9 Does the fact that an AGA dues exclusion of approximately 40 percent applied to a Florida utility have any bearing on this case?

A. 9 No. Staff's proposed 40 percent disallowance of AGA dues is purely arbitrary, and Staff has not presented any evidence or analysis demonstrating the reasonableness of its proposed disallowance or the inappropriateness of Southwest's adjustment. To the contrary, my direct and rebuttal testimony demonstrate the reasonableness of Southwest's proposed adjustment, which has also not been challenged by RUCO.

Q. 10 Has Staff discussed the functions of Public Affairs, Corporate Affairs, or General Counsel that would customarily be disallowed had they been conducted by Southwest directly?

A. 10 No. However, in Exhibit No.__(RLA-2) of my direct testimony, I provided AGA descriptions of its functional cost centers. In Rebuttal Exhibit No.__(RLA-1), I provided a narrative prepared by AGA which describes various functional cost centers in more detail and explains how customers benefit from the activities performed within each function. The General Counsel

Office is described on page 10 and the Public Affairs function is described on pages 11 through 13. I have demonstrated through these exhibits that customers benefit from AGA activities in excess of the dues that Southwest pays and it is reasonable for Southwest to recover the non-lobbying portion of these functions in rates.

Q. 11 Staff pointed out that the percentages that Southwest used for marketing and lobbying could be updated to 2008 values, and that a portion of AGA general and administrative costs (G&A) should be allocated to the advertising function (Smith surrebuttal, pages 34-35). Is Southwest opposed to this?

A. 11 No, these proposals are reasonable. Southwest agrees that an increase to its proposed adjustment to AGA dues for G&A and to reflect 2008 AGA budget percentages is reasonable. Accordingly, Southwest's proposed exclusion for AGA dues should be increased by $4,575.

EMPLOYEE RECOGNITION EXPENSES

Q. 12 RUCO disagrees with the Company's rationale that employee recognition expenses should be included in rates, as the expenses are "...additional compensation to its employees to perform work functions, some of which are county mandated, that should be considered a condition of employment." (Moore surrebuttal, page 10). Do you agree that the work functions that the employees may receive recognition awards for should be considered

a condition of employment?

A. No. First of all, Maricopa County's Trip Reduction Program ("TRP", the mandated program to which RUCO refers) does not mandate that Southwest's employees take alternative forms of transportation to and from work. Rather, the County mandates that Southwest offer incentives to encourage employees to make voluntary changes in their choice of transportation as part of the Company's participation in the TRP. It is unreasonable to expect Southwest to force employees to take alternative forms of transportation to and from work as a condition of employment.

Secondly, the other three employee recognition programs, described in my rebuttal testimony at pages 9 through 11, reward outstanding performance by employees. Outstanding performance of work functions goes above and beyond expected performance. It is unreasonable to have an expectation that all Southwest employees' performance should exceed expectations at all times, simply as a condition of their continued employment.

Finally, RUCO recognizes that it is important that Southwest "have proactive programs and policies on safety, productivity, and cost containment," (Moore surrebuttal, page 10), which provides validity to the Company's position that it is appropriate that Southwest offer these programs, and that it is inappropriate to make the performance rewarded by these programs a

condition of employment. Southwest continues to recommend that the Commission allow the modest costs of these programs in rates since the benefits of these programs outweigh the costs, and these employees provide service to customers above and beyond a satisfactory level.

MISCELLANEOUS EXPENSES

Q. 13 Did RUCO recognize that it double counted gift certificates in its miscellaneous adjustment and its employee recognition adjustment?

A. 13 Yes, it did. RUCO increased operating expenses by $19,160 to correct for this.

Q. 14 RUCO states that it has "philosophical differences" (Moore surrebuttal, page 7) with Southwest regarding the appropriateness of cost recovery for the remaining items. Do you agree?

A. 14 In some cases this may be true. However, RUCO did not provide specific testimony as to why it disagreed with my rebuttal testimony, other than to state the fact that it has philosophical differences with Southwest. I don't believe that RUCO has raised a reasonable doubt that these expenses should not be appropriately included in rates. RUCO simply states that it believes these expenses are unnecessary. RUCO does not provide any evidence or analysis to support its conclusion.

Q. 15 Did you provide additional testimony in your rebuttal supporting the appropriateness of these expenses?

A. 15 Yes. I provided detailed descriptions of these items at pages 12 and 13 of my rebuttal testimony, and I have explained how these expenses provide customer benefits and/or cost savings, and are appropriately included in rates. Also, on page 14 (Q&A 27), I summarized the remaining categories of expenses that RUCO removed that it did not describe in its direct testimony or its surrebuttal testimony. Based on my rebuttal testimony, Southwest has met its burden of proof that these expenses are appropriately included in rates.

UNCOLLECTIBLES, CUSTOMER ADVANCES, AND CUSTOMER DEPOSITS

Q. 16 Since RUCO withdrew its proposed adjustment to uncollectibles expense in its surrebuttal testimony (Moore, page 10), does Southwest support Staff's proposed adjustment to customer advances and customer deposits?

A. 16 Yes. No party opposes Southwest's uncollectibles expense as filed. As such, Southwest supports Staff's proposal to use end of test year amounts for customer advances and customer deposits.

MANAGEMENT INCENTIVE PLAN (MIP) EXPENSE

Q. 17 On page 26 of Mr. Smith's surrebuttal testimony he asserts that Southwest's MIP expense is 76 percent higher in this rate case than in the prior case, is this correct?

A. 17 No. I have attached two exhibits showing recorded MIP expense since 2001. Exhibit No.__(RLA-2) is Southwest's

response to a data request in the Company's 2004 rate case, which shows the recorded MIP expense in the 2004 rate case was $6,677,800, and not $3,366,667 as purported by Mr. Smith on p. 26 of his surrebuttal testimony. Exhibit No.__(RLA-3) is Southwest's response to a data request in the Company's current general rate case, which shows the recorded MIP expense in this rate case is $5,919,502. Contrary to Mr. Smith's assertion, the MIP expense has actually decreased from the test year in the 2004 rate case by approximately 11 percent.

Q. 18 Does this conclude your prepared rejoinder testimony?

A. 18 Yes, it does.

Human Resources News

SOUTHWEST GAS

Rejoinder Exhibit No.__(RLA-1)
Sheet 1 of 1

Spotlight

Companywide Distribution

May 9, 2008

2008 WAGE AND SALARY INCREASE APPROVED

Southwest's Board of Directors has approved salary increases for both exempt and non-exempt employees. This increase, which is consistent with market compensation trends, will become **effective for the pay period beginning June 23, 2008 and will be reflected in the July 11th paychecks.**

An Overview of Total Compensation

Before we get into details about the pay increases and how they will work, we thought we'd share some information with you about the total compensation program at Southwest Gas. In 2008, wages and benefits compose almost 63% ($218 million) of our Operations and Maintenance Expense budget. Budgeted company contributions for 2008 include:

- $19 million for the pension plan;
- $17.3 million for the medical plan;
- $2.2 million for the annual step-rate increase (for employees not yet at Step 9); and
- $2.6 million for non-exempt wage adjustment (NEWA).

Total compensation encompasses the increases in health and welfare expenses like insurance premiums, retirement contributions and employer matching on your 401(k) contributions. We believe that the components of your total compensation that make up your complete package of wages and benefits must be balanced to ensure your overall well-being.

What Kind of Increase You Can Expect

Non-exempt (overtime eligible) employees will receive an increase based on your classification:

- If you are a Step 9 employee, you will receive a 3% non-exempt wage adjustment (NEWA).
- If you are a Step 1 through Step 8 employee, you will continue to receive "step increases" plus the 3% NEWA.

The following shows the exceptional salary increases received each year—**including NEWA**—starting at Step 1:

Year 1	20.1% increase
Year 2	17.7% increase
Year 3	9.5% increase
Year 4	9.1% increase
Year 5	8.7% increase
Year 6	8.4% increase

Rejoinder Exhibit No.__(RLA-2)
Sheet 1 of 1

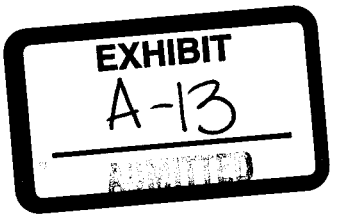
SOUTHWEST GAS CORPORATION
MANAGEMENT INCENTIVE PROGRAM
TOTAL COMPANY COSTS FOR THE YEARS ENDED
DECEMBER 31, 2001 THROUGH 2004 AND THE TEST YEAR ENDED AUGUST 31, 2004
RESPONSE TO RUCO DATA REQUEST NO. 2-13

Description	2001	2002	2003	2004	TME 8/31/04
Recorded Amounts	$ 4,770,000	$ 5,000,000	$ 6,400,000	$ 5,850,000	$ 6,800,000
Less: Special Incentive Award	108,700	113,000	114,700	122,200	122,200
Management Incentive	$ 4,661,300	$ 4,887,000	$ 6,285,300	$ 5,727,800	$ 6,677,800

Rejoinder Exhibit No.__(RLA-3)
Sheet 1 of 1

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
INCENTIVE PROGRAMS
IN RESPONSE TO DATA REQUEST NO. RUCO-1-10
UPDATED 3/25/08

	DATE		CORP		AZ	Account
MIP						
Eligiblity: Sr Mgrs and Above	2004	$	5,699,300			920
	2005		5,681,550			920
	2006		5,241,806			920
	12ME Apr 07		5,919,502			920
Exempt Special Incentive						
Eligibility: All non-incentive	2004	$	150,700			920
exempts with at least 6	2005		148,450			920
mos. service	2006		154,500			920
	12ME Apr 07		151,250			920
Service Planning						
Quality Incentive Award	2004	$	168,035	$	431,425	903
Eligiblity: service planners,	2005		140,171		465,150	903
their supvs and managers,	2006		143,865		367,534	903
industrial gas engineers	12ME Apr 07		137,522		290,004	903
Stock Option Expense						
Expense that must be	2004		-			n/a
recognized on Southwest's	2005		-			n/a
books	2006		1,493,694			920
	12ME Apr 07		1,507,520			920



IN THE MATTER OF
SOUTHWEST GAS CORPORATION
Docket No. G-01551A-07-0504

PREPARED REBUTTAL TESTIMONY
OF
JEROME T. SCHMITZ

ON BEHALF OF
SOUTHWEST GAS CORPORATION

May 9, 2008

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Of
JEROME T. SCHMITZ

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BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rebuttal Testimony
of
Jerome T. Schmitz

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Jerome T. Schmitz. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150-0002.

Q. 2 Please briefly describe your background and experience?

A. 2 My background and experience is attached as Appendix A.

Q. 3 Did you sponsor direct testimony on behalf of Southwest Gas Corporation (Southwest or the Company) in this proceeding?

A. 3 No.

Q. 4 What is the purpose of your prepared written rebuttal testimony?

A. 4 The purpose of my prepared rebuttal testimony is to respond to specific aspects of the direct testimony presented by Arizona Corporation Commission Utilities Division Staff (Staff) witness Mr. Corky Hanson regarding "...the concerns Pipeline Safety has relating to the costs and reasons for replacing the gas distribution system in the Manors subdivision ("Manors") in Yuma."[1] My

[1] Hanson Direct, p. 1, lns. 21-23

testimony and that of Company witness Robert Mashas will also address Mr. Hanson's recommendations related to Staff's proposal to disallow all gas plant required to replace approximately 50-year old pipe in the Manors subdivision in Yuma, Arizona (Yuma Manors).

Q. 5 Did you prepare exhibits to support your rebuttal testimony?

A. 5 Yes. I prepared the exhibits identified as Rebuttal Exhibit No.__(JTS-1) through Rebuttal Exhibit No.__(JTS-3).

II. STEEL DISTRIBUTION PIPE

Q. 6 How would you characterize Mr. Hanson's statement that "[p]ipe corrosion is one of the leading causes of pipeline failures?

A. 6 Mr. Hanson's statement is vague and misleading. Furthermore, it is not representative of recent national incident data for gas distribution systems, or Southwest's leakage data for its distribution system in Arizona. It also is not representative of the risk associated with corrosion on distribution systems in general.

Q 7 When were the federal pipeline safety regulations amended to include corrosion protection requirements?

A. 7 The federal pipeline safety regulations, adopted by the US Department of Transportation (USDOT), Title 49 Code of Federal Regulations, Part 192 (49 CFR 192) were amended

in June 1971 to include Subpart I, which contains the corrosion protection requirements. The requirement to protect steel gas distribution piping installed prior to August 1, 1971 with cathodic protection did not go into effect until August 1976.

Q. 8 What does Southwest's leak data show regarding corrosion compared to other leak causes in Arizona?

A. 8 In Arizona, corrosion accounts for only 14.2% of the total leaks by cause for the period 2003-2007 (Exhibit No___(JTS-1). Leaks caused by excavation damages are nearly three times greater. These statistics are consistent with national numbers.

Q. 9 Has Southwest had any USDOT reportable incidents caused by corrosion in Arizona during the last 5 years (2003-2007)?

A. 9 No.

Q. 10 What information do you rely upon in support of your answer?

A. 10 First, Southwest's own leakage data for its distribution system in Arizona. As noted above, corrosion is not a leading cause of pipeline leaks, as excavation related damages dwarf corrosion damage by nearly three times. Second, the US Department of Transportation (USDOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) commissioned Allegro Energy Consulting (Allegro) to analyze reporting information and produce a report to

examine this very issue, among many others. Allegro's report, "Safety Incidents on Natural Gas Distribution Systems: Understanding the Hazards, April 2005" provides guidance to PHMSA as to how many pipeline safety issues can be addressed from a risk-based perspective in PHMSA's anticipated Distribution Integrity Management Program. Allegro's report, which was based on data collected nationally, indicated in particular the following:

> *"…only 3% of gas distribution incidents reported to USDOT were caused by Corrosion, all of it external corrosion. This is a marked departure from the situation with other types of pipeline systems such as gas transmission and oil pipelines, where corrosion is one of the leading causes of reportable incidents. It is interesting that the reason for this difference does not seem to lie in the use of polyethylene mains and services that do not corrode. Even in steel assets, corrosion accounts for less than 4% of the reportable incidents for gas distribution systems. One factor is that corrosion leaks, while plentiful, can usually be repaired without the kind of consequences that make it a reportable incident. Another consideration is that the pipe wall thickness on these small diameter lines is relatively greater than it is*

for larger diameter transmission lines, providing an extra margin of safety before a corrosion pit fails. (If the small diameter lines had the same ratio of wall thickness to diameter as the larger diameter lines, they would be too thin to maintain structural integrity for regular use.)" [Emphasis added.]

III. YUMA MANOR DISTRIBUTION PIPE

Q. 11 Please provide a brief summary of the history of the gas distribution pipe in the Yuma Manors subdivision.

A. 11 The system operates at or below 27 psig. Most of the steel mains and services were installed between 1954 and 1958 by Arizona Public Service Company (APS). The system had no cathodic protection following installation until September 1982 at which time a ground-bed and rectifier was installed, which provided cathodic protection to the system. Southwest acquired this system when it purchased the APS gas properties in 1984. In April 1991, Southwest replaced the old rectifier with a new rectifier at the same site using the existing ground-bed.

In February 2004, Southwest's Technical Service personnel determined that the ground-bed was no longer effective and a work plan to replace the ground-bed was initiated. The rectifier was returned to operation again in January 2006.

Q. 12 Why did Southwest elect to install a ground bed and re-energize the rectifier in February 2004?

A. 12 As a prudent and safe operator, Southwest strives to comply with all state and federal pipeline safety regulations. At the time, the installation of an anode ground bed was the most cost-effective way to maintain the safety of the system and comply with those regulations.

Q. 13 What was Southwest's intent with the installation of the ground bed?

A. 13 It was Southwest's intent to maintain a safe and reliable system in compliance with pipeline safety regulations.

Q. 14 Was it Southwest's intent to extend the service life of the Manors system for 20 years?

A. 14 Not directly. As previously stated, it was Southwest's intent to maintain a safe and reliable system in compliance with pipeline safety regulations. Any extension of service life to pipe of this vintage is a possible consequence of actions done to remain compliant with the pipeline safety regulations. The long-term effect on the service life of the pipe due to the replacement of the ground bed is uncertain. As such, Southwest continues to assess its distribution systems to annually determine the need for replacement, regardless of when cathodic protection facilities have been installed.

Q. 15 Staff contends that had Southwest connected the rectifier correctly the Yuma Manors distribution systems had significant remaining life that could have been extended, do you agree?

A. 15 No. Mr. Hanson is making too many assumptions to arrive at his conclusion. A pipeline does not operate in a constant environment, like a laboratory setting, at standard temperatures and conditions, so it is difficult, if not impossible, to predict any remaining life for a pipeline after it has served its average useful service life, as was the case with the Yuma Manors system. In my opinion, given the age of the pipe, the type of coating, the lack of cathodic protection for approximately the first 25 years of its existence, this system would have been a candidate for replacement any time in the near future. Mr. Hanson has provided no studies or other evidence to support his conclusion that the pipe "had significant remaining life" or "could have last for many more years."

Q. 16 What process does Southwest use to determine the need for main and service replacements?

A. 16 Main and service replacements are generally determined through the distribution integrity management policies and procedures, which Staff has reviewed on an annual basis. This is a risk-based process, which includes criteria such as: type and age of pipe; operating

pressure; pipe coating; leakage; class location of pipe (proximity to buildings); pipe condition; pipe cover; potential for external damage; soil conditions; cathodic protection system effectiveness; type of customer(s) served; etc. This does not preclude replacement of mains and services for conditions found that are an immediate public safety concern.

Q. 17 Why did Southwest initiate the replacement in the Yuma Manors?

A. 17 In early 2007, Southwest observed an unusual increase in leakage. At the time, the cause of this increase was not known to Southwest[2] As a prudent operator, Southwest made the decision to replace the steel pipe in concert with Southwest's policies and procedures to address what Southwest felt was an immediate public safety concern. Southwest evaluated which steel needed replacement, and which could remain in service. An action plan was instituted during the replacement process to make sure that public safety was maintained. (See Exhibit No.__ (JTS-2)). Construction resources were immediately mobilized to expedite the replacement project. The replacement work started on January 22, 2007 and was completed on April 14, 2007.

Many compelling factors, including age of the system piping (1950s vintage), pipe coating type (tar), prior

[2] It was later learned by Southwest that an employee had incorrectly installed the rectifier, which likely contributed to the increase in leakage.

maintenance history, which included periods without cathodic protection, leakage and general public safety concerns, were considered in the decision to replace the pipe.

Q. 18 Was all the steel pipe serving Yuma Manors replaced by Southwest?

A. 18 No. Some 4-inch steel pipe serving the Yuma Manors was checked at tie-in locations during replacement work and left in service, as the condition of this pipe and its coating were found to be good.

Q. 19 Do you consider the decision to replace the gas distribution piping in the Yuma Manors to be prudent?

A. 19 Yes.

Q. 20 Does Mr. Hanson also believe that the decision to replace the gas distribution piping in the Yuma Manors was prudent?

A. 20 Yes. In his response to Southwest Data Request 2.4, Mr. Hanson indicates that the decision to replace the piping in the Yuma Manors was prudent. However, Mr. Hanson qualified his response by further noting that "but only after SWG reversed polarity on the rectifier creating the need to replace the system." At the time of the replacement, both Mr. Hanson and Mr. Bohnenkamp visited the site and agreed that the actions that were being taken by the Company were appropriate.

Q. 21 Was the Yuma Manors part of what Mr. Hanson refers to as

"...the Company's failure to conduct CP monitoring in 2006"?

A. 21 No. The Yuma Manors system was monitored in 2006 Rebuttal Exhibit No.__(JTS-3).

Q. 22 Do you have any other comments regarding Mr. Hanson's recommendation?

A. 22 Yes. First, when a new ground bed was installed and the rectifier was reenergized in January 2006, it was not known what condition the pipe was in at that time. Given the information Southwest had available to it at that time, it determined that replacement of the pipe was not necessary. It very well could have been on the verge of failure at that time, no one knows. Mr. Hanson disregards this fact and other facts that are known when he speculates as to how much longer this pipe may have lasted before it needed replacement. For example, most of this pipe was over 50-years old, approximately 25 years of which did not include cathodic protection.

Second, contrary to Mr. Hanson's testimony and responses to data requests, Company replacement of the approximately 50-year old pipe results in an improvement to the Yuma Manors distribution system, which has an associated extension of useful life to the system or betterment value. As previously noted, it is speculative to ascertain the remaining life of the pipe that was replaced. However, given the facts that are known, this

pipe very well could have been a candidate for replacement any time in the near future. To the contrary, I can say with a reasonable degree of certainty that the replacement pipe should last 40 or more years. Had this been ten or fifteen year old steel pipe that had been cathodically protected I could better appreciate Mr. Hanson's recommendation. Even then, as Company witness Mashas states in his rebuttal testimony, regardless of the cause for the need to replace the pipe, the Commission has historically always given the utility a betterment (or life extending) value associated with the replacement pipe. Accordingly, given the facts that are known by the parties surrounding this particular pipe, there is simply no support for a disallowance of the entire cost of the distribution pipe.

Q. 23 Are you aware of any previous Commission orders relating to the treatment of vintage pipe as it is removed from service?

A. 23 I am aware of several Commission determinations related to this issue, which Company witness Robert Mashas will address in further detail.

Q. 24 What concerns do you have regarding the potential effect such a disallowance, such as the one proposed by Mr. Hanson, may have on decisions relating to utility investment decisions?

A. 24 I am concerned that such a disallowance may result in less than optimum decisions when maintenance versus replacement decisions are being made. This is especially true on a long-term asset that has served or exceeded its expected service life, and is eligible for retirement. Such a disallowance sends the wrong policy message and seems to encourage operators to consider pursuing minimum investments, perhaps by spending only maintenance funds, instead of making larger long-term investments that will provide long-term benefits to customers and the utility's system.

Q. 25 Does this conclude your testimony?

A. 25 Yes, it does.

SUMMARY OF QUALIFICATIONS
Jerome T. Schmitz, P.E.

Jerome T. Schmitz is the director/Engineering Staff for Southwest Gas Corporation (Southwest). He directs and coordinates support to five operating divisions for pipeline safety code compliance; distribution integrity management; material specifications and approval; environmental compliance; proper energy measurement; pipeline cathodic protection; project design; and the training and qualification of technical services personnel.

Schmitz joined Southwest in 1989 as an engineer in Phoenix. He was subsequently promoted to distribution engineer in 1991; distribution engineer/Compliance and Operations Audit Staff in Engineering Staff later that year; supervisor/Engineering in the Central Arizona Division in 1993; manager/Operational Quality Assurance for Engineering Staff in 1998; and director/Gas Operations Support in 2003. He holds a bachelor of science degree in Genetics from the University of California, Davis, and a bachelor of science degree in Mechanical Engineering from Arizona State University. He is a registered Professional Engineer in the State of Arizona with a proficiency in Mechanical Engineering, and is certified as a Quality Auditor with the American Society for Quality. He also served on the Distribution Integrity Government Industry Team (DIGIT) that oversaw the production of

the American Gas Foundation report, *Safety Performance and Integrity of the Natural Gas Distribution Infrastructure.* In addition, he served on the Risk Control Practices Group of the Distribution Integrity Management Quality Action Team sponsored by the Pipeline and Hazardous Materials Safety Administration (PHMSA). These groups were designed to collect and analyze available information and to reach findings and conclusions to inform future work by the PHMSA relative to implementing integrity management principles for gas distribution pipelines.

Schmitz currently serves as a member of the ASME B31Q Qualification of Pipeline Personnel Technical Committee. He also serves on the AGA Distribution and Transmission Engineering Committee as well as the Operations Safety Regulatory Action Committee.

JEROME T. SCHMITZ

7612 Grassy Bank Street
Las Vegas, NV 89139

Home (702) 492-1412
Work (702) 364-3263

Work Experience

2004- Director/Engineering Staff, Southwest Gas Corporation, Las Vegas, Nevada
Direct the Company's design and standards, pipeline safety compliance, distribution integrity management program, environmental programs, measurement, regulation, instrumentation and corrosion control technical skills training, material specifications, and technical services and engineering-related policy and procedures manuals. Prepare budgets, hire and train personnel and coordinate department activities to meet corporate strategic goals.

2003-2004 Director/Gas Operations Support Staff, Southwest Gas Corporation, Las Vegas, Nevada
Directed the Company's technical skills training, Operator Qualification training and testing, tool and equipment evaluations, operations-related procedures manuals, Incident Management System and operation of a state-of-the-art emergency response training facility.

1998-2003 Manager/Operational Quality Assurance, Southwest Gas Corporation, Tempe, Arizona
Managed a department that develops and conducts operational quality assurance reviews and customer supplier quality audits. The department provides an independent and objective assessment of the level of quality associated with the Company's gas operations and guides corporate quality improvement activities.

1993-98 Engineering Supervisor, Southwest Gas Corporation, Phoenix, Arizona
Supervised the activities of various engineering groups including New Business, Franchise, Code Compliance, Planning, Special Projects, System Improvement and Pipe Replacement.

1991-93 Distribution Engineer/Code Compliance, Southwest Gas Corporation, Las Vegas, Nevada
Monitored external pipeline safety audits and conducted internal audits of natural gas transmission, storage and distribution facilities to evaluate the level of compliance with federal and state regulations and Company standards. Provided interpretations of regulatory codes and code-related standards for gas operations personnel.

1989-91 Engineer, Southwest Gas Corporation, Phoenix, Arizona
Completed a year-long training program in all aspects of natural gas operations including customer service, construction, engineering, system planning, measurement, regulation and corrosion control. Supervised an engineering group for one year designing new installations, system improvements and other projects.

1983-85 Site Coordinator (Administrator), Central Texas College, Fort Greely, Alaska
Represented Central Texas College and oversaw all educational contract obligations including two-year degree programs, military specialty courses and the operation of a library, testing center and learning resource center at a remote military post. Hired, trained and supervised all site personnel; counseled students; and prepared all administrative and financial reports for the operation of the satellite campus.

Education

Arizona State University, Tempe, Arizona
Bachelor of Science in Engineering, Mechanical Engineering, 1988, summa cum laude

University of California, Davis
Bachelor of Science, Genetics, 1981

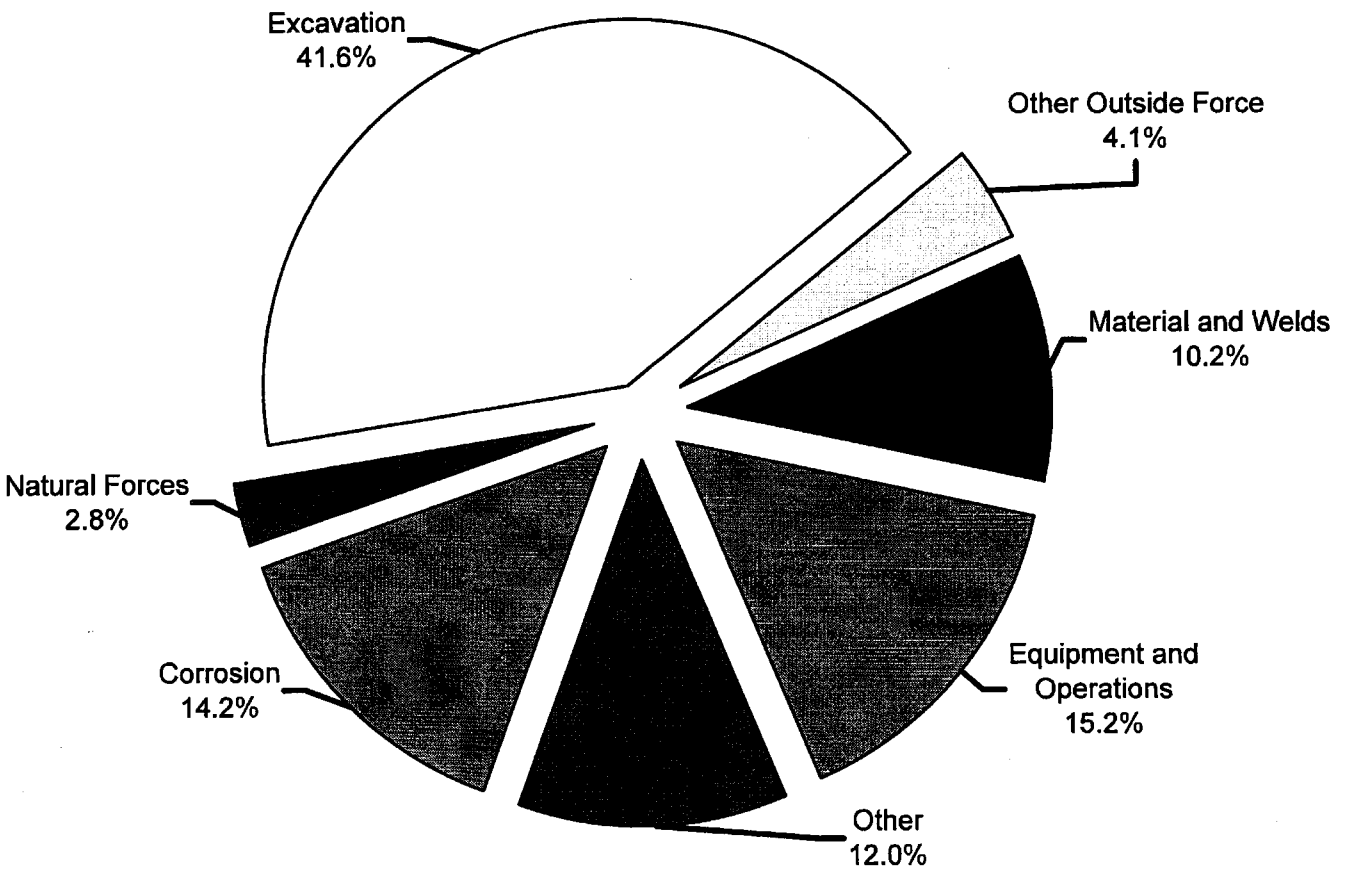
Servite High School, Anaheim, California
Valedictorian, 1977

Registered Professional Engineer, Mechanical Engineering, Arizona, Certificate Number 28206

Awards, Organizations and Interests

National Society of Professional Engineers, Southern Nevada Chapter Member, Central Arizona Chapter President (2000-2001); American Gas Association, Distribution and Transmission Engineering Committee Member and Operations Safety Regulatory Action Committee Member; American Society of Mechanical Engineers, Member and ASME B31Q Qualification of Pipeline Personnel Technical Committee Member; American Society for Quality, Senior Member and Certified Quality Auditor; National Engineers Week Future City Competition, Phoenix Region Co-coordinator (1998-2003); 2002 Chairman's Award, National Engineers Week (Phoenix, Arizona); Distribution Infrastructure Government Industry Team (DIGIT) Member; Distribution Integrity Quality Action Team Member; and President of Board of Directors for Academy for Learning.

Arizona Gas Leak Data
2003-2007 By Cause



Source: Southwest's 2003-2007 Annual DOT reports

Rebuttal Exhibit No.__(JTS-1)
Sheet 1 of 1

SOUTHWEST GAS CORPORATION

February 23, 2007

Mr. Robert Miller
Supervisor of Pipeline Safety
Office of Pipeline Safety
Arizona Corporation Commission
2200 N. Central Ave. Suite 300
Phoenix, AZ 85004

Delivered 2/23/07 RRC

Re: Leaks and Evacuations, Yuma Manors, Arizona
Informal Data Request – Amendment to Item REM 1.5

Dear Mr. Miller:

Southwest Gas Corporation (Southwest) respectfully submits the attached Amendment to Attachment # ACC - REM 1.5 in the Southwest Response to the Arizona Corporation Commission Staff's Data Request on the leaks and evacuations in Yuma, Arizona that occurred during January and February, 2007. The amended portion is contained in the Manors System Improvement Project (MSIMP) ACTION PLAN attachment, Page 1 of 2, section subtitled "Leak Survey". I have bolded and highlighted the amended portion of the attached Plan for your convenience. All other data in the response remains the unchanged.

Please let me know if you have any questions. I can be reached at 602-525-4787.

Sincerely,

Robert Clarillos
Administrator/Compliance/Arizona
Engineering Staff

Attachment

c: Galen Denio

5241 Spring Mountain Road / Las Vegas, Nevada 89150-0002
P.O. Box 98510 / Las Vegas, Nevada 89193-8510 / (702) 876-7011
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ARIZONA CORPORATION COMMISSION
STAFF'S FIRST SET OF DATA REQUESTS
SOUTHWEST GAS CORPORATION
YUMA DISTRICT LEAKAGE

ATTACHMENT # ACC-REM 1.5
AMENDMENT TO ACTION PLAN

Manors System Improvement Project (MSIMP)
ACTION PLAN

Purpose
The Manors System Improvement Project is being performed as a result of corrosion leakage identified on 1950's vintage steel main and service within the Manors Subdivision in Yuma, Arizona. This Action Plan places into motion the rapid and systematic replacement of steel main and service pipe to eliminate the potential of future corrosion leakage within the corrosion control area (s) currently served by rectifier system Y-18.

Location
The system boundaries are: west: Arizona Avenue; east: Engler Avenue; north: Morrison avenue; and south: 26th Place. The area is primarily comprised of single family homes, a trailer park, and a few adjacent apartment complexes and small businesses.

Scope of Project
Replacement or abandonment of 36,690 feet of main and 545 services as follows:

Main

Abandon	32,650 feet of 4", 2", and 1¼" steel
Install	35,340 feet of 4" and 2" PE 8100
	1,350 feet of 2" steel

Service

Abandon	406 - ¾" steel
	139 - ½" plastic
Install	545 - ½" PE 8100

Schedule
It is the intent of this plan to provide adequate manpower and material to accomplish design and replacement of the existing steel facilities described above on or prior to the target date of April 30th, 2007.

Implementation
To accomplish the aggressive replacement schedule, the design and installation of the project will be completed in approximately 9 phases of similar size. By dividing the project into phases replacement work can commence on the early phases while later phases are being designed. The entire design process is anticipated to take approximately 4½ weeks to complete, with approximately 2 phases of design completed each week.

Design – Phased design process will be completed by Yuma District engineering technician.

Construction - To accomplish work in rapid order, a temporary parallel construction work group will be staffed to provide supervision, inspection, construction crews, and, clerical support to process necessary Blue Stake requests, permits, traffic control and documentation.

Leak Survey – A baseline leak survey of the steel main and service within the affected area was completed on 02/05/2007. A subsequent survey will be performed within two weeks and the results reviewed. **The leak survey will continue to be performed daily until all of the remaining steel main and services in the Manors subdivision has been surveyed (at this**

Manors System Improvement Project (MSIMP)
ACTION PLAN

time, the survey cycle for the remaining steel takes approximately 8 days). The leak survey cycle will then continue to repeat itself upon any remaining steel until all steel in the subdivision affected by the rectifier and ground bed in question has been replaced. At that point, this specialized leak survey will end.

Southwest Gas Corporation
Pipe To Soil Inspection Form

CP Area	Yuma	**Date First Protected**	**District** 48
System Number	1-4090230032	1/30/1990	**Area** Yuma
QS/Grid/Tile	4090230032 S97-W269		**Group** TS

Read Cycle	January
Type of Protection (G / I)	I
Main Footage	32140
Current Requirement of the System:	0

Rectifier(s)

Y-18

Test #	Component Type / Meter Number	Location / Location Description / Measurement		QS/Grid/Tile / GPS: Lat — Long		Pipe To Soil (VOLTS)	Test Date
	Test Point - .85 V	2407 S DONNA AVE	808	4090230032	S97-W269	-.36	5-3-2005
				0— 0			
)	Test Point - .85 V	2028 E 26 ST		4090230032	S97-W269	-.32	
				0— 0			
	Test Point - .85 V	2520 S BARBARA AVE	808	4090230032	S97-W269	-.43	
				0— 0			
	Test Point - .85 V	920 E LA MESA ST	708	4090230032	S97-W269	-.31	
				0— 0			
	Test Point - .85 V	1351 E MORRISON ST	709	4090230032	S97-W269	-.27	
				0— 0			
	Test Point - .85 V	1362 E 25 PL		4090230032	S97-W269	-.27	
				0— 0			
	Test Point - .85 V	2402 S MARY AVE		4090230032	S97-W269	-.32	
				0— 0			
	Test Point - .85 V	2572 S MARY AVE		4090230032	S97-W269	-.32	
				0— 0			
	Test Point - .85 V	2001 E 25 ST		4090230032	S97-W269	-.36	
				0— 0			
	Test Point - .85 V	2049 E 24 PL		4090230032	S97-W269	-.32	
				0— 0			
)	Test Point - .85 V	1335 E 25 PL (TW)		4090230032	S97-W269	-.30	
				0— 0			
)	Test Point - .85 V	2036 E LA MESA ST		4090230032	S97-W269	-.30	5-3-2005
				0— 0			

Southwest Gas Corporation
Pipe To Soil Inspection Form

CP Area	Yuma	**Date First Protected**	**District** 48
System Number	1-4090230032	1/30/1990	**Area** Yuma
QS/Grid/Tile	4090230032 S97-W269		**Group** TS

Read Cycle	January
Type of Protection (G / I)	I
Main Footage	32140
Current Requirement of the System:	0

Rectifier(s)

Y-18

est #	Component Type Meter Number	Location Location Description Measurement	QS/Grid/Tile GPS: Lat — Long		Pipe To Soil (VOLTS)	Test Date
1	Test Point - .85 V	2400 E JAMES AVE	4090230032	S97-W269	-.34	5-3-2005
			0— 0			
2	Test Point - .85 V	2500 S BARBARA AVE	4090230032	S97-W269	-.33	
			0— 0			
3	Test Point - .85 V	1355 E 24 PL	4090230032	S97-W269	-.31	
			0— 0			
4	Test Point - .85 V	1360 E 26 ST	4090230032	S97-W269	-.27	
			0— 0			
5	Test Point - .85 V	2049 E 26 ST	4090230032	S97-W269	-.27	
			0— 0			
5	Test Point - .85 V	2022 E 24 PL	4090230032	S97-W269	-.30	
			0— 0			
7	Test Point - .85 V	2541 S DONNA AVE	4090230032	S97-W269	-.32	
			0— 0			
8	Test Point - .85 V	1353 E LA MESA ST	4090230032	S97-W269	-.31	
			0— 0			
1	Test Point - .85 V	929 E 24 PL 808	4090230032	S97-W269	-.31	
			0— 0			
2	Test Point - .85 V	2480 SIERRA VISTA 808	4090230032	S97-W269	-.28	
			0— 0			
3	Test Point - .85 V	2550 S MARION	4090230032	S97-W269	-.26	
			0— 0			
4	Test Point - .85 V	2598 S MARION	4090230032	S97-W269	-.28	5-3-2005
			0— 0			

Southwest Gas Corporation
Pipe To Soil Inspection Form

CP Area	Yuma	Date First Protected	District 48
System Number	1-4090230032	1/30/1990	Area Yuma
QS/Grid/Tile	4090230032 S97-W269		Group TS

Read Cycle	January
Type of Protection (G / I)	I
Main Footage	32140
Current Requirement of the System:	0

Rectifier(s): Y-18

Test # / Component Type / Meter Number	Location / Location Description / Measurement	QS/Grid/Tile	GPS: Lat — Long	Pipe To Soil (VOLTS)	Test Date
Test Point - .85 V	2411 S CAROL AVE	4090230032	S97-W269	-.33	5-3-2005
		0— 0			
Test Point - .85 V	927 E 26 ST	4090230032	S97-W269	-.31	
		0— 0			
Test Point - .85 V	2274 E 25 ST	4090230032	S97-W269	-.23	
		0— 0			
Test Point - .85 V	2269 E 25 ST	4090230032	S97-W269	-.27	
		0— 0			
Test Point - .85 V	2199 E 25 PL	4090230032	S97-W269	-.29	
		0— 0			
Test Point - .85 V	909 E 25 ST	4090230032	S97-W269	-.36	
		0— 0			
Test Point - .85 V	917 E LA MESA ST	4090230032	S97-W269	-.35	
		0— 0			
Test Point - .85 V	940 E 26 PL	4090230032	S97-W269	-.36	5-3-2005
		0— 0			

Inspection Verification

Inspected By: Alex Garcia ALEX GARCIA CORROSION SPECIALIST

Inspection Date: 5-3-2005

Supervisor Verification

Supervisor: DARREN N. RUTLEDGE Supervisor/T.S.-Engr.

Review Date: 6/17/05

System Information

	Yes	No
Down System	X	
LMR Created		
LMR Number		
WR Created		
WR Number		
Man Hours	4.0	

Remarks

Southwest Gas Corporation - Work Management
WR Work Activity Report

Report Run on May 7, 2008 09:12:23 AM

Work Request Information

Service Address | | | 48DCP0000833 | | |
City, State, and Zip Yuma,AZ
Location/Cross Street
WR Name CATHODIC PROTECTION PIPE TO SOIL SYSTEM
Nature of Request
WR Type ISPCP-INSPECTION CP
AC Code DANNLPPESOILSRV - CATHODIC PROT PIPETOSOIL SYS
Operating District 48-YUMA
Crew Headquarter 6975T-YUMA TECH SERVICES
WR Owner YBARRA, SAMUEL EDWARD **Premise ID** **Atlas** 4090230032 **Tile** x-300y618

WR Number **212686**
Related WR
WO #

Construction Complete Date 02/28/2006
Reporting Complete Date 01/29/2007

Compatible Unit Cost Summary

As-Built Level

P/S #1 **Tax Code** INVALID CODE **Acct #** 88701699 **Contractor**
Facility Action **Facility Type** **Facility ID** 48DCP0000833

Crew ID	Accept Date	CU Code	CU Description	ACT CD	CAT CD	CO/ CN	Install Qty	Retire Qty	Material Rate	Labor Cost	Amount
4502	02/28/06	GLABOR	LABOR - MAINS (SWG ONLY)	I	ISP	CO	5	0		$13.57	$67.85

Total amount for this Point/Span $67.85
Total amount in As-Built Level $67.85

WR Attributes

Mandatory Attributes are Bolded

MATL INVESTIGATION **NO** PROJECT PROGRAM NO _____

Compliance Work Results
Procedure Details

Approved Y **Procedure Code** DPSSYSTEM **Facility** DPSSYSTEM - 48DCP0000833
Atlas **Survey Area**
Tile **X Coordinate** **Gps Latitude**
Altitude Zone **Y Coordinate** **Gps Longitude**

Component Type & ID RECTIFIER 119493

Step Instruction	Result	Executed On	By	Comments
RECTIFIER READ TAKEN	YES	02/28/2006	GARCIA, ALEXANDER F	
DC VOLTAGE READ	7.8	02/28/2006	GARCIA, ALEXANDER F	
DC CURRENT READ	5.5	02/28/2006	GARCIA, ALEXANDER F	
P/S POTENTIAL	-2.13	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118291

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.52	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118292

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.72	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Compliance Work Results
Procedure Details

Approved Y **Procedure Code** DPSSYSTEM **Facility** DPSSYSTEM - 48DCP0000833
Atlas **Survey Area**
Tile **X Coordinate** **Gps Latitude**
Altitude Zone **Y Coordinate** **Gps Longitude**

Component Type & ID 850TESTPT 118293

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.22	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118294

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.19	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118295

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.32	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118296

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.34	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118297

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.41	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118298

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.39	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118299

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.37	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118300

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.49	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Compliance Work Results
Procedure Details

Approved Y **Procedure Code** DPSSYSTEM **Facility** DPSSYSTEM - 48DCP0000833
Atlas **Survey Area**
Tile **X Coordinate** **Gps Latitude**
Altitude Zone **Y Coordinate** **Gps Longitude**

Component Type & ID 850TESTPT 118301

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.37	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118302

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.70	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118303

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.21	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118304

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.25	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118305

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.62	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118306

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.41	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118307

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.58	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118308

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.29	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Compliance Work Results
Procedure Details

Approved Y **Procedure Code** DPSSYSTEM **Facility** DPSSYSTEM - 48DCP0000833
Atlas **Survey Area**
Tile **X Coordinate** **Gps Latitude**
Altitude Zone **Y Coordinate** **Gps Longitude**

Component Type & ID 850TESTPT 118309

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.32	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118310

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.22	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118311

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	NO	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118312

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-.97	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118313

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-.96	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118314

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-.95	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118315

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.05	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118316

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	NO	02/28/2006	GARCIA, ALEXANDER F	TEST POINT NO LONGER NEEDED.

Component Type & ID 850TESTPT 118317

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.01	02/28/2006	GARCIA, ALEXANDER F	

Southwest Gas Corporation - Work Management
WR Work Activity Report

Report Run on May 7, 2008 09:12:23 AM

Compliance Work Results
Procedure Details

Approved Y **Procedure Code** DPSSYSTEM **Facility** DPSSYSTEM - 48DCP0000833
Atlas **Survey Area**
Tile **X Coordinate** **Gps Latitude**
Altitude Zone **Y Coordinate** **Gps Longitude**

Component Type & ID 850TESTPT 118317

Step Instruction	Result	Executed On	By	Comments
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118318

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-.99	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118319

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.00	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118320

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.21	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

Component Type & ID 850TESTPT 118321

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	YES	02/28/2006	GARCIA, ALEXANDER F	
ON AS FOUND P/S READ	-1.18	02/28/2006	GARCIA, ALEXANDER F	
P/S EVALUATION	PASS	02/28/2006	GARCIA, ALEXANDER F	

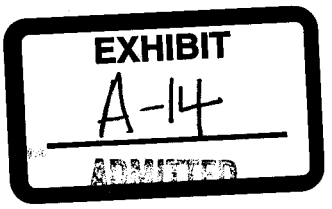
Component Type & ID 850TESTPT 118322

Step Instruction	Result	Executed On	By	Comments
TEST POINT READ	NO	02/28/2006	GARCIA, ALEXANDER F	TEST POINT NO LONGER NEEDED.

Component Details

Component ID 118311 **Component Type** 850TESTPT **Action** Uninstall
Atlas **Tile** **Address** Yuma AZ
Manufacturer **Serial Number** **Lot Number** **Gps Longitude**
X Coordinate **Y Coordinate** **Gps Latitud**
Characteristic **Original Value** **New Value**

Component ID 118316 **Component Type** 850TESTPT **Action** Uninstall
Atlas **Tile** **Address** Yuma AZ
Manufacturer **Serial Number** **Lot Number** **Gps Longitude**
X Coordinate **Y Coordinate** **Gps Latitud**
Characteristic **Original Value** **New Value**



IN THE MATTER OF
SOUTHWEST GAS CORPORATION
Docket No. G-01551A-07-0504

PREPARED REJOINDER TESTIMONY
OF
JEROME T. SCHMITZ

ON BEHALF OF
SOUTHWEST GAS CORPORATION

June 9, 2008

Southwest Gas Corporation
Docket No. G-01551A-07-0504

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Of
JEROME T. SCHMITZ

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Southwest Gas Corporation
Docket No. G-01551A-07-0504

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rejoinder Testimony
of
Jerome T. Schmitz

INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Jerome T. Schmitz. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150.

Q. 2 Are you the same Jerome T. Schmitz who sponsored rebuttal testimony on behalf of Southwest Gas Corporation (Southwest or the Company) in this proceeding?

A. 2 Yes, I am.

Q. 3 What is the purpose of your prepared rejoinder testimony?

A. 3 The purpose of my rejoinder testimony is to respond to certain aspects of Arizona Corporation Commission Utilities Staff (Staff) witness Mr. Corky Hanson's surrebuttal testimony related to the replacement of the natural gas distribution pipe at Yuma Manors.

STAFF WITNESS MR. CORKY HANSON

Q. 4 Do you agree with Mr. Hanson's characterization of his direct testimony on page 1, lines 2-4 of his surrebuttal testimony?

A. 4 No. Mr. Hanson states that his direct testimony addresses pipe replacement associated with the "Company's negligence in making earlier repairs to the

pipeline." This is an example of Mr. Hanson's vague and misleading statements regarding the Yuma Manors pipe replacement project. There is no evidence in this case that the Company was negligent nor did Mr. Hanson allege any negligence by Southwest in his direct testimony. On page 2, line 7 of Mr. Hanson's direct testimony, he attributes the pipe replacement to "incorrect actions" taken by Southwest personnel. The Company does not dispute that an employee made a mistake which may have contributed to the need to replace the steel pipe sooner than may have been required, but Southwest strenuously objects to Mr. Hanson's implication that the Company was negligent. Negligence is generally defined as "the failure to use such care as a reasonably prudent and careful person would use under similar circumstances."1 An employee mistake is entirely different than "Company negligence" as Mr. Hanson incorrectly states.

Q. 5 Do you agree with Mr. Hanson's characterization of Rebuttal Exhibit No.__(JTS-1)?

A. 5 No. In his direct testimony, Mr. Hanson made the unsupported statement that "pipe corrosion is one of the leading causes of pipeline failures."2 This quote is another example of Mr. Hanson's vague and misleading statements regarding this incident, as I mentioned in my rebuttal testimony. Mr. Hanson did not qualify his

1 Black's Law Dictionary 930 (Fifth Edition 1979).
2 Hanson Direct, p. 3, line 3.

original statement as pertaining only to steel pipe, nor does he seem to recognize that corrosion leaks on distribution systems are generally not failures that result in incidents. The purpose of Rebuttal Exhibit No.__(JTS-1) was to simply put his statement into proper context and to demonstrate that there are numerous factors to consider when making conclusions regarding pipe failures.

CATHODIC PROTECTION

Q. 6 Can you provide a simple example of how pipe is protected?

A 6 Yes. Without any protection, bare steel in a natural environment tends to revert to its natural state through an electrochemical corrosion reaction, which is ferric oxide, or rust. In order to prevent this reaction from occurring, steel must be insulated from the environment by applying a pipe coating or by reversing the electrical current flow causing the reaction, or both. For example, steel pipe can be protected by applying a pipe coating to insulate the pipe from the environment and then by impressing a small direct electric current to reverse the electrical corrosion reaction process at locations where the coating has a defect that exposes the steel pipe to the environment.

Q. 7 Mr. Hanson continues to contend that had the Southwest employee connected the rectifier correctly, the Yuma

Manors distribution system had significant remaining life that could have been extended. Do you agree?

A. 7 No. Mr. Hanson has provided no analysis, studies or other evidence to support his conclusion that the pipe "had significant remaining life." Instead, he merely relies upon the fact that leak survey reports show a significant increase in leaks after the ground bed was placed back in service in 2006. His testimony continues to imply that impressed current is the only element required to protect pipe. As in the example I discussed above, two other elements, pipeline environment and the pipe coating, must also be considered to provide effective protection of pipe. Mr. Hanson recognizes that a pipeline does not operate in a constant environment; however, he does not provide any information as to why environment is an important consideration. Similarly, he does not discuss pipeline coatings, which provide an insulating barrier on the pipe against a potentially corrosive environment. Effective pipeline protection relies on both the pipe coating and the impressed current to counteract the effects of the environment in which the pipeline is installed.

Q. 8 Why is pipe coating an important consideration when analyzing cathodic protection?

A. 8 Pipe coating is critical to the overall protection of the pipe and is considered to be the first barrier of defense in preventing and mitigating corrosion. A structurally

sound coating with few holes or cracks exposing the steel requires minimal impressed current. Pipe coating integrity ultimately determines the level of impressed current protection needed. When the coating fails, it compromises the protection of the pipe. Impressed current from the rectifier can be increased to a point to overcome a coating failure, but at some level the amount of impressed current to protect the pipe will actually accelerate the disbonding of the pipe coating to the point where the pipe can no longer be effectively protected. The power costs of providing the required impressed current will correspondingly increase.

Q. 9 Would you expect to see widespread corrosion damage if the pipe coating was sound and had few imperfections, even if the polarity was reversed?

A. 9 If the polarity was reversed, I believe corrosion would be accelerated at the coating hole or crack locations, but should not result in the widespread and general corrosion, as appeared to be the case in the Yuma Manors system.

Q. 10 Does the Company have any information related to possible coating problems?

A. 10 The tar coating on the steel pipe in Yuma Manors was "mature" and had been subject to over 50 years of environmental fluctuations, particularly in areas proximate to residential yards. As I address in more detail later in my rejoinder testimony, the pattern of

leaks from the leak surveys are concentrated in one of the four subdivisions, which suggests that this particular area of the system had possible coating problems. It is also important to note, as I indicated in my rebuttal testimony, not all steel pipe connected to this rectifier had to be replaced, even though it was all the same vintage.

Q. 11 Do you agree with Mr. Hanson that "…properly installed, cathodic protection has the potential to extend the life of a buried pipe of any vintage?"

A. 11 No. As I indicated earlier, a number of things other than impressed current must be considered for adequate protection of buried steel pipe. For older piping, such as with Yuma Manors, the condition of the tar coating, and the nature of the environment in which the pipe is installed, may render additional cathodic protection inadequate sooner, rather than later, so that impressed current will not provide the needed protection.

YUMA MANORS SUBDIVISION

Q. 12 Please describe the distribution system in the Yuma Manors subdivision.

A. 12 As illustrated on the map included herewith as Rejoinder Exhibit No.__(JTS-1), the distribution system in the Yuma Manors subdivision is located within the geographic area generally bounded by 24th Street on the north; Engler Avenue on the east; 26th Place and San Marcos Drive on the south, and James Avenue on the west. The subdivision

consists of 4 units: Manors 1, 2, and 3, and East of Pacific. The subdivision is divided by two canal rights-of-way, one of which runs north/south between Carol Avenue in Manors 1 and Mary Avenue in Manors 2, and one of which parallels the west side of Pacific Avenue. The distribution system was, and still is, served by a 4-inch steel main running along 24th Street. Prior to the pipe replacement project, the interior of the distribution system (excepting the 4-inch steel feeder main in 24th Street) consisted of steel mains. Many of the steel services in Manors 1 and most of the services in Manors 2 had been replaced with plastic pipe prior to 1985. The steel distribution system was protected by a rectifier (designated as "Y-18") located near the back of the lots on Mary Street and 26th Street near the canal right-of-way.

Q. 13 Please describe the history of the Yuma Manors system.

A. 13 As I indicated in my rebuttal testimony, the gas distribution system for the Yuma Manors was installed between 1954 and 1958 by Arizona Public Service Corporation (APS). Southwest's records show remaining steel services in Manors 1 and Manors 2 dating to 1955, and remaining steel services in Manors 3 and East of Pacific dating to the 1956 to 1958 time frame. It is not unreasonable to assume that the development of this subdivision occurred from Manors 1 and 2, first, then to Manors 3 and East of Pacific, last.

Q. 14 Are you aware of any other information germane to the discussion regarding the purported condition of the distribution system just prior to the rectifier being reversed?

A. 14 Yes. Southwest contacted the Yuma Mesa Irrigation and Drainage District and learned that flood irrigation was available to homes in the Yuma Manors until the early 1960s. This fact was also confirmed by a Southwest employee who grew up in the subdivision. This fact is germane to the discussion regarding the purported condition of the distribution system because, as discussed in more detail below, the cyclical wet/dry nature of the environment in residential yards will likely cause the pipe coating to deteriorate more quickly than in a more stable environment.

Q. 15 Do Southwest's records provide any additional information that pertains to historic replacements within the subdivision?

A. 15 Yes. Steel pipe, not plastic pipe, was utilized in the construction of gas distribution systems in the 1950s. It is noteworthy that many of the original steel services in Manors 1 and all but a few of the services in Manors 2 were replaced with plastic pipe prior to the replacement project undertaken in 2007 by Southwest. APS, the owner and operator of the system until 1984 when Southwest purchased the APS gas properties, apparently replaced many of the steel service lines with plastic pipe prior

to 1984. APS' pipe replacement is reflected in the current Southwest maps.

Q. 16 Why did APS replace the steel services?

A. 16 The only reasonable conclusion I can draw is that the original steel services were replaced early due to leakage from corrosion. As I indicated in my rebuttal testimony, these steel lines had no cathodic protection until 1982.

Q. 17 Please describe Southwest's Yuma Manors replacement project.

A. 17 The replacement project challenged by Staff witness Mr. Corky Hanson, replaced all of the interior steel mains and steel services with plastic pipe. In some locations, the steel pipe was used as a sleeve into which the new plastic pipe was inserted; in others, mains were moved from the alley to the street to eliminate future maintenance challenges with backyard services. Existing plastic services were utilized and tied over to the new plastic mains where possible.

Q. 18 Was all of the distribution system within the Yuma Manors subdivision replaced?

A. 18 No. The 4-inch steel pipe along 24th Street was not replaced and remains in service because it was determined to still be in good condition. Southwest also determined that unlike the service lines, any future replacement of this pipe could be done with little customer interference. Following the completion of the

replacement project, the existing 4-inch steel pipe along 24th Street was connected to the Y-18 rectifier by a cable inserted into a 1200-foot plastic conduit running north along the canal right-of-way behind the homes on Mary Avenue from 26th Street to 24th Street.

Q. 19 Do you believe that the pipe that was replaced in Yuma Manors was poorly coated and would need replacement in the near future?

A. 19 Yes. I believe one can reasonably conclude that the cyclical wet/dry nature of the environment in residential yards caused the coating on steel services to deteriorate more quickly than in the more stable environment that would exist for mains under pavement in streets or alleys. As such, it was only a matter of time before these coating deficiencies would come to light. Furthermore, I believe that the inadvertent reversed polarity actually revealed this deficient coating. The leaks found during late 2006 and early 2007 were primarily concentrated in a single subdivision - Manors 3, and most of the leaks found prior to and during the replacement project occurred on services where the pipeline environment continually changed over the years, undergoing cycles of wet and dry environments. As noted above, flood irrigation was available to homes in this subdivision until the early 1960s. Furthermore, the fact that most of the leaks were found on services in Manors 3, a reasonable person can conclude that the effect of

the reversed polarity at the rectifier simply identified the weak links in a system that were at or near the point where coating deterioration would have become evident in the near future. Accordingly, the employee's mistake did nothing more than expose this potential issue sooner than Southwest may otherwise have learned about it, which then resulted in a pipe replacement project that occurred sooner than it otherwise would have. Nothing more, nothing less.

Q. 20 If few leaks were found on mains, why did Southwest not just replace the service lines?

A. 20 Southwest did that initially. Given the facts and circumstances surrounding this distribution system, it did not make sense to continue service replacements on a piecemeal basis as leaks were found, considering that replacement of mains might be deferred for only a few years. A new main installation at a future date would likely require abandonment of some of these newer services because the main would be relocated from an alley (back of residence) to a street (front of residence). By completing the entire replacement at one time, service disruptions to customers were kept to a minimum. Additionally, the Company was able to relocate some services and mains to be more easily accessible and gained economic efficiencies related to a complete project. As a result, the customers benefit from the extension of life to an existing system and a new state-

of-the-art system that has fewer maintenance requirements.

Q. 21 Does Mr. Hanson acknowledge that the Company acted as a prudent operator in replacing the entire Yuma Manors pipeline system?

A. 21 Yes. Mr. Hanson acknowledges that the Company acted as a prudent operator to maintain a safe and reliable system on page 2 of his surrebuttal testimony.

Q. 22 In the 2007 or 2008 Pipeline Safety Audits, did Staff cite to any probable noncompliance or violation of either federal or state pipeline safety regulations with respect to the Yuma Manors system?

A. 22 No.

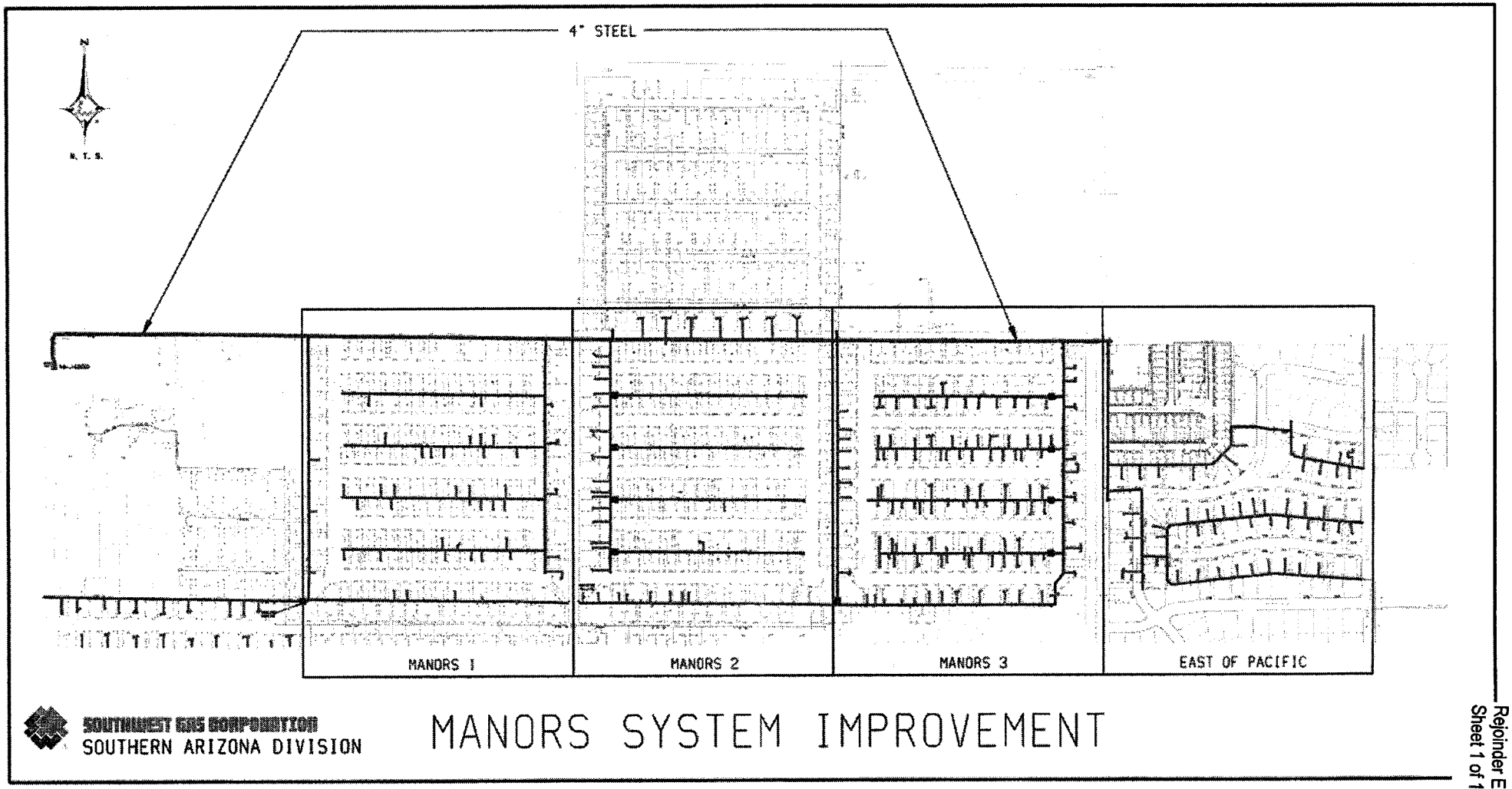
Q. 23 Does the replacement pipe provide any value to the customer?

A. 23 Yes. The replacement project results in betterment to the distribution system that should extend the useful life of the system for 40 or more years. The point that Mr. Hanson continues to ignore is that the replacement of the system is simply a timing issue. Given the facts and circumstances surrounding this system, it was only a matter of time before it would have been replaced. It was simply replaced sooner than it otherwise would have been, had the rectifier not been reversed. Yet, reading Mr. Hanson's testimony, one could reasonably conclude that the employee mistake ruined the entire Yuma Manors distribution system. As discussed above, this was not

the case. The reversal resulted in increased leaks primarily in a concentrated area - service lines in Manors 3. The replacement project of the distribution system was much more extensive than Manors 3 due to the facts and circumstances surrounding the distribution system.

Q. 24 Does this conclude your prepared rejoinder testimony?

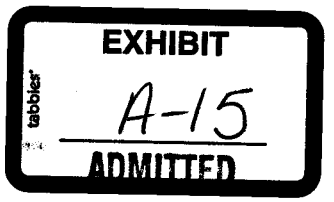
A. 24 Yes.



SOUTHWEST GAS CORPORATION
SOUTHERN ARIZONA DIVISION

MANORS SYSTEM IMPROVEMENT

Rejoinder Exhibit No.__(JTS-1)
Sheet 1 of 1



IN THE MATTER OF
SOUTHWEST GAS CORPORATION
Docket No. G-01551A-07-___

PREPARED DIRECT TESTIMONY
OF
ROBERT A. MAHSAS

ON BEHALF OF
SOUTHWEST GAS CORPORATION

August 31, 2007

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Of
Prepared Direct Testimony
Of
ROBERT A. MASHAS

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Appendix A - Summary of Qualifications of Robert A. Mashas

Exhibit No.___(RAM-1)

Southwest Gas Corporation
Docket No. G-01551A-07-___

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
Of
ROBERT A. MASHAS

I. INTRODUCTION

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 Does Appendix A summarize your educational background and business experience?

A. 3 Yes, it does.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 Yes. I previously testified before the Arizona Corporation Commission (Commission or ACC), the Public Service Commission of Nevada (PUCN), the California Public Utilities Commission (CPUC). I also provided written testimony to the Federal Energy Regulatory Commission (FERC).

Q. 5 What is the purpose of your prepared direct testimony in this proceeding?

A. 5 My testimony comprises four 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 discusses the proposed adjustments to the test year that Southwest is proposing and which I support. The last part supports the Company's rate base Schedules B-1 through B-6.

II. RATE CASE OVERVIEW

Q. 6 What is the test year for this rate application?

A. 6 The test year is the 12-month period ended April 30, 2007. The test year results were adjusted to normalize and annualize the effects of known and measurable changes that occurred through April 30, 2007. In addition, Southwest proposes 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 go into effect.

Q. 7 When was Southwest's last Arizona general rate case application?

A. 7 Southwest filed the Arizona 2004 general rate case (Docket No. G-1551A-04-0786) on December 9, 2004, nearly three years ago. The test year in that proceeding was based on the 12 months ended August 31, 2004. The 2004 rate case was fully litigated and resulted in Commission Decision No. 68487, which granted Southwest an increase in non-gas revenue ("Revenue") of approximately $49.3 million, effective March 1, 2006. Decision No. 68487

authorized an overall rate of return (ROR) of 8.40 percent, calculated using a 9.50 percent return cost of equity on a ratio of 40 percent common equity.

Q. 8 How does the Company determine if a revenue deficiency exists?

A. 8 A revenue deficiency occurs when a Company's annualized and normalized revenue, at its current rates, is less than the Company's annualized and adjusted cost of service (COS) including the cost of capital. If the resulting overall rate of return (ROR) is either less than authorized in the Company's last rate case, or is not equal to the ROR that would be deemed reasonable given current market conditions and the Company's overall cost of capital, a revenue deficiency exists.

Q. 9 What is Southwest's revenue deficiency in its Arizona operations?

A. 9 Schedule A-1, Sheet 2, Column (d) illustrates that the adjusted revenue of approximately $399.2 million at present rates yields a ROR of 6.68 percent. In this proceeding, Southwest requests that the Commission grant ROR of 9.45 percent. In order to produce the 9.45 percent ROR, a revenue increase in the amount of approximately $50.2 million is required.

Q. 10 What does the term revenue mean?

A. 10 The term revenue refers to non-gas revenues Southwest receives through base rates. Because there is a separate purchased gas adjustment 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 and costs associated with the gas commodity are excluded from the general rate case.

Q. 11 Please indicate the Company witnesses who support the proposed adjustments to the recorded test year amounts.

A. 11 There are 17 adjustments to the test year data. These adjustments are listed on Schedule C-2, Sheets 1 through 2. Company witness A. Brooks Congdon supports Adjustment Nos. 1 and 2, Company witness Randi L. Aldridge supports Adjustment Nos. 3 through 7, and 11 through 17. I support Adjustment No. 8 Leak Survey and Repair, Adjustment No. 9, Surcharge Adjustment, and Adjustment No. 10, Injuries and Damages.

Q. 12 Identify the adjustments that Southwest is proposing related to events that occurred or will occur after April 30, 2007.

A. 12 There are four adjustments that fall into this category. They are: 1) wage increases and within-grade movement; 2) completed construction not classified (CCNC); 3) post test year new and expired software amortizations; and 4) the 2008 property tax assessment ratio.

Q. 13 Why has Southwest included these adjustments in this general rate case?

A. 13 Consistent with Southwest's prior Arizona rate cases, when events are known or reasonably certain to occur and

are measurable prior to hearing, the Commission has allowed adjustments similar to the four adjustments proposed herein. The test year more accurately reflects the level of expenses and costs Southwest will incur when the rates in this proceeding are in effect with these proposed adjustments. The four post test year adjustments are easily reconcilable to test year accounts without distortion or mismatching.

The adjustments for CCNC, post test year wage increases and within-grade movement, and post test year new and expiring amortizations were approved by the Commission in several previous rate cases.

In the Company's 2004 rate case (test year ended August 31, 2004), the Commission approved the use of the 2006 property tax assessment ratio. The Company's proposal to use the 2008 assessment ratio in this rate case is consistent with Decision No. 68487.

Ms. Aldridge's testimony provides additional detail related to the post test year wage increases, within-grade wage adjustment, CCNC, expiring and new amortizations, and the property tax assessment ratio.

III. MAJOR REASONS AND UNDERLYING CAUSES FOR THE DEFICIENCY

Q. 14 Please identify the major reasons and underlying causes for Southwest's revenue deficiency in Arizona.

A. 14 There are six major underlying causes for Southwest's present revenue deficiency: 1) declining average residential usage; 2) the loss of general service

customers who were taking service at the end of the 2004 rate case; 3) increased expenses; 4) the Company's "overall cost of capital" compared to what is currently authorized; 5) the Company's request for inclusion of the costs related to the management incentive plan (MIP) and supplemental executive retirement plan (SERP); and 6) the costs resulting from changes in rate base (gas plant net of depreciation and other rate base items, such as finance, depreciation, property tax and interest on customer deposits) net of new customer revenue derived from the customer-related portion of rate base.

IV. DECLINING AVERAGE RESIDENTIAL USAGE

Q. 15 How does declining average residential useage cause a revenue deficiency?

A. 15 At the time a rate case is filed, the Company proposes and ultimately the Commission establishes a COS that is deemed to be appropriate for the development of rates that each customer class will be charged. In most instances, a fixed and variable rate is developed to recover the revenue responsibility allocated to each rate class. The portion of the designed revenue responsibility recovered through the fixed component is predicated on the number of customers requesting service. The portion of the revenue responsibility that is designed to be recovered through the variable component is predicated on volume (therm) level used in the test year. Failure to sell the average therm level will

create a revenue deficiency that is not caused by an increase in costs.

Q. 16 How does the Company determine the revenue deficiency component resulting from residential declining average use?

A. 16 The Company calculates this deficiency by comparing the average use per customer utilized to establish its current rates to the average customer use experienced during the test year in the current rate case times the authorized revenue usage rate. Only the customers that were included in the previous rate case are used in this calculation. Customers added subsequent to the end of the test year used to establish rates in the Company's last rate case are excluded.

Q. 17 What is the impact of the decline in average residential usage per customer on the revenue deficiency in this rate case?

A. 17 In his prepared direct testimony, Company witness Jamie Cattanach states that average residential usage per customer declined 15 therms (from 347 therms to 332 therms) since Southwest's 2004 general rate case. The 15 therm reduction results in an $8.00 per customer revenue shortfall (15 therms x $.53 per therm average revenue rate). The 2004 rate case contained approximately 822,000 residential customers. The $8.00 per customer shortfall equates to a $6.5 million annual reduction in residential authorized revenue recovery due to declining

average residential use. Accordingly, if the Company did not add a single customer, and incurred no additional costs above those authorized, the Company would still be deficient by $6.5 million.

V. GENERAL SERVICE CUSTOMERS

Q 18 What impact does the general service customers no longer taking service since the last rate case have on the current deficiency?

A. 18 In the Company's 2004 rate case, the general service class (Small, Medium & Large) revenue responsibility was spread to 39,740 customers who were taking gas service on August 31, 2004. In the current proceeding, which is based on a test year ended April 30, 2007, the Company served 40,092 general service customers, which is 352 more than the number of customers served at the end of the test year used to establish rates in the 2004 rate case. Although the Company is providing service to 352 more customers, there are two underlying events in play. One is that 2,442 general service customers in the current rate case first began taking service subsequent to the end of the test year in the 2004 rate case. The second is that 2,090 general service customers left the system after the 2004 rate case and are no longer customers as of April 30, 2007. The revenue responsibility assigned to these 2,090 customers, for recovery through the basic service charge and commodity rate, has been lost. When applying the average revenue

per customer from the last rate case, the Company was expected to recover approximately $4.3 million of the designed revenue responsibility from these 2,090 customers. Accordingly, if the only change from the last general rate case was the loss of the 2,090 general service customers, the Company's revenue deficiency would be $4.3 million as a result of general service customer attrition.

Q. 19 Does the revenue realized from the 2,442 general service customers added since the last rate case offset the deficiency resulting from the 2,090 customers that are no longer taking service?

A. 19 No. In order to serve the new general service customers, new capital was required. The new capital was not included in the derivation of rates in the last proceeding. The "incremental" revenue received from the new customers is required to offset the new costs that result from providing the "incremental" facilities to serve new customers. As long as the incremental revenue is equal to, or greater, than the incremental cost of serving the new customers, the new customers do not create a deficiency. The addition of new customers and the loss of previously-served customers are separate events which independently impact the revenue deficiency.

VI. EXPENSES

Q. 20 What is the increase in expenses since the last general rate case?

A. 20 Excluding SERP and MIP, the expense level requested in this proceeding is approximately $21 million higher than the amount used to establish rates in the 2004 rate case. The $21 million increase can be grouped into three major categories: 1) labor directly charged to Arizona and corporate system allocable; 2) employee benefits, primarily basic retirement plan (BRP) and medical claims; and 3) expenses other than labor and employee benefits.

Q. 21 Please discuss the expense increase due to labor.

A. 21 The labor cost in this proceeding is approximately $6.3 million, or 8.9 percent greater than the amount authorized in the last general rate case. In the 2004 rate case, the Company requested, and the Commission approved, the Company's annualized labor at August 2004 adjusted for the impact of the June 2005 post test year wage increase. The Company's 2004 rate case did not include the cost related to the June 2006 wage increase because it was not known and measurable until after rates from the 2004 rate case went into effect. As a result, the cost related to the June 2006 wage increase is now a component of the revenue deficiency in the current rate case. On May 5, 2007, the Company's Board of Directors approved a three percent general wage increase. The test year labor requested by the Company in this proceeding includes the annualized labor as of April 2007, adjusted for the impact of the approved May 2007 general wage increase. In addition, the Company included the cost

related to the anticipated second quarter 2008 wage increase. Rates in this proceeding are not anticipated to go into effect until the fourth quarter of 2008. Thus, the actual second quarter 2008 wage increase will be known and measurable prior to the effective date of rates pursuant to this proceeding. Inclusion in the labor cost of the 2007 and 2008 wage increases reduces the impact of regulatory lag and is consistent with the Commission's decisions in Southwest's prior rate cases.

Q. 22 What is the increase in employee benefits since the last general rate case?

A. 22 The Company's requested expense includes an employee benefits cost component that is approximately $7.8 million higher than the level authorized in the last general rate case. Most of the increase is due to the BRP (approximately $3.9 million) and medical claims (approximately $2.0 million). The remaining $1.9 million is related to the labor loading on higher wages. Company witness Randi Aldridge supports the annualized labor calculation and benefits adjustment and describes the components of employee benefits in more detail.

Q. 23 Please discuss the increased expense related to costs other than labor and employee benefits.

A. 23 The increase in expense related to costs other than labor and employee benefits is $7 million. Factors impacting non-labor related costs include inflation, safety, code compliance and customer growth. In this proceeding, the

Company serves 958,542 customers compared to 863,474 customers in the last rate case. The current rate case includes 95,068 more customers, an increase of approximately 11 percent, which accounts for a significant portion of the $7 million.

VII. COST OF CAPITAL

Q. 24 What is the impact on the deficiency related to the Company's request for a higher level of, and a higher return on, common equity?

A. 24 The Company requests that the Commission establish rates resulting in a 9.45 overall rate of return, or 105 basis points higher than the 8.40 percent approved in the last rate case. In this proceeding, the Company requests rates be established using a 45 percent common equity weighting (40 percent approved in the last rate case) and 11.25 percent return on common (9.50 percent approved in the last rate case). Company witness Theodore Wood presents testimony supporting a 45 percent level of common equity weighting and the cost of debt and preferred. Company witness Frank J. Hanley presents testimony supporting an 11.25 percent return on common equity. The combination of the above cost of capital proposals increases the Company's deficiency by approximately $20.6 million.

VIII. MIP AND SERP

Q 25 What is the impact on the deficiency related to the Company's request for the inclusion in rates of the cost

of MIP and SERP.

A. 25 The cost of MIP and SERP is $2.0 million and $1.6 million, respectively.

Q. 26 Was the Commission's ruling in the Company's 1999 and 2004 rate cases regarding the inclusion of MIP and SERP in the COS the same?

A. 26 No. The Commission ruled differently on the MIP and the SERP in the 2004 rate case and the 1999 rate case (Docket No. G1551A-00-0309).

In the 1999 rate case, the Commission removed the cost of two of five factors used to calculate the MIP and allowed 100 percent of the remaining three factors. The Commission rejected the Residential Utility Consumers Organization (RUCO) proposal to disallow cost recovery of 50 percent of MIP expense. In the 2004 rate case, however, the Commission accepted a similar proposal to remove 50 percent of the MIP expense.

In the 1999 rate case the Commission rejected a RUCO proposal to remove 100 percent of SERP expense and ruled that it was appropriate to recover 100 percent of SERP expense. In the 2004 rate case, the Commission adopted RUCO's proposal to disallow 100 percent of SERP. The justification provided by RUCO was essentially identical in both the 1999 and 2004 rate cases.

Q. 27 Does the Company provide a witness supporting the reasonableness of Southwest's MIP and SERP costs?

A. 27 Yes, Company witness Laura Hobbs provides testimony

showing that Southwest's total management/executive compensation is reasonable.

IX. RATE BASE AND REVENUE OFFSET

Q. 28 What is the impact on the deficiency related to rate base changes?

A. 28 The deficiency is $6.2 million.

Q. 29 Please discuss the changes in rate base components since the end of the test year in the Company's last general rate case.

A. 29 Since the last rate case (September 2004 through April 2007), rate base increased by approximately $172.1 million (Commission authorized rate base is approximately $922.7 million compared to the requested amount of approximately $1,094.8 million). The $172.2 million rate base increase is the net of an approximately $212.1 million increase of net gas plant in service offset by approximately a $40 million credit increase in the other rate base items.

The net plant increase was the result of approximately $371 million of transfers to gas plant in service offset by approximately $149.6 million in depreciation and amortization expense. The $371 million of transfers include both revenue and non-revenue capital expenditures.

The $40 million increase in other rate base items is the net of approximate credit increases in deferred taxes ($7.1 million), customer advances ($30.8 million)

and customer deposits ($8.0 million) exceeded by the approximate debit increases in materials and supplies ($3.2 million), prepayments ($.9 million) and cash working capital ($.7 million).

Q. 30 What costs result from the increase in rate base?

A. 30 The cost to finance the approximate $172.1 million increase in rate base is $18.8 million when the pre-tax authorized return is applied. The resulting increases in depreciation expense, property tax and interest on customer deposits are approximately $13.1 million, $1.0 million and $0.5 million, respectively. The total cost related to the increase in rate base is approximately $33.4 million.

Q. 31 What is the offsetting new revenue from the revenue-producing portion of capital incurred since the last rate case?

A. 31 Decision No. 68487 authorized a $49.3 million revenue increase to the $322.8 million revenue at the then-present rates, resulting in $372.1 million revenue requirement. The revenue at present rates in this proceeding is $399.3 million or approximately $27.2 million greater. The approximate $33.4 million rate base related cost exceeds the approximate $27.2 million net increase in revenue by approximately $6.2 million.

Q. 32 Why do you refer to the $27.2 million as the net increase in revenue?

A. 32 The $27.2 million is the change from the revenue at

present rates in this proceeding to the authorized revenue resulting from the Company's last general rate case. Earlier in my testimony I addressed the decline in residential revenue resulting from the decline in average therm use. I also discussed the lost revenue that resulted from general service customers leaving the system since the last rate case. The authorized $372.1 million revenue requirement would only be realized by the Company if the residential customers requesting service at the end of the 2004 rate case test year, on average, were to use 347 therms. The $372.1 million amount also presumed that all general service customers would remain on the system. If Southwest did not add a single customer since the last rate case, the $372.1 million authorized revenue would have declined by approximately $10.6 million ($6.5 million Residential plus $4.3 million General Service) to approximately $361.5 million. If the approximately $399.3 million revenue at present rates is compared to the $361.5 million, then the increase due to new customers requesting service since the last rate case is approximately $38.0 million.

Q. 33 What is the deficiency impact of the new customer revenue and the costs related to changes in rate base?

A. 33 Exhibit No.___(RAM-1) provides a summary of the new revenue and rate base related cost that occurred since the end of the test year in the 2004 rate case. The approximate $38.0 million of new revenue exceeds the

$33.4 million cost of new rate base creating a reduction in the deficiency of approximately $4.6 million. Although cash outflow resulting from capital investment adds significant additional cost, these costs have been offset by the cash inflow due to depreciation expense, the aggressive management of other rate base items, along with the revenue acquired from the new customer portion of capital.

X. RATE CASE ADJUSTMENTS

Q. 34 Please explain Adjustment No. 8, Leak Survey and Repair.

A. 34 Adjustment No. 8, Leak Survey and Repair, reduces test year accelerated leak survey and leak repair expense related to both Aldyl A and Aldyl HD pipe by a percent calculated using the 40-year criteria adopted by the Commission in Decision No. 68487.

The year 2008 percentage is used to calculate Adjustment No. 8, and is consistent with the proposal approved by the Commission in the Company's 2004 general rate case.

Q. 35 Has the Company written-off a portion of the capital expenditures required to replace Aldyl A and Aldyl HD using the 40-year criteria ordered by the Commission?

A. 35 Yes. The Company prepares a journal entry each quarter which calculates the appropriate amount of replacement expenditures that need to be written-off and excluded from rate base. For the current rate application, the Company prepared a journal entry in April 2007 in order

to ensure that the recorded plant on the books as of April 2007 complies with prior Commission decisions.

Q. 36 Please explain Adjustment No. 9, Surcharge Adjustments.

A. 36 Adjustment No. 9 removes from Account 407.3, Regulatory Amortizations, the recorded test year expense for: 1) Research and Development (R&D); 2) Demand Side Management (DSM); and 3) the Transmission Integrity Management Program (TRIMP). The adjustment also transfers to distribution maintenance expense the amount removed from Account 407.3 for TRIMP.

Q. 37 Please explain why R&D and DSM expense recorded in Account 407.3, is removed from the COS?

A. 37 Decision No. 68487 directed the Company to fund annually $688,712 in R&D and $4,385,000 in DSM. The Commission also provided recovery through specific surcharges and balancing account mechanisms. The expenses resulting from funding R&D and DSM are recorded in Account 407.3. The Company proposes to continue funding both R&D and DSM in the same manner as set forth in Decision No. 68487. The surcharge revenue recorded during the test year is not included in the revenues at present rates; therefore, it is appropriate to remove the related expense.

Q. 38 Please explain why TRIMP expense recorded in Account 407.3 is removed from the COS?

A. 38 Decision No. 68487 provided for the recovery of fifty (50) percent of TRIMP-related cost through a surcharge and balancing account mechanism. The expense resulting

from funding 50 percent is recorded in Account 407.3 and the remaining 50 percent of the TRIMP cost is charged to Account 887, Maintenance of Mains. The TRIMP-related surcharge revenue recorded during the test year is not included in the revenue at present rates, therefore, it is appropriate to remove the related expense. In addition, the Company proposes to discontinue recovering 50 percent of TRIMP cost through a surcharge and to recover the test year TRIMP-related expense in Account 887 in base rates. Adjustment No. 9 removes the TRIMP cost recorded in account 407.3 and transfers it to Account 887.

Q. 39 What account has the Company used to record the balancing of TRIMP expense incurred and revenues recovered?

A. 39 The Company charges 50 percent of the TRIMP cost incurred and the related surcharge revenue billed to Account 182.3, Regulatory Assets.

Q. 40 When does the Company propose to cease charging expense to Account 182.3 and discontinue the TRIMP surcharge?

A. 40 The Company proposes to cease charging TRIMP-related expense to Account 182.3 the month the proposed new rates take effect. The surcharge will discontinue once the deferred balance in Account 182.3 reaches zero.

Q. 41 Explain why the Company proposes recovering all of its TRIMP-related costs in this proceeding?

A. 41 TRIMP-related maintenance costs are incurred as a result of the Federal Pipeline Safety Improvement Act of 2002

(2002 Act). Every gas utility subject to federal regulation must comply with the provisions of the 2002 Act. Southwest is not aware of any other gas utility in the nation that must comply with the provisions of this act that is not recovering 100 percent of the prudently-incurred cost of compliance. In fact, in the last UNS Gas rate case processed in 2006, neither UNS Gas nor any party to the proceeding proposed an adjustment limiting the recovery of TRIMP-related costs. Likewise, neither UNS Gas nor any of the parties to the proceeding proposed a surcharge mechanism to recover any of the TRIMP-related costs. The 2002 Act is only one of many federal, state and local safety regulations that must be complied with by any gas utility that provides natural gas service. Based on the foregoing, the Company believes it is fair and reasonable that 100 percent of the test year recorded TRIMP-related cost be recovered in base rates.

Q. 42 Please explain Adjustment No. 10, Injuries and Damages.

A. 42 Adjustment No. 10 adjusts the recorded self-insured accruals charged to Account 925 during the test year to a normalized level.

Q. 43 Please describe the types of charges included in Account 925, Injuries and Damages.

A. 43 Account 925 includes four types of charges: 1) insurance premiums; 2) the reserve for the self-insured portion of liability claims; 3) legal and other related expenses necessary to defend and process claims; and 4) worker

compensation claims.

Q. 44 What is the level of self-insurance that the Company has at the end of the test year.

A. 44 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 $5.0 million. Once the $5.0 million aggregate is reached, any amount paid above the $5.0 million is the responsibility of the insurance carrier. The $5.0 million aggregate can be the result of payouts from more than one incident.

Q. 45 Please explain the accounting for the self-insured portion of liability claims.

A. 45 When an incident is identified that may require payment the Company accrues the estimated 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 costs paid are charged against the accrual in Account 228.2. If the amounts paid are different than the amount accrued, then the net difference is removed from Account 228.2 and charged back against Account 925.

Q. 46 Given the method used to account for the self-insured portion of liability claims, does the test year expense reflect on-going operations?

A. 46 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 result in an amount in any recorded period in Account 925 not being representative of on-going operations. In fact, the recorded test year expense was a net credit of $567,165. The credit resulted from the net accruals to previous claims exceeding accruals for new claims. The Company uses a ten-year average of these fluctuating amounts to normalize this expense for ratemaking purposes.

Q. 47 Is the accounting and normalization method described above consistent with prior Company proposals and Commission decisions?

A. 47 Yes. The accounting described above is consistent with every Southwest rate case filed before the Commission for at least twenty years. The 10-year period and the method of normalization were approved by the Commission in Decision No. 68487.

XI. RATE BASE

Q. 48 What is the fair value and original cost rate base that Southwest requests be approved by the Commission?

A. 48 Southwest proposed and supports a fair value rate base of $1,469,159,432. The fair value rate base was determined by giving equal weight (50/50) to the original cost rate base of $1,094,814,020 and the reconstruction cost new rate base of $1,843,505,043. 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 twelve months ended April 30, 2007. Details of the various rate base components can be found in Schedules B-2 through B-6.

Q. 49 Is the company proposing any adjustments to the recorded rate base amounts at April 2007?

A. 49 Yes, Adjustment No. 17, CCNC, adds to rate base the recorded amounts as of April 2007 of non-revenue producing CCNC that resides in construction work-in-progress, along with an adjustment to System Allocable Miscellaneous Intangible Plant (to synchronize the plant with the adjustment to System Allocable amortization expense in Adjustment No. 14). This consists of two components: a direct Arizona component of $2,976,115 and a System Allocable component (after 4-Factor) of $1,373,330. Company witness Ms. Randi Aldridge discusses Adjustment Nos. 14 and 17 in her prepared direct testimony.

Q. 50 Please describe and explain Southwest's Schedules B-3 and B-4.

A. 50 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 ACC. 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, by FERC account.

Q. 51 Please describe and explain the items of other rate base items contained in Southwest's Schedule B-5 and B-6 that do not use the end of test year balance?

A. 51 Schedules B-5 and B-6 contain four items that employ the thirteen-month average balance method for inclusion in rate base: 1) materials and supplies; 2) prepayments; 3) customer advances for construction; and 4) customer deposits. The use of the 13-month average balance as the method of calculation has been used and accepted by this Commission in many past rate cases.

Q. 52 Please describe and explain the other items contained in Schedule B-5 and B-6 that do not employ the 13-month average balance method?

A. 52 The cash working capital allowance and the accumulated balance of deferred income taxes do not use the 13-month average balance method of calculation.

The cash working capital allowance is determined through a comprehensive lead-lag study. In performing the lead-lag study, Southwest examined every non-gas invoice over $10,000 processed during the test year. The Company also examined every gas invoice processed during

the test year regardless of the expense level. As a result, approximately 80 percent of total adjusted operating expenses were reviewed to determine the net lag attributable to operating expenses.

The April 2007 balance of accumulated deferred income taxes is used for the inclusion in rate base. The end of test year balance, rather than the 13-month average balance has been used and accepted by the Commission in many past rate cases.

Q. 53 Does this conclude your prepared direct testimony?

A. 53 Yes, it does.

SUMMARY OF QUALIFICATIONS
ROBERT A. MASHAS

I graduated from the University of Texas at El Paso in 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.

Prior to joining Southwest in 1984, I held a positions as a staff accountant (one year) with Marriott Corporation, auditor (five years) with the Federal Energy Regulatory Commission (FERC) Office of Chief Accountant, and as a senior auditor (one year) Public Service Commission of Nevada (PSCN) now known as the Public Utilities Commission of Nevada (PUCN). My responsibilities at the FERC 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. My responsibilities at the PSCN included the examination of the books and records of gas, electric, and water utilities, as well as testifying as an expert witness.

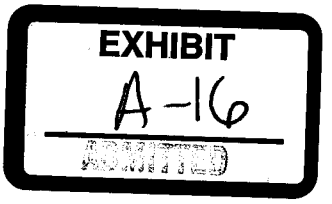
I joined the Rate Department of Southwest, in 1984, as a cost analysis. In 1985, I was promoted to Manager/Revenue Requirements. In 1992, I was promoted to

Director, Revenue Requirements and Resource Planning, and in 1998, with the regulatory requirements for resource planning reduced, my focus was primarily revenue requirements. During my more than twenty years overseeing the Revenue Requirements Department, I have either directly or indirectly prepared and participated, as an expert witness, in every Southwest Gas and Paiute Pipeline general rate case since 1986. I have also represented the Company in numerous dockets that addressed accounting and regulatory issues.

SOUTHWEST GAS CORPORATION
ARIZONA
DEFICIENCY REDUCTION
NEW MARGIN NET OF NEW CAPITAL RELATED COST
($MILLIONS)

Line No.	Description	Increase / (Decrease) Detail	Increase / (Decrease) Result	Deficiency Impact	Line No.
	(a)	(b)	(c)	(d)	
	Margin				
1	Add: Net Margin Growth at Present rates		$ (27.2)		1
2	Add back Margin Attrition				2
3	Declining Residential Average Use		(6.5)		3
4	General Service Customer Attrition		(4.3)		4
5	**Adjusted New Margin Reducing Deficiency**		$ (38.0)	$ (38.0)	5
	Rate Base				
6	Authorized	$ 922.7			6
7	Requested	1,094.8			7
8	Change	$ 172.1			8
9	Authorized Pre Tax Return	10.90%			9
10	Finance Cost of New Rate Base		$ 18.8		10
	Depreciation				
11	Authorized	$ 74.7			11
12	Requested	87.8			12
13	Change		$ 13.1		13
	Property Tax				
14	Authorized	$ 32.1			14
15	Requested	33.1			15
16	Change		$ 1.0		16
	Interest on Customer Deposits				
17	Authorized	$ 1.4			17
18	Requested	1.9			18
19	Change		$ 0.5		19
20	**Investment Related Cost Increasing Deficiency**		$ 33.4	$ 33.4	20
21	**Deficiency Reduction**			$ (4.6)	21

Exhibit No.___(RAM-1)
Sheet 1 of 1



IN THE MATTER OF
SOUTHWEST GAS CORPORATION
Docket No. G-01551A-07-0504

PREPARED REBUTTAL TESTIMONY
OF
ROBERT A. MASHAS

ON BEHALF OF
SOUTHWEST GAS CORPORATION

May 9, 2008

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Of
Prepared Rebuttal Testimony
Of
ROBERT A. MASHAS

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Rebuttal Exhibit No.__(RAM-1)

Rebuttal Exhibit No.__(RAM-2)

Rebuttal Exhibit No.__(RAM-3)

Rebuttal Exhibit No.__(RAM-4)

Rebuttal Exhibit No.__(RAM-5)

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rebuttal Testimony
of
ROBERT A. MASHAS

I. INTRODUCTION

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 Did you sponsor direct testimony on behalf of Southwest Gas Corporation (Southwest or the Company) in this proceeding?

A. 2 Yes, I did.

Q. 3 What is the purpose of your rebuttal testimony?

A. 3 The purpose of my rebuttal testimony is to respond to specific aspects of the direct testimony presented by Arizona Corporation Commission Utilities Division Staff (Staff) witnesses Messrs. Ralph C. Smith, Corky Hanson, Phillip S, Teumim, and Residential Utility Consumer Office (RUCO) witness Mr. Rodney L. Moore, regarding their recommendations for ratemaking treatment of rate base, certain operating expense items, and the Company's line extension procedures and policies.

Q. 4 Did you prepare exhibits to support your rebuttal testimony?

A. 4 Yes. I prepared the exhibits identified as Rebuttal

Exhibit No.__(RAM-1) through Rebuttal Exhibit No.__(RAM-5).

Q. 5 Please summarize your rebuttal testimony?

A. 5 My rebuttal testimony will address the following issues:

- Injuries and Damages: Staff's calculation of the 10-year average of self-insured retentions.
- Yuma Manors: Staff's proposal to disallow all gas plant required to replace 50-year old pipe.
- Deferred Taxes: RUCO's proposal to remove deferred taxes related to Supplemental Executive Retirement Plan (SERP) and Management Incentive Plan (MIP).
- Lead-Lag Study: RUCO's proposal regarding interest expense lag and revenue tax lag.
- Line Extension Analysis: Staff's recommendation to update certain inputs in the Company's Incremental Contribution Model.

II. INJURIES AND DAMAGES

Q. 6 Please summarize Staff's adjustment to the Company's proposed injuries and damages expense?

A. 6 Staff's adjustment focuses on the calculation of the ten-year average self-insured retentions. First, Staff calculates a ten-year average level of direct Arizona self-insurance using the ten years of direct Arizona recorded self-insurance amounts. Second, Staff calculates a ten-year average level of System Allocable self-insurance by using the ten years of recorded System

Allocable self-insured expense. However, Staff excludes a $10 million dollar expense recorded in 2006 related to an incident that occurred in Arizona in 2005.

Q. 7 Is Staff's methodology flawed?

A. 7 Yes. Staff calculates its 10-year average (Staff Schedule C-12, Sheet 2 of 2, Column (C) lines 1 through 16) by using the recorded net accruals charged directly to Arizona. Although on the surface that appears appropriate, in reality it is not. The period shown on that schedule is from January 1998 through November 2007. From January 1998 through July 2004, the Company's insurance policies, in effect during that time period, provided that Southwest was self-insured for up to the first $1 million of expense related to a single claim. As such, Southwest's accounting records would only reflect a maximum of $1 million for the cost of self insurance. Beginning August 1, 2004 through July 31, 2005, the insurance policies in effect provided that Southwest was self-insured for not only the first $1 million per claim, but also self-insured for aggregate claims up to $10 million. In other words, the $10 million can come from more than one incident. Beginning August 1, 2005, and continuing through the present, Southwest acquired an additional policy that covers any aggregate claim amounts from $5 to $10 million.

During the periods August 1, 2004 though July 31, 2005, and August 1, 2005 through the present, Southwest's

accounting records reflect the cost of self-insurance that may result due to either the $10 million or $5 million aggregate self-insurance. Since August 1, 2004, only one claim has exceeded the $1 million per incident self-insured amount, and that was the May 2005 incident that occurred in Arizona, but was recorded as a System Allocable expense. This is the claim that Staff has removed from its ten-year average of System Allocable expense.

Accordingly, Staff's ten-year calculation does not properly reflect the cost of self insurance that is reflective of what the Company will experience during the rate effective period because it only reflects the average of the recorded $1 million per claim self-insurance and not Southwest's $5 million aggregate level of self-insurance.

Q. 8 Is the Company's proposed ratemaking for the self-insured aggregate consistent with its proposal that Staff and RUCO accepted and the Commission adopted in the Company's last general rate case that resulted in Decision No. 68487.

A. 8 Yes. My direct testimony in that proceeding detailed the Company's proposed change in ratemaking related to the $1 million self-insurance per incident and the introduction of the self-insurance up to $10 million aggregate. In that proceeding, the Commission ultimately approved the parties' agreed upon methodology of using a ten-year

average of self-insurance including the average of the restated claims above $1.0 million but less than the $10.0 million aggregate to properly calculate the level of injuries and damages expense that the Company anticipates incurring during the rate effective period.

Q. 9 Please describe how the ten-year average was calculated in the Company's last general rate case.

A. 9 The Company treated all self-insured amounts as system allocable. Therefore, the total of the up to $1 million incident amount recorded on the Company's books and the $1 million up to $10 million aggregate not recorded on the Company's books were used in the calculation of the ten year average. Once the ten year average was calculated, Arizona's allocation was determined using the Four Factor allocation methodology. In order to derive a reasonable estimate that reflected the up to $10 million aggregate level, the Company used its previous ten years of claims history for all rate jurisdictions. These amounts were not reflected on the Company's books because these amounts would have been indemnified by insurance carriers based upon the insurance policies in place during applicable the time period (1994-2004). To the extent claims exceeded the $10 million aggregate level, those amounts were not used in the calculation. This exercise is necessary to calculate a ten-year average that is reflective of a level of expense that will be incurred by the Company during the rate effective period.

Q. 10 Are there any changes to the Company's level of self insurance since its last general rate case?

A. 10 The only change is that the aggregate is limited to $5 million instead of $10 million as a result of the Company acquiring an additional layer of insurance that covers the $5 million to $10 million portion of aggregate claims.

Q. 11 Has RUCO proposed a deviation from the methodology that was accepted in the Company's last general rate case?

A. 11 No. RUCO proposes no adjustment to the Company's calculation of Arizona's portion of the self-insured $1 million per incident or the $5 million aggregate.

Q. 12 What adjustment to Staff's proposal is needed to reflect the 10-year average of Arizona direct amounts subject to the up to $5 million aggregate?

A. 12 Staff's proposed level of self insurance would need to be increased by $1,596,611. During the previous 10 years (1997-2007), there were a number of incidents experienced where the amount of claims paid exceeded $1 million but were less than $5 million. The ten-year average of these Arizona direct amounts was $1,596,611. Staff Schedule C-12, Sheet 2, Line 12, Column (e) should be increased from the $820,000 to $2,410,000 and should be brought forward to Sheet 1, Line 2, Column (d). Staff Schedule C-12, Sheet 1, Line 2, Column (e) should be $2,968,765 and Line 18, Column (e) should be a positive $728,283. Using the average of the Arizona direct amounts rather than the

Four Factor of all Southwest amounts (proposed by Southwest) results is a number that is higher by $728,283. Southwest Rebuttal Exhibit No.__(RAM-1) provides Staff's Schedule C-12, Sheets 1 and 2, adjusted to reflect the Arizona direct $1,596,611 ten-year average aggregate self-insurance for amounts paid between $1 million to $5 million.

Q. 13 Do you have exhibits that support this calculation of the $1,596,611?

A. 13 Yes. Rebuttal Exhibit No.__(RAM-2) consists of two sheets, both of which were included in the workpapers to this application and provided to both Staff and RUCO. The first sheet summarizes the ten-year historical claims paid by each rate jurisdiction. This workpaper supports the summarized amounts shown on the Company's filing Schedule C-2, Adjustment. 10, sheet 1. Rebuttal Exhibit No.__(RAM-2) Sheet 2, shows the dollars paid by year, and rate jurisdiction, grouped into three categories. The first category includes claim dollars related to incidents resulting in payments less than $1 million. The second category includes claim dollars related to incidents resulting in payments of at least $1 million. Both of these categories would have been recorded on the Company's books and charged directly to the respective rate jurisdiction throughout the ten year period (1997-2007). The third category shown on sheet 2 lines 25 through 36, relates to claim amounts that resulted from

incidents where the payment exceeded $1 million per claim, but to the extent that payments related to a claim exceeded $5 million, that additional amount is not included on the schedule. With the exception of the amount on line 33, these amounts were not recorded on the Company's books and therefore, not included in Staff's calculation. Staff also removes the claim shown on line 33, therefore none of the amounts in this third category are reflected in Staff's calculation.

Q. 14 In regards to the calculation of the appropriate level of self-insurance, should the Commission deviate from the methodology it adopted in Decision No. 68487?

A. 14 No. The methodology agreed to by the Company, Staff and RUCO and adopted by the Commission in the Company's last general rate case is reasonable and appropriate. Nothing has changed except for the lowering of the self-insured aggregate exposure.

III. YUMA MANORS

Q. 15 Please summarize the Staff proposal concerning Yuma Manors.

A. 15 Staff believes that the Commission should disallow 100 percent of Southwest's costs incurred in replacing the pipe to serve the Manors subdivision in Yuma because "the circumstances that necessitated the immediate replacement of this system were the direct result of incorrect actions taken by Southwest personnel resulting in the failure of this system."

Q. 16 Please describe the scope of your rebuttal testimony with regard to this issue.

A. 16 My rebuttal testimony, on this issue, is limited to a review of the ratemaking standards and precedents that the Commission has established in past Southwest rate proceedings to determine the appropriate level of pipe replacement costs in rate base.

Q. 17 Please describe the standard that the Commission has used in previous Southwest rate case proceedings.

A. 17 The Commission has previously used a betterment/remedial approach to guide it in determining the appropriate portion of pipe replacement cost to be included in rate base. Betterment is the life extending value that results from installing new pipe, while the remedial portion is the maintenance value associated with pipe replacement. The Commission has consistently ruled that the betterment portion benefits the customer and 100 percent of this cost should be included in rate base. Conversely, the Commission has historically ruled that the remedial portion of pipe replacement does not directly benefit customers and this cost should not be included in rate base.

Beginning in Commission Decision No. 57075 and in every subsequent Commission rate case decision for Southwest, the remedial portion of pipe replacement was shared equally between customers and shareholders, if the original installation of the pipe was by a gas company

other than Southwest. This was the case regarding Arizona Public Service (APS) installed ABS pipe. This was also the Commission ruling in regards to Tucson Gas and Electric (TG&E), now Tucson Electric Power (TEP), installed Aldyl A, ABS and 1960s vintage steel pipe. In the one instance where pipe replacement was the result of Southwest installed Aldyl HD pipe, the remedial portion of pipe replacement was the sole responsibility of Southwest's shareholders.

Q. 18 Did each of the five pipe replacement programs share anything in common?

A. 18 Yes. All five pipe replacement programs resulted in the premature replacement of pipe resulting from either defective material and/or installation. For example, the APS ABS pipe replacement took place from 1985 to 1990 and replaced pipe that was originally installed from 1960 through 1970, or on average, after only 23 years of service. The reason for the replacement was related to defective material. In Decision No. 57075, page 35, the Commission found that 43 percent of the replacement expenditure was betterment and the responsibility of the customer. The Commission later, on page 41, ruled that the remedial portion, after certain adjustments, would be shared equally between shareholders and customers.

Another example was TG&E installed Aldyl A pipe that was installed from 1967 though 1979 and replaced from 1986 through 1993, after an average useful life of

approximately 22 years. The Commission determined in Decision No. 57745, page 12, that 28.1 percent of the replacement was betterment and also ruled that the remedial portion be shared equally between shareholders and customers.

Q. 19 Please comment on the Commission's previous ruling regarding 1960s steel installed by TG&E.

A. 19 In 1971, the federal government ordered all gas utilities to cathodically protect their steel pipe systems by 1976. The steel portion of the gas distribution system that Southwest acquired in 1979 from TG&E was not fully cathodically protected. In 1989, the Company began a program to have the entire steel pipe system cathodically protected by 1998. The portions of the steel system that could not be protected were replaced.

In Decision No. 58693, the Commission adopted and approved a settlement between all parties to that proceeding. The settlement addressed the appropriate level of steel pipe replacement that would be included in rate base. For steel originally installed in the 1960s and replaced from July 1993 through June 1994, 81 percent would be included in rate base and the remaining 19 percent would be written-off. The average year of original install of 1960s steel pipe was 1964. Therefore, pipe that had an average useful life of approximately 30 years was afforded 81 percent rate base treatment. The settlement also provided that for

replacement expenditures taking place in future years, an additional one percent of rate base inclusion would be granted. As a result, in the case of 1960s steel pipe, all replacement expenditures would be included in rate base by 2012. Therefore, the settlement also provided 100 percent rate base treatment for all Pre-1960's steel pipe replacement, similar to Yuma Manors pipe.

Q. 20 Did the Commission amend the 1993 Settlement agreement in the Company's last general rate case?

A. 20 Yes. In its Decision No. 68487, the Commission granted the Company's request to adopt a "40-Year rule". The Company requested that the Commission modify the write-off percentages contained in the 1993 Settlement to acknowledge that once pipe has served customers for 40 years, any subsequent replacement expenditures would be afforded 100 percent rate base treatment. As a result of its decision, 100 percent of the cost to replace 1960s steel pipe made after 2004 would be included in rate base.

Q. 21 Is Staff's proposal consistent with any of the above Commission rulings on pipe replacement?

A. 21 No. In Decision No. 58693, the Commission adopted a settlement, which provided 100 percent recovery of replacement cost for steel pipe that was first installed prior to 1960. The 100 percent recovery was for pre-1960 steel pipe that was replaced in the 1990s. In this proceeding Staff is recommending 100 percent disallowance

of pre-1960 steel pipe that was replaced in 2007 more than ten years later. Staff's proposal is totally inconsistent with previous Commission precedent acknowledging the betterment value of pipe replacement, as I am not aware of a single instance where the Commission disallowed 100 percent of any Southwest pipe replacement cost.

Q. 22 Are there any pipe costs incurred in replacing the 50-year old steel pipe system at the Yuma Manors subdivision that Southwest would be willing to exclude from rate base in this and future proceedings?

A. 22 Yes. Southwest is willing to make an adjustment to exclude the additional cost incurred by the Company due to the urgency required to replace the Yuma Manors steel pipe system in a relatively short period of time. The Company incurred costs that were above the level that would be experienced had the replacement took place over a more routine time period. The Company considers the cost related to overtime, shift premiums, and other related costs to be over and above those that it would have experienced had the replacement been done in a more routine manner. The Company has identified this amount to be $320,779 (Mains $123,397 and Services $197,382). As such, the Company believes if any adjustment should be made to the Yuma Manors pipe replacement it should be limited to these additional costs. The balance of the cost represents a reasonable level required to replace

50-year old pipe that betters the system and will serve customers for 40 or more years, and as such, should be allowed in rate base.

IV. DEFERRED TAXES - MIP AND SERP

Q. 23 Please explain RUCO's adjustment to deferred taxes relative to the Management Incentive Plan (MIP) and the Supplemental Executive Retirement Plan (SERP).

A. 23 RUCO attempts to remove a portion of deferred taxes related to the MIP and SERP. Deferred taxes resulting from MIP and SERP are debits properly recorded in Account 283, Accumulated Deferred Income Taxes-Other. RUCO refers to the Company's response to Staff Data Request No. 11-11, which indicates that the deferred taxes in question are recorded in Account 283. RUCO's adjustment results in a decrease in rate base of $880,989 by increasing deferred taxes from a credit of $142,464,212 to a credit of $143,513,286 as shown on RUCO Schedule RLM-2 Page 1, line 8.

Q. 24 Is RUCO's adjustment appropriate?

A. 24 No. Southwest's Schedule B-6, Sheet 3 of 3, lines 1 and 2, show deferred taxes recorded in Accounts 282, Accumulated Deferred Income Taxes-Other Property, and Account 190, Accumulated Deferred Income Taxes, netting to the amount of $142,632,297. Account 283, Accumulated Deferred Income Taxes is not used as a component of rate base. Therefore, RUCO's adjustment removes from rate base deferred taxes that were not included by the Company

in rate base. Furthermore, the MIP and SERP are System Allocable amounts and would first need to be allocated to Paiute and the balances then allocated to the Company's state ratemaking jurisdictions using the Four Factor allocation methodology. RUCO's adjustment is not appropriate and should not be adopted by the Commission for ratemaking.

V. LEAD-LAG STUDY - INTEREST EXPENSE LAG

Q. 25 Please comment on RUCO's proposed changes to the Company's interest expense lag in its lead-lag study.

A. 25 RUCO proposes to include preferred securities and interest on customer deposits in the calculation of the interest expense lag. The Company agrees with RUCO on the inclusion of preferred securities, but disagrees with interest on customer deposits. Interest on preferred securities is afforded similar ratemaking treatment as other interest expense, and is included in the cost of capital. Although the weighted cost of preferred securities is included in the $48,035,008 shown on Southwest Schedule B-5, Sheet 2 of 5, line 6, column (b), the lag impact of preferred securities is not included in the computation of the 84.65 lag days shown on line 6, column (c). The interest lag on preferred securities should be considered in the interest expense lag. The interest expense lag including the impact of preferred securities is only 79.5 days.

Interest on customer deposits is not afforded

similar ratemaking treatment as other debt and preferred securities. Customer deposits are not a component of the cost of capital and more importantly, the 13-month average balance is used as a rate base deduction. A customer already receives the cash flow value of the average balance in rate base, and to include the lag in the interest expense calculation would be giving customers the cash flow value twice. The interest on customer deposits should not be included in the interest lag calculation if the 13-month average balance is used as a rate base deduction.

VI. LEAD-LAG STUDY - REVENUE TAX LAG

Q. 26 Please comment on RUCO's proposal to include a revenue tax lag in its proposed lead-lag study.

A. 26 RUCO Schedule RLM-6, Page 2 of 5, line 9, includes a component for revenue based taxes. Column A shows $97,747,450 under the caption "Company Expenses as Filed". Column D shows a lag of 51.75 days. The Company did not include revenue taxes in its cash working capital allowance as shown on Schedule B-5, Sheet 2 of 4. The Company has not included revenue taxes in its lead-lag studies in previous rate cases. Although the adjusted $100,949,060 revenue tax shown on Schedule RLM-6, Page 2 of 5, line 9, column C is Southwest's total revenue taxes, the 51.75 day lag is not a Southwest calculated number. A review of the current TEP rate case shows 51.75 days is TEP's revenue tax lag, and it appears this

number may have been included in Southwest's case in error.

Q. 27 Should the Commission include revenue taxes in the lead-lag study, and, if so, what is the appropriate lag?

A. 27 Approximately 90 percent of the revenue taxes are paid monthly and the lag on these taxes closely approximate the revenue lag and, as such, would not impact the lead-lag study results. The remaining taxes (mill and franchise) would impact the lead-lag study. A review of the most recent APS rate case shows a revenue tax lag of 42.5 days. APS provides service to customers residing in more than one county throughout Arizona much like Southwest's service territory. Southwest has calculated its revenue tax lag to be 45.24 days, which not surprisingly is closer to APS' lag days, however Southwest's lag calculation does fall between the APS and TEP lag days. Should the Commission decide to include revenue taxes in the lead-lag study, the 45.24 day lag is more appropriate.

Q. 28 Please describe Rebuttal Exhibit No.__(RAM-3).

A. 28 Rebuttal Exhibit No.__(RAM-3) sheet 1, calculates the interest expense lag including the impact of the preferred securities lag, while sheet 2 calculates the Southwest revenue tax lag.

VII. LINE EXTENSION POLICY

Q. 29 Did Staff provide an opinion on the Company's Tariff Rule No. 6, which addresses the Company's line extension

policies and procedures?

A. 29 Yes. Staff opines that conceptually it is a reasonable methodology, assuming current cost figures and revenue estimates (emphasis added) are used. However, Staff indicates that it has not examined the application of the methodology.

Q. 30 Is this the first time that the Company's application of Tariff Rule No. 6 and the Incremental Contribution Study (ICS) methodology has been addressed in Southwest rate proceedings?

A. 30 No. This is the third consecutive Arizona rate case proceeding where the Company's application of the ICS has been addressed. The ICS uses the Incremental Contribution Model (ICM) as the tool that ensures new customer additions are cost-justified and do not place a burden on existing customers.

Q. 31 Please summarize the rate case history of the ICM?

A. 31 In Docket No. G-01551A-00-0309, resulting in Decision No. 64172, one intervener took issue with the Company's application of Tariff Rule No. 6. Decision No. 64172, at page 32, line 6, states: "Based on the evidence before us, we do not believe that the allowance, or the methodology for its calculation should be changed. We believe, however, that in its next rate case, the Company should specifically address the issue of how it determines the allowance for the hookup of new residential customers."

In compliance with the Commission's order, in its next filed general rate case (G-01551A-04-0879) Southwest included direct testimony detailing its line extension policies and procedures. Specifically, the Company detailed how average therm use by type of appliance, investment and operating expenses are determined and how the projected results are compared to the authorized rate of return to determine if the customer is required to provide a non-refundable contribution in aid of construction (CIAC). Neither Staff nor RUCO took exception to the Company's ICS practice, or ICM application.

Q. 32 When was the last time the Company reviewed, changed, or modified the revenue and cost components contained in the ICM?

A. 32 Although it has been nearly ten years since the Company has filed with the Commission to modify the Rule 6 portion of its tariff, one should not conclude that the Company has not updated the ICM. Since the last tariff change the Company has modified the model on numerous occasions. The most recent updates were implemented March 2008.

Q. 33 What are the important ICM drivers that require periodic review and updating?

A. 33 There are five primary drivers that need periodic updating to keep the ICM current. They are as follows: 1) gas appliance estimated therm use; 2) standard lengths

and cost per foot estimates for service stubs and extensions; 3) incremental expense; 4) pressure reinforcement standard amounts; and 5) Commission authorized amounts.

Q. 34 How often are these drivers updated?

A. 34 Items one through four are updated annually and item five is updated immediately following a Commission rate case decision.

Q. 35 Please describe how the Company calculates the estimated levels of therm use for the appliances, and how they are used in the ICM.

A. 35 The ICM calculates margin per new customer by multiplying the authorized margin rate per customer times the estimated therm use for the following appliances: 1) space heat; 2) water heat; 3) cooking; 4) clothes drying; and 5) natural gas logs. All other gas appliances are not considered in determining residential customer margin. The Company's Demand Planning department annually conducts an analysis of new "vintage year" customer additions and determines the estimated use for the five appliances. The analysis is performed annually on a district basis. The most recent study analyzed the normalized use (12-months ended August 2007) for customers added for vintage years 2003 through 2005. Resulting changes were implemented in March 2008.

Q. 36 Please describe how the Company calculates the average length of service stubs and service extensions and

average cost per foot for each, and how they are used in the ICM.

A. 36 Due to the high volume of relatively small lengths of service pipe that run from the main in the street to a customer's premise, the Company records the cost of service in blanket work orders. On an annual basis, the dollars charged to blankets and associated footage are compiled to determine the average length and cost per foot of the service stub (pipe from the main in the street to the stub near the curb or sidewalk) and the service extension (pipe from the stub to the meter). The statistics are compiled by each district office. The results are entered into the ICM and used to analyze all new residential customer additions. Staff Exhibit No. PST-2 shows the six years (2002 - 2007) of cost statistics that are embedded in the ICM in regards to the cost of service stubs and extensions. During this six year period, Southwest extended service to 235,000 new Arizona customers, or approximately 24 percent of all Arizona customers served as of December 2007. As previously mentioned, the most recent change to this component of the ICM was March 2008.

Q. 37 Please describe how the Company calculates the average incremental expense, and how it is used in the ICM.

A. 37 The ICM contains a component for the incremental expense that is expected as a result of adding a new customer. Expenses such as meter reading, billing, uncollectibles,

customer assistance and blue stake line location expense are used in the ICM. The standard amount used in the ICM is determined using average per customer amounts experienced during the most recent twelve months. In March 2008, the model was updated to reflect the average expense during the twelve months ended December 2007.

Q. 38 Please describe how the Company calculates pressure reinforcement, and how it is used in the ICM.

A. 38 During the last two years, the ICM was modified to include a component for pressure reinforcement capital expenditures that result from load growth over an extended period of time. This is an indirect cost of customer growth. The cost estimates for pressure reinforcements are reviewed annually on a district basis. Historical and projected costs are used in the estimate. As previously mentioned, the most recent change was implemented in March 2008.

Q. 39 What are the Commission authorized amounts used in the ICM.

A. 39 The ICM uses the cost of capital, state and federal income tax rates, property tax assessment ratio, and assessment rate that was used by the Commission to set rates in the Company's most recent rate case. The current basic service charges and margin rates for all rate schedules are also used in the model.

Q. 40 Please describe how the Company calculates the cost of mains, and how it is used in the ICM.

A. 40 The cost of mains is determined through engineering estimates and captured through the work authorization process included in the Company's Work Management System (WMS). The cost of mains includes all pipe, diameter, sizes. WMS provides a tool to estimate the cost of mains and a review of the estimate to actual cost once the project is completed.

Q. 41 Is the ICM updated by the Company to reflect the most recent cost data available.

A. 41 Yes. The five primary drivers used in the ICM are updated annually by the Company or following a Commission decision in a general rate case filing.

Q. 42 Do these periodic changes require a tariff filing with the Commission?

A. 42 No.

Q. 43 Has the Company formalized the change process regarding the ICM?

A. 43 Yes. The Company has formalized the policies and procedures for the ICM. Exhibit No.__(RAM-4) contains the "Project Charter to Formalize Policies and Procedures for the ICM". Also, Exhibit No.__(RAM-5) is a copy of Standard Practice 920.0 Incremental Contribution Method (ICM) Model (Arizona)(SP 920.0). The purpose of SP 920.0 is to describe the use, change in management controls, processes and procedures related to the ICM. SP 920.0 goes on to describe the Company's policy, scope and the responsibilities of the twelve departments that are

involved in the use, change in management controls, processes and procedures regarding the ICM.

Q. 44 Was Southwest's senior management kept apprised of the final results of the project?

A. 44 Yes.

Q. 45 Since the Company filed its general rate case in Docket No. G-01551A-00-0309, where the ICM was first addressed by the Commission, has the Company strived to improve the mechanics and keep key drivers current?

A. 45 Yes. Since the filing of Docket No. G-1551A-00-0309, the Company has frequently reviewed how the ICM is used and the key drivers have been frequently updated.

Q. 46 Does the above testimony, in this proceeding, adequately respond to Staff's proposal for the Company in its next rate case proceeding?

A. 46 Yes. Staff's testimony beginning at the top of page 8, recommends that the Company, in its next rate proceeding, file an explanation of how it has been implementing Tariff Rule No. 6 provisions and to explain whether and to what extent it has made changes in the methodology and its application over the 10 years the current tariff provisions have been in place. The Company believes this testimony should satisfy Staff's concerns. As for the recommendation to file sample calculations, the Company is willing to get together with Staff to explain how the model works with real examples of actual projects. The Company believes that the recommendation to present this

information in the next rate case is not necessary and should not be ordered by the Commission.

Q. 47 Does this conclude your rebuttal testimony?

A. 47 Yes, it does.

Southwest Gas Corporation
Injuries and Damages, Account 925

Docket No. G-01551A-07-0504
Schedule C-12
Page 1 of 2

Test Year Ended April 30, 2007

Line No.	Description		Company Test Year As Recorded (A)	Company Requested As Filed (B)	Company Requested As Corrected (C)	Staff Proposed (D)	Staff Adjustment (E)
	Arizona Direct						Col.D - Col.B
1	Legal and Other Costs		$ 467,269	$ 467,269	$ 467,269	$ 467,269	$ -
2	Reserve for Self Insurance		$ (558,765)	$ (558,765)	$ (858,765)	**$ 2,410,000** c	**$ 2,968,765**
3	Self-Insured Workmen's Comp		$ 497,524	$ 497,524	$ 497,524	$ 497,524	$ -
4	Total Arizona Direct		$ 406,028	$ 406,028	$ 106,028	$ 3,374,793	$ 2,968,765
	Common Before Allocation to Arizona						
5	Legal and Other Costs		$ 179,014	$ 179,014	$ 179,014	$ 179,014	$ -
6	Reserve for Self Insurance		$ 200,000	$ 4,130,256	$ 5,030,024	$ 200,000 c	$ (3,930,256)
7	Self-Insured Workmen's Comp		$ 23,243	$ 23,243	$ 23,243	$ 23,243	$ -
8	Insurance		$ 9,292,136	$ 9,738,915	$ 9,738,915	$ 9,738,915	$ -
9	Subtotal before Paiute Allocation		$ 9,694,393	$ 14,071,428	$ 14,971,196	$ 10,141,172	$ (3,930,256)
10	Paiute Allocation	3.96%	$ (395,033) a	$ (380,379) a	$ (592,859)	$ (401,590)	$ (21,211)
11	Subtotal after Paiute Allocation		$ 9,299,360	$ 13,691,049	$ 14,378,337	$ 9,739,582	$ (3,951,467)
	Arizona Allocation of Common						
12	Legal and Other Costs	56.70%	$ 101,501	$ 101,501	$ 101,501	$ 101,501	$ -
13	Reserve for Self Insurance	56.70%	$ 113,400	$ 2,341,855	$ 2,852,024	$ 113,400	$ (2,228,455)
14	Self-Insured Workmen's Comp	56.70%	$ 13,179	$ 13,179	$ 13,179	$ 13,179	$ -
15	Insurance	56.70%	$ 5,268,641	$ 5,521,965	$ 5,521,965	$ 5,521,965	$ -
16	Paiute Allocation	56.70%	$ (223,984)	$ (215,675)	$ (336,151)	$ (227,702)	$ (12,027)
17	Total Common Allocated to Arizona		$ 5,272,737	$ 7,762,825	$ 8,152,518	$ 5,522,343	$ (2,240,482)
18	Total Arizona Direct and Allocated		$ 5,678,765	$ 8,168,853	$ 8,258,546	$ 8,897,136	**$ 728,283**
19	Company's proposed adjustments to Account 925 in its filing			$ 2,490,088	$ 2,579,781	**$ 728,283**	
				Col.B - Col.A	Col.C - Col.A		
	Components of Company's proposed adjustments to Account 925, I&J Expense:						
20	SWG Adjustment 7, Out of Period Expenses			$ 253,324	$ 253,324	$ 253,324	
21	SWG Adjustment 10, Self Insured Retention Normalization			$ 2,228,455 b	$ 2,318,148 b	**$ 2,956,738**	
22	SWG Adjustment 12, A&G Expenses, Annualized Paiute Allocation			$ 8,309	$ 8,309	$ 8,309	
23	Total Company-proposed adjustments to Account 925 expense			$ 2,490,088	$ 2,579,781	**$ 3,218,371**	
24	Percentage increase over test year recorded amount			44%	45%	57%	
25	Staff proposed adjustment to SWG as-filed pro forma expense for Account 925					**$ 728,283**	$ 728,283
						L.23, Col.D - Col.B	

Notes and Source

A SWG response to Staff data request STF-9-14
B Derived from SWG filing, Schedule C-2, Company Adjustment Nos. 7, 10 and 12 and response to STF-9-14
C SWG response to Staff data request STF-9-14
D See page 2 of this schedule for Staff analysis of ten years of recorded expense for
a Paiute allocation used by SWG in its filing does not calculate exactly to 3.96%
b SWG Adjustment 10, Self Insured Retention Normalization

	Component	SWG Recorded	SWG Filed	SWG Corrected	Staff Adjusted	Staff Adjustment
26	Arizona Direct	$ (558,765)	$ (558,765)	$ (858,765)	**$ 2,410,000**	**$ 2,968,765**
27	Common Allocated to Arizona	$ 113,400	$ 2,341,855	$ 2,852,024	$ 113,400	$ (2,228,455)
28	Subtotals	$ (445,365)	$ 1,783,090	$ 1,993,259	**$ 2,523,400**	**$ 740,310**
29	Net SWG Proposed Adjustment, before change in Paiute allocation		$ 2,228,455	$ 2,438,624	**$ 2,968,765**	
			L.27, Col.B - Col.A To Line 21	L.27, Col.C - Col.A		
				Line 16 Less line 22		
30	Paiute allocation	$ (223,984) Line 16		$ (344,460)	$ (236,011)	$ (12,027)
31	Change in Paiute allocation from test year recorded			$ (120,476)	$ (12,027)	
32	Company's proposed corrected adjustment, net of change in Paiute allocation			$ 2,318,148		**$ 728,283** c
				To Line 21		
33	Staff adjustment to Southwest recorded, net of change in Paiute allocation				**$ 2,956,738**	
					To Line 21	

c See page 2 of this schedule for details of Staff recommended normalized amount for self-insured expense.

Southwest Gas Corporation
Injuries and Damages, Account 925
Reserve for Self-Insurance Expense Normalization
Test Year Ended April 30, 2007

Docket No. G-01551A-07-0504
Schedule C-12
Page 2 of 2

Line No.	Description	Year	Total Expense Recorded Arizona (A)	Total Expense Recorded Common (B)	Total Expense Recorded Without Extreme Expense from May 2005 Leaking Gas Line Fire Arizona (C)	Total Expense Recorded Without Extreme Expense from May 2005 Leaking Gas Line Fire Common (D)	Staff Proposed Arizona (E)	Staff Proposed Common (F)
	Reserve for Self-Insurance Expense							
1		1998	$ 751,083	$ 500,000	$ 751,083	$ 500,000		
2		1999	$ 500,000	$ (200,000)	$ 500,000	$ (200,000)		
3		2000	$ 1,080,545	$ -	$ 1,080,545	$ -		
4		2001	$ 426,955	$ 100,000	$ 426,955	$ 100,000		
5		2002	$ 350,000	$ 200,000	$ 350,000	$ 200,000		
6		2003	$ 1,941,509	$ (300,000)	$ 1,941,509	$ (300,000)		
7		2004	$ 2,154,000	$ 275,000	$ 2,154,000	$ 275,000		
8		2005	$ 1,360,224	$ 10,367,500 a	$ 1,360,224			
9		2006	$ (975,540)	$ 200,000	$ (975,540)	$ 200,000		
10		2007 YTD November	$ 588,629	$ (25,500)	$ 588,629	$ (25,500)		
11	Total		$ 8,177,405	$ 11,117,000	$ 8,177,405	$ 749,500		
12	**Ten Year Average Plus $1,596,611**		$ 817,741	$ 1,111,700	**$ 2,414,352**	$ 74,950	**$ 2,410,000** b	$ 200,000 c
13	Pauite allocation	0.0396		$ (44,023)		$ (2,968)		$ (7,920)
14	Common before AZ allocation			$ 1,067,677		$ 71,982		$ 192,080
15	AZ allocation	56.7%		$ 605,373		$ 40,814		$ 108,909
16	AZ allocated and direct		$ 817,741	$ 605,373	$ 2,414,352	$ 40,814	$ 2,410,000	$ 108,909
	Adjustment to Southwest Proposed as Filed							
17	Page 1, Col.B, Lines 2 and 13, respectively		$ (558,765)	$ 2,341,855	$ (558,765)	$ 2,341,855	$ (558,765)	$ 2,341,855
18	Adjustment to SWG Proposed As Filed, Based on Ten-Year Average	L.16 - L.17	$ 1,376,506	$ (1,736,482)	$ 2,973,117	$ (2,301,041)	**$ 2,968,765**	$ (2,232,946)
19	Net adjustment to Arizona expense		$ (359,977)		$ 672,076		**$ 735,819**	
			L.18, Col.A&B		L.18, Col.C&D		L.18, Col.E&F	
	Adjustment to Southwest Proposed as Corrected							
20	Page 1, Col.C, Lines 2 and 13, respectively		$ (858,765)	$ 2,852,024	$ (858,765)	$ 2,852,024	$ (858,765)	$ 2,852,024
21	Adjustment to SWG Proposed As Filed, Based on Ten-Year Average	L.16 - L.20	$ 1,676,506	$ (2,246,651)	$ 3,273,117	$ (2,811,210)	**$ 3,268,765**	$ (2,743,115)
22	Net adjustment to Arizona expense		$ (570,146)		$ 461,907		**$ 525,650**	
			L.21, Col.A&B		L.21, Col.C&D		L.21, Col.E&F	

Notes and Source

Ten-Year Average is from the Company's' workpapers for Schedule C-2, Adjustment No. 10, Sheets 72 to 75 and response to data requests STF-6-60 and STF-9-14.

a The 2005 common expense is abnormally high because of the impact of a May 2005 leaking gas line fire. The eventual settlement of that incident exceeded the Company's self-retention in effect at the time of the occurrence, per the response to data requests, such as STF-10-11(B) and (F)

b Ten-Year Average, rounded upward to nearest $10,000

c 2006 accrual used as reasonably representative; note this amount exceeds the 10-year average, excluding the impact of the abnormal and extreme payout relating to the May 2005 leaking gas line fire.

Rebuttal Exhibit No.__(RAM-1)
Sheet 2 of 2

SOUTHWEST GAS CORPORATION
ARIZONA
ALLOCATION OF SELF-INSURANCE (10 YEAR AVERAGE)
ADJUSTMENT NO. 10

Line No.	Claims Paid (a)	FERC (b)	So. Ca. (c)	No. Ca. (d)	So. Nv. (e)	No. Nv. (f)	Arizona (g)	System Allocable (h)	Total (i)	Line No.
1	< $1MM Per Claim	$ 0	$ 177,500	$ 24,375	$ 1,350,143	$ 195,000	$ 5,809,865	$ 141,255	$ 7,698,138	1
2	At $1MM Per Claim	0	0	0	1,000,000	2,000,000	5,000,000	0	8,000,000	2
3	At $5MM Aggregate	0	0	0	0	997,774	15,966,105	0	16,963,879	3
4		$ 0	$ 177,500	$ 24,375	$ 2,350,143	$ 3,192,774	$ 26,775,970	$ 141,255	$ 32,662,017	4
5	Total Company Experience 10 Year Average	$ 0	$ 17,750	$ 2,438	$ 235,014	$ 319,277	$ 2,677,597	$ 14,126	$ 3,266,202	5
6	Less: Paiute & SGTC at 3.96%								(129,342)	6
7	Net System Allocable								$ 3,136,860	7
8	Four Factor %		7.9%	2.3%	27.3%	5.7%	56.7%			8
9	Allocation of Self-Insurance	$ 129,342	$ 249,067	$ 72,775	$ 856,049	$ 180,056	$ 1,778,600	$	$ 3,136,546	9
10						Arizona Allocation Percent			56.70%	10
11						Arizona Allocation			$ 1,778,422	11
12						Less: Test Year as Recorded			(449,856)	12
13						Arizona Revised Adjustment			$ 2,228,278	13

Rebuttal Exhibit No.__(RAM-2)
Sheet 1 of 2

Acct 925 $5MM Aggr.(10YrAvg.) 97-06

WP Adj10 Sh 1

WORKPAPERS
SCHEDULE C-2, ADJ. 10
Sheet 72 of 90

SOUTHWEST GAS CORPORATION
ARIZONA
TEN YEAR HISTORY OF LIABILITY CLAIMS
FOR AMOUNTS LESS THAN ONE MILLION AND FIVE MILLION AGGREGATE PER YEAR

Line No.	Year (a)	Palute (b)	So. Ca. (c)	No. Ca. (d)	So. Nv. (e)	No. Nv. (f)	Arizona (g)	Sys Alloc. (h)	Total (i)	Line No.
					Less Than $1,000,000 Self-Insurance Per Claim					
1	1997						450,384		450,384	1
2	1998						1,494,253	123,755	1,618,008	2
3	1999			6,250	256,333		37,545		300,128	3
4	2000			18,125	208,216	195,000			421,341	4
5	2001		100,000		415,093		609,455		1,124,548	5
6	2002						400,000		400,000	6
7	2003		50,000		31,000		95,491		176,491	7
8	2004				92,500		560,500		653,000	8
9	2005		27,500		342,000		179,500	17,500	566,500	9
10	2006						1,853,678		1,853,678	10
11	2007				5,001		129,059		134,060	11
12		$ 0	$ 177,500	$ 24,375	$ 1,350,143	$ 195,000	$ 5,809,865	$ 141,255	$ 7,698,138	12
					$1,000,000 Self-Insurance Per Claim					
13	1997						1,000,000		1,000,000	13
14	1998					1,000,000	2,000,000		3,000,000	14
15	1999								0	15
16	2000					1,000,000			1,000,000	16
17	2001								0	17
18	2002								0	18
19	2003						1,000,000		1,000,000	19
20	2004						0		0	20
21	2005				1,000,000		1,000,000		2,000,000	21
22	2006								0	22
23	2007								0	23
24		$ 0	$ 0	$ 0	$ 1,000,000	$ 2,000,000	$ 5,000,000	$ 0	$ 8,000,000	24
					$5 Million Agregate above $1,000,000 Self-Insurance Per Claim					
25	1997						2,726,235		2,726,235	25
26	1998					6,272	1,739,870		1,746,142	26
27	1999								0	27
28	2000					991,502			991,502	28
29	2001								0	29
30	2002								0	30
31	2003						5,000,000		5,000,000	31
32	2004						1,500,000		1,500,000	32
33	2005						5,000,000		5,000,000	33
34	2006								0	34
35	2007								0	35
36		$ 0	$ 0	$ 0	$ 0	$ 997,774	$ 15,966,105	$ 0	$ 16,963,879	36
37	Total	$ 0	$ 177,500	$ 24,375	$ 2,350,143	$ 3,192,774	$ 26,775,970	$ 141,255	$ 32,662,017	

[1] Amounts for 1997 (May-December) and 2007 (January-April) are a partial year; 1998 through 2006 are based on calendar year amounts.

SOUTHWEST GAS CORPORATION
COMPUTATION OF INTEREST LAG DAYS
FOR THE 2007 ARIZONA RATE CASE

Line No.	Description (a)	Principal Amount Outstanding (b)	Unamortized Debt Expense and Discount (c)	Net Proceeds (b)	Effective Interest Rate (c)	Interest Expense (d)	Lag Days (e)	Dollar Days (f)	Line No.
	Debentures								
1	8.0% Debenture, Due 2026	75,000,000	6,089,371	68,910,629	8.89%	6,126,155	91.25	559,011,638	1
2	8.375% Note, Due 2011	200,000,000	1,807,388	198,192,612	8.61%	17,064,384	91.25	1,557,125,031	2
3	7.625% Note, Due 2012	200,000,000	1,380,294	198,619,706	7.79%	15,472,475	91.25	1,411,863,356	3
4	Total Debentures	$ 475,000,000	$ 9,277,052	$ 465,722,948	8.30%	$ 38,663,014		3,528,000,025	4
	Medium Term Notes								
5	7.59% MTN, Due 2017	25,000,000	147,215	$ 24,852,785	7.68%	$ 1,908,694	91.25	174,168,319	5
6	7.78% MTN, Due 2022	25,000,000	175,679	24,824,321	7.86%	1,951,192	91.25	178,046,239	6
7	7.92% MTN, Due 2027	25,000,000	204,455	24,795,545	8.00%	1,983,644	91.25	181,007,479	7
8	6.89% MTN, Due 2007	17,500,000	7,731	17,492,269	7.00%	1,224,459	91.25	111,731,869	8
9	6.76% MTN, Due 2027	7,500,000	3,458	7,496,542	6.88%	515,762	91.25	47,063,289	9
10	6.27% MTN, Due 2008	25,000,000	42,553	24,957,447	6.40%	1,597,277	91.25	145,751,493	10
11	Total Medium Term Notes	$ 125,000,000	$ 581,090	$ 124,418,910	7.38%	$ 9,181,027		837,768,689	11
12	Total Fixed Rate Debt [1]	$ 600,000,000	$ 9,858,142	$ 590,141,858	8.11%	$ 47,844,041		4,365,768,714	12
	Variable Rate Debt								
13	Term Facility [2]			$ 30,441,057	6.83%	$ 2,079,124	3.67	7,619,990	13
14	CP Facility [3]			22,728,142	5.96%	1,354,597	-24.05	(32,578,064)	14
15	Total Variable Rate Debt			$ 53,169,199	6.46%	$ 3,433,721		(24,958,074)	15
						$ 51,277,762		4,340,810,640	
	Perferred equity					7,722,141	45.25	349,426,880	
	customer deposits			31,921,898	0.06		182.5	-	
						58,999,903	79.50	4,690,237,521	

Rebuttal Exhibit No.__(RAM-3)
Sheet 1 of 2

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504

ESTIMATED LAG DAYS FOR REVENUE BASED TAXES

Line No.	Revenue Based Taxes (1)	Paid Monthly	Paid Quarterly	Paid Annually	Total	Line No.
1	Franchise Fees	$ 6,448,399	$ 10,717,071	$ 0	$ 17,165,470	1
2	Privilege/Sales Taxes	82,412,358	0	354	82,412,712	2
3	Business Occupational Taxes	0	85,768	0	85,768	3
4	Mill Assessments (ACC/RUCO)	0	0	1,757,145	1,757,145	4
5	Totals	$ 88,860,757	$ 10,802,839	$ 1,757,499	$ 101,421,095	5
6	Ratio to Total	87.62%	10.65%	1.73%	100.00%	6
7	Lag Days	39.53	66.43	203.93		7
8	Weighted Lag Days	34.63	7.08	3.53	45.24	8
9	Dollar Days				$ 4,588,290,338	9

MEMORANDUM

To: **Distribution**

From: Eric DeBonis, Ed Janov

Date: August 7, 2007

Subject: Project Charter to Formalize Policies and Procedures for the ICM

Please be advised that effective August 1, 2007, Mike Harrington is the Project Manager of the Project to Formalize Policies and Procedures for the Incremental Contribution Method (ICM) Model. During this assignment, Mike will work closely with Tom Rader, Director/Special Projects, to facilitate the documentation and development of procedures to update and maintain the Arizona ICM.

We will serve as joint Project Sponsors and have authorized Mike and Tom to coordinate and manage the overall process. The immediate goals are to reconstitute the ICM model, document the code, and develop the change management process. Secondary goals are to determine the best long-term platform for the application, establish internal controls and auditing protocols; and develop a verification process to ensure model accuracy.

The primary project stakeholders will consist of an Oversight Committee and a Project Team. A kick-off meeting will be scheduled shortly with the stakeholders. Attached is the project Organization Chart.

Please join us in welcoming Mike to this assignment. Please give him all of your support in leading the group to a successful project completion.

Distribution:

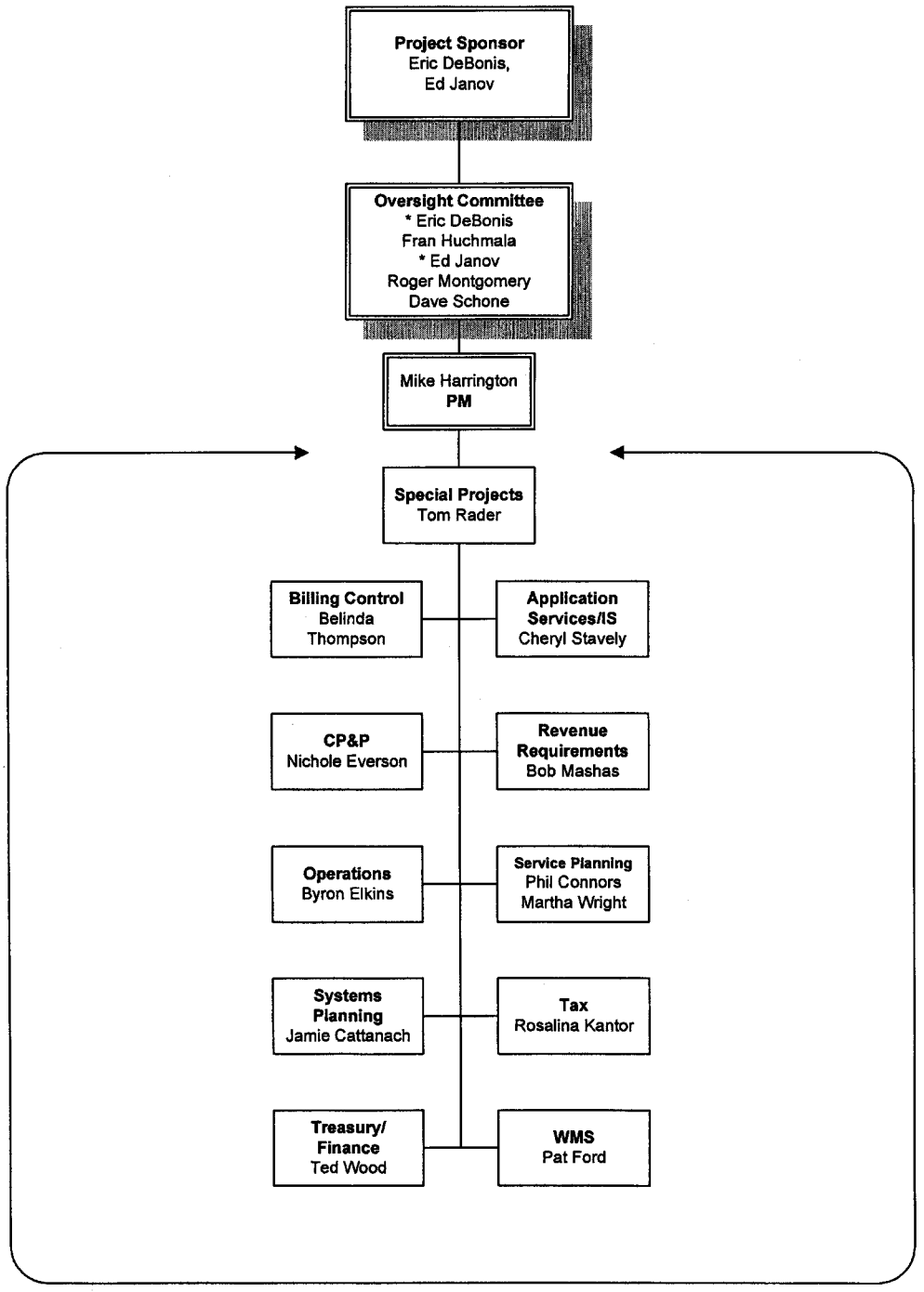
Jamie	Cattanach
Phil	Connors
Byron	Elkins
Nichole	Everson
Pat	Ford
Mike	Harrington
Fran	Huchmala
Rosalina	Kanter
Bob	Mashas
Roger	Montgomery
Tom	Rader
Dave	Schone
Cheryl	Stavely
Belinda	Thompson
Ted	Wood
Martha	Wright

c. Gary Clark
Eric DeBonis
John Hester
Roxann DelVecchio
Ed Janov
Richard Jordan
Jim Kane
Ken Kenny
Bill Moody
Lisa Moses
Chris Palacios
Jeff Shaw
Lisa Wamble
Bob Weaver

Attachment

Project Organization Chart

Project To Formalize Policies and Procedures For The ICM



*** Joint Project Sponsors**

Project to Formalize Policies and Procedures for the ICM Model

PROJECT DEFINITION DOCUMENT

Last Updated: August 28, 2007

Approved By:	Signature	Date
Eric DeBonis Project Sponsor		
Ed Janov Project Sponsor		

Project to Formalize Policies and Procedures for the ICM Model
Project Definition Document

Table of Contents

Project Background and Objectives 2
The specific objectives of this project are to: 2
Project Success Criteria 3
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Project Background and Objectives

Southwest Gas Corporation (Southwest) utilizes an Incremental Contribution Method (ICM) model to conduct economic feasibility analyses for potential natural gas projects in Arizona. The ICM model is used to determine the appropriate level of refundable advance and non-refundable contribution to ensure an adequate rate of return during and after the build-out phase of the potential project.

This model has been updated periodically to conform to Arizona regulatory requirements (Tariff Rule No. 6.B.4) and to reflect current costs, margins and volumes. The primary platform for the ICM model is an Excel spreadsheet, designed with the appropriate instructions, security, fields (cells) and formulas. The Revenue Requirements department has held primary responsibility for ensuring the accuracy and functionality of the model.

The primary user of the ICM model is Division Service Planning. After obtaining estimated costs for proposed new projects from Division Engineering, these costs are entered into the model by Division Service Planners. Other developer provided information such as number of residential units, number of appliances, and build-out projections are entered into the model by Division Service Planners.

To ensure the ICM model remains accurate and reflective of current rates, policies and demand data, a Project Team was formed to develop procedures to verify, document, and update the model. The Project Team and stakeholders will re-build the model, fully document all of the calculations and assumptions in the model, and establish the change management and auditing procedures to maintain the integrity of the model. The team will also identify the best form and/or application database environment for the model to reside in the long term.

The specific objectives of this project are to:

- Re-build and verify the accuracy of the ICM model.
- Document the calculations, logic and assumptions in the ICM model.
- Develop procedures for maintaining and updating the ICM model.
- Develop control procedures and an audit trail for model changes.
- Develop procedures for handling change requests.
- Develop procedures for distributing the model and managing revisions.
- Develop training materials and a Users Manual for the ICM model.
- Determine the best platform and database for the model.
- Evaluate specific training needs for users.
- Document the procedures and application environment.
- Close the project in a timely manner.

Project Success Criteria

This Project to Formalize Policies and Procedures for the ICM model will be measured by the following success criteria (Note: See Responsibility Assignment Matrix beginning on page 6, and Exhibit 1 at the end of this document for a description of the groups and team members):

- The Oversight Committee and Project Team will take an active role in the project to ensure project quality.
- The Project Team will have a working understanding of the components of the ICM and its purpose.
- The ICM Model Owner will be responsible for coordinating development of policies and procedures.
- The Project Manager and ICM Model Owner will report progress and escalate matters to the Oversight Committee and Project Sponsors.
- The Project Team will re-build and document the calculations, logic, and assumptions in the ICM model.
- The Project Team will complete procedures for maintaining and updating the ICM model.
- The Project Team will create internal controls and change management procedures for the ICM model.
- The Project Team will create training materials and a Users Manual for the ICM model.
- The Project Team will recommend the best platform for the database application for the model to reside in the long term.

Project Scope

The project scope is limited to the following tasks:

- Develop a focused Project Team review of the ICM model (including sub-committees) and reconstitute the model.
- Develop a set of standard procedures for the use of the ICM model.
- Develop a set of procedures for handling changes to the ICM model.
- Determine the best application and database environment for the ICM model.
- Establish a method of approving changes to the ICM model.
- Establish a means of periodically testing and verifying the ICM model.
- Establish audit trails for tracking changes and version controls of the ICM model.
- Research and evaluate potential integration with other systems.
- Develop a communication process for educating users of the ICM model.

The project scope will **not** include:

- Evaluation and modification of the ICM methodology.
- Review and development of any other analysis tool using different criteria than the ICM model.
- Evaluation and purchase of available software packages for modeling.
- Development of a similar model for the California and Nevada jurisdictions.
- Development of Arizona Division business processes for Service Planning.

Business Impact

The ICM model is used primarily by Arizona Division Service Planning to conduct economic feasibility analyses for potential natural gas projects in Arizona. The Excel spreadsheet model was originally developed and maintained by the Revenue Requirements department.

Data input for the model is provided by various departments, including Systems Planning, Revenue Requirements, and Division Service Planning. The data provided by corporate departments includes average gas loads, estimated costs and margin.

The ICM model does not directly interface with the Work Management System (WMS); however, the current ICM model is accessible through WMS as an Excel worksheet. Therefore, modifications to the ICM during the course of this project will need to consider impacts, if any, to WMS.

In addition, the project will introduce tighter controls in the change control process for the model. All impacted departments will require notification when changes to the ICM model are made and approved. Version control will be available in the new process for historical versions of the model.

Deliverables

The deliverables of this project are:

Phase I

- A comprehensive review, documentation of code and reconstitution of the ICM model.
- An improved change management process.
- A comprehensive set of procedures for the use, maintenance and revision process for the ICM model.
- A Business Process Flow document for handling revisions, document retention and communications regarding the ICM model and ownership processes.
- A Responsibility Support Matrix identifying all support roles and responsibilities.

Phase II

- A recommendation for the best application and/or database platform for housing the ICM model.
- Implementation of the recommended application and/or database following management approval.
- Improved internal controls and auditing protocols for the ICM model.
- An improved verification process to ensure the ICM model integrity.

Project Approach

Existing Southwest project management methodology will be used to formally document the project process and results.

The project documentation will also include periodic progress reports and documented results of working sessions.

A detailed work plan will be prepared and will be maintained.

The project reporting structure will be as follows:

- Project Sponsors - Eric DeBonis and Ed Janov
- Oversight Committee
- Project Manager
- ICM Model Owner
- Project Team
- Project Sub-committees (as needed)

(See Exhibit 1 for the full Project Organization Chart)

Responsibility Assignment Matrix

Resource	Title(s)	Roles and Responsibilities
Project Sponsors		
Eric DeBonis	General Manager/CAD Operations	– Responsible for authorizing the project and providing high level direction. Provide high level go, no go decisions.
Ed Janov	Senior VP/Finance	
Oversight Committee		Applies to all:
Eric DeBonis	General Manager/CAD Operations	– Responsible for providing the overall business and corporate area direction to the project.
Fran Huchmala	Dir./Cntrl Ops and Planning	– Advise the Project Manager and discuss status of the project with the manager on a regular basis.
Ed Janov	Senior VP/Finance	– Resolution of escalated issues and go, no go decisions at an overall company level.
Roger Montgomery	VP/Pricing	– Ensure adequate departmental resources for project tasks.
Dave Schone	Dir./Bus Ops and Tech Support	– Ensure all regulatory and governmental issues are adhered to.
Lisa Wamble	Director/Accounting	
Project Manager		
Mike Harrington	Project Manager/IS	– Responsible for coordinating and managing the project through completion.
		– Provide status reports to appropriate project members and conduct meetings as necessary.
		– Work with and coordinate activities with the ICM Model Owner.

Resource	Title(s)	Roles and Responsibilities
ICM Model Owner		
Tom Rader	Director/Special Projects	– Responsible for coordinating the development of the ICM model procedures. – Responsible for ensuring an annual update process. – Responsible for coordinating the development of user guides and instructions where applicable. – Responsible for coordinating the scheduling of regular audits. – Responsible for developing and maintaining version controls for the ICM model.
Project Team		
Roxanne DelVecchio	Manager/Accounting Billing Control	– Responsible for supporting the current Excel spreadsheet model and providing accounting controls and information related to Billing Control. – Responsible for inputting and validating data to the current Excel ICM model as provided by Revenue Planning and Demand Planning. – Responsible for version control and document retention.
Cheryl Stavely	Mgr/Application Services	– Responsible for providing input for the database and application environment. – Responsible for assisting with documentation of the ICM Excel spreadsheet model. – Responsible for evaluation and documentation to support analysis for different application platforms. – Responsible for supporting a new application and database if the Excel ICM model is transitioned to another environment.
Nichole Everson	Admin/Accounting (CPP)	– Responsible for providing policy and procedures documentation expertise.

Resource	Title(s)	Roles and Responsibilities
Project Team (cont)		
Bob Mashas	Dir./Revenue Requirements	– Responsible for providing input and information for the ICM model. – Responsible for making physical changes to current ICM model and coordinating with Treasury Services and the Model Owner.
Byron Elkins	Mgr./Ops Planning and Development	– Responsible for representing Arizona Divisions and ensuring regulatory adherence.
Phil Connors	Dir./Service Planning CAD	– Responsible for coordinating the development and implementation of procedures to periodically update the ICM model input, such as loads and costs to ICM model for CAD.
Martha Wright	Mgr./Service Planning SA	– Responsible for coordinating the development and implementation of procedures to periodically update the ICM model input, such as loads and costs to ICM model for SAZ
Jamie Cattanach	Mgr./Demand Planning	– Responsible for providing load information and planning for ICM model input.
Rosalina Kantor	Specialist/Corp Tax	– Responsible for Tax input and other ICM accounting and tax information impacting the ICM.
Ted Wood	Sr. Mgr./Treasury Services	– Responsible for providing financial analysis input and rate of return information.
Pat Ford	Sr. Mgr./ B.O.A.T.S./WMS	– Responsible for assisting with physical changes to the current ICM model and coordinating changes with Revenue Planning and the ICM Model Owner. – Responsible for providing information for the ICM model. – Responsible for how WMS will utilize the ICM model in new platforms and environments.

Dependencies

Each identified department may have dependencies with other departments. In addition to scheduled team meetings, each department representative will be required to schedule time as needed with dependent departments in order to assist with analyses and tasks.

Examples of dependencies:

- The ICM Excel worksheet is attached to WMS. The ICM Model Owner and other departments need to be aware that updates to the ICM model may impact WMS.
- Systems Planning and Regulatory Affairs will need to coordinate changes to the ICM model with the ICM Model Owner.
- Treasury Services may need to be involved with changes to the model and will need to coordinate activities with the ICM Model Owner as well as other departments as necessary.
- The Corporate Policy and Procedures department (CP&P) will be instrumental in developing written procedures and will need to interface with the various departments impacted.
- Division Service Planning will be directly impacted by the ICM model and will need assurance that the model is accurate and up to date.

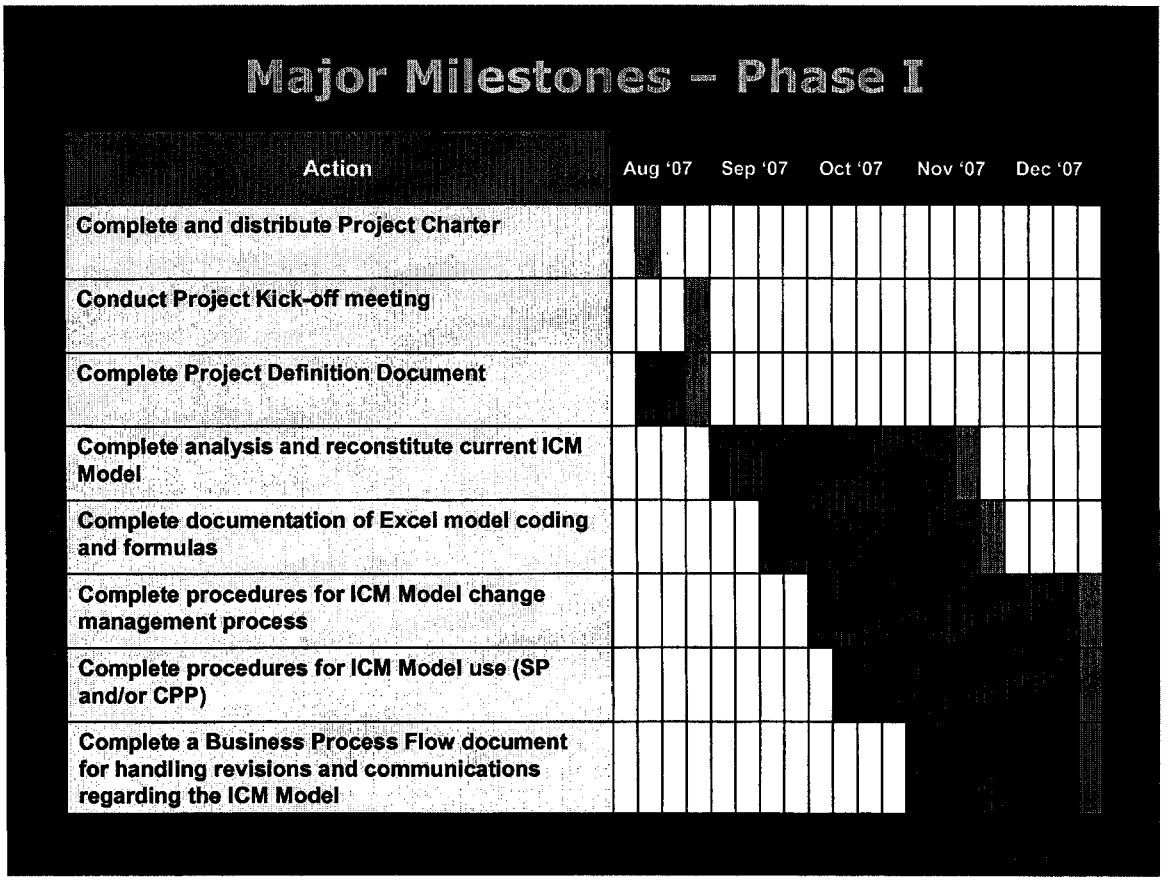
Schedule

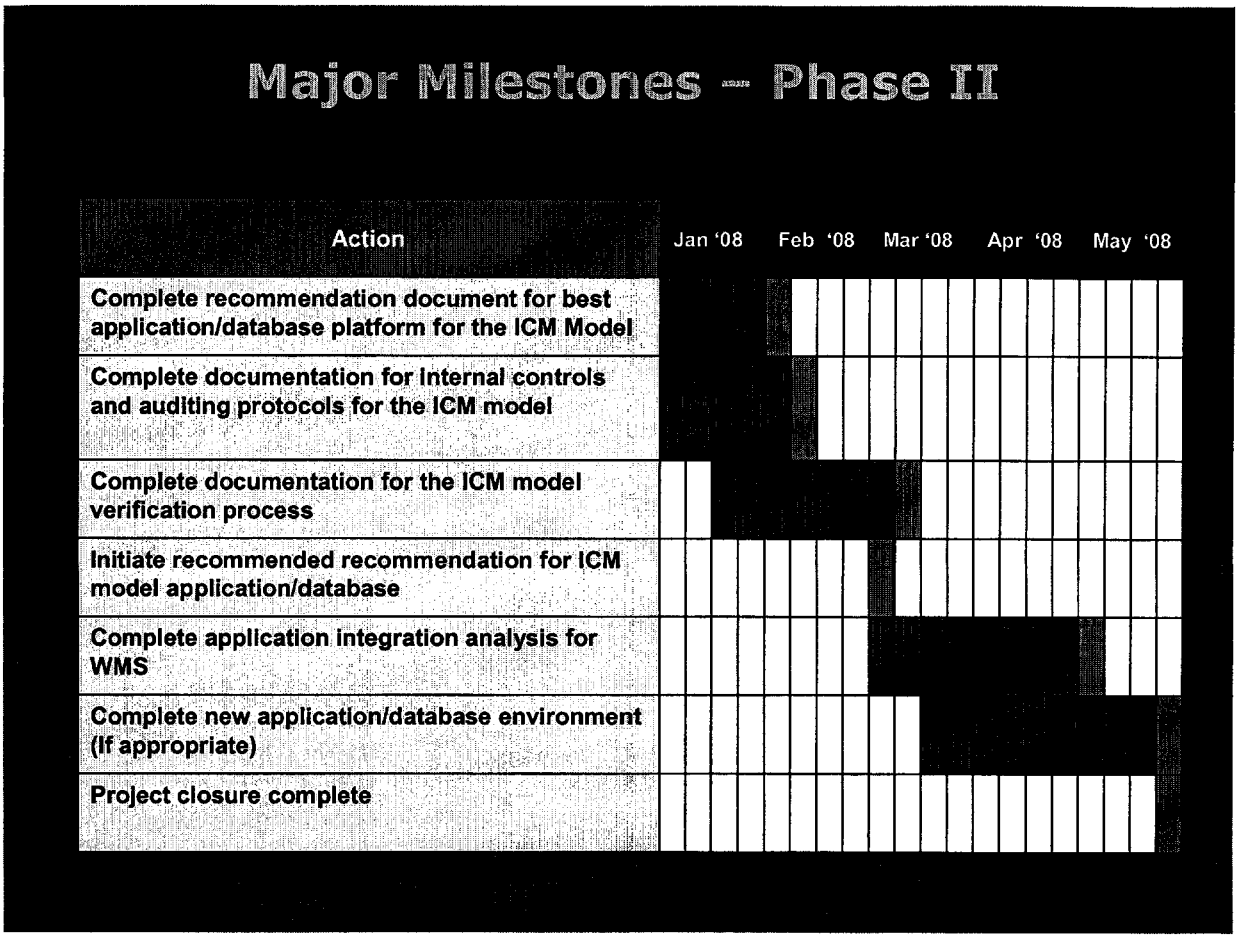
The request to formalize policies and procedures utilizing a project methodology was initiated in May 2007 and a formal Project Charter was issued in August 2007. The project will consist of two phases with Phase I scheduled for completion by the end of 2007. Senior management has requested the completion of formal procedures by December 2007. The selection and development of a new Application database and environment is dependent on further research and will fall into Phase II of the project. Integration with other applications may also be considered during a later phase of the project. Every effort will be made to complete all tasks prior to the end of each phase.

Milestones

The following graphs represent high level milestone estimates based on information available at August 2007. Dates may be modified based on additional information received during the course of the project.

Areas marked in blue represent an estimated duration of the task. Areas marked in green represent an approximate milestone completion date. Some tasks will run concurrently with other tasks as necessary.





Risks

Risks identified in this document are high level and may require more extensive analyses and plans for contingency/mitigation. The known project risks, at this time are:

Risk: *Dependent tasks impacting each other and the projected timeline.*

Mitigation(s):

- *Identify all dependent tasks in the project plan schedule and prioritize accordingly.*

Risk: Time restrictions on Project Team members or sub-committees may cause restrictions that delay completion of identified tasks.

Mitigation(s):

- *Obtain department head commitments for personnel prior to and during the project kick-off meeting.*

- *Ensure a copy of the Project Definition Document is routed to all project stakeholders.*
- *Obtain senior management support for the project.*

Risk: *The Excel spreadsheet (i.e. ICM model) is not accurately calculating customer Contributions/Advance requirements due to incorrect formulas, logic errors, or data inputs and/or assumptions.*

Mitigation(s):

- *As one of the initial tasks of the project, the Project Team will analyze in detail the ICM model and identify each cell and formula to ensure accuracy prior to documenting.*

Risk: *Requirements for the new platform and/or database are more complex than originally thought and will impact the project timeline (Phase II issue)*

Mitigation(s):

- *Schedule a series of requirements meetings with the appropriate Project Team personnel and sub-committees to determine extent of potential changes required for a new application/database platform.*
- *Ensure that representatives from I/S represent not only applications, but also Technical Services and database administrators.*

Contingencies:

- *Maintain the current Excel spreadsheet as a production tool until a full assessment can be made for changing to a different platform.*

Risk: *Requirements for integration with other applications may be more complex than originally thought and will impact the project timeline (Phase II issue).*

Mitigation(s):

- *Include application services representatives for WMS, CSS and other applications if appropriate to determine requirements for integration.*
- *Delay integration until a future phase.*

Contingencies:

- *Maintain current copy of ICM model until full requirements are developed.*

Risk: *Requests from management to add or modify a significant piece of the spreadsheet may require lengthy evaluation and coding.*

Mitigation(s)

- *Significant changes to the ICM model will be considered outside the scope of this project. Normal change management processes will be used to develop changes and will be approved by the Director/Special Projects.*

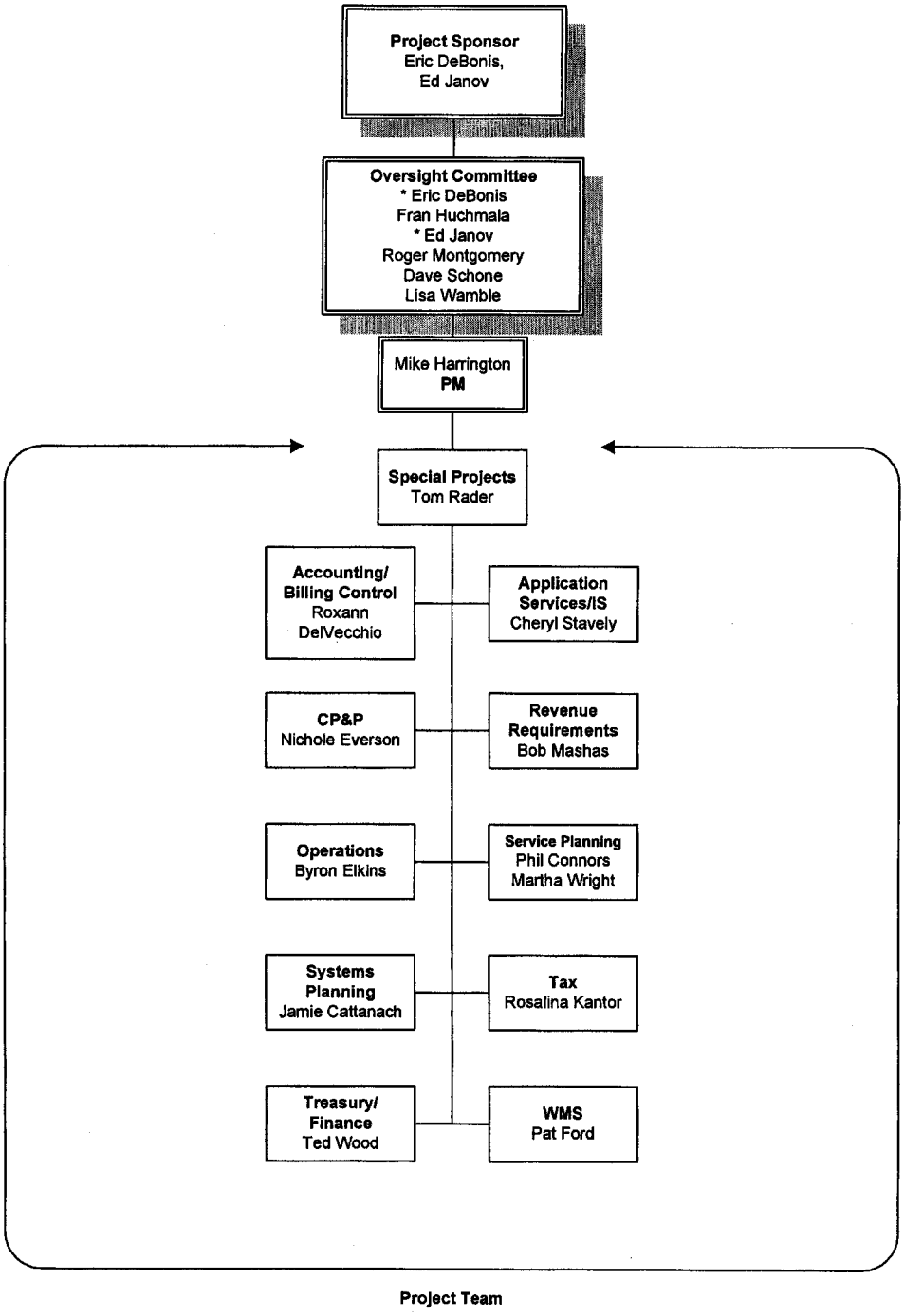
Assumptions

This project is based on certain assumptions:

- The current Excel version of the ICM model has been reviewed by a prior team and is functional for production use.
- Formulas, logic, and input data are accurate in the current production ICM model.
- Ownership of the ICM model will be formally transitioned to the ICM Model Owner.
- All Project Team members (or designates) will be available to assist with the project tasks and will attend the working meetings.
- The ICM model is currently in use as a WMS attachment and is updated as changes are made to the model.

Exhibit 1

Project to Formalize Policies and Procedures for the ICM



*** Joint Project Sponsors**

Rebuttal Exhibit No.__(RAM-5)
Sheet 1 of 28

SOUTHWEST GAS CORPORATION

SP 920.0 Incremental Contribution Method (ICM) Model (Arizona)

Effective Date: 01/01/2008

SP Owner: Corporate Development

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Purpose

Policy

Scope

Responsibility

1. Corporate Development
2. Billing Control
3. Revenue Requirements
4. Demand Planning
5. Treasury Services
6. Corporate Tax
7. Service Planning (Arizona Divisions)
8. Industrial Gas Engineer (IGE) (Arizona Divisions)
9. Key Account Management (KAM)
10. Service Planning Management (Arizona Divisions)
11. Operations Systems Support (OSS)
12. Customer Assistance Support and Training (CAST)

Procedure A--Usage - Service Planning

Procedure B--Usage - Key Account Management

Procedure C--Annual Consumption Changes

Procedure D--Rate Changes

Procedure E--Service Line Average Length and Cost Changes (Arizona - Standard Amounts)

Procedure F--Model Modifications

Reference

ICM Change Process Flow Charts

Purpose

To describe the use, change management controls, processes and procedures related to the Incremental Contribution Method (ICM) model.

Policy

1. To conform to Arizona regulatory requirements, Southwest Gas Corporation (the Company) utilizes an ICM model (the model) to conduct economic feasibility analyses for potential natural gas projects in Arizona. The model is used to determine the appropriate level of refundable advance and non-refundable contribution to ensure an adequate rate of return during and after the build-out phase of a potential project.

2. The model is updated as needed to conform to Arizona regulatory requirements (Arizona Gas Tariff Rule No. 6.B.4) and to reflect current costs, margins, and volumes.

3. The processes and procedures in this Standard Practice (SP) will be followed to ensure the model is utilized appropriately, remains accurate and includes current rates, policies, and demand data.

4. The current model is maintained on the InfoNet (Online Manuals) and is accessed and used by all departments.

5. The model consists of fourteen spreadsheets, all of which are password protected. Billing Control is responsible for protecting and maintaining security on the Standard Amounts worksheet and the ACC Authorized Rates worksheet within the model. Revenue Requirements is responsible for protecting and maintaining security on the other twelve worksheets within the model.

Rebuttal Exhibit No.__(RAM-5)
Sheet 3 of 28

6. Departments will receive notification when approved changes are placed into production.

Scope

This SP applies to all Company employees that utilize and maintain the model.

Responsibility

1. Corporate Development

   a. Ensure annual consumption changes (through Demand Planning), annual service line average length and cost changes (through Revenue Requirements), and authorized rate changes (through Revenue Requirements) are initiated and completed in a timely manner.

   b. Act as initial contact point for problems identified in the model that may result in modifications to the model.

   c. Provide final approval for all model updates and modifications including:

      - Consumption changes
      - Service line average length and cost changes
      - Rate changes
      - Model modifications

   d. Rename tested and verified model to a production version using the appropriate naming convention.

   e. Forward approved production version of model to Billing Control for placement into production environments [InfoNet and Work Management System (WMS)].

2. Billing Control

   a. Create and maintain password protection for the Standard Amounts worksheet and Arizona Corporation Commission (ACC) Authorized Rates worksheet in the model.

b. Input data into the Standard Amounts worksheet and ACC Authorized Rates worksheet (as provided by Revenue Requirements and Demand Planning).

c. Review and update documentation comments on the Standard Amounts worksheet and ACC Authorized Rates worksheet.

d. Name and route test version of data changes to the department originally providing the data for verification and approval prior to placing into production.

e. Open a change request through the Help Desk to attach the new model version in the WMS (for Operations Systems Support) and InfoNet (for Customer Assistance Support and Training).

NOTE: The change request will consist of two activities – one to attach the new model version to WMS (for Operations Systems Support) and one to place the new model version on the InfoNet (for Customer Assistance Support and Training).

f. Monitor Action Request System (ARS) for change request closure prior to placing new version model into production environments.

g. Confirm new version is attached to WMS and placed on the InfoNet.

h. Maintain an accurate notification list.

i. Notify departments (key management and user departments and Corporate stakeholders) of production version model release.

3. Revenue Requirements

a. Create and maintain password protection for model worksheets other than the Standard Amounts worksheet and ACC Authorized Rates worksheet.

b. Provide input data for the Standard Amounts worksheet and ACC Authorized Rates worksheet including:

- Average margin rate per therm

- Service line historical information for average length and cost
- Key parameter information

c. Work with Treasury Services and Demand Planning to determine data inputs for the model.

d. Forward data input information to Corporate Development for approval prior to entry into the Standard Amounts worksheet and ACC Authorized Rates worksheet.

e. Maintain documentation for data inputs provided to Corporate Development.

f. Consult with Treasury Services for model modifications.

g. Maintain document support for comments and descriptions within the model, except for the Standard Amounts worksheet and ACC Authorized Rates worksheet (Billing Control responsibility).

h. Maintain verified version in electronic files within department.

i. Enter current version release notes in the Release Notes worksheet.

j. Work with Division Service Planning for review of annual service line information.

4. Demand Planning

a. Develop analyses and input data for the Standard Amounts worksheet (including District consumption averages).

b. Work with Revenue Requirements to determine data inputs for model.

c. Forward data input information to Corporate Development for approval prior to entry into the Standard Amounts worksheet.

d. Maintain documentation for data inputs provided to Corporate Development.

e. Consult with Revenue Requirements and Treasury Services for model

modifications.

f. Maintain documentation support for comments and descriptions within the model, except for the Standard Amounts worksheet and ACC Authorized Rates worksheet (Billing Control responsibility).

g. Maintain verified test version in electronic files within department.

5. Treasury Services

a. Provide consultation for model design and formulas.

b. Maintain formulas used in the model and assist with testing of the model if changes are made.

c . Provide input data to Revenue Requirements for the ACC Authorized Rates worksheet.

d. Provide input for comments and documentation within the model to Revenue Requirements as needed.

6. Corporate Tax

a. Provide consultation for tax related information within the model.

b. Provide Revenue Requirements with document support for tax related comments and descriptions within the model.

7. Service Planning (Arizona Divisions)

a. Use the model to justify residential and non-residential construction projects.

b. Provide suggestions for model changes to Division Service Planning Management.

c. Assure completed analysis is attached to WMS job.

d. Use model from InfoNet to justify or consider projects outside of WMS.

8. IGE (Arizona Divisions)

Rebuttal Exhibit No.__(RAM-5)
Sheet 7 of 28

a. Use the model to justify non-residential new construction projects.

b. Provide suggestions for model changes to Division Service Planning Management.

c. Assure completed analysis is attached to WMS job.

d. Use model from InfoNet to justify or consider projects outside of WMS.

9. Key Account Management (KAM)

a. When appropriate, use the model to justify non-residential new construction projects.

b. Provide suggestions for model changes to Corporate Development, Revenue Requirements, and/or Division Service Planning Management.

c. Assure completed analysis is attached to WMS job.

d. Use model from InfoNet to justify or consider projects outside of WMS.

e. Notify department employees each time the model is updated.

f. Provide model training for department personnel.

10. Service Planning Management (Arizona Divisions)

a. Use the model to justify residential and non-residential new construction projects.

b. Provide suggestions for model changes to Corporate Development.

c. Work with Revenue Requirements to review annual service line information.

d. Assure completed analysis is attached to WMS job.

e. Notify department employees each time the model is updated.

f. Provide model training for department personnel.

11. Operations Systems Support (OSS)

a. Receive and process ARS activity ticket for attaching the model to WMS.

12. Customer Assistance Support and Training (CAST)

a. Receive and process ARS activity ticket for updating and maintaining the model on the InfoNet.

PROCEDURE A--Usage - Service Planning

A-1. Service Planning (Arizona Divisions)

a. Access the current model on the InfoNet.

b. Provide project information to Engineering (to process through WMS and engineering design), and receive cost estimates and designs From Engineering (includes main, stub, and service extensions, etc.).

c. Input data in the Cost and Resi Sales Input worksheet, Gen Serv Sales Input worksheet, and Build-out worksheet in the model.

d. Review the rate of return calculated from the advance amount.

e. Determine the amount of refundable advance and/or contribution (if necessary) to ensure the appropriate rate of return.

f. Forward project to Service Planning Management for review and approval.

A-2. Service Planning Management (Arizona Divisions)

a. Review and approve project – completing appropriate tasks in WMS.

PROCEDURE B--Usage - Key Account Management

B-1. IGE (Arizona Divisions)

a. Access the current model on the InfoNet.

b. Input data in the Cost and Resi Sales Input worksheet, Gen Serv Sales Input worksheet, and Build-out worksheet in the model.

c. Assemble project package (includes print out of cost model, copy of customer contract, and other related documentation).

d. Save associated project model in accordance with department practices.

e. Send project package to Key Account Management (KAM) for review and approval.

B-2. Key Account Management (KAM)

a. Review and approve project package from IGE.

b. Ensure associated project contracts are reviewed and approved by Legal Affairs and the VP/Gas Resources.

PROCEDURE C--Annual Consumption Changes

NOTE: Annual consumption analyses should begin each August with model inputs due to Corporate Development by January the following year. These changes should be coordinated along with annual service line length and cost information due each February.

C-1. Corporate Development

a. Each August, confirm that Demand Planning and Revenue Requirements have initiated analysis of annual residential consumption data to determine annual estimates for each appliance (at District level), and are maintaining related information and records in accordance with department practices. Confirm January, or earlier due date.

b. Coordinate annual consumption changes with Revenue Requirements to determine if changes are required to the average rates section of model.

C-2. Demand Planning

a. Conduct analysis of residential end use/consumption, determine annual estimates for each appliance (at District level), and file results in accordance with department practices.

b. Provide residential consumption estimates to Revenue Requirements and conduct review, as required.

C-3. Revenue Requirements

a. Review residential consumption estimates and determine if a change to the average margin rate section of the model is required.

b. Forward decision with justification and inputs to Corporate Development no later than January, or earlier due date.

C-4. Corporate Development

a. Review justification with Demand Planning and Revenue Requirements.

b. **If no change to the model is required**, provide notification to Billing Control.

NOTE: This completes the annual consumption change process.

c. **If a change to the model is required**, route the approved residential consumption inputs to Billing Control.

C-5. Billing Control

a. Access the current model on the InfoNet, and create a test version using appropriate naming convention.

b. Input annual consumption changes and average margin rate per therm changes into the Standard Amounts worksheet in the model, verify the accuracy, update documentation comments, and protect the worksheet.

Rebuttal Exhibit No.__(RAM-5)
Sheet 11 of 28

c. Forward the updated, protected model test version to Demand Planning for verification.

C-6. Demand Planning

a. Verify and test Billing Control inputs for annual consumption changes.

b. Route to Revenue Requirements for verification of the average margin rate section of the Standard Amounts worksheet.

C-7. Revenue Requirements

a. Verify and test Billing Control inputs for the average margin rate section of the Standard Amounts worksheet.

b. Unprotect the current Release Notes worksheet.

c. Enter current version comments into the Release Notes worksheet and protect worksheet.

d. Route to Corporate Development for final approval.

C-8. Corporate Development

a. Review and approve the updated, protected model test version and notify Demand Planning of approval.

b. Ensure that all worksheets in the model are adequately protected.

c. Rename tested and verified version of model to production version using appropriate naming convention.

d. Forward approved production version of model to Billing Control for placement into production environments.

C-9. Billing Control

a. Call the Help Desk to open a change request to move the model into production.

NOTE 1: The parent change request will consist of two activities

– one to attach the new version to WMS (for Operations Systems Support) and one to place the new version on the InfoNet (for Customer Assistance Support and Training).

NOTE 2: The new version will be the current model, and the replaced version will be added to the historical versions for control purposes.

C-10. Operations Systems Support (OSS)

a. Receive ARS activity ticket to place new version of model in WMS attachments area.

b. Schedule new version to be attached to WMS.

NOTE: Change should be coordinated with InfoNet change for same production release date.

c. Close activity in ARS and notify Billing Control.

d. Add new version to notification e-mail.

C-11. Customer Assistance Support and Training (CAST)

a. Receive ARS activity ticket to place new version of model on InfoNet (Online Manuals).

b. Schedule new version to be placed on InfoNet.

NOTE: If change is a result of an approved rate change, the new version should be expedited.

c. Add new version to page and move old version into previous version section.

NOTE: Change should be coordinated with WMS change for same production release date.

d. Close activity in ARS and notify Billing Control.

C-12. Billing Control

a. Maintain an accurate notification list.

b. Notify departments (key management and user departments and Corporate stakeholders) of production version model release.

c. Close the parent change request.

C-13. Service Planning Management (Arizona Divisions) and Key Account Management (KAM)

a. Notify department employees each time the model is updated.

PROCEDURE D--Rate Changes

D-1. Corporate Development

a. Ensure Revenue Requirements is providing timely updates for authorized rate changes, and maintaining related information and records in accordance with department practices.

D-2. Revenue Requirements

a. Conduct analysis of customer rates and tariffs, and file results in accordance with department practices.

b. Provide related rate and tariff proposed changes to Corporate Development for review and approval.

D-3. Corporate Development

a. Review and approve proposed rate change information.

b. Route the approved rate change information to Billing Control.

D-4. Billing Control

a. Access the current model on the InfoNet, and create a test version using appropriate naming convention.

b. Input rate changes into the Standard Amounts worksheet in the

model, verify the accuracy, update documentation comments, and protect the worksheet.

c. Input rate changes into the ACC Authorized Rates worksheet in the model, verify the accuracy, update documentation comments, and protect the worksheet.

d. Forward the updated, protected model test version to Revenue Requirements for verification.

D-5. Revenue Requirements

a. Verify and test Billing Control inputs for rate changes.

b. Unprotect the current Release Notes worksheet.

c. Enter current version comments into the Release Notes worksheet and protect worksheet.

d. Route to Corporate Development for final approval.

D-6. Corporate Development

a. Review and approve the updated, protected model test version and notify Revenue Requirements of approval.

b. Ensure that all worksheets in the model are adequately protected.

c. Rename tested and verified version of model to production version using appropriate naming convention.

d. Forward approved production version of model to Billing Control for placement into production environments.

D-7. Billing Control

a. Call the Help Desk to open a change request to move the model into production.

NOTE 1: The parent change request will consist of two activities – one to attach the new version to WMS (for Operations

Systems Support) and one to place the new version on the InfoNet (for Customer Assistance Support and Training).

NOTE 2: The new version will be the current model, and the replaced version will be added to the historical versions for control purposes.

D-8. Operations Systems Support (OSS)

a. Receive ARS activity ticket to place new version of model in WMS attachments area.

b. Schedule new version to be attached to WMS.

NOTE: Change should be coordinated with InfoNet change for same production release date.

c. Close activity in ARS and notify Billing Control.

d. Add new version to notification e-mail.

D-9. Customer Assistance Support and Training (CAST)

a. Receive ARS activity ticket to place new version of model on InfoNet (Online Manuals).

b. Schedule new version to be placed on InfoNet.

NOTE: If change is a result of an approved rate change, the new version should be expedited.

c. Add new version to page and move old version into previous version section.

NOTE: Change should be coordinated with WMS change for same production release date.

d. Close activity in ARS and notify Billing Control.

D-10. Billing Control

a. Maintain an accurate notification list.

b. Notify departments (key management and user departments and Corporate stakeholders) of production version model release.

c. Close the parent change request.

D-11. Service Planning Management (Arizona Divisions) and Key Account Management (KAM)

a. Notify department employees each time the model is updated.

PROCEDURE E--Service Line Average Length and Cost Changes (Arizona - Standard Amounts)

NOTE: Revenue Requirements will work with Division Service Planning to review service line average length and cost information prior to review by Corporate Development. Changes to service line information should be coordinated along with annual consumption changes to the model. The year-end information to conduct the annual service line analysis is not available to Revenue Requirements until mid-January.

E-1. Corporate Development

a. Each December, confirm that Revenue Requirements has initiated analysis of service line average length and cost and is maintaining related information and records in accordance with department practices. Confirm February, or earlier due date.

E-2. Revenue Requirements

a. Conduct analysis of service line average length and cost and document and maintain results in accordance with department practices.

b. Work with Division Service Planning Management to review the annual service line information.

c. Provide proposed service line average length and cost to Corporate Development each February for review and approval.

E-3. Service Planning Management (Arizona Divisions)

a. Work with Revenue Requirements to review the annual service line information.

E-4. Corporate Development

a. Review justification with Revenue Requirements.

b. **If no change to the model is required**, provide notification to Billing Control.

NOTE: This completes the annual service line average length and cost change process.

c. **If a change to the model is required**, route the approved service line average length and cost inputs to Billing Control.

E-5. Billing Control

a. Access the current model on the InfoNet, and create a test version using appropriate naming convention.

b. Input applicable data into the Standard Amounts worksheet, verify the accuracy, update documentation comments, and protect the worksheet.

c. Forward the updated, protected model test version to Revenue Requirements for verification.

E-6. Revenue Requirements

a. Verify and test Billing Control inputs for service line average length and cost changes.

b. Unprotect the current Release Notes worksheet.

c. Enter current version comments into the Release Notes worksheet and protect worksheet.

d. Route to Corporate Development for final approval.

E-7. Corporate Development

a. Review and approve the updated, protected model test version and notify Revenue Requirements of approval.

b. Ensure that all worksheets in the model are adequately protected.

c. Rename tested and verified version of model to production version using appropriate naming convention.

d. Forward approved production version of model to Billing Control for placement into production environments.

E-8. Billing Control

a. Call the Help Desk to open a change request to move the model into production.

NOTE 1: The parent change request will consist of two activities – one to attach the new version to WMS (for Operations Systems Support) and one to place the new version on the InfoNet (for Customer Assistance Support and Training).

NOTE 2: The new version will be the current model, and the replaced version will be added to the historical versions for control purposes.

E-9. Operations Systems Support (OSS)

a. Receive ARS activity ticket to place new version of model in WMS attachments area.

b. Schedule new version to be attached to WMS.

NOTE: Change should be coordinated with InfoNet change for same production release date.

c. Close activity in ARS and notify Billing Control.

d. Add new version to notification e-mail.

E-10. Customer Assistance Support and Training (CAST)

a. Receive ARS activity ticket to place new version of model on InfoNet (Online Manuals).

b. Schedule new version to be placed on InfoNet.

c. Add new version to page and move old version into previous version section.

NOTE: Change should be coordinated with WMS change for same production release date.

d. Close activity in ARS and notify Billing Control.

E-11. Billing Control

a. Maintain an accurate notification list.

b. Notify departments (key management and user departments and Corporate stakeholders) of production version model release.

c. Close the parent change request.

E-12. Service Planning Management (Arizona Divisions) and Key Account Management (KAM)

a. Notify department employees each time the model is updated.

PROCEDURE F--Model Modifications

NOTE: Modifications to the model that result in changes, additions, and/or deletions to the Standard Amounts worksheet or the ACC Authorized Rates worksheet and data therein will be subject to the appropriate processes set forth in Procedures C, D, and E.

F-1. Key Account Management (KAM), Revenue Requirements, Service Planning Management, Corporate Tax, or Treasury Services

a. Determine that a modification is necessary.

b. Provide data and information regarding modification request to Revenue Requirements.

F-2. Revenue Requirements

a. Consult with Treasury Services to review and conduct analysis of modification, determine impact to the model, and determine if a change to the model is required.

b. Route proposed model changes, including justification, to Corporate Development for review and final approval.

F-3. Corporate Development

a. Review the proposed model changes and notify Revenue Requirements of decision.

b. Determine the timing of the proposed modifications.

F-4. Revenue Requirements

a. If changes are required for the Standard Amounts worksheet or the ACC Authorized Rates worksheet within the model, request unprotected version from Billing Control.

b. If no changes are required for the Standard Amounts worksheet or the ACC Authorized Rates worksheet, access the current model on the InfoNet, create a test version using appropriate naming convention, and proceed to Procedure F-6.

F-5. Billing Control

a. If contacted by Revenue Requirements for an unprotected version of the Standard Amounts worksheet or the ACC Authorized Rates worksheet, access the current model on the InfoNet, and create a test version (unprotected) using appropriate naming convention.

b. Forward the unprotected version to Revenue Requirements.

F-6. Revenue Requirements

a. Modify the test version model.

b. Verify and test the updated model. Document and maintain results in accordance with department practices.

c. Enter current version release notes in the Release Notes worksheet and protect worksheet.

d. Route the model test version to Billing Control if changes were made to the Standard Amounts worksheet or the ACC Authorized Rates worksheet.

e. If changes were not made to the Standard Amounts worksheet or the ACC Authorized Rates worksheet, protect the model and route to Corporate Development for final approval.

F-7. Billing Control

a. If changes were made to Standard Amounts worksheet or the ACC Authorized Rates worksheet, verify changes, update documentation comments, and re-protect the worksheets. Rename the model using appropriate naming convention.

b. Route protected model to Corporate Development for final approval.

F-8. Corporate Development

a. Review the updated, protected model test version and notify Revenue Requirements and Treasury Services of approval.

b. Ensure that all worksheets in the model are adequately protected.

c. Rename tested and verified version of model to production version using appropriate naming convention.

d. Forward approved production version of model to Billing Control for placement into production environments.

F-9. Billing Control

a. Call the Help Desk to open a change request to move the model into production.

NOTE 1: The parent change request will consist of two activities – one to attach the new version to WMS (for Operations Systems Support) and one to place the new version on the InfoNet (for Customer Assistance Support and Training).

NOTE 2: The new version will be the current model, and the replaced version will be added to the historical versions for control purposes.

F-10. Operations Systems Support (OSS)

a. Receive ARS activity ticket to place new version of model in WMS attachments area.

b. Schedule new version to be attached in WMS.

NOTE: Change should be coordinated with InfoNet change for same production release date.

c. Close activity in ARS and notify Billing Control.

d. Add new version to notification e-mail.

F-11. Customer Assistance Support and Training (CAST)

a. Receive ARS activity ticket to place new version of model on InfoNet (Online Manuals).

b. Schedule new version to be placed on InfoNet.

c. Add new version to page and move old version into previous version section.

NOTE: Change should be coordinated with WMS change for same production release date.

d. Close activity in ARS and notify Billing Control.

F-12. Billing Control

a. Maintain an accurate notification list.

b. Notify departments (key management and user departments and Corporate stakeholders) of production version model release.

c. Close the parent change request.

F-13. Service Planning Management (Arizona Divisions) and Key Account Management (KAM)

a. Notify department employees each time the model is updated.

F-14. Key Account Management (KAM), Revenue Requirements, Service Planning Management, Corporate Tax, or Treasury Services

a. If a problem or issue is identified with the new version, notify Revenue Requirements directly. (Changes will be made as required, repeating the above change process.)

Reference

Other

Action Request System (ARS)

Arizona Gas Tariff

Incremental Contribution Method (ICM) Model

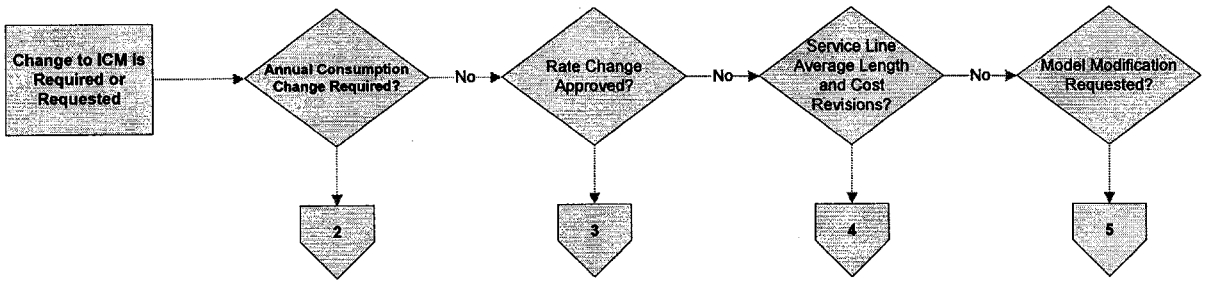
Online Manuals

Work Management System (WMS)

* * *

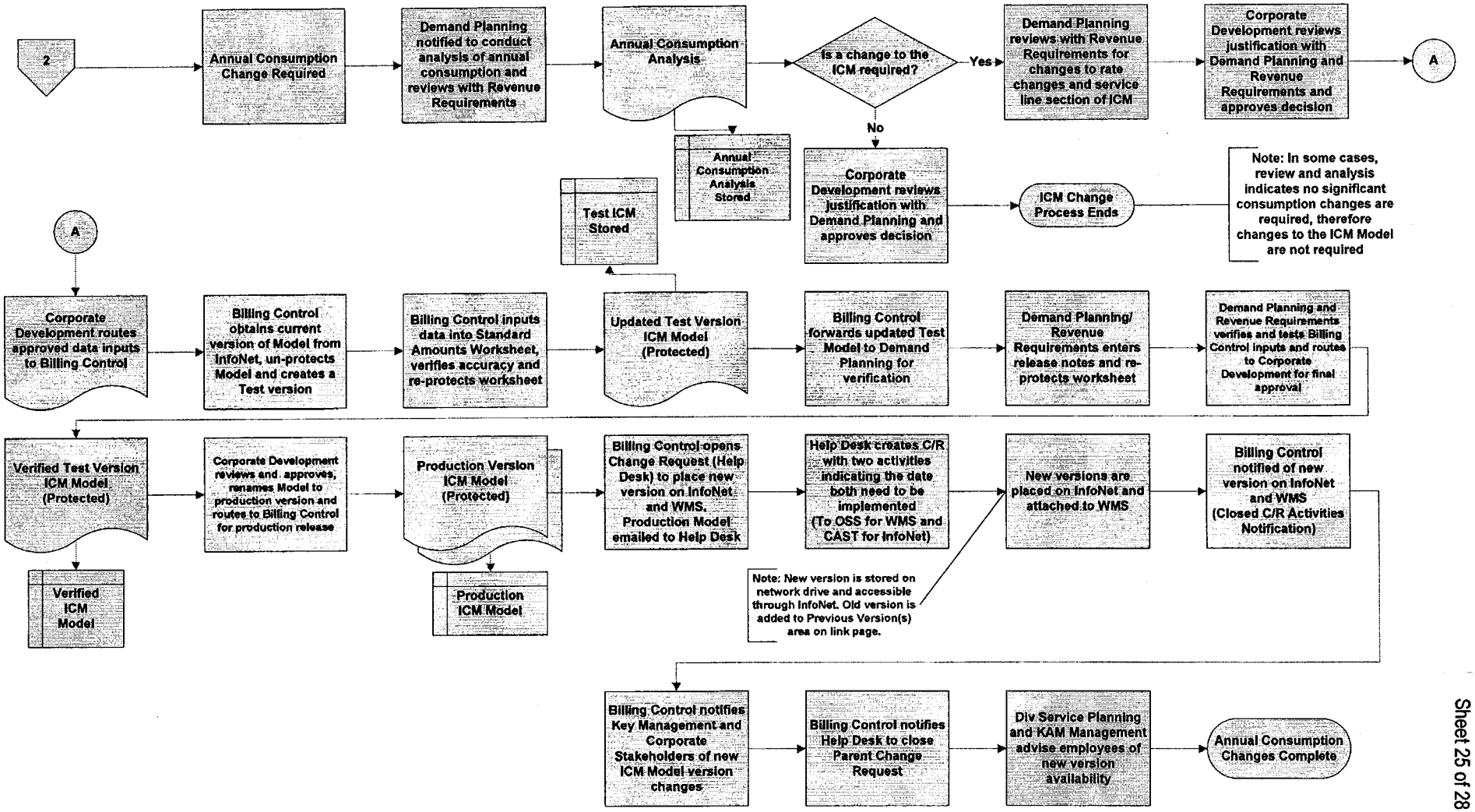
Rev: 1/16/2008

High Level ICM Change Process



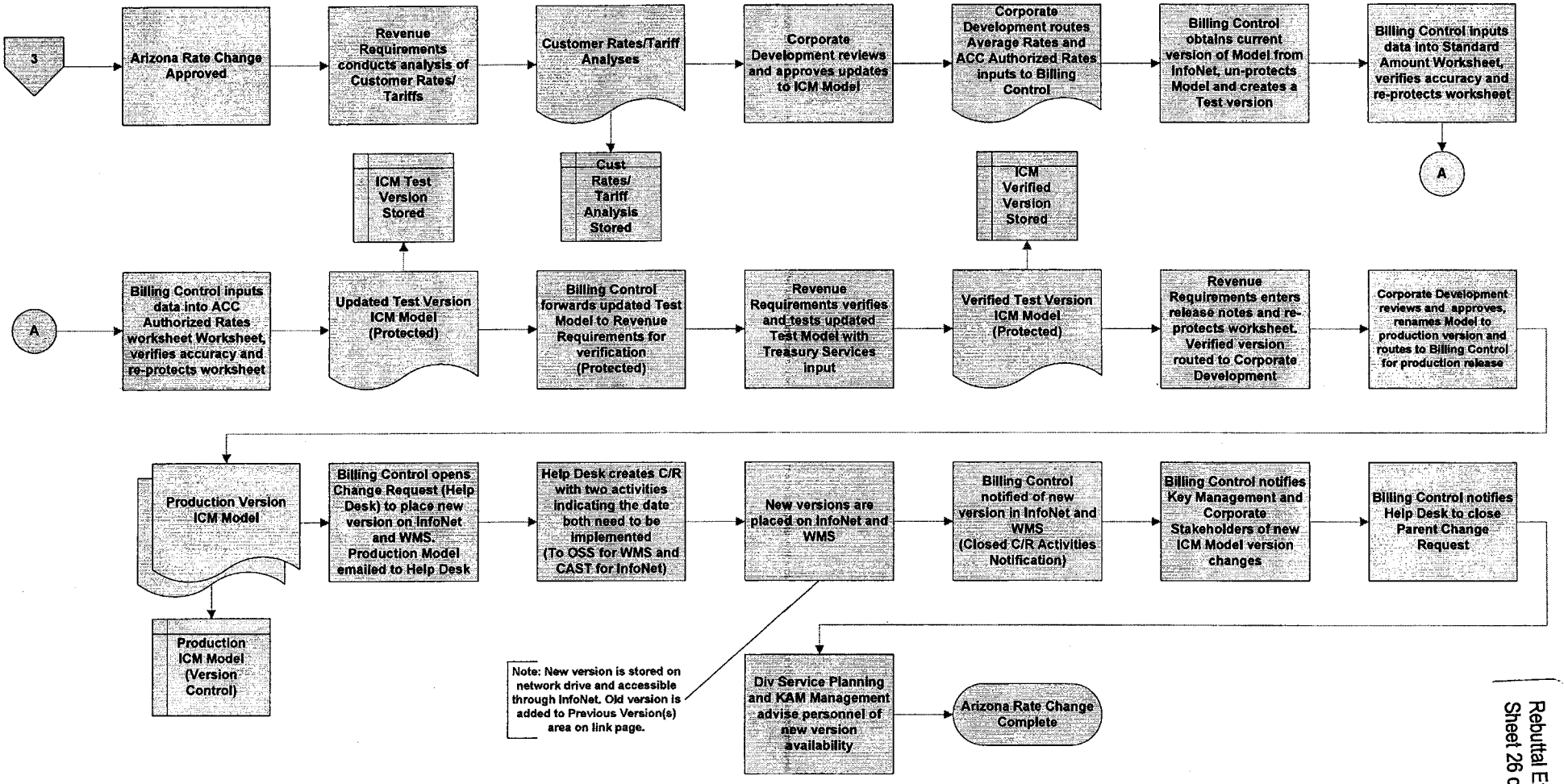
Rev: 1/16/2008

ICM Model – Annual Residential Consumption Updates



Rev: 1/16/2008

ICM Model – Rate Change Updates
ACC Authorized Rates and Standard Amounts Tabs



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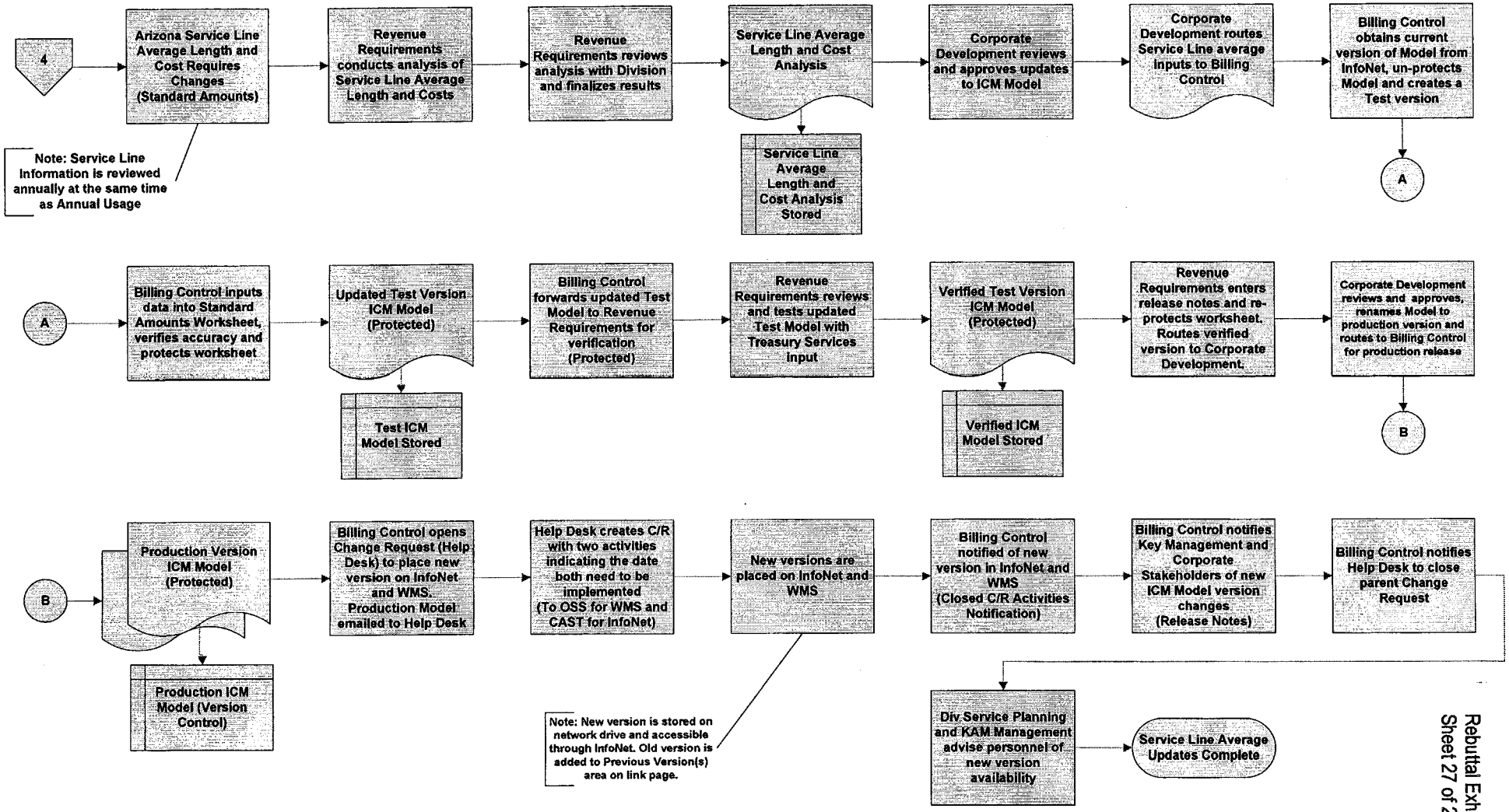
Rev: 1/16/2008

ICM Model – Annual Service Line Average Length and Cost Updates



Rebuttal Exhibit No.___(RAM-5)
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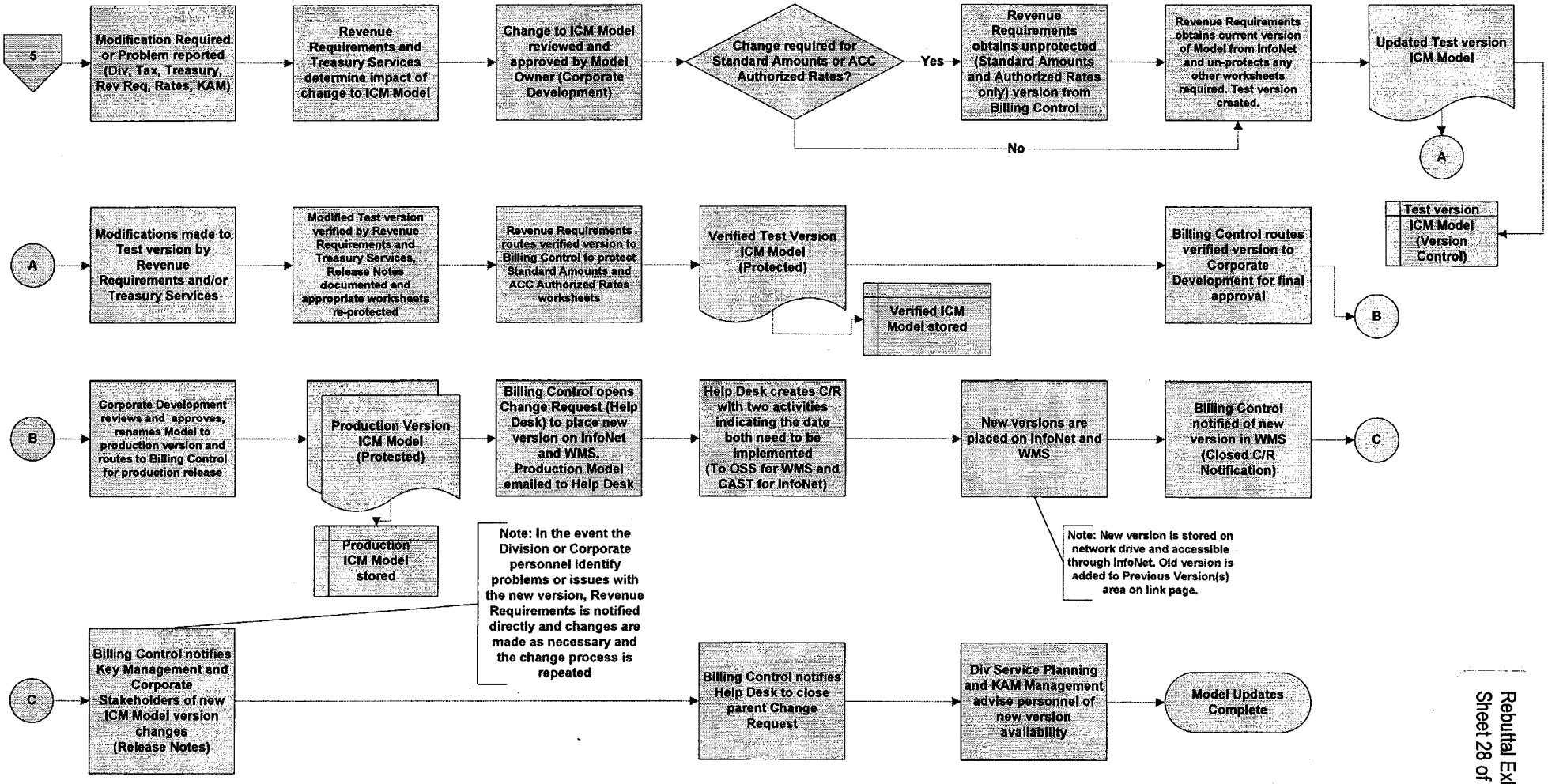
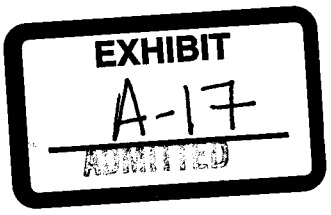
Rev: 1/16/2008

ICM Model Modifications Change Process



Rebuttal Exhibit No.__(RAM-5)
Sheet 28 of 28



IN THE MATTER OF

SOUTHWEST GAS CORPORATION

Docket No. G-01551A-07-0504

PREPARED REJOINDER TESTIMONY

OF

ROBERT A. MASHAS

ON BEHALF OF

SOUTHWEST GAS CORPORATION

June 9, 2008

Southwest Gas Corporation
Docket No. G-01551A-07-0504

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Prepared Rejoinder Testimony
Of
ROBERT A. MASHAS

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Rejoinder Exhibit No.__(RAM-1)

Southwest Gas Corporation
Docket No. G-01551A-07-0504

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rejoinder Testimony
of
ROBERT A. MASHAS

INTRODUCTION

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.

Q. 2 Are you the same Robert A. Mashas who previously sponsored direct and rebuttal testimony on behalf of Southwest Gas Corporation (Southwest or the Company) in this proceeding?

A. 2 Yes, I am.

Q. 3 What is the purpose of your prepared rejoinder testimony?

A. 3 The purpose of my rejoinder testimony is to respond to specific aspects of the surrebuttal testimony presented by Arizona Corporation Commission Utilities Division Staff (Staff) witnesses Messrs. Ralph C. Smith, Corky Hanson, Phillip S. Teumim, and Residential Utility Consumer Office (RUCO) witness Mr. Rodney L. Moore, regarding their recommendations for ratemaking treatment of rate base, certain operating expense items, and the Company's line extension procedures and policies.

Q. 4 Did you prepare exhibits to support your rejoinder testimony?

A. 4 Yes. I prepared the exhibit identified as Rejoinder Exhibit No.__(RAM-1).

Q. 5 Please summarize your rejoinder testimony?

A. 5 My rejoinder testimony will address the following issues:

- Injuries and Damages: Staff's calculation of the 10-year average of self-insured retentions.
- Yuma Manors: Staff's proposal to disallow all gas plant required to replace 50-year old pipe.
- Gain on sale of Sundt Plant: Staff's calculation of the gain.
- Lead-Lag Study: Staff's calculation of preferred equity expense lag.
- Line Extension Policy: Staff's recommendation related to the Company's line extension policy.

INJURIES AND DAMAGES

Q. 6 Does Staff witness Mr. Smith concede that in the last rate case Staff, RUCO and Southwest agreed upon a methodology to derive the self-insured portion of injuries and damages?

A. 6 Yes.

Q. 7 Did Southwest use the same methodology to determine the appropriate level of self-insured expense in this rate case?

A. 7 Yes. Consistent with the methodology established in the Company's last general rate case, for ratemaking

purposes, Southwest treats all self-insured costs as "system allocable" rather than direct jurisdictional expenses. The Company has two categories of self-insured expense. The first category is the self-insured retention for up to the first $1 million of claim expense for each incident, regardless of the number of incidents that may occur in a claim year (August 1 through July 31 of the following year). The second category is the self-insured aggregate amount per claim year, which covers claim expense above the first $1 million self-insured retention up to an aggregate not to exceed $5 million. The $5 million can come from more than one incident and is not jurisdictional-specific. Consistent with the agreed-to methodology in the last rate case, the Company used a 10-year average of both categories of self-insured expense. Finally, in order to determine an appropriate level of the $5 million aggregate expense, the Company needed to use the ten-year history of actual claims expense paid and not the amounts recorded on the Company's books during this period.

Q. 8 Did RUCO propose a methodology different from the one it agreed to in the Company's last general rate case?

A. 8 No. RUCO did not recommend a change in methodology from the one agreed to in the Company's last general rate case. However, in its direct case, RUCO is recommending that the Company's proposed self-inured expense level be increased by $283,664 to reflect the impact of an

accounting error that occurred in June 2006.

Q. 9 Did the Company provide Staff with a comparison of the Company's current calculation to that agreed upon in the last rate case?

A. 9 Yes. The Company's response to Staff Data Request No. 13-14 provides a side-by-side comparison. A copy of Staff Data Request No. 13-14 is included in Staff's surrebuttal testimony as Attachment RCS 8, pages 25 through 32. The comparison is shown on page 30 of the Attachment.

Q. 10 Please discuss the three levels of claims expense detailed on Staff surrebuttal Attachment RCS 8, page 30.

A. 10 The first level of claims expense shown on line 1 is the ten-year total of claims resulting in amounts less than $1 million. Line two is the ten-year total of $1 million self-insured retentions. Both of these amounts were recorded on the Company's books. Line three is the ten-year total of claims expense that exceeded $1 million, but did not exceed $10 million in the last rate case, and was less than $5 million in the current rate case. Except for the May 2005 incident, none of these amounts were recorded on the Company's books since, prior to August 1, 2004, the Company had insurance coverage that indemnified it for these costs. However, on a going-forward basis, the Company is self-insured for the up to $5 million aggregate level of claims expense. Effective with the August 2004 plan year, to the extent claims

expense exceeds $1 million, and up to the $5 million aggregate, these amounts are recorded on the Company's books.

Q. 11 Please compare the "Arizona allocated" derived in this rate case to that agreed to in the Company's last rate case.

A. 11 Staff Attachment RCS 8, page 30, line 8 shows the Arizona allocation in this rate case is $1,762,263 compared to the last rate case amount of $1,731,312. The allocation in this rate case is only $30,951 higher, or 1.8 percent.

Q. 12 Please compare the ratemaking adjustment required in this rate case to that required in the last rate case.

A. 12 Staff surrebuttal Attachment RCS 8, page 30, line 15, shows that in the last rate case, an adjustment of $1,168,760 was necessary to increase the recorded "positive" $562,552 to the $1,731,312 level of self-insured expense. In this rate case, an adjustment of $2,512,119 is necessary to increase the recorded "negative" $749,856 to the $1,762,263 level of self-insured expense.

Q. 13 Please explain why the adjustment in this proceeding is more than double the adjustment in the last rate case when the end result is only $30,951 higher.

A. 13 The current adjustment is $1,343,359 higher than the adjustment required in the last rate case proceeding primarily because of the difference in the two recorded test year amounts. The difference between the recorded

test year amount of a positive $562,552 (2004 test year) and a negative $749,856 (2007 test year) equals $1,312,408. The remaining $30,951 is the increase in the level of self-insured expense.

Q. 14 Is it possible to have a "negative" claims expense on a going-forward basis?

A. 14 No. Actual claims expense will always be positive. However, liability claims can take years to process and during that time, an accrual for a "positive" accrual estimate recorded in one accounting period can result in a "negative" adjustment to a previous accounting period's accrual. Any negative adjustment will only be to a previous positive accrual. The negative adjustment will never exceed the positive accrual.

Q. 15 Is the dollar magnitude of the adjustment to recorded amounts indicative of the reasonableness of the end result?

A. 15 No. The end result determines the reasonableness. For instance, if the recorded expense happened to be $1,762,263 and no adjustment was required, it does not make the $1,762,263 any more reasonable, it just makes it less controversial.

Q. 16 Is Staff's proposed level of self-insured expense reasonable?

A. 16 No. Staff relies on recorded Arizona direct amounts and removes the only incident recorded on the Company's books related to the self-insured aggregate established in

August 1, 2004. Staff's calculation provides for "zero dollars" for this level of expense.

Q. 17 Staff removed the recorded $10 million amount related to the May 2005 Tucson, Arizona incident that was recorded as a System Allocable expense in December 2005. Staff describes this incident as extreme, unprecedented, extraordinary, and not expected to recur. Is this a fair characterization of this incident?

A. 17 No, not when the incident is put into the proper context. The May 2005 incident resulted from a leaking pipe in Tucson, Arizona. The self-insured aggregate level in place at that time was $10 million, which was recorded as a System Allocable common expense consistent with the ratemaking methodology agreed to by Staff, RUCO, and the Company in the previous rate case. The $10 million could have been recorded as a direct Arizona expense and it would have been, but the Company recorded it as system allocable to be consistent with the methodology agreed to by all the parties in the last Arizona general rate case. The Company acknowledges that the claims expense related to the May 2005 incident was the first time that the dollar impact of a jurisdictional-specific incident was recorded as a System Allocable expense. However, comparing that expense to the previously recorded System Allocable amounts is an "apples to oranges" comparison because prior to the last Arizona general rate case, System Allocable recorded amounts were limited to

automobile or personal injury incidents involving corporate employees or facilities located at the corporate headquarters in Las Vegas, Nevada; not state specific incidents involving gas leaks. The potential dollar impact of an explosion caused by a gas leak is not comparable to an automobile or personal injury incident. Mr. Smith's proposal to exclude the impact of the Tucson incident because it is large, and when taken out of context, may appear extreme, unprecedented, extraordinary, and not expected to recur when compared to automobile accidents or personal injury claims, is improper.

Q. 18 During the ten-years ending April 2007, was the May 2005 incident the only time where claims paid reached the $5 million aggregate threshold?

A. 18 No. The $5 million threshold was met as a result of a January 2003 Arizona incident. In 1993, the Company had two incidents where the $5 million threshold was met. Furthermore, in 1997 and 1998, there were three incidents where the claims paid exceeded the $1 million self-insured retention, but did not exceed the $5 million threshold. Except for the May 2005 incident, all of the other incidents were not recorded on Southwest's books because the Company had insurance for claims expense above $1 million. Since August 1, 2004, the Company has been and continues to be self-insured for these amounts. Therefore, it is appropriate and necessary to provide for

this level of self-insured expense. The methodology agreed to by Staff, RUCO, and the Company in the Company's last general rate case is as reasonable now as was then. Staff's proposed "zero dollar" level is not.

Q. 19 What adjustment to Staff's proposed cost of service is necessary in order to provide a reasonable level of both the up to $1 million self-insured retention and the not to exceed $5 million aggregate self-insurance?

A. 19 The $1,135,381 increase to pre-tax operating expense shown at the top of page 40 of Mr. Smith's Surrebuttal testimony is the adjustment necessary to provide a reasonable level of self-insured expense on a going-forward basis. The adjustment consists of two parts. The first part is an increase of $283,664 to reflect the impact of the accounting error referred to in RUCO's operating expense Adjustment No. 2. Both RUCO witness Rodney Moore and Company witness Randi Aldridge address this adjustment in their respective testimonies. The second part of the adjustment is the $851,717 reversal of Staff's proposed Adjustment No. C-12 Revised.

YUMA MANORS

Q. 20 Does Staff continue to propose that Southwest write-off 100 percent of the cost of replacing the 50-year old Yuma Manors steel pipe system?

A. 20 Yes. Staff witnesses Smith and Hanson continue to propose that 100 percent of the replacement cost of the 50-year old steel pipe system be excluded from rate base.

This exclusion will require the Company to permanently write-off the $1,231,762 spent to replace the 50-year old system.

Q. 21 Why does Staff believe that a ratemaking treatment considerably harsher than that approved by the Commission in similar cases where the premature replacement of pipe was addressed is appropriate in this case?

A. 21 Staff believes that the circumstances in the Yuma Manors are different than those of the four pipe replacement programs that I discussed in my Rebuttal testimony. Therefore, harsher punishment of Southwest is somehow warranted.

Q. 22 What are the differences noted by Staff witness Smith?

A. 22 Mr. Smith, on page three, line 17 of his surrebuttal testimony, states "… in the current rate case as a cost that has arisen as the direct result of incorrect actions taken by SWG personnel resulting in the failure of that system." On page 5, line 12 of his surrebuttal testimony, Mr. Smith further states, "With respect to Yuma Manors, as explained by Staff witness Hanson, the premature replacement was not attributed to defective material and/or installation, but rather to the actions of SWG employees." Staff places significant importance on the notion that a mistake by Southwest "employees" warrants a more extreme ratemaking treatment than replacement resulting from defective material and/or improper installation.

Q. 23 How many Southwest employees were involved?

A. 23 Only one Southwest employee was involved. Once all the facts were known, Southwest applied corrective and remedial actions. The employee also faced disciplinary action.

Q. 24 Were improper actions taken by Tucson Gas and Electric (TGE) personnel that resulted in the premature replacement of Aldyl A pipe?

A. 24 Yes. TGE used Aldyl A pipe as its primary gas distribution pipe material during the years 1967 through 1978. Southwest acquired the gas distribution system from TGE in 1979. In 1981-82, Southwest noted a significant number of pipe failures due to rock impingement. By 1983, Southwest determined that the large number of leaks was caused by TGE's use of: 1) improper backfill material; 2) improper pipe squeeze; 3) improper heat-fusion; and 4) problems with amp fittings and service tee caps. As a result of improper actions by TGE personnel during the ten years that Aldyl A pipe was installed by TGE personnel, Southwest began replacing Aldyl A pipe in the 1980s after only a ten-year average useful life. Approximately 50 percent of the nearly 1,300 miles of Aldyl A pipe, at a cost of approximately $40 million in 1980 dollars, was replaced.

Q. 25 Despite the improper actions of TGE personnel, did the Commission disallow 100 percent of the replacement cost?

A. 25 No. The Commission allowed the life extending benefit of

the new pipe when compared to pipe that was ten to twenty years old. In the Company's last rate case, the Commission adopted a 40-year rule where, regardless of the reason - even improper installation, 100 percent of the cost resulting from the replacement of pipe that has served ratepayers at least 40 years will be included in rate base.

Q. 26 Are the circumstances similar with regard to the Aldyl HD replacement pipe?

A. 26 Yes. As part of the TGE acquisition, Southwest acquired TGE personnel who continued the same installation practices used to install Aldyl HD pipe from 1979 through 1981. In 1993, a gas leak resulted in an explosion causing bodily injuries and property damage. As a result of the ACC Pipeline Safety review of the incident, the Company undertook a significant pipe replacement program. The replacement program was completed in 1998.

Q. 27 Did the Commission disallow 100 percent of the cost to replace Aldyl HD pipe?

A. 27 No. Even though the replacement was undertaken for the improper installation practices of former TGE personnel acquired by Southwest, the Commission did not disallow 100 percent of the replacement cost. To the extent that the replacement pipe extended the life of the system, the betterment portion was included in rate base.

Q. 28 Was the mistake of one Southwest employee of significantly greater magnitude than the examples

previously cited and relied on by the Commission so as to justify penalizing Southwest as recommended by Staff?

A. 28 No. One individual made a mistake and personally suffered the consequences of his actions. Southwest witness Jerome T. Schmitz, in both his rebuttal and rejoinder testimony, discusses in detail the events that led up to the replacement of the 50-year old steel pipe and the actions taken by Southwest.

Q. 29 Does the error made by this one individual warrant the extreme punishment of requiring a 100 percent write-off of the replacement of the 50-year old steel system?

A. 29 No. As detailed above, the Commission has dealt with considerably larger replacement programs that resulted from human error with more restrained and reasonable judgment than what the Staff is recommending in this proceeding.

Q. 30 Is the $320,779 adjustment to the cost of the replacement pipe that the Company is proposing appropriate?

A. 30 Yes. This represents nearly 25 percent of the replacement cost of the Yuma Manors system. The betterment is 100 percent when the 40-year rule is applied. No additional adjustment is warranted.

GAIN ON SALE OF SUNDT PLANT

Q. 31 Does the Company agree with Staff's proposed adjustment to share the gain on the sale of natural gas facilities to TEP?

A. 31 Yes. However, the Company notes that there is an error

in Staff's calculation. Staff's Schedule C-16, Page 1, line 1, column (B) is $(67,937) and should be $(37,942). This will change the gain shown on line 3, column (E), from Staff's $609,825 to $579,623. The 50 percent three-year shared gain is $96,504 and not the $101,600 shown on Staff surrebuttal Schedule C-16.

Q. 32 Please explain Rejoinder Exhibit No.__(RAM-1).

A. 32 Rejoinder Exhibit No.__(RAM-1) is the Company's response to Staff Data Request No. STF-14-3, which illustrates the proper final calculation of the gain on the sale of the natural gas facilities to TEP.

LEAD-LAG STUDY: STAFF'S CALCULATION OF PREFERRED EQUITY LAG

Q. 33 Does the Company agree with Staff's calculation of preferred equity lag?

A. 33 Conceptually yes, but Staff's application is flawed. Staff Schedule B-3 Revised is its cash working capital calculation. Line 6 is described as Staff's interest calculation when in reality the $48,083,335 is the weighted cost of debt and preferred equity ($1,065,457,617 rate base x 4.512%(4.145% debt + 0.367% preferred equity). The 84.65 lag days shown on Staff Schedule B-3 Revised line 6, column (d) is the interest lag days. The weighted interest and preferred lag days is 79.50 as shown in my Rebuttal Exhibit No.__(RAM-3), Sheet 1 of 2. The 79.50 weighted interest and preferred equity lag should be applied to the weighted cost of interest and preferred equity shown on Staff Schedule B-3

Revised line 6, column (c).

Q. 34 Is the preferred equities calculation shown on Staff Schedule B-3 Revised line 7 appropriate?

A. 34 No. Based on the above, the calculation on line 7 is not appropriate. The lag on preferred equity is considered when the 79.5 lag days is substituted on line 6, column (d). Furthermore, the $7,772,141 is the total Company preferred equity cost and not the Arizona allocated portion. It is inappropriate to include the total Company expense in column (c) when all other amounts in column (c) are Arizona direct.

Q. 35 Did RUCO calculate the preferred equity lag correctly?

A. 35 Yes. RUCO used the 79.5 average interest and preferred equity lag days.

LINE EXTENSION POLICY

Q. 36 In his surrebuttal testimony, Staff witness Phillip S. Teumim continues to recommend that Southwest provide additional information on Southwest's line extension policy. Please comment.

A. 36 Southwest has presented extensive testimony and supporting documentation in this proceeding on its line extension policy. In response to a Commission directive in the Company's 2000 general rate case proceeding, Southwest provided testimony and documentation to support its line extension policy in its 2004 general rate case. No party in that proceeding expressed concerns with the Company's line extension policy. To the extent

applicable, any changes in the Company's line extension policy that result from the ongoing hook-up fee investigation will be incorporated into the Company's line extension policy. In addition, Southwest is willing to meet with Staff to explain the Company's line extension policy on an informal basis at any time Staff requests.

Q. 37 Does this conclude your rejoinder testimony?

A. 37 Yes, it does.

321-003

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
***
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-14
(ACC-STF-14-1 THROUGH ACC-STF-14-3)

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MAY 21, 2008

Request No. ACC-STF-14-3:

Gain on sale of metering facility and piping to TEP related to Sundt bypass. Refer to the May 14, 2008 supplemental response to RUCO 7-2. Please confirm that SWG anticipates the sales prices and net gains upon sale of these assets, as of March 31, 2008, the expected sales date:

Net Book Value At Sales Date	Tentative Sales Prices	Net Gain
$ 114,156	$ 398,381	$ 284,225
$ 24,400	$ 350,000	$ 325,600
$ 138,556	$ 748,381	$ 609,825

If any of the above amounts, which were provided in, or derived from, the Company's 5/14.08 supplemental response to RUCO 7-2 are inaccurate, or have subsequently been revised or changed, please provide the most current information available and indicate whether it corresponds with the finalized transaction.

Respondent: Revenue Requirements

Response:

Attached is a worksheet that provides the final calculation of the sale of facilities to TEP. The final net book value at the time of sale for the metering facility is $144,150 and not the $144,156 reported in the supplement to RUCO 7-2 and the $114,156 shown on Staff Surrebuttal Schedule C-16, Page 1 of 1. The final net book value at the time of sale of the piping is $24,439 and not the $24,440 reported in the supplement to RUCO 7-2 and the $24,400 shown on Staff Schedule C-16 Page 1 of 1. The final total net book value is $168,589 and not the $168,596 sum of the two amounts in the Supplement to RUCO 7-2 and the $138,556 shown in Staff Schedule C-16, Page 1 of 1. The final sale proceeds are $748,212 and that is consistent with the Supplement to RUCO 7-2 and Staff Schedule C-16. The final net gain is, therefore, $579,623 and not the $609,825 shown on Staff Schedule C-16. The three-year normalization period to provide 50 percent of the gain to customers is $96,604 and not the $101,606 shown on Staff Schedule C-16.

SOUTHWEST GAS CORPORATION
ARIZONA
GAIN ON SALE OF CERTAIN FACILITIES TO TUSCON ELECTRIC COMPANY
AS OF MARCH 31, 2008
Docket No. G-01551A-07-0504
STF 14.3

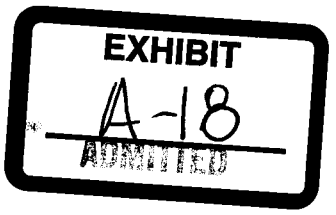
Line No.	Description	Original Cost	Accumulated Depreciation	Net Book Value	Sales Price	Net Gain	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Gain on Sale of Utility Property						
1	High Pressure Steel Main	$ 28,526	$ 4,087	$ 24,439	$ 398,212	$ 373,773	1
2	Meter Set Assembly	182,093	37,943	144,150	350,000	205,850	2
3	Total	$ 210,619	$ 42,030	$ 168,589	$ 748,212	$ 579,623	3
	Sharing of Gain with Ratepayers						
4	Ratepayer sharing percent					50.00%	4
5	Ratepayer sharing amount of gain					$ 289,812	5
6	Normalization period, in years					3	6
7	Adjustment to pre-tax NOI for gain sharing					$ 96,604	7

SOUTHWEST GAS CORPORATION
ARIZONA
CALCULATION OF ACCUMULATED DEPRECIATION ON ORIGINAL INVESTMENT
AS OF MARCH 31, 2008
Docket No. G-01551A-07-0504
STF 14.3

Line No.	Description	Original Cost	Month Placed In-Service	Depreciation Rate	Months	Accumulated Depreciation
	(a)	(b)	(c)	(d)	(e)	(f)
	Gain on Sale of Utility Property					
1	High Pressure Steel Main	$ 28,526	Jun-04	3.82%	45	4,087
2	Meter Set Assembly	182,093	May-03	4.31%	58	37,943
3	Total	210,619				42,030

SOUTHWEST GAS CORPORATION
ARIZONA
DEPRECIATION FOR PLANT SOLD TO TUSCON ELECTRIC COMPANY
AS OF MARCH 31, 2008
Docket No. G-01551A-07-0504
STF 14.3

Line No.	Description	Gross Plant	Depreciation Rate	Depreciation Expense	Line No.
	(a)	(b)	(c)	(d)	
	Gain on Sale of Utility Property				
1	High Pressure Steel Main	$ (28,526)	3.82%	$ (1,090)	1
2	Meter Set Assembly	(182,093)	4.31%	(7,850)	2
3	Total	$ (210,619)		$ (8,940)	3



IN THE MATTER OF
SOUTHWEST GAS CORPORATION
Docket No. G-01551A-07-___

PREPARED DIRECT TESTIMONY
OF
FRANK J. MAGLIETTI, JR.

ON BEHALF OF
SOUTHWEST GAS CORPORATION

August 31, 2007

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Prepared Direct Testimony
Of
FRANK J. MAGLIETTI, JR.

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Southwest Gas Corporation
Docket No. G-01551A-07-___

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
Of
FRANK J. MAGLIETTI, JR.

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Frank J. Maglietti, Jr. 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) as Senior Specialist in the Pricing and Tariffs Department.

Q. 3 Please state your education background and business experience.

A. 3 My background and experience are reflected in Appendix A.

Q. 4 What is the purpose of your direct testimony?

A. 4 I sponsor Southwest's customer class cost of service study (CCOSS), an amendment to Southwest's Purchased Gas Cost Adjustment, and a ministerial tariff change to remove the references to Title Assignment Service in the Interstate Pipeline Capacity Services Provision of the tariff. I also sponsor several summary schedules identified in the Table of Contents for Volume II of the application.

II. CLASS COST OF SERVICE STUDY

Q. 5 What is the purpose of preparing a Class Cost of Service

Study (CCOSS)?

A. 5 The purpose of a CCOSS is to determine the cost of providing service to each customer class. The CCOSS provides the parties a tool to evaluate return on investment, or economics, of the service provided to each customer class.

Q. 6 Please explain the CCOSS methodology.

A. 6 The CCOSS apportions or "allocates" Southwest's rate base, operating costs and taxes to each of Southwest's customer classes based on various cost causation determinations. Subtracting operating costs from revenue for each class yields the net income by class of service. Net income divided by rate base produces the rate of return (ROR) for each rate class. The Company can then gauge the economics of providing service to various customer classes by determining whether customer class' revenues are sufficient to recover all expenses (O&M, A&G, depreciation and taxes) while still providing investors a sufficient enough return to continue attracting capital.

Q. 7 Please describe the costs factored into the CCOSS methodology?

A. 7 The following are apportioned or allocated via the CCOSS to each of Southwest's customer classes based on various cost causation determinations:

- Capital investment in facilities. These costs include the cost of meters, pipes, regulators, and

other equipment necessary to deliver natural gas to customers. Investment in these facilities comprises the majority of what is called "rate base" in the CCOSS;

- Operating and Maintenance (O&M) expenses. These costs are directly attributable to providing service in Arizona, such as the cost of materials and labor to maintain Southwest's mains, services, meters, the cost to read meters and to provide customer information and customer assistance;
- Administrative and General (A&G) expenses. These costs are not directly attributable to Southwest's Arizona operations, but nonetheless support those operations at a corporate level. These cost include the billing and accounting systems;
- Annual depreciation expenses. This includes the depreciation costs associated with Southwest's investment in facilities to serve customers; and
- State and federal income taxes.

Q. 8 How is the CCOSS used?

A. 8 The CCOSS is used as a tool to develop the proposed rate design, which is discussed more fully by Southwest witness Mr. Brooks Congdon.

Q. 9 Has Southwest changed the CCOSS methodology utilized in recent Arizona rate cases?

A. 9 No, the overall embedded CCOSS methodology and model are the same ones used by Southwest and supported by

Commission Staff in Southwest's last general rate case. However, in this case, Southwest changed how certain accounts (or costs) are allocated to each customer class to more correctly match how they are incurred on Southwest's system.

Q. 10 Please describe Southwest's proposed allocation changes and explain how they more appropriately allocate the costs.

A. 10 Southwest proposes the following modifications:

- Changing Southwest's calculation of the coincident peak demand (CP) allocation factor by basing the CP allocation factor on peak month throughput rather than a combination of three-day sustained peak data and peak month throughput used in the previous case. This change establishes consistency in the data used to develop the CP allocation factor;
- Changing the allocation for measuring and regulating station plant and expenses (accounts 378, 875 and 889) by apportioning these costs using distribution mains (allocation factor 2.2 in the CCOSS) instead of using throughput. Allocating these accounts using distribution mains more accurately reflects the actual use of these facilities;
- Finally, various components of "Other Revenues" are allocated separately based on the characteristics of each component, rather than as a single item, which more accurately reflects the cost.

III. PURCHASED GAS COST ADJUSTMENT (PGA)

Q. 11 Please briefly summarize Southwest's Monthly PGA process.

A. 11 Southwest's monthly gas cost adjustment mechanism has been in effect since June, 1999, and benefits Arizona customers by reducing the fluctuations in the cost of gas billed to customers. The monthly mechanism utilizes a twelve month rolling average of actual gas costs to calculate each month's rate. The original mechanism included a $0.07 per therm PGA bandwidth to limit the movement of the monthly PGA rate over a 12-month period. In other words, rates could not change by more than $0.07 upward from the lowest rate during the previous twelve months or $0.07 downward from the highest rate during the previous twelve months. The $0.07 per therm bandwidth was later raised to $0.10, and then further raised to the current $0.13.

Q. 12 How has the bandwidth limit on changes in the monthly gas cost affected Southwest's purchased gas cost adjustment mechanism?

A. 12 The bandwidth limit has had the desired effect on Arizona customers of "smoothing" rate changes so that no drastic changes occur from month-to-month. However, given increased price volatility in today's natural gas markets, the current $0.13 bandwidth has proven to be a relatively restrictive limit on monthly rate changes, and has had the negative effect of creating large balances in

Southwest's gas cost balancing account. Ironically smoothing month-to-month changes in PGA rates has resulted in the need to implement significant one time changes in Southwest's surcharge to recover under-collections in the gas cost balancing account. For example, the Commission approved Southwest's request for a surcharge of $0.11000 per therm effective January 31, 2006 to recover deferred gas costs.

Q. 13 How has the $0.13 per therm bandwidth affected the recovery of Southwest's deferred gas costs?

A. 13 Since its implementation in March 2006 through today, the $0.13 bandwidth has resulted in an additional amount of $24 million in deferred or under-recovered gas costs versus what would have occurred had no bandwidth been in place over the same time period.

Q. 14 Does Southwest have a proposal that will improve the current PGA methodology?

A. 14 Yes. Natural gas commodity prices change daily in the market, but the overall trend of gas costs has been upward since 1999. In June 1999, when Southwest's PGA mechanism, including a $0.07 per therm bandwidth limit on monthly changes, was implemented, the monthly Inside FERC index price at the Permian Basin was $.208 per therm. Therefore, the originally effective bandwidth was approximately 34 percent of the index price. In comparison, the Inside FERC index price at the Permian Basin for June 2007 was $.698 per therm, or over three

times the cost of gas in June 1999. During the same time period, the bandwidth only increased to $.13 per therm, which represents approximately 19 percent of current gas costs.

Southwest proposes to increase the bandwidth limit to $0.24 per therm so the bandwidth limit, as a percent of market gas prices, is restored to its original level. Changing the limit allows the monthly PGA rate to more closely follow the natural gas market, which results in more accurate price signals to customers and reduces the need for, and magnitude of, any surcharge rate adjustments in the future. Finally, the proposed change is in line with the percentage increases recommended by RUCO and Staff for UNS Gas' PGA bandwidth limit in that company's current rate case application.

Q. 15 Will increasing the $0.13 per therm bandwidth limit to $.0.24 per therm result in excessive month-to-month changes in Southwest's gas cost rate?

A. 15 No. Southwest's monthly gas cost calculation will still be based on a 12-month rolling average which smoothes out the peaks and valleys and therefore mitigates the effect of price volatility in the natural gas markets.

IV. MINISTERIAL TARIFF CHANGE

Q. 16 Please briefly describe the proposed ministerial change to Southwest's tariff.

A. 16 In addition to the rate design changes addressed by Southwest witness Mr. Brooks Congdon, Southwest proposes

to remove the references to Title Assignment Service in the Interstate Pipeline Capacity Services Provision of the tariff.

The Interstate Pipeline Capacity Services Provision currently contains a section on Title Assignment Service for operating agreements executed prior to April 1, 1993. Southwest no longer has any Title Assignment Operating Agreements executed prior to April 1, 1993. Therefore, Southwest proposes to eliminate the Title Assignment section of the schedule.

Q. 17 Please describe the schedules you are supporting.

A. 17 There are two schedules summarizing the results of the CCOSS at present and proposed rates. Schedule G-1 illustrates the rate of return on rate base at current rates by rate schedule. Schedule G-2 illustrates the rate of return on rate base at proposed rates by rate schedule.

Schedule A-1 and Schedules H-1 through H-4, which I am sponsoring, summarize the distribution of Southwest's proposed increase among customer classes and show the dollar and percentage change between Southwest's currently effective rates and its proposed rates. The sheets included in Schedule Nos. C-1 and C-2 quantify the differences in Southwest's recorded sales and revenue data and similar data annualized at adjusted test period bills and volumes. Schedule E-7 is a simple compilation

of recorded customer and sales data for three twelve-month periods prior to the test year in this case.

Q. 18 Does this conclude your prepared direct testimony?

A. 18 Yes, it does.

SUMMARY OF QUALIFICATIONS
FRANK J. MAGLIETTI, JR.

I graduated from Central Washington University in 1991 with a Bachelor of Science degree in Economics. I received a Master of Science in Economics from the University of Wyoming in 1994. I began my utility career as a utility rate analyst with the Washington Utilities and Transportation Commission in 1993. My career with Southwest began in 1997 as a rate analyst. I was subsequently promoted to a Specialist/Pricing and Tariffs in 1999, and was promoted to my current position as a Senior Specialist/Pricing and Tariffs in 2005.

I report to the Manager/Pricing and Tariffs. My primary responsibilities include the development of Class Cost of Service Studies and rate design, as well as other pricing and tariff analyses.

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
Docket No. G-01551A-07-0504

PREPARED REBUTTAL TESTIMONY
OF
FRANK J. MAGLIETTI, JR.

ON BEHALF OF
SOUTHWEST GAS CORPORATION

May 9, 2008

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Of
FRANK J. MAGLIETTI, JR.

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Rebuttal Exhibit No.__(FJM-1)

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rebuttal Testimony
of
Frank J. Maglietti, Jr.

Q. 1 Are you the same Frank J. Maglietti, Jr. who submitted prepared direct testimony in this Docket before the Arizona Corporation Commission (the Commission) on behalf of Southwest Gas Corporation (Southwest)?

A. 1 Yes, I am.

Q. 2 What is the purpose of your rebuttal testimony?

A. 2 The purpose of my rebuttal testimony is to respond to the direct testimony presented by Commission Staff witness Mr. Robert G. Gray concerning the increase of the purchased gas adjustment mechanism (PGA) bandwidth.

Q. 3 Please summarize your rebuttal testimony.

A. 3 My rebuttal testimony will discuss why Southwest's proposed bandwidth is better for customers and superior to unnecessarily prolonging gas cost credit or debit balances into future periods.

Q. 4 Have you reviewed Mr. Gray's direct testimony concerning Southwest's proposal to increase the PGA mechanism to 24-cents per therm?

A. 4 Yes. Mr. Gray agrees that the natural gas market has seen increased volatility, and that Southwest is justified to request that the Commission increase the

bandwidth. However, he notes that the bandwidth Southwest is requesting would provide Southwest with the ability to increase rates $0.24 per therm (over a 12 month period) without a formal Commission review or approval, and instead suggests Southwest employ the implementation of a gas cost surcharge to adjust rates in times of increasing or decreasing gas costs to protect customers.

Q. 5 How would customers benefit if the gas cost rate more closely followed the historical 12 month rolling average cost?

A. 5 An advantage of allowing the tariff gas cost rate to more closely track the twelve month rolling average gas cost is the minimization of the need for and the length of time that gas cost balances are either recovered from, or returned to, customers. Rebuttal Exhibit No.__(FJM-1) illustrates the affect on customers of not allowing the gas cost rates to more closely reflect the market price of gas. The graph is a representation of the actual deferral balances Southwest booked from December 2005 through March 2008 compared to the balances that would have occurred if the gas cost rate had not been limited by the bandwidth. As illustrated by the graph, Southwest will remove the current $0.11 gas cost surcharge on June 1 of this year. However, if the proposed $0.24 bandwidth would have been in place over the same time period, Southwest would have removed the surcharge in October

2007 - eight months earlier. The removal of the surcharge before the winter months would have provided customers reduced rates just before the high use winter season.

Q. 6 Why is Mr. Gray's proposal that Southwest file for a surcharge or surcredit to clear the bank balance if the natural gas market prices are changing faster than the mechanism is allowing the tariff gas cost to adjust inferior to Southwest's proposal to expand the bandwidth?

A. 6 Increasing the bandwidth of the PGA would allow continued price gradualism while sending a more correct price signal to customers since the tariff gas cost would be more reflective of the market price of gas. As illustrated in Rebuttal Exhibit No.__(FJM-1), limiting the gas cost rate may have provided customers with a lower rate initially, however the trade-off is higher rates for an extended period of time. The more correct price signal will lead to a more efficient use of resources. This may, in turn, have a positive effect on conservation.

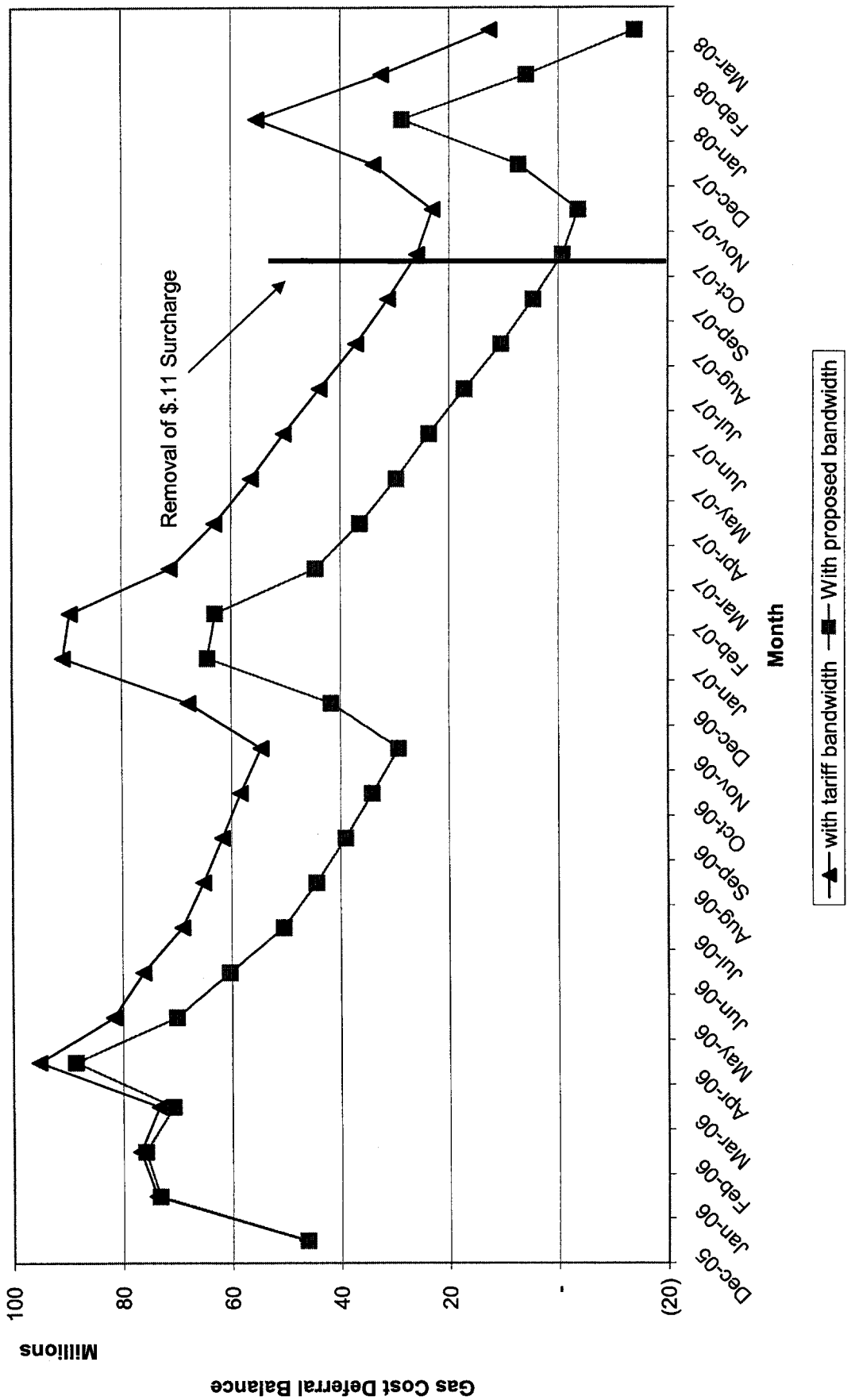
Q. 7 Mr. Gray proposes the bank balance threshold for over-collections be increased to $55.78 million and that the bank balance threshold for under-collections be eliminated. Does Southwest oppose these changes?

A. 7 No. Southwest does not oppose making Mr. Gray's proposed changes to the bank balance thresholds.

Q. 8 Does this conclude your prepared rebuttal testimony?

A. 8 Yes, it does.

Southwest Gas Corporation
Comparison of Gas Cost Deferral Balances
With Tariff and Proposed Bandwidths



IN THE MATTER OF
SOUTHWEST GAS CORPORATION
Docket No. G-01551A-07-0504

PREPARED REJOINDER TESTIMONY
OF
FRANK J. MAGLIETTI, JR.

ON BEHALF OF
SOUTHWEST GAS CORPORATION

June 9, 2008

Southwest Gas Corporation
Docket No. G-01551A-07-0504

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Of
FRANK J. MAGLIETTI, JR.

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BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rejoinder Testimony
of
Frank J. Maglietti, Jr.

INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is Frank J. Maglietti, Jr. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150.

Q. 2 Are you the same Frank J. Maglietti, Jr. who previously submitted prepared direct and rebuttal testimony in this Docket on behalf of Southwest Gas Corporation (Southwest or Company)?

A. 2 Yes, I am.

Q. 3 What is the purpose of your prepared rejoinder testimony?

A. 3 My rejoinder testimony responds to the surrebuttal testimony presented by Arizona Corporation Commission Operations Staff (Staff) witness Mr. Robert G. Gray related to Southwest's purchase gas adjustor (PGA) bandwidth in which he continues to recommend that the PGA bandwidth be increased from $0.13 per therm to $0.15 per therm instead of $0.24 per therm, as proposed by Southwest.

PGA BANDWIDTH

Q. 4 Mr. Gray states in his surrebuttal testimony that increasing the PGA bandwidth "must be balanced with the

Commission's interest in having oversight and involvement in situations where natural gas costs, and therefore, natural gas rates, are increasing significantly." Do you agree?

A. 4 Yes. However, Southwest does not believe that increasing the PGA bandwidth from $0.13 per therm to $0.15 per therm, as proposed by Staff, or to $0.24 per therm, as proposed by Southwest, changes the Commission's oversight authority or involvement in natural gas cost and rates.

The increased bandwidth proposed by the Company will provide the same level of price flexibility and Commission oversight that was originally provided by the Commission when it approved the implementation of the monthly gas cost adjustment mechanism in 1997.

Southwest currently provides the Commission with monthly gas purchase information as part of its monthly filing to adjust rates, and also provides the Commission with an annual report that details its annual purchases. In addition, the prudence of Southwest's gas cost purchases is reviewed by the Commission in each general rate case. These reporting requirements will continue to be in place, regardless of which bandwidth is approved by the Commission.

Q. 5 Although Mr. Gray states that establishment of the bandwidth requires the balancing of competing interests between the Company and Commission, he has not specifically addressed the interests of Southwest's

customers. Why do you believe that Southwest's customer's interests are better served by the Company's proposed PGA bandwidth?

A. 5 Southwest's proposal to increase the bandwidth to $0.24 per therm is intended to smooth out the peaks and valleys of the PGA Bank Balancing Account, reduce price volatility for customers, and give customers a more accurate price signal, all of which benefit customers.

As I demonstrated in Rebuttal Exhibit No.__(FJM-1), if the $0.24 per therm bandwidth had been in place beginning in December 2005, Southwest would have been able to remove the $0.11 PGA surcharge in October 2007, before the 2007/2008 winter heating season. Instead, the surcharge remained in place throughout the winter and was not eliminated until May 30, 2008.

It is prevailing economic theory that prices established closer to actual cost will provide customers a more accurate price signal, which will lead to customer decisions that result in more efficient use of resources. This should, in turn, have a positive effect on conservation.

For each of the foregoing reasons, I believe Southwest's proposed PGA bandwidth better serves the interests of customers, the Commission and the Company.

Q. 6 Did Mr. Gray dispute or comment on Rebuttal Exhibit No.__(FJM-1) in his surrebuttal testimony?

A. 6 No, he did not.

Q. 7 Does this conclude your prepared rejoinder testimony?

A. 7 Yes, it does.

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
Docket No. G-01551A-07-___

PREPARED DIRECT TESTIMONY
OF
JAMES L. CATTANACH

ON BEHALF OF
SOUTHWEST GAS CORPORATION

August 31, 2007

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Of
JAMES L. CATTANACH

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Southwest Gas Corporation
Docket No. G-01551A-07-___

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
Of
JAMES L. CATTANACH

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is James L. Cattanach. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150.

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/Demand Planning in the Systems Planning Department.

Q. 3 Does Appendix A summarize your educational background and business experience?

A. 3 Yes, it does.

Q. 4 Have you previously testified before any regulatory commission?

A. 4 Yes. I have testified before the Arizona Corporation Commission (Commission), the Public Utilities Commission of Nevada, the California Public Utilities Commission, and the Federal Energy Regulatory Commission.

Q. 5 Briefly describe the purpose of your prepared direct testimony in this proceeding.

A. 5 I sponsor testimony in support of Southwest's billing determinants (number of bills and therms) for the test period, and associated adjustments to the recorded number

of bills and therms. The billing determinants for the test period are set forth in Schedule H-2, Sheets 1 to 4 and are utilized in the development of revenues and proposed rates in Southwest's application.

I also present testimony that provides a description of the short- and long-term trends in residential consumption per customer that occurred in Southwest's Arizona rate jurisdiction.

II. VOLUME AND CUSTOMER ADJUSTMENTS

Q. 6 Please describe the methodology Southwest utilized to develop the billing determinants (number of bills and therms) for the test period.

A. 6 The billing determinants were developed by compiling the monthly recorded number of bills and therms by rate schedule for the 12-month period ended April 30, 2007, and making a number of adjustments to the recorded information.

Q. 7 Please describe the adjustments to Southwest's recorded number of bills and therms for the test year.

A. 7 Southwest made the following adjustments:

(1) Billing Adjustments;

(2) Volume Annualizations;

(3) Customer Reclassifications;

(4) Weather Normalization;

(5) Customer Annualizations; and

(6) Post Test Period Adjustments.

The details supporting the adjustments are shown in the

H-2 Workpapers.

Q. 8 Why have you made these adjustments to the recorded number of bills and therms for the test year?

A. 8 The purpose of the six adjustments is to ensure that Southwest's test period number of bills and volumes accurately reflect a full 12 months of consumption under normal weather conditions for the development of revenues and proposed rates.

Q. 9 Has Southwest made any changes to the methodology utilized to develop the billing determinants for the test period?

A. 9 No. Southwest has utilized the same methodology to develop the billing determinants for both its 2000 (Docket No. G-01551A-00-0309) and 2004 (Docket No. G-01551A-04-0876) general rate cases filed in Arizona and approved in Decision Nos. 64172 and 68487, respectively.

Q. 10 Please explain the purpose of Southwest's proposed "Billing Adjustments."

A. 10 After compiling recorded test year information, billing anomalies were investigated to ensure that the correct consumption level is reflected for each month in the test year. A majority of the corrections for Billing Adjustments involved restating the monthly consumption levels for customer bills to reflect actual monthly usage with no impact upon the total test period sales. This adjustment is necessary to ensure that the monthly adjusted volumes reflect an accurate portrayal of actual

test period consumption. Otherwise, distorted monthly values would affect the reliability of the regression analyses associated with the "Weather Normalization" adjustments, which are addressed later in my testimony.

Q. 11 Please explain Southwest's "Volume Annualization" adjustments.

A. 11 Upon completion of the process of correcting for Billing Adjustments, customer-specific Volume Annualization adjustments were performed to reflect a full year of consumption for each customer. This adjustment excludes residential and small commercial customer classes billed during April 2007, which are adjusted separately and addressed later in my testimony. This process involves estimating additional consumption for months during the test period for which a new customer was not on-line or was clearly in a start-up phase, as well as removing consumption attributable to specific customers who discontinued service during the test period.

Q. 12 Please outline the purpose of Southwest's "Customer Reclassification" adjustments.

A. 12 Southwest performed Customer Reclassification adjustments to ensure that customer-specific consumption reflected a full 12 months of usage under the correct rate schedule. Customer Reclassifications do not impact the overall number of bills or volumes for the test period.

Q. 13 Explain the purpose of Weather Normalization adjustments.

A. 13 Weather Normalization adjustments were performed to

accurately depict monthly test period volumes under normal weather conditions. To the extent that weather for the test year deviates from normal weather conditions, heat-sensitive consumption per customer must be adjusted to accurately represent monthly test period volumes under normal weather conditions.

For the test period, actual billing cycle heating degree days were approximately 0.6 percent warmer-than-normal in Tucson, and approximately 2.5 percent colder-than-normal in Phoenix. As a result of these deviations from normal weather, adjustments to test period volumes were computed to reflect anticipated volumes under normal weather conditions.

Weather Normalization adjustments were completed for the following rate schedules: single-family residential; multi-family residential; single-family low income residential; multi-family low income residential; special residential; the master-metered apartment, small commercial, armed forces and large commercial classes within the general service; the master-metered mobile home park; and weather-sensitive customers whose volumes are aggregated under a single transportation service agreement.

Q. 14 What heating degree day standard did Southwest utilize to weather normalize the heat-sensitive volumes for the test period?

A. 14 Southwest utilized a ten-year average (120 months ended

April 2007) of heating degree days to represent normal weather conditions. Southwest has consistently utilized ten-year average heating degree days to weather normalize test period volumes in every general rate case filed since 1986 (U-1551-86-300, U-1551-86-301, U-1551-89-102, U-1551-89-103, U-1551-90-322, U-1551-92-253, U-1551-93-272, U-1551-96-596, G-01551A-00-0309, G-01551A-04-0876).

Q. 15 Please explain Southwest's procedure for calculating the Weather Normalization adjustments.

A. 15 Southwest utilized regression analysis to quantify the relationships between actual monthly consumption per customer and weighted heating degree days for each heat-sensitive customer class. The monthly consumption per heating degree day factors (the regression coefficients) quantified in the regression analyses were then applied to monthly weighted heating degree day deviations from normal, to quantify the corresponding adjustments to consumption per customer.

Q. 16 Were there any other adjustments made to the number of bills or volumes for the test year under present rate schedules?

A. 16 Yes. "Customer Annualization" adjustments were computed for the residential rate schedules and small commercial customers within the small, medium, and large general service rate schedules.

Q. 17 What method was utilized to develop the Customer Annualization adjustments?

A. 17 Southwest utilized the same methodology adopted by the Commission in Decision Nos. 60352, 64172 and 68487. This Customer Annualization methodology was recommended by both Utilities Division Staff witness Michael L. Brosch and RUCO witness Marylee Diaz Cortez in Southwest's 1996 general rate case (Docket No. U-1551-96-596), and adopted in Decision No. 60352. This method captures the seasonal nature of test year customer growth by comparing the number of customers in the last month of the test year, April 2007, to the same month of the prior year, April 2006. The growth in customers is then prorated across the test period in declining intervals with 11/12ths of the adjustment in the first month of the test period (May 2006), 10/12ths in the second month (June 2006) and so forth. Adjustments to annualize volumes were made by multiplying the monthly customer additions by the respective monthly weather-adjusted average use per customer. Customer and volume adjustments are then added to the weather-normalized monthly bills and volumes to produce annualized test period monthly bills and volumes.

Q. 18 Why were the Customer Annualization adjustments only performed for the residential and small commercial customer classes?

A. 18 With the exception of the residential rate schedules and the small commercial class within the general service rate schedules, all other rate schedules were annualized by individual customers, based upon customer-specific

information. These customer-specific annualization adjustments were covered under the Volume Annualization adjustments previously discussed in my testimony. Because of the sheer magnitude of the residential and small commercial customer classes, which include thousands of billing records, tracking each individual's billing history to perform customer-specific billing or annualization adjustments was impractical. Accordingly, Customer Annualization adjustments were performed using the outlined methodology for the residential and small commercial customer classes.

Q. 19 Were any other adjustments required?

A. 19 Yes. "Post Test Period Adjustments" were made to the test period bills and volumes by rate schedules that reflect known and measurable changes that will occur after April 2007 for two of Southwest's largest customers. First, Eurofresh, which currently takes service on rate Schedule No. G-25(TE), executed an agreement to begin service under the Special Procurement Agreement provisions of Southwest's rate Schedule No. G-30. Eurofresh is expected to begin taking service under this agreement on September 1, 2007. Therefore, the test period bills and volumes for Eurofresh were reclassified from rate Schedule No. G-25(TE) to rate Schedule No. G-30. Second, Tucson Electric Power Company expressed its intent to bypass Southwest and take service directly from El Paso Natural Gas Company at its Sundt Generating Station.

Accordingly, the test period bills and volumes for the Sundt Generating Station have been removed from the rate case. Finally, bills and volumes for full-margin transportation customers were reclassified to their applicable sales rate schedules to reflect pricing for these customers at present rate schedules.

Q. 20 Please summarize the adjustments performed for the preparation of the billing determinants for the test period.

A. 20 The impact of each adjustment is reflected in the number of bills and volumes for the test period presented in Schedule H-2, Sheets 1 to 4. All of the adjustments were performed to ensure the accuracy and propriety of the number of bills and therms used to establish rates.

III. DECLINING RESIDENTIAL CONSUMPTION PER CUSTOMER

Q. 21 Describe the residential consumption per customer trend in Arizona.

A. 21 Southwest experienced significant declines in residential consumption per customer over the last 21 years.

Q. 22 Were the declines in residential consumption per customer reflected in the general rate cases Southwest filed over the last 21 years?

A. 22 Yes. Weather-normalized residential consumption per customer declined from 556 therms in the 1986 rate case (Docket Nos. U-1551-86-300, U-1551-86-301) to 332 therms in the current case. Between the 1986 and the 2007 rate cases, Southwest experienced a decline of 224 therms or

40.2 percent. Between Southwest's 2004 (Docket No. G-01551A-04-0876) and 2007 rate cases, weather-normalized residential consumption per customer dropped from 347 therms to 332 therms resulting in a decline of 15 therms or 4.3 percent. This equates to an approximate decline of 6 therms per year between Southwest's 2004 and 2007 rate cases. The declines in residential consumption per customer utilized in Southwest's general rate proceedings between 1986 and 2007 are graphically presented in Exhibit No.___(JLC-1).

Q. 23 Have you performed any other analysis that illustrates the significant declines in residential consumption per customer associated with Southwest's previous general rate cases?

A. 23 Yes, Southwest also examined the historical trend in residential baseload consumption per customer by examining residential consumption per customer for the month of August associated with each test year included in the historical rate case comparison. Because zero heating degree days are recorded during August in Tucson and Phoenix for each test year, August is an ideal month to analyze the historical trend in baseload consumption. Between the 1986 rate cases and the 2007 rate cases, August consumption per customer has declined from 16.4 therms to 9.6 therms, respectively. This is a decline of 6.8 therms or 41.5 percent between the 1986 and the 2007 rate cases. August baseload consumption per customer has

dropped four-tenths of a therm or 4 percent since the 2004 rate case. The significant downward trend in August consumption per customer is graphically depicted in attached Exhibit No.___(JLC-2). This analysis provides empirical support that declining residential consumption per customer is occurring with both space heating (seasonal) and baseload consumption.

Q. 24 What are the primary reasons that residential consumption per customer has declined over the last 21 years?

A. 24 The dramatic decline in residential consumption per customer occurred primarily because of continued improvements in dwelling and appliance efficiencies of Southwest's customer base. In fact, the relatively pronounced declines in residential consumption per customer that began in the 1990s roughly coincide with the implementation of the Energy Policy Act of 1992.

Q. 25 What roles have existing and new customers played in the decline of overall residential consumption per customer in Arizona?

A. 25 For new customers, their appliances and dwellings reflect efficiencies mandated by federal legislation, local building codes, and competition among builders to deliver a more energy efficient product. The resulting lower residential consumption per customer for new customers exerts downward pressure on overall residential consumption per customer. For existing customers, the turnover or replacement of older appliances with more

efficient, newer appliances contributes to the decline in overall consumption per customer. Southwest expects that a certain number of existing residential customers will adopt energy conservation practices related to the thermal integrity of their homes which results in lower overall residential consumption per customer. Therefore, the improved energy efficiencies of natural gas appliances and dwellings for both new customer additions and existing customers contributed to the overall decline in residential consumption per customer.

Q. 26 Is the significant downward trend in residential consumption per customer unique to Southwest's Arizona service areas?

A. 26 No. Southwest also experienced significant declines in residential consumption per customer in its Nevada and California service areas. In addition, the American Gas Association has performed studies that identify a national phenomenon of declining residential natural gas consumption per customer.

Q. 27 What do you anticipate in the way of future declines in residential consumption per customer?

A. 27 I expect overall residential consumption (weather normalized) to continue declining for the foreseeable future. A number of factors foreshadow further declines in residential consumption per customer. Consumers are increasingly encouraged to adopt energy conservation practices. For example, the Energy Policy Act of 2005

provides tax incentives for appliance manufacturers, consumers and home builders to pursue energy conservation. The continued emphasis on energy conservation to reduce energy-related household expenditures and the heightened interest in conservation measures and practices to mitigate CO_2 (carbon dioxide) emissions by residential dwellings into the atmosphere will contribute to the likelihood of this scenario. The issue of global warming and how consumers can participate in carbon abatement measures through reduced household energy consumption will be an important component of both state and federal energy policies in the future. It is also a reasonable hypothesis that home builders in Arizona will continue to pursue higher energy efficiencies in the new homes built in the future. In 2006, Arizona ranked second in the nation in terms of Energy Star-certified homes built. Furthermore, Southwest is currently implementing a number of new and expanded energy efficiency (demand-side management) programs which will have the effect of further lowering residential consumption per customer.

Q. 28 Please summarize the results of your research related to the phenomenon of declining residential consumption per customer in Arizona.

A. 28 The most recent data indicates residential consumption per customer in Arizona continues to decline. The structural change in residential natural gas consumption

per customer that occurred in the mid-1990s continues through the present. It is my belief that improvements in dwelling and appliance efficiencies and consumers' response to higher natural gas prices and bills by both existing and new customers contributed to the historical declines in residential consumption per customer and are expected to continue to have downward pressure on overall residential consumption per customer in the future.

Q. 29 Does this conclude your prepared direct testimony?

A. 29 Yes, it does.

SUMMARY OF QUALIFICATIONS
JAMES L. CATTANACH

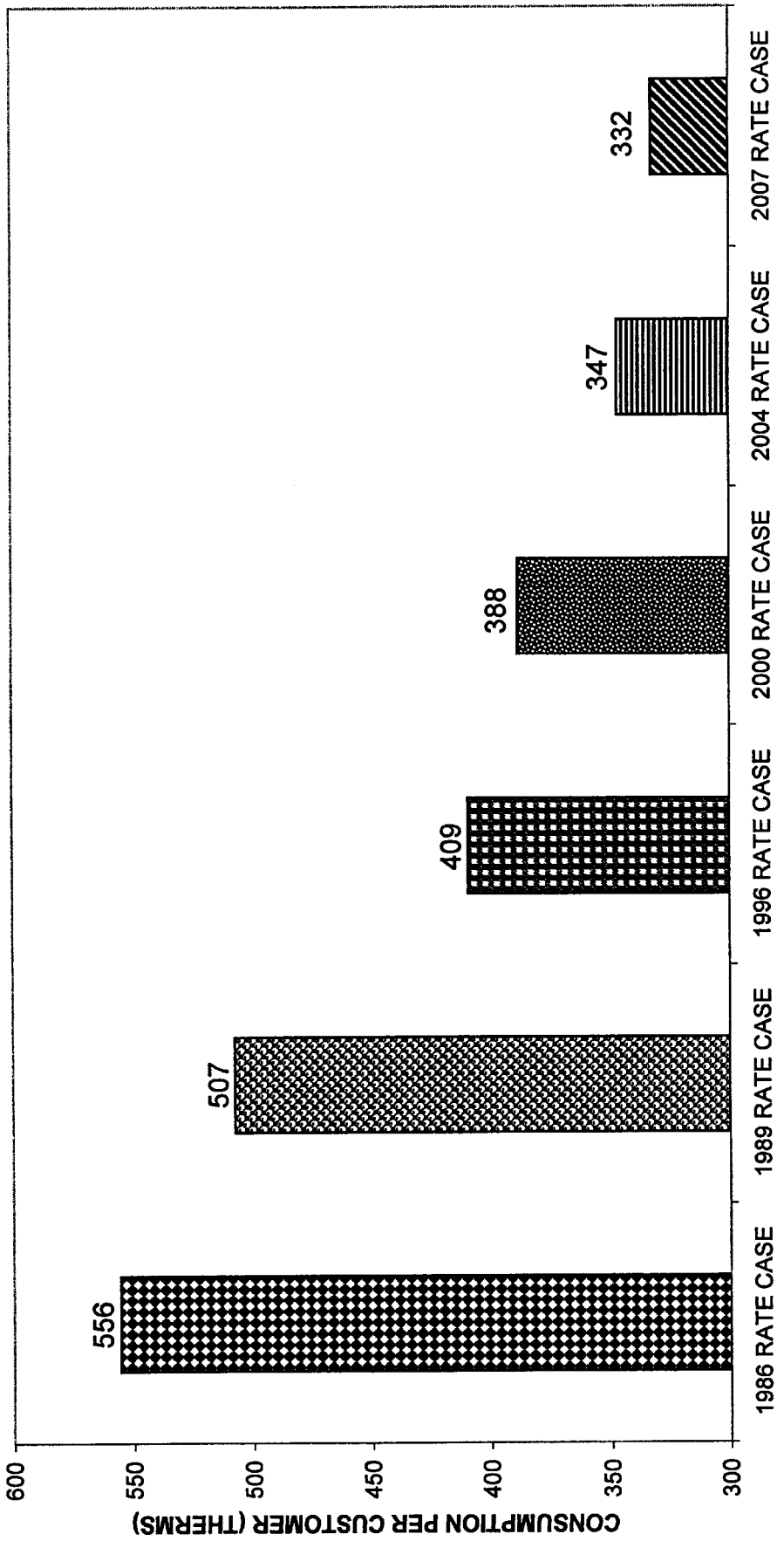
I graduated from Utah State University, Logan, Utah, with a Bachelor of Science degree in Economics in 1983. Thereafter in 1990, I graduated from the University of Nevada, Las Vegas with a Master of Arts degree in Economics.

In 1984, I joined Southwest Gas Corporation as a Load Research Analyst in the Rate Department. In September 1985, I was promoted to the position of Economist in the Resource Planning Department. In November 1993, I was promoted to Senior Economist in the Revenue Requirements and Resource Planning Department. In August 2002, I was promoted to Supervisor in the Systems Planning Department. In July 2003, I was promoted to my current position as Manager/Demand Planning in the Systems Planning Department. I am responsible for the development of weather normalized billing determinants for rate cases, the development of short- and long-range demand forecasts for rate cases and systems planning, analysis and monitoring of the regional economy in each of Southwest's rate jurisdictions, assorted load research activities, and the ongoing review of weather normalization procedures and heating degree days. I supervise three analysts and two economists in the Systems Planning Department.

Since 1989, I have held the position of Adjunct Lecturer in the College of Business, Department of Economics, at the University of Nevada, Las Vegas. I currently teach an Applied Regression Analysis and Forecasting course each Fall and Spring Semester. I have previously taught courses in Business Statistics, Microeconomics, and Macroeconomics.

In addition to receiving my formal degrees in the study of Economics, I have attended seminars related to both public utility ratemaking and load forecasting. I am a member of the American Statistical Association, International Association for Energy Economics, National Association of Business Economics, National Association of Forensic Economics, Institute of Business Forecasting, and Southern Nevada Population Projection and Estimation Committee. I am also a contributing panel member of the Western Blue Chip Economic Forecast published by the Bank One Economic Outlook Center, W.P. Carey College of Business, Arizona State University. Between 1997 and 2000, I was an advising member of the Energy Economics Project Advisors Group, at The Gas Research Institute.

ARIZONA
RESIDENTIAL GAS SERVICE (G-5 & G-6)
ANNUAL RATE CASE CONSUMPTION PER CUSTOMER
1986 - 2007



ARIZONA
RESIDENTIAL GAS SERVICE (G-5 & G-6)
AUGUST RATE CASE CONSUMPTION PER CUSTOMER
1986 - 2007

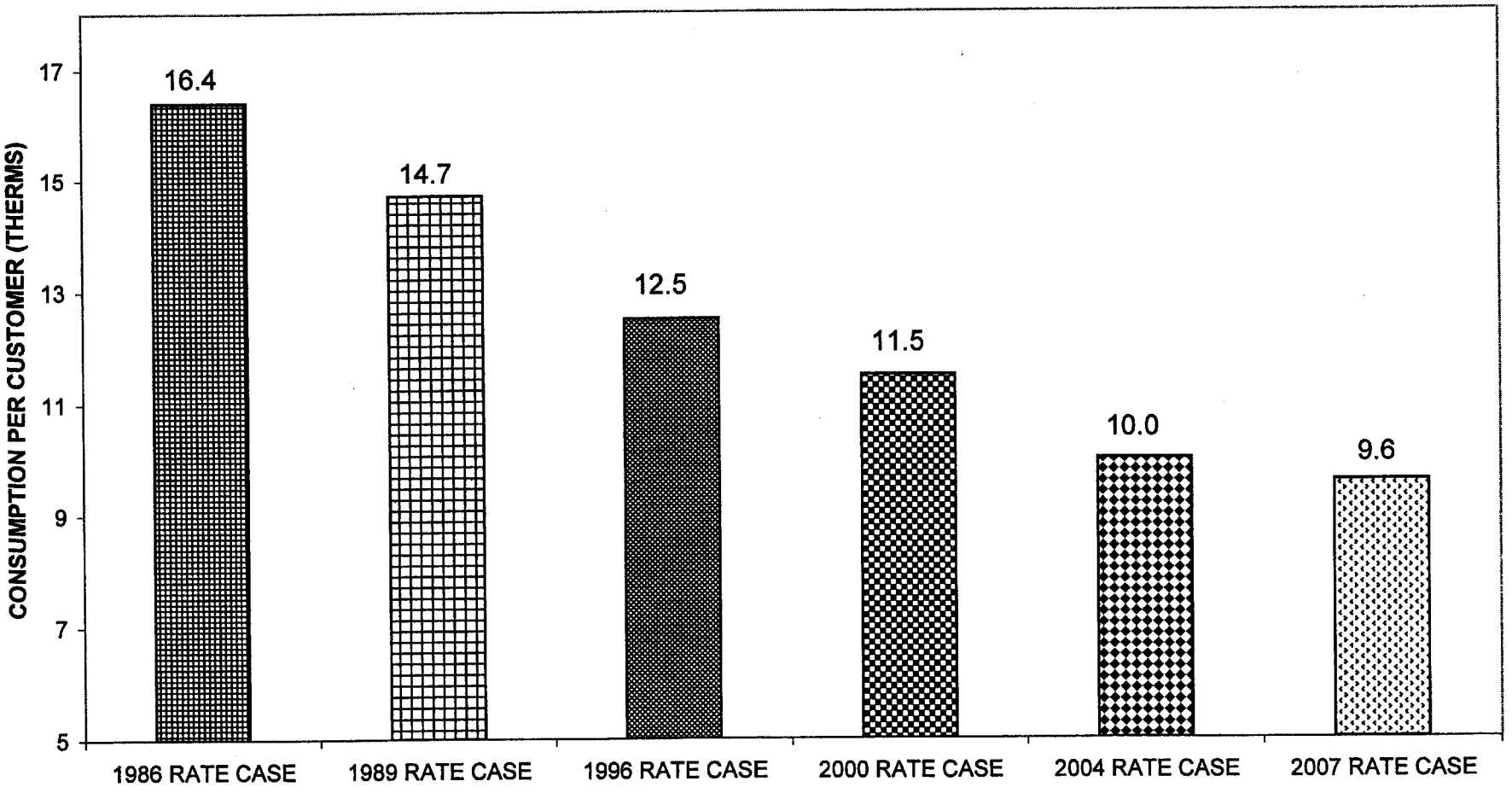


Exhibit No. ___(JLC-2)
Sheet 1 of 1

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
Docket No. G-01551A-07-0504

PREPARED REBUTTAL TESTIMONY
OF
JAMES L. CATTANACH

ON BEHALF OF
SOUTHWEST GAS CORPORATION

May 9, 2008

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Prepared Rebuttal Testimony
Of
JAMES L. CATTANACH

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Rebuttal Exhibit No.__(JLC-1)

Rebuttal Exhibit No.__(JLC-2)

Rebuttal Exhibit No.__(JLC-3)

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rebuttal Testimony
of
James L. Cattanach

Q. 1 Please state your name and business address.

A. 1 My name is James L. Cattanach. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150.

Q. 2 Are you the same James L. Cattanach who sponsored direct testimony on behalf of Southwest Gas Corporation (Southwest or the Company) in this proceeding?

A. 2 Yes, I am.

Q. 3 What is the purpose of your prepared rebuttal testimony?

A. 3 The purpose of my prepared rebuttal testimony is to reply to the direct testimonies presented by Residential Utility Consumer Office (RUCO) witness Mr. William A. Rigsby and Arizona Corporation Commission Utilities Division Staff (Staff) witness Mr. Frank Radigan regarding their statements related to declining residential consumption per customer.

Q. 4 Did you prepare exhibits to support your rebuttal?

A. 4 Yes. I prepared the exhibits identified as Rebuttal Exhibit No.___(JLC-1) through Rebuttal Exhibit No.__(JLC-3).

Q. 5 Please summarize your rebuttal testimony.

A. 5 I will reply to the statement made by RUCO witness Mr.

Rigsby that "This data indicates that there is a limit to the amount customers can conserve and that this phenomenon is abating" (William A. Rigsby, Direct Testimony, Page 6, Lines 20 - 22, April 11, 2008). I will also rebut the statement made by Staff witness Mr. Frank Radigan that "With relatively low per-customer total usage, the losses from conservation will also likely be small" (Frank Radigan, Direct Testimony, Page 11, Lines 15 - 16, March 28, 2008). I will provide quantitative evidence that residential consumption per customer continues to decline at a significant rate and has had a significant impact on the annualized volumes in the test year.

Q. 6 Do you agree with Mr. Rigsby's testimony that the phenomenon related to declining residential consumption per customer is abating?

A. 6 No, I do not. The most recent data suggests that declines in residential consumption per customer have not abated and have actually accelerated.

Q. 7 What is the most recent trend in residential consumption per customer?

A. 7 Since the test year in the current rate case, weather normalized residential consumption per customer has declined from 332 to 319 therms per customer. This is a decline of 13 therms or 3.9 percent over the last 11 months. The attached Rebuttal Exhibit No.___(JLC-1) presents a time series plot that depicts 12-month moving

totals of weather normalized consumption per customer for the period January 1995 through March 2008. The graph illustrates both the long-term decline in consumption per customer and the recent acceleration in declines that commenced in January 2007.

Q. 8 Do you agree with Mr. Radigan's statement that "With relatively low per-customer total usage, the losses from conservation will also likely be small."

A. 8 No, I do not. Since the 2004 rate case, residential consumption per customer has declined from 347 therms to 332 therms (current rate case) to 319 therms (March 2008). In my opinion, these declines of 15 therms and 13 therms, respectively, are not small. In fact, I would not consider declines of 3 therms per customer to be insignificant. With a relatively low residential consumption per customer in Arizona, any decline in residential consumption that is experienced by the Company from its current levels is deemed to be significant.

Q. 9 Have you performed any other analysis that quantifies the impact of continuing declines in residential consumption per customer since the end of the test year?

A. 9 Yes, I updated the test year weather normalized residential consumption per customer for the months of May 2006 through March 2007 with weather normalized consumption per customer for May 2007 through March 2008. I performed the consumption per customer updates for the

Single-Family Residential (G-5), Multi-Family Residential (G-6), Single-Family Low Income Residential (G-10) and Multi-Family Low Income Residential (G-11) rate schedules. With the residential consumption per customer updates, the annualized test year volumes decline by 11,930,476 therms or 3.9 percent. A summary of the impact of declining residential consumption on the test year volumes is presented in the attached Rebuttal Exhibit No.__(JLC-2). The details of the adjustments are presented in the attached Rebuttal Exhibit No.__(JLC-3). The negative financial implications of the decline in residential average usage since the test year is quantified and discussed in the rebuttal testimony of Southwest witnesses A. Brooks Congdon and Theodore Wood.

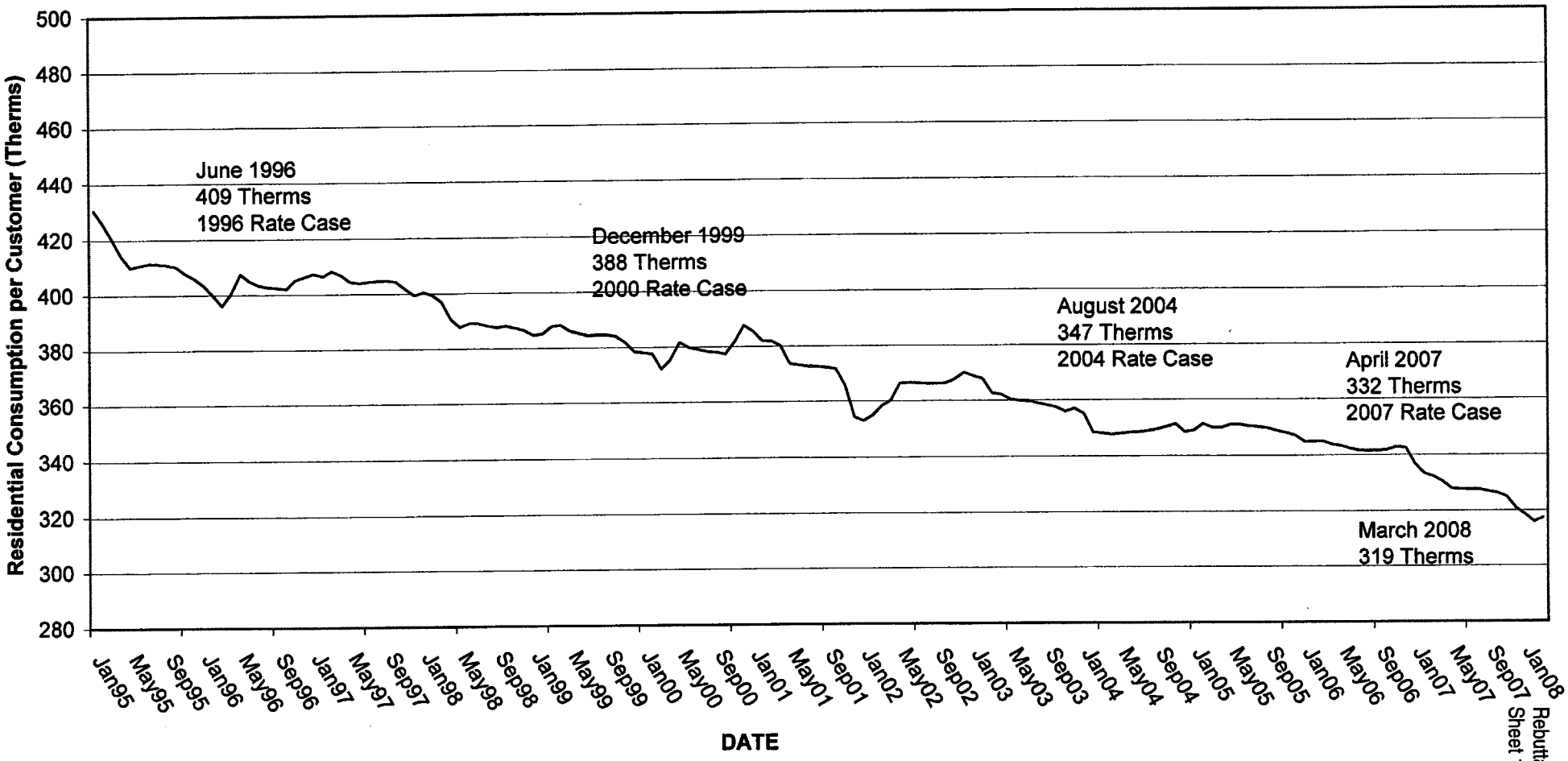
Q. 10 Could you please summarize your conclusions based on the information presented?

A. 10 Yes. Southwest continues to experience significant declines in residential consumption per customer. In fact, the most recent data suggests that the decline has accelerated. The continued declines in residential consumption per customer since the end of the test year in the current rate case has reduced the annualized volumes by 11,930,476 therms.

Q. 11 Does this conclude your prepared rebuttal testimony?

A. 11 Yes, it does.

SOUTHWEST GAS CORPORATION
ARIZONA
RESIDENTIAL CUSTOMER CLASS (G-5 & G-6)
12-MONTH WEATHER NORMALIZED CONSUMPTION PER CUSTOMER
JANUARY 1995 - MARCH 2008



10-Year Normal HDDs: 2007 Rate Case

Rebuttal Exhibit No. __(JLC-1)
Sheet 1 of 1

SOUTHWEST GAS CORPORATION
ARIZONA
UPDATED ANNUALIZED SALES VOLUMES (THERMS)
TEST YEAR - 12 MONTHS ENDED APRIL 2007

Description	Rate Schedule	Test Year Sales Volumes	Updated Test Year Sales Volumes	Difference from Test Year Amount	Difference from Test Year Percent
Single-Family Residential	G-5	289,056,115	277,828,428	-11,227,687	-3.9%
Multi-Family Residential	G-6	6,508,059	6,107,019	-401,040	-6.2%
Single-Family Low Income Residential	G-10	8,658,972	8,379,460	-279,512	-3.2%
Multi-Family Low Income Residential	G-11	552,643	530,406	-22,237	-4.0%
Total		304,775,789	292,845,313	-11,930,476	-3.9%

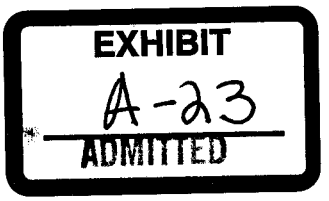
Notes:
(1) Test year weather normalized residential consumption per customer (May 2006 - March 2007) updated with the months of May 2007 through March 2008.
(2) The test year number of bills were not updated.

SOUTHWEST GAS CORPORATION
TOTAL ARIZONA
TWELVE MONTHS ENDED APRIL 2007
ANNUALIZED DELIVERIES (THERMS) AND CUSTOMERS

WEATHER NORMALIZED RESIDENTIAL CONSUMPTION PER CUSTOMER UPDATE: MAY 2007 - MARCH 2008

Rate Schedule	Description	May 2006	June 2006	July 2006	August 2006	September 2006	October 2006	November 2006	December 2006	January 2007	February 2007	March 2007	April 2007	TOTAL
G-5	Residential Gas Service													
	Weather Normalized Sales	14,224,761	10,422,997	8,454,311	7,977,298	8,157,569	9,719,048	15,582,959	37,920,974	53,698,625	46,031,619	39,531,765	23,136,346	274,836,272
	Customers	827,021	827,222	828,854	830,548	832,405	837,849	845,813	854,076	859,146	865,256	868,830	860,591	10,137,611
	Sales/Customer	17.2	12.6	10.2	9.6	9.8	11.6	18.4	44.4	62.5	53.2	45.5	26.9	321.9
	April 2006 Customers												831,424	
	Annual Customer Growth												29,167	
	Customer Adjustment	26,736	24,306	21,875	19,445	17,014	14,584	12,153	9,722	7,292	4,861	2,431	0	160,419
	Therm Adjustment	459,859	306,256	223,125	186,767	166,737	169,174	223,615	431,657	455,750	258,605	110,611	0	2,992,156
	Annualized Sales	14,684,620	10,729,253	8,677,436	8,164,065	8,324,306	9,888,222	15,786,574	38,352,631	54,152,375	46,290,224	39,642,376	23,136,346	277,828,428
	Annualized Customers	853,757	851,528	850,729	849,993	849,419	852,433	857,966	863,798	866,438	870,117	871,261	860,591	10,298,030
	Sales/Customer	17.2	12.6	10.2	9.6	9.8	11.6	18.4	44.4	62.5	53.2	45.5	26.9	321.9
G-6	Multi-Family Residential Gas Service													
	Weather Normalized Sales	398,122	327,424	287,271	269,505	265,087	293,716	403,243	753,328	937,980	824,694	775,199	541,683	6,077,250
	Customers	30,391	30,317	30,239	29,945	29,785	29,971	30,319	30,748	31,266	31,719	32,033	31,549	368,282
	Sales/Customer	13.1	10.8	9.5	9.0	8.9	9.8	13.3	24.5	30.0	26.0	24.2	17.2	196.3
	April 2006 Customers												31,135	
	Annual Customer Growth												414	
	Customer Adjustment	380	345	311	276	242	207	173	138	104	69	35	0	2,280
	Therm Adjustment	4,978	3,726	2,955	2,484	2,154	2,029	2,301	3,381	3,120	1,794	847	0	29,769
	Annualized Sales	403,100	331,150	290,226	271,989	267,241	295,745	405,544	756,707	941,100	826,488	776,046	541,683	6,107,019
	Annualized Customers	30,771	30,662	30,550	30,221	30,027	30,178	30,492	30,886	31,370	31,788	32,068	31,549	370,562
	Sales/Customer	13.1	10.8	9.5	9.0	8.9	9.8	13.3	24.5	30.0	26.0	24.2	17.2	196.3
G-10	Low Income Residential G.S.													
	Weather Normalized Sales	431,216	316,742	265,720	251,826	246,728	285,787	491,764	1,170,442	1,598,405	1,397,351	1,248,026	681,870	8,383,877
	Customers	26,951	26,177	25,550	25,437	24,922	25,069	25,090	25,063	25,707	26,718	27,369	27,090	311,143
	Sales/Customer	16.0	12.1	10.4	9.9	9.9	11.4	19.6	46.7	62.1	52.3	45.6	25.2	321.2
	April 2006 Customers												27,133	
	Annual Customer Growth												(43)	
	Customer Adjustment	(39)	(36)	(32)	(29)	(25)	(22)	(18)	(14)	(11)	(7)	(4)	0	(237)
	Therm Adjustment	(624)	(436)	(333)	(287)	(248)	(251)	(353)	(654)	(683)	(366)	(182)	0	(4,417)
	Annualized Sales	430,592	316,306	265,387	251,539	246,480	285,536	491,411	1,169,788	1,595,722	1,396,985	1,247,844	681,870	8,379,460
	Annualized Customers	26,912	26,141	25,518	25,408	24,897	25,047	25,072	25,049	25,696	26,711	27,365	27,090	310,906
	Sales/Customer	16.0	12.1	10.4	9.9	9.9	11.4	19.6	46.7	62.1	52.3	45.6	25.2	321.2
G-11	Multi-Family Low Income Residential G.S.													
	Weather Normalized Sales	30,653	25,894	22,040	21,020	21,059	22,756	32,175	63,455	82,946	75,801	70,535	46,110	514,444
	Customers	2,174	2,140	2,099	2,130	2,085	2,107	2,145	2,151	2,206	2,311	2,391	2,381	26,320
	Sales/Customer	14.1	12.1	10.5	9.9	10.1	10.8	15.0	29.5	37.6	32.8	29.5	19.4	231.2
	April 2006 Customers												2,187	
	Annual Customer Growth												194	
	Customer Adjustment	178	162	146	129	113	97	81	65	49	32	16	0	1,068
	Therm Adjustment	2,510	1,960	1,533	1,273	1,141	1,048	1,215	1,918	1,842	1,050	472	0	15,962
	Annualized Sales	33,163	27,854	23,573	22,293	22,200	23,804	33,390	65,373	84,788	76,851	71,007	46,110	530,406
	Annualized Customers	2,352	2,302	2,245	2,259	2,198	2,204	2,226	2,216	2,255	2,343	2,407	2,381	27,388
	Sales/Customer	14.1	12.1	10.5	9.9	10.1	10.8	15.0	29.5	37.6	32.8	29.5	19.4	231.2

Rebuttal Exhibit No.___(JLC-3)
Sheet 1 of 1



IN THE MATTER OF
SOUTHWEST GAS CORPORATION
Docket No. G-01551A-07-0504

PREPARED REJOINDER TESTIMONY
OF
JAMES L. CATTANACH

ON BEHALF OF
SOUTHWEST GAS CORPORATION

June 9, 2008

Southwest Gas Corporation
Docket No. G-01551A-07-0504

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Of
JAMES L. CATTANACH

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Southwest Gas Corporation
Docket No. G-01551A-07-0504

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rejoinder Testimony
of
James L. Cattanach

INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is James L. Cattanach. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150.

Q. 2 Are you the same James L. Cattanach who sponsored direct and rebuttal testimony on behalf of Southwest Gas Corporation (Southwest or the Company) in this proceeding?

A. 2 Yes, I am.

Q. 3 What is the purpose of your prepared rejoinder testimony?

A. 3 The purpose of my rejoinder testimony is to reply to the surrebuttal testimony presented by Arizona Corporation Commission Utilities Division Staff (Staff) witness Mr. Frank Radigan regarding his statements related to declining residential consumption per customer.

RESIDENTIAL CONSUMPTION PER CUSTOMER

Q. 4 Did you prepare exhibits to support your rejoinder testimony?

A. 4 Yes. I prepared an exhibit identified as Rejoinder Exhibit No.___(JLC-1).

Q. 5 Please summarize your rejoinder testimony.

A. 5 I will reply to the statement made by Staff witness Mr. Radigan that "You cannot just conclude that because you see declining customer usage from one year to the next that it will continue to decline." (Radigan, Surrebuttal Testimony, Page 6, Lines 8 - 10, May 27, 2008). I will also respond to Mr. Radigan's statement, "In my opinion, Mr. Cattanach's testimony does not provide any of the information necessary for the Commission to make an informed decision on this matter. Mr. Cattanach's exhibits show average use per customer for selected historic years. It does not show that declining usage will continue, it does not show what the projected end level customer usage will be, and it does not demonstrate that energy conservation efforts are the cause for this declining usage, if in fact it exists." (Radigan, Surrebuttal Testimony, Page 7, Lines 7 - 12, May 27, 2008). I will provide analyses and historical data that suggests there is a significant likelihood that residential consumption per customer will continue to decline in the foreseeable future.

Q. 6 Could you briefly comment on Mr. Radigan's statement that "You cannot just conclude that because you see declining customer usage from one year to the next that it will continue to decline"?

A. 6 Yes. Although we do not know with 100 percent certainty that residential consumption per customer will continue to decline in the future, the long-term historical data

trend provides insight into the likely trajectory of future consumption over the near term. I believe that a reasonable person would conclude after reviewing the historical consumption information provided in both my direct and rebuttal testimonies (Direct Testimony Exhibit No.__(JLC-1), Rebuttal Testimony Exhibit No.__(JLC-1)), a significant likelihood exists that residential consumption per customer will continue to decline for the foreseeable future. In the absence of being clairvoyant or having perfect vision of the future, economists must utilize history as a guide to help assess future trends in consumption per customer.

The historical data presented in this proceeding indicates that an expectation of future declines in residential consumption is not unreasonable. At page 8 of my prepared direct testimony in the Company's 2004 rate case, I testified as follows:

> Q. 13 Do you have any expectations regarding when this dramatic decline in residential consumption per customer will possibly slowdown or stop in the Arizona rate jurisdiction?
>
> A. 13 Unfortunately, no. However, reasonable conjecture would conclude a significant likelihood exists that the downward trend in residential consumption per customer will continue for the foreseeable future.

Indeed, consumption did decline from 347 therms in the 2004 rate case to 332 therms in the current rate case.

In my direct testimony in the current case, I stated an expectation that consumption would continue to decline. As outlined in my rebuttal testimony, residential consumption per customer has declined from 332 therms to 319 therms between the end of the test year (April 2007) and March 2008. My expectation is that based on the ongoing declines in residential consumption per customer, consumption will continue to trend downward for the foreseeable future.

Q. 7 Have you performed any empirical analyses that provide insight into the future trend in residential consumption per customer?

A. 7 Yes. Based on the 12-month moving totals of weather normalized residential consumption data used to construct the graph presented in my rebuttal testimony (Exhibit No.__(JLC-1), I estimated a statistical equation through the data set to quantify the trend in residential consumption per customer between January 1995 and March 2008. The graph of the data, the estimated statistical regression equation, and the regression statistics are presented in Rejoinder Exhibit No.__(JLC-1). The regression statistics indicate a statistically significant (T-Statistic=-64.49) negative trend in the residential consumption per customer data over the estimation period. The regression results suggest a

strong statistical fit (Rsquare=.9636) to the data. On average, residential consumption per customer has declined approximately 7 therms per year over the estimated period. Since the consumption data is weather normalized (the impact of weather variations has been removed from the data), the estimated downward trend of 7 therms per year is a reasonable approximation of the impact of conservation-related factors on residential consumption per customer. Even though the statistical trend equation has underestimated the recent acceleration in consumption declines, it is a plausible expectation that residential consumption per customer will continue to decline by approximately 7 therms per year in the foreseeable future.

I do not think the recent acceleration in the declines is sustainable over a longer period. Therefore, I would expect to observe residential consumption per customer falling below 310 therms within the next couple of years. Although I would not want to use the estimated statistical equation to forecast declines in residential consumption per customer over a ten to fifteen year forecast horizon, the equation is a reasonable statistical tool to assess the trend in residential consumption per customer over the foreseeable future.

Q. 8 Have you performed any other quantitative studies that will provide insight into the direction of future changes in residential consumption per customer?

A. 8 Yes. Examining calendar year weather normalized residential consumption per customer data for a longer period (1985 through 2007), I compared consumption in a given year to the change (positive/negative) one and two years ahead. Based on this information, I constructed high level discrete probability distributions using the empirical or long-run relative frequency approach to probability assessment. Based on the constructed discrete probability distributions, there is approximately an 82 percent chance that residential consumption per customer will decline over the next year and an 86 percent chance of a decline two years ahead. In my opinion, these probabilities suggest a significant likelihood that residential consumption per customer will continue to decline in the foreseeable future.

Q. 9 Is it reasonable to assume that declines in residential consumption per customer will decelerate and find an equilibrium or base consumption level in the future?

A. 9 Yes, this is a reasonable assumption. However, when that deceleration or equilibrium will occur and at what level of consumption cannot be predicted with any certainty, but given the most recent data available to me, I do not believe this will occur in the foreseeable future. As a researcher, I can continue to monitor the trends and patterns in residential consumption data that will provide evidence of a deceleration to a base consumption or equilibrium level. In the meantime, the null

hypothesis (nothing is different from the status quo) is that residential consumption per customer will continue to decline. When I see evidence through graphing techniques, statistical analysis and other supporting information (e.g., public policy) that the declines have ceased, I will reject the null hypothesis and change my opinion regarding further declines. Up to this point, I have observed no evidence that residential consumption per customer has reached a bottom or plateau. In fact, continued public policy at the federal, state and local levels that promotes energy conservation reinforces the reasonable assumption that residential consumption per customer will continue to decline. These policies include building codes, appliance standards, and utility DSM programs to reduce residential energy consumption and greenhouse gas emissions.

Q. 10 Do you agree with Mr. Radigan's assertion that Southwest has not provided any of the information necessary for the Commission to make an informed decision related to the matter of declining residential consumption per customer?

A. 10 I strongly disagree with Mr. Radigan's assertion. I have provided more than ample evidence in both direct and rebuttal testimony that Southwest has continued to experience declines in weather normalized consumption per customer. Although I did not, and cannot, provide an explicit estimate of the date in the future that residential consumption per customer will stop declining

or at what level, I believe a reasonable person, even with no formal training in statistics or economics, would conclude after a careful review of the historical data and information provided in this case, that further declines are very likely.

Mr. Radigan also seems to be attempting to confuse the issue by questioning whether declines are actually due to conservation. With all due respect to Mr. Radigan, this is unreasonable speculation. It does not matter if you are examining the significant downward trends over the last thirty years in macro level data such as energy consumption per dollar of economic output in the United States, residential natural gas consumption per customer in the United States at the aggregate level, or natural gas consumption per customer in Arizona, the primary contributing factors have been continuing conservation related to improved efficiencies. In fact, the American Gas Association in at least two studies identified increasing efficiencies of natural gas appliances as the primary cause of declining residential consumption per customer since 1980.[1] The declines in weather normalized residential consumption per customer, which is an excellent proxy for the conservation-related declines in consumption, have occurred since the early 1980s in spite of the two longest peacetime economic

[1] The American Gas Association studies were provided to the parties in response to Staff data request 6-47.

expansions in the United States since the end of World War II and the upward trend in square footage of single-family homes in the United States. Mr. Radigan has presented no studies or analysis to suggest that residential consumption per customer will stop or even slow down.

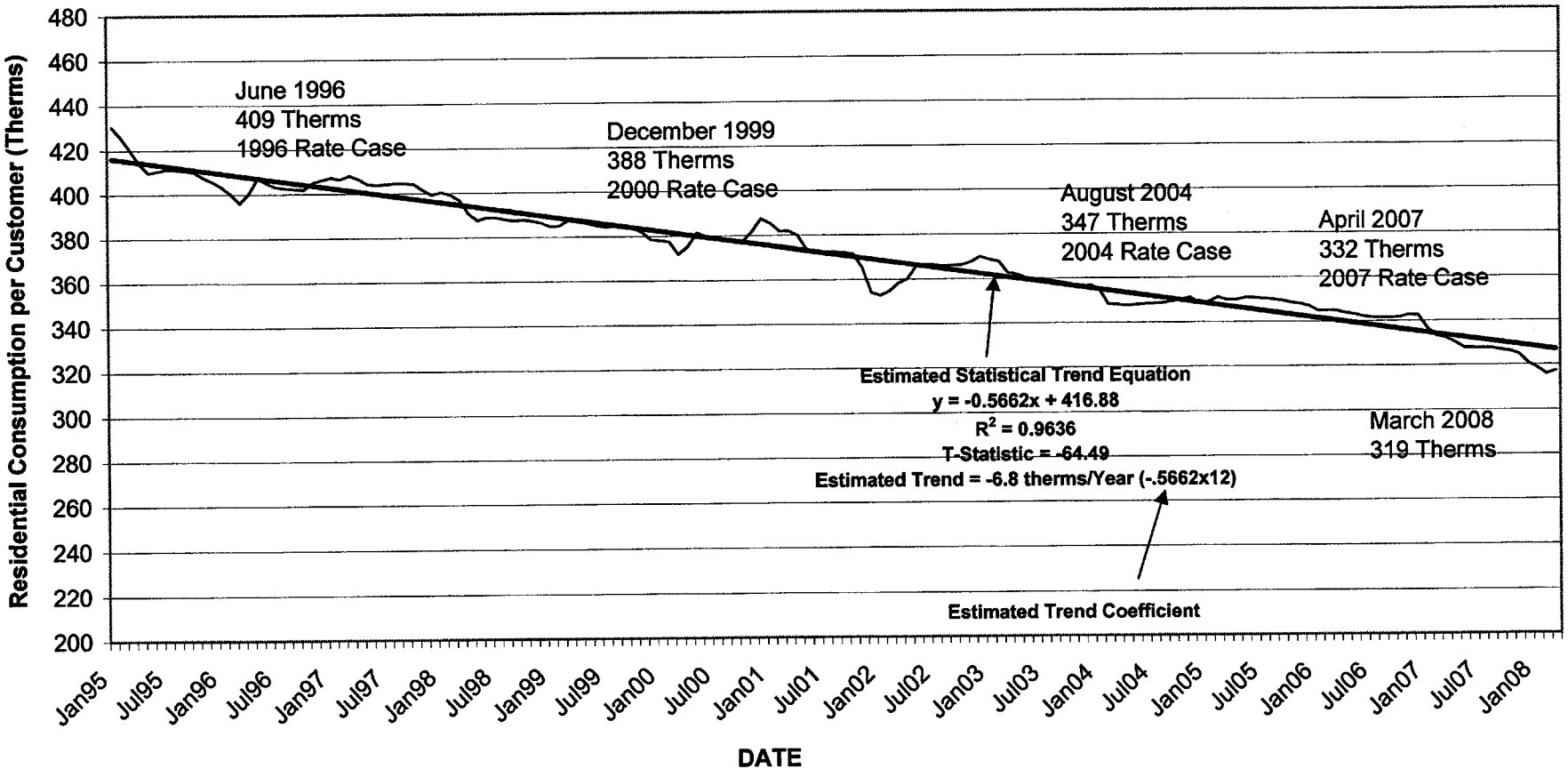
Q. 11 Could you please summarize your conclusions based on the information presented?

A. 11 Yes. Southwest has experienced statistically significant declines in weather normalized residential consumption per customer over the last twenty plus years, caused primarily by factors related to conservation. Based on the statistical analyses and information presented, there is a significant likelihood that residential consumption per customer will continue to decline for the foreseeable future, and there is no evidence presented in this docket to the contrary. The Company has provided sufficient data and analysis for the Commission to assess both the historical and near-term trends in residential consumption per customer.

Q. 12 Does this conclude your prepared rejoinder testimony?

A. 12 Yes, it does.

SOUTHWEST GAS CORPORATION
ARIZONA
RESIDENTIAL CUSTOMER CLASS (G-5 & G-6)
12-MONTH WEATHER NORMALIZED CONSUMPTION PER CUSTOMER & ESTIMATED STATISTICAL TREND EQUATION
JANUARY 1995 - MARCH 2008



10-Year Normal HDDs: 2007 Rate Case

Rejoinder Exhibit No.__(JLC-1)
Sheet 1 of 1

IN THE MATTER OF
SOUTHWEST GAS CORPORATION
Docket No. G-01551A-07-___

PREPARED DIRECT TESTIMONY
OF
A. BROOKS CONGDON

ON BEHALF OF
SOUTHWEST GAS CORPORATION

August 31, 2007

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Of
Prepared Direct Testimony
Of
A. BROOKS CONGDON

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BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Direct Testimony
Of
A. BROOKS CONGDON

I. INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is A. Brooks Congdon. 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/Pricing and Tariffs.

Q. 3 Please state your educational background and business experience.

A. 3 My background and experience are reflected in Appendix A to my direct testimony.

Q. 4 What is the purpose of your testimony?

A. 4 I am sponsoring the Company's rate design proposals.

II. RATE DESIGN INTRODUCTION

Q. 5 Please discuss the objective of Southwest's rate design and other tariff proposals in this case.

A. 5 Southwest continues to face significant instability in its cost recovery due to changes in customer consumption attributable to weather as well as erosion of revenues due to continued customer conservation. These effects are most pronounced in the residential class of customers but are also experienced to a lesser extent in

the weather-sensitive small, medium and large general service classes. Therefore, Southwest's rate design and tariff proposals in this case focus on achieving greater stability in revenues from these customer classes.

In Southwest's last general rate case, Docket No. G-01551A-04-0876, Decision No.68487, the Commission stated, "We encourage the parties to this proceeding to seek rate design alternatives that will truly encourage conservation efforts, while at the same time providing benefits to all affected stakeholders". Accordingly, Southwest proposes the following tariff and rate design tools: (1) a new tariff mechanism, the Revenue Decoupling Adjustment Provision, to recover or return differences between customers' actual and authorized non-gas revenue; (2) a new tariff mechanism, the Weather Normalization Adjustment Provision, to remove weather-related volatility from the non-gas component of individual customer bills; (3) gradual increases to basic service charges (BSCs); and (4) elimination of Southwest's currently-effective declining block residential rate structure for billing purposes while stabilizing recovery of authorized non-gas revenue with offsetting blocks for the non-gas and gas cost components of the sales rate. The Company believes that these tools can resolve Southwest's cost recovery problems while benefiting customers and encouraging conservation efforts.

III. RESIDENTIAL RATE DESIGN

Q. 6 Please provide the background for the development of Southwest's residential rate design proposals in this case.

A. 6 In its last Arizona rate case, Southwest's residential rate design proposals were driven by the need to address cost recovery issues associated with a chronic decline in average use per residential customer. Using the rate design tools "traditionally" available, Southwest proposed shifting cost recovery away from usage-sensitive components of the rate structure into BSC and the less-usage-sensitive first block of the declining block commodity charge.

Southwest also requested the implementation of a regulatory mechanism, the Conservation Margin Tracker (CMT), to allow Southwest to record the difference between its actual monthly residential non-gas revenue and the amount that would have been realized at the Commission-authorized monthly non-gas revenue per customer for future recovery or refund. Although the Commission did not approve Southwest's residential rate design proposals, it acknowledged that Southwest "faces increased financial pressure due to declining usage on a per customer basis."

Q. 7 Why did the Commission reject Southwest's rate design and CMT proposals?

A. 7 The Commission indicated that Southwest's proposed increase to the BSC was too large and violated the principle of gradualism. Further, the Commission was concerned that Southwest's proposal to significantly reduce the marginal commodity charge of the rate design from its then-effective level would reduce customers' incentive to conserve. The Commission expressed similar conservation-related concerns regarding the CMT.

However, recognizing Southwest's cost recovery predicament, the Commission encouraged Southwest and other interested rate case participants to conduct discussions regarding this issue. In response, Southwest initiated a "rate design collaborative" which included Staff and Residential Utility Consumer Office (RUCO). The collaborative held four meetings from September 2006 thru April 2007.

In developing its proposals for this proceeding, Southwest considered the Commission's concerns and the opinions expressed at the rate design collaborative.

Q. 8. Please discuss Southwest's proposed new tariff mechanisms and rate design changes and how they conform to Decision No. 68487.

A. 8 The proposed tariff mechanism and rate design changes are discussed below.

A. Revenue Decoupling Adjustment Provision (RDAP)

Decision No. 68487 contained several references to the need to promote maximum energy efficiency. Clearly, the

Commission is committed to protecting energy supplies for future Arizona generations. Accordingly, Southwest's proposed RDAP is a tariff mechanism that positions the Company to aggressively promote customer conservation and energy efficiency, without adverse financial impact, by allowing the recovery or refund of any differences between actual and Commission-authorized non-gas revenue.

The RDAP is styled after a mechanism recently approved by the Public Service Commission of Utah for Questar Gas Company. The RDAP provides for recovery of non-weather related dollar differences between actual and authorized non-gas revenue by recording monthly differences in non-gas revenue in a deferred account and recovering the balance annually through a rate adjustment (surcharge). The process is identical in nature to the accounting for Southwest's Purchased Gas Cost Adjustment Provision. The mechanics of the RDAP are provided in Exhibit No.___(ABC-1). The following table illustrates that total customer savings, including the RDAP surcharge, can be increased thru a successful conservation program.

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	Effective Sales Rate	Change in Use/Customer	Annual Savings
Status Quo			
Per Customer Savings	$1.49065	-5.0 therms	-$7.45
Breakeven With RDAP			
Per Customer Savings	$1.49065	-6.1 therms	-$9.09
Plus RDAP Surcharge			1.65
Total Savings			-$7.44
Difference from Status Quo			$0.01
Breakeven RDAP Surcharge Calculation			
6.1 therms * $.26956* = $1.65 / 325.9 = $0.00505			
SWG Proposed DSM Programs With Decoupling			
Per Customer Savings	$1.49065	-6.7 therms	-$10.00
Plus RDAP Surcharge			1.81
Total Savings			-$8.19
Difference from Status Quo			$0.74
Breakeven RDAP Surcharge Calculation			
6.7 therms * $.26956* = $1.81 / 325.3 = $0.00556			

* $.26956 is weighted average winter non-base-load rate.

The "Status Quo" scenario shows that at Southwest's current average annual decline in use per residential customer of approximately 5 therms, per customer savings is $7.45.

The "Breakeven With RDAP" scenario demonstrates that if the Commission approves Southwest's proposed RDAP, conservation must be increased by slightly more than one therm, from 5 therms to 6.1 therms per customer in order for residential customers to be indifferent, in terms of the total amount paid, to the RDAP. Although customers may be indifferent financially, increasing conservation, will achieve reductions in the total amount of natural gas consumed.

If a more aggressive set of conservation measures,

such as those reflected in Southwest's 2006 Arizona Demand Side Management Program Plan filed in June of 2006, is successful in increasing conservation per customer from the base rate of 5 therms per year to 6.7 therms (as Southwest estimates would be accomplished with the implementation of its filed DSM programs), average customer savings, including the RDAP surcharge, can be increased by $0.74, or 10 percent, per customer per year on average. This equates to total additional residential customer savings of $0.7 million annually and an additional 1.6 million therm per year reduction in the amount of natural gas consumed vis-à-vis simply maintaining the status quo.

This information demonstrates that well-supported conservation and energy efficiency programs, in conjunction with the proposed RDAP, can "provide benefits to all affected stakeholders" as envisioned by the Commission in Decision No. 68487.

B. Weather Normalization Adjustment Provision(WNAP)

Southwest's proposed WNAP is a tariff mechanism that removes weather-related volatility from the non-gas component of customer bills for each winter season billing cycle. The WNAP functions similarly to two other utilities' weather adjustment mechanisms with which Southwest is familiar: Questar Gas in Utah and Northwest Natural Gas in Oregon. The mechanics of the WNAP are provided in Exhibit No.___(ABC-2).

Removing weather-related volatility from customer bills has the following benefits: (1) customers are shielded from over-paying for the fixed cost of distribution service when the weather is colder than normal; (2) the Company is protected from under-recovery of its cost of providing service when weather is warmer than normal; and (3) distribution revenues collected more closely mirror amounts authorized by the Commission in setting rates. Reducing weather-related volatility in customer bills improves the overall balance of risk for customers and the Company. As such, the WNAP is a proposal that benefits both customers and the Company.

Removing weather volatility on a real-time basis eliminates the Commission's concerns expressed in Decision No. 68487 that deferring dollar impacts of both weather- and non-weather-related changes in customer usage for amortization in a future period could result in potentially large swings in surcharge rates from year to year. In addition, it ensures that the dollar impacts related to each customer's usage is reflected on that customer's bill.

C. Basic Service Charge

In Decision No. 68487, the Commission authorized an increase of approximately twenty one (21) percent in Southwest's BSC from $8.00 to $9.70 per month. At $9.70 per month, approximately forty (40) percent of total

authorized residential non-gas revenue is recovered through the BSC. In authorizing a BSC of $9.70 per month, the Commission stated:

> "Based on consideration of competing interests and concerns, we agree that Staff's rate design recommendation appropriately makes significant movement towards cost based rates while providing a measure of protection for customers who will incur substantial rate increases as a result of this base rate case increase".

To continue building upon the movement toward cost-based rates authorized in Decision No. 68487, Southwest now proposes to increase the amount of its total residential non-gas revenue recovered through the BSC from forty (40) to forty-five (45) percent. This increase equates to a thirty-two (32) percent increase in Southwest's current single-family residential basic charge to $12.80 per month. Southwest proposes to retain its currently-effective multi-family basic service charge of $8.70 per month. Southwest's proposed basic service charges recover approximately forty-one (41) percent of the monthly fixed cost of service developed in Southwest's embedded customer class cost of service study and reflected on Sheet 1 of Exhibit No.___(ABC-4).

This more modest increase in Southwest's proposed single-family residential basic service charge responds to the Commission's concern in Decision No. 68487, that the movement of rates closer to cost-based rates "must

be balanced with consideration of the principles of gradualism, fairness, and encouragement of conservation."

D. Commodity Charge

In Decision No. 68487, the Commission encouraged the parties to seek rate design alternatives that would promote conservation efforts, while benefiting all affected stakeholders.

Southwest addressed these concerns through its proposal to flatten the sales rate (commodity charge) of its proposed residential rate design, while stabilizing its non-gas revenues through an innovative allocation of the non-gas and gas cost components of the sales rate as reflected below.

Illustrative "Average" and Proposed "Allocated" Single-Family Residential Rates

Description	Delivery (Non-Gas) Charge	Monthly Gas Cost & Rate Adj	Effective Sales Rate
Illustrative Average Rate Components			
Basic Service Charge	$12.80		$12.80
Commodity Charge per Therm			
All Usage	$.55376	$0.93689	$1.49065
Proposed Rate Components			
Basic Service Charge	$12.80		$12.80
Commodity Charge per Therm			
Summer			
First 15 Therms	$.88069	$0.60996	$1.49065
Over 15 Therms	.00000	1.49065	1.49065
Winter			
First 35 Therms	$.88069	$0.60996	$1.49065
Over 35 Therms	.00000	1.49065	1.49065

Southwest developed proposed rates for its single- and multi-family residential gas service as follows:

- Calculated basic service charges;
- Retained the currently effective summer and winter rate blocks for single- and multi-family residential service;
- Set the second block non-gas or delivery charge at $.00000 per therm;
- Calculated the first block non-gas rate required to recover the proposed residential non-gas revenue;
- Calculated the gas cost rates for each block so customers see a single charge per therm for all usage.

Unlike traditional declining block rates, Southwest's proposed rate design removes the declining block rate "price signal" from customers' bills. This rate design better aligns customer and Company interests, vis-à-vis traditional declining block rates, because 1) customers are provided greater incentive to "invest in conservation" thru elimination of the declining-block-rate price signal, and 2) cost recovery is enhanced by more accurately reflecting how non-gas and gas costs change, on average, with increases or decreases in customer usage. Exhibit No.___(ABC-3) provides a complete reconciliation of Southwest's proposed "Allocated" rate design versus a typical "Average" rate

design.

Laclede Gas Company, a natural gas distribution company in Saint Louis, Missouri, has had this type of residential rate design in place since November 2002. Southwest has a similar allocation of non-gas and gas cost between consumption blocks for service to residential natural gas customers in its South Lake Tahoe, California service area. Southwest has not experienced any customer or administrative difficulties related to this rate design. In both of these examples, the non-gas rate for second block consumption is zero.

Thus, Southwest's proposed rate design for residential gas service responds to the Commission's concerns that traditional declining block rate design can send the unintended message: "the more you use, the more you save."

IV. NON-RESIDENTIAL RATE DESIGN CHANGES

Q. 9 Please discuss the rate design changes Southwest proposes for its non-residential rate schedules.

A. 9 Southwest proposes to increase basic service charges for several of its non-residential rate schedules. Specifically, Southwest proposes to adjust basic service charges to the lesser of: 1) the monthly amount required to recover forty-one (41) percent of each schedules' allocated average fixed cost per month as reflected on Sheets 1 and 2 of Exhibit No.___(ABC-4) or 2) each schedules' currently effective basic charge increased by

thirty-two (32) percent. This approach gradually increases the basic service charges for non-residential schedules, with the exception of rate Schedule Nos. G-20, Master Meter Mobile Home Park; G-25(S), General Gas Service Small; and G-55(S), Gas Service for Compression Small. To avoid potentially large impacts on customers within these schedules, Southwest proposes to retain its currently effective basic service charges.

V. ALLOCATION OF SOUTHWEST'S PROPOSED NON-GAS REVENUE TO CUSTOMER CLASSES AND PROPOSED RATE DESIGN

Q. 10 Please describe Southwest's allocation of the proposed non-gas revenue requirement to customer classes.

A. 10 Southwest used the proportional cost responsibility method (PCRM) in apportioning its requested increase to customer classes. The PCRM is a cost of service based allocation methodology that narrows the difference between the system average rate of return on rate base and rate of return of the various classes of customers to establish non-gas revenue requirements by class that more accurately reflect the cost of providing service. Southwest used this method in prior rate cases and continues to believe that a cost of service based approach to determining each customer class' revenue requirement is superior to more subjective methods.

Q. 11 Have you summarized Southwest's proposed allocation of non-gas revenue and proposed rate design by customer classes?

A. 11 Yes. Southwest's allocation of non-gas revenue and resulting customer class rate design is developed in Exhibit No.___(ABC_4), Sheets 3-8. Sheets 3 and 4 reflect Southwest's PCRM allocation of non-gas revenue to customer classes. Southwest's proposed rates to recover proposed class non-gas revenue requirements are reflected on Sheets 5-8.

Q. 12. Can the PCRM and Southwest's proposed rate design methodology be utilized regardless of the level of non-gas revenue increase ultimately approved by the Commission?

A. 12. Yes.

VI. RATE DESIGN SUMMARY

Q. 13 Has Southwest prepared summary schedules quantifying the impact of its proposed changes in rates?

A. 13 Yes. Exhibit No.___(ABC-5) provides an in-depth look at Southwest's proposed rate designs and their impact on customers. Sheet 1 is a comparison of the differences between Southwest's currently-effective and proposed rates for single-residential service. Sheet 1 shows the dollar and percentage changes in rates by rate component as well as the per therm and percentage changes in the average rates for distribution sales service. Sheet 2 of Exhibit No.___(ABC_5) is a graphical representation

of the monthly bill impact that most single-family residential customers would experience. Sheets 3 and 4 of Exhibit No.___(ABC_5) are graphical representations of typical winter and summer season monthly bills at Southwest's currently-effective and proposed rates for service to single-family residential customers. Sheets 2-4 show that the effect of Southwest's proposed single-family residential rates is actually very smooth across the months and across various ranges of consumption. Sheets 5-8 of Exhibit No.___(ABC_5) reflect the above information for Southwest's currently-effective and proposed rates for multi-family residential service. Schedules H-1 through H-4 provide additional information for all customer classes on the impact of Southwest's proposed rate design changes. These schedules are discussed by Southwest witness Mr. Frank Maglietti in his prepared direct testimony.

Q. 14 Does this conclude your prepared direct testimony?

A. 14 Yes, it does.

SUMMARY OF QUALIFICATIONS
A. BROOKS CONGDON

I received a Bachelor of Science degree in Economics from Iowa State University in 1975.

From 1976 to 1980, I was employed as a Forecasting Analyst for General Telephone of the Midwest in the Company's Columbus, Nebraska office. My responsibilities there primarily involved projecting growth in demand for telephone service in eastern Nebraska and western Iowa.

From 1980 to 1984, I was employed as a Rate Analyst in the Rate Department of Pacific Power and Light Company in Portland, Oregon involved primarily in performing cost-of-service studies and designing rates for electric and water utilities.

In 1984, I accepted a position at Kansas Electric Power Cooperative in Topeka, Kansas where my primary responsibilities included coordination of intervention in wholesale power rate cases at the Federal Energy Regulatory Commission and preparation of the cooperatives' rate case activity before the Kansas Corporation Commission.

I began my employment with Southwest in 1987 in the Rate Department (now the Pricing and Tariffs Department) as a Rate Specialist. Since that time, I have held positions of increasing responsibility. My present position is Manager/Pricing and Tariffs. I report to the Director/Pricing and Tariffs. I am responsible for the

development of rate design and tariff proposals for Southwest in its three-state retail rate jurisdictions. I have submitted testimony and testified before the Public Utilities Commission of Nevada, the California Public Utilities Commission, the Arizona Corporation Commission and the Kansas Corporation Commission.

PARAMETERS FOR SOUTHWEST GAS' REVENUE DECOUPLING ADJUSTMENT PROVISION (RDAP)

Purpose of the RDAP:
The purpose of the RDAP is to maximize total customer savings thru aggressive promotion of conservation and energy efficiency without harming the Company financially by creating a new deferred account to record for future amortization differences between Southwest's Commission-authorized non-gas revenue calculated on a per customer basis, and weather-adjusted non-gas revenue actually billed. The RDAP applies to residential (G-5, G-6, G-10 and G-11) and general service (G-25S, G-25M and G-25L) customer classes.

Data Required:
Commission-authorized monthly non-gas revenue per customer, the number of customers billed in each month and monthly weather-adjusted non-gas revenue actually billed.

RDAP Process:
An entry will be made to the RDAP balancing account (RDAPBA) each month equal to the difference between authorized non-gas revenue on a per customer basis and actual weather-adjusted non-gas revenue billed. Separate subaccounts will be maintained for each customer class included in the RDAP. The RDAPBA will be amortized every twelve months by dividing the balance in each subaccount by the volume of gas expected to be delivered to the respective customer classes over the following twelve month period. Individual surcharges will be calculated for each customer class included in the RDAP. The RDAP process is set forth below.

- Calculate Commission-authorized monthly non-gas revenue per customer for each customer class included in the RDAP. Authorized monthly non-gas revenue per customer is set forth in Southwest's proposed RDAP tariff provision and the calculations are set forth in Sheets 2 and 3 of Exhibit No. ____(ABC-2).

- Calculate authorized monthly non-gas revenue for each class by multiplying the authorized non-gas revenue per customer by the number of customers actually billed.

- Using billing system records, determine the amount of monthly weather-adjusted non-gas revenue actually billed to customers.

- Record the difference between authorized and actual non-gas revenue in the RDAPBA for each customer class included in the RDAP. A credit RDAPBA entry will be made when actual non-gas revenue exceeds authorized non-gas revenue and a debit entry will be made when actual non-gas revenue is less than authorized non-gas revenue.

- After accumulating twelve months of entries, calculate RDAP surcharges/surcredits by dividing the balance for each customer class by the total volume of gas expected to be delivered to customers in the class over the following twelve month period.

- Include the resulting RDAP surcharges/surcredits in Southwest's Rate Adjustment.

SOUTHWEST GAS CORPORATION
ARIZONA
CALCULATION OF MONTHLY MARGIN PER CUSTOMER
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	May-06	June-06	July-06	August-06	September-06	October-06	November-06	December-06	January-07	February-07	March-07	April-07	Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
	Single-Family Residential Monthly Billing Determinants														
1	Customers	853,757	851,528	850,729	849,993	849,419	852,433	857,966	863,798	866,438	870,117	871,261	860,591	10,298,030	1
2	First Block Volumes	10,253,294	8,236,001	7,270,996	6,928,414	7,368,261	7,991,675	14,290,707	24,402,411	26,537,666	26,133,576	24,457,474	18,134,523	182,004,998	2
3	Second Block Volumes	6,747,280	2,583,884	1,512,290	1,235,651	1,600,730	2,327,269	2,662,649	17,459,253	29,488,186	22,557,133	13,874,969	5,001,823	107,051,117	3
4	Total Volume	17,000,574	10,819,885	8,783,286	8,164,065	8,968,991	10,318,944	16,953,356	41,861,664	56,025,852	48,690,709	38,332,443	23,136,346	289,056,115	4
	Proposed Margin Rates														
5	Basic Service Charge	$ 12.80	$ 12.80	$ 12.80	$ 12.80	$ 12.80	$ 12.80	$ 12.80	$ 12.80	$ 12.80	$ 12.80	$ 12.80	$ 12.80		5
6	First Block Margin Rate	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069		6
7	Second Block Margin Rate	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000		7
	Proposed Margin														
8	First Block Margin Revenue	$ 9,029,973	$ 7,253,363	$ 6,403,493	$ 6,101,785	$ 6,489,154	$ 7,038,188	$ 12,585,683	$ 21,490,959	$ 23,371,457	$ 23,015,579	$ 21,539,453	$ 15,970,893	$ 160,289,981	8
9	Second Block Margin Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	9
10	Basic Service Charge Revenue	10,928,090	10,899,558	10,889,331	10,879,910	10,872,563	10,911,142	10,981,965	11,056,614	11,090,406	11,137,498	11,152,141	11,015,565	131,814,784	10
11	Total Margin Revenue	$ 19,958,063	$ 18,152,922	$ 17,292,825	$ 16,981,695	$ 17,361,717	$ 17,949,331	$ 23,567,648	$ 32,547,573	$ 34,461,864	$ 34,153,076	$ 32,691,594	$ 26,986,458	$ 292,104,765	11
12	Margin per Customer	$ 23.38	$ 21.32	$ 20.33	$ 19.98	$ 20.44	$ 21.06	$ 27.47	$ 37.68	$ 39.77	$ 39.25	$ 37.52	$ 31.36	$ 339.55	12
	Multi-Family Residential Monthly Billing Determinants														
13	Customers	30,771	30,662	30,550	30,221	30,027	30,178	30,492	30,886	31,370	31,788	32,068	31,549	370,562	13
14	First Block Volumes	189,009	178,220	170,745	165,354	167,819	173,286	353,453	456,033	476,337	477,912	465,029	404,327	3,677,522	14
15	Second Block Volumes	278,619	163,312	128,508	113,302	124,189	142,074	88,792	378,605	534,182	441,523	300,073	137,356	2,830,537	15
16	Total Volume	467,628	341,532	299,253	278,656	292,008	315,360	442,245	834,638	1,010,519	919,435	765,102	541,683	6,508,059	16
	Proposed Margin Rates														
17	Basic Service Charge	$ 8.70	$ 8.70	$ 8.70	$ 8.70	$ 8.70	$ 8.70	$ 8.70	$ 8.70	$ 8.70	$ 8.70	$ 8.70	$ 8.70		17
18	First Block Margin Rate	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069		18
19	Second Block Margin Rate	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000		19
	Proposed Margin														
20	First Block Margin Revenue	$ 166,458	$ 156,956	$ 150,373	$ 145,626	$ 147,796	$ 152,611	$ 311,282	$ 401,623	$ 419,505	$ 420,893	$ 409,546	$ 356,087	$ 3,238,757	20
21	Second Block Margin Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	21
22	Basic Service Charge Revenue	267,708	266,759	265,785	262,923	261,235	262,549	265,280	268,708	272,919	276,556	278,992	274,476	3,223,889	22
23	Total Margin Revenue	$ 434,166	$ 423,716	$ 416,158	$ 408,548	$ 409,031	$ 415,160	$ 576,563	$ 670,332	$ 692,424	$ 697,448	$ 688,538	$ 630,563	$ 6,462,646	23
24	Margin per Customer	$ 14.11	$ 13.82	$ 13.62	$ 13.52	$ 13.62	$ 13.78	$ 18.91	$ 21.70	$ 22.07	$ 21.94	$ 21.47	$ 19.99	$ 208.53	24
	Special Residential Monthly Billing Determinants														
25	Customers	108	108	108	108	108	108	108	108	108	108	108	108	1,296	25
26	First Block Volumes	1,383	1,295	1,309	1,245	1,331	1,336	2,537	3,437	3,581	3,569	3,393	2,792	27,208	26
27	Second Block Volumes	8,689	11,510	14,004	12,739	11,510	6,875	4,151	9,039	12,084	10,081	7,627	6,003	114,312	27
28	Total Volume	10,072	12,805	15,313	13,984	12,841	8,211	6,688	12,476	15,665	13,650	11,020	8,795	141,520	28
	Proposed Margin Rates														
29	Basic Service Charge	$ 12.80	$ 12.80	$ 12.80	$ 12.80	$ 12.80	$ 12.80	$ 12.80	$ 12.80	$ 12.80	$ 12.80	$ 12.80	$ 12.80		29
30	First Block Margin Rate	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069	$ 0.88069		30
31	Second Block Margin Rate	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000		31
	Proposed Margin														
32	First Block Margin Revenue	$ 1,218	$ 1,140	$ 1,153	$ 1,096	$ 1,172	$ 1,177	$ 2,234	$ 3,027	$ 3,154	$ 3,143	$ 2,988	$ 2,459	$ 23,962	32
33	Second Block Margin Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	33
34	Basic Service Charge Revenue	1,382	1,382	1,382	1,382	1,382	1,382	1,382	1,382	1,382	1,382	1,382	1,382	16,589	34
35	Total Margin Revenue	$ 2,600	$ 2,523	$ 2,535	$ 2,479	$ 2,555	$ 2,559	$ 3,617	$ 4,409	$ 4,536	$ 4,526	$ 4,371	$ 3,841	$ 40,551	35
36	Margin per Customer	$ 24.08	$ 23.36	$ 23.47	$ 22.95	$ 23.65	$ 23.69	$ 33.49	$ 40.83	$ 42.00	$ 41.90	$ 40.47	$ 35.57	$ 375.47	36

Exhibit No. ____(ABC-1)
Sheet 2 of 3

SOUTHWEST GAS CORPORATION
ARIZONA
CALCULATION OF MONTHLY MARGIN PER CUSTOMER
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	May-06	June-06	July-06	August-06	September-06	October-06	November-06	December-06	January-07	February-07	March-07	April-07	Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
	Small General Service														
	Monthly Billing Determinants														
1	Customers	16,641	16,463	16,346	16,429	16,398	16,481	16,742	17,075	17,437	17,416	17,433	16,944	201,805	1
2	Therms	243,327	154,277	134,964	136,522	141,052	157,208	247,474	718,732	1,112,774	970,917	659,709	343,798	5,020,754	2
	Proposed Margin Rates														
3	Basic Service Charge Revenue	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00		3
4	Margin Rate All Usage	$ 0.75852	$ 0.75852	$ 0.75852	$ 0.75852	$ 0.75852	$ 0.75852	$ 0.75852	$ 0.75852	$ 0.75852	$ 0.75852	$ 0.75852	$ 0.75852		4
	Proposed Margin														
5	Commodity Margin Revenue	$ 184,568	$ 117,022	$ 102,373	$ 103,555	$ 106,991	$ 119,245	$ 187,714	$ 545,173	$ 844,061	$ 736,460	$ 500,402	$ 260,778	$ 3,808,342	5
6	Basic Service Charge Revenue	416,025	411,575	408,650	410,725	409,950	412,025	418,550	426,875	435,925	435,400	435,825	423,600	5,045,125	6
7	Total Margin Revenue	$ 600,593	$ 528,597	$ 511,023	$ 514,280	$ 516,941	$ 531,270	$ 606,264	$ 972,048	$ 1,279,986	$ 1,171,860	$ 936,227	$ 684,378	$ 8,853,467	7
8	Margin per Customer	$ 36.09	$ 32.11	$ 31.26	$ 31.30	$ 31.52	$ 32.24	$ 36.21	$ 56.93	$ 73.41	$ 67.29	$ 53.70	$ 40.39	$ 522.45	8
	Medium General Service														
	Monthly Billing Determinants														
9	Customers	16,117	16,079	16,023	16,002	15,958	16,048	16,059	16,242	16,368	16,293	16,333	16,268	193,790	9
10	Therms	3,020,571	2,505,961	2,234,466	2,142,536	2,335,242	2,556,274	3,596,629	5,891,658	6,455,032	5,939,096	5,222,869	3,829,935	45,530,269	10
	Proposed Margin Rates														
11	Basic Service Charge Revenue	$ 43.50	$ 43.50	$ 43.50	$ 43.50	$ 43.50	$ 43.50	$ 43.50	$ 43.50	$ 43.50	$ 43.50	$ 43.50	$ 43.50		11
12	Margin Rate All Usage	$ 0.40988	$ 0.40988	$ 0.40988	$ 0.40988	$ 0.40988	$ 0.40988	$ 0.40988	$ 0.40988	$ 0.40988	$ 0.40988	$ 0.40988	$ 0.40988		12
	Proposed Margin														
13	Commodity Margin Revenue	$ 1,238,072	$ 1,027,143	$ 915,863	$ 878,183	$ 957,169	$ 1,047,766	$ 1,474,186	$ 2,332,897	$ 2,645,789	$ 2,434,317	$ 2,140,750	$ 1,569,814	$ 18,661,947	13
14	Basic Service Charge Revenue	701,090	699,437	697,001	696,087	694,173	698,088	698,567	706,527	712,008	708,746	710,486	707,658	8,429,865	14
15	Total Margin Revenue	$ 1,939,161	$ 1,726,580	$ 1,612,863	$ 1,574,270	$ 1,651,342	$ 1,745,854	$ 2,172,753	$ 3,039,424	$ 3,357,797	$ 3,143,062	$ 2,851,235	$ 2,277,472	$ 27,091,812	15
16	Margin per Customer	$ 120.32	$ 107.38	$ 100.66	$ 98.38	$ 103.48	$ 108.79	$ 135.30	$ 187.13	$ 205.14	$ 192.91	$ 174.57	$ 140.00	$ 1,674.06	16
	Large General Service														
	Monthly Billing Determinants														
17	Customers	7,122	7,112	7,114	7,123	7,095	7,116	7,080	7,108	7,152	7,143	7,175	7,170	85,510	17
18	Therms	10,706,299	9,069,748	8,056,226	7,855,457	8,337,682	9,252,867	12,815,044	17,769,956	18,237,397	17,322,726	16,523,224	13,276,228	149,222,854	18
	Proposed Margin Rates														
19	Basic Service Charge Revenue	$ 160.00	$ 160.00	$ 160.00	$ 160.00	$ 160.00	$ 160.00	$ 160.00	$ 160.00	$ 160.00	$ 160.00	$ 160.00	$ 160.00		19
20	Margin Rate All Usage	$ 0.28843	$ 0.28843	$ 0.28843	$ 0.28843	$ 0.28843	$ 0.28843	$ 0.28843	$ 0.28843	$ 0.28843	$ 0.28843	$ 0.28843	$ 0.28843		20
	Proposed Margin														
21	Commodity Margin Revenue	$ 3,088,018	$ 2,615,987	$ 2,323,657	$ 2,265,749	$ 2,404,838	$ 2,668,804	$ 3,696,243	$ 5,125,388	$ 5,260,212	$ 4,996,394	$ 4,765,793	$ 3,829,262	$ 43,040,348	21
22	Basic Service Charge Revenue	1,139,520	1,137,920	1,138,240	1,139,680	1,135,200	1,138,560	1,132,800	1,137,280	1,144,320	1,142,880	1,148,000	1,147,200	13,681,600	22
23	Total Margin Revenue	$ 4,227,538	$ 3,753,907	$ 3,461,897	$ 3,405,429	$ 3,540,038	$ 3,807,364	$ 4,829,043	$ 6,262,668	$ 6,404,532	$ 6,139,274	$ 5,913,793	$ 4,976,462	$ 56,721,948	23
24	Margin per Customer	$ 593.59	$ 527.83	$ 486.63	$ 478.09	$ 498.95	$ 535.04	$ 682.07	$ 881.07	$ 895.49	$ 859.48	$ 824.22	$ 694.07	$ 7,956.53	24

Exhibit No. ____(ABC-1)
Sheet 3 of 3

PARAMETERS FOR SOUTHWEST GAS' WEATHER NORMALIZATION ADJUSTMENT PROVISION (WNAP)

Purpose of the WNAP:
The purpose of the WNAP is to eliminate weather-related risk by adjusting each customer's winter bill to reflect what the customer would have paid for delivery service assuming "normal" weather for each winter billing cycle. The WNAP applies to heat-sensitive residential (G-5, G-6, G-10 and G-11) and general service (G-25S, G-25M and G-25L) customer classes.

Data Required:
Actual average daily temperatures and 10-year average heating degree day (HDD) data.

WNAP Process:
A "WNAP Volume Adjustment" will be calculated for each customer for each winter billing cycle to reflect the difference between the customer's actual use and usage assuming normal weather. The WNAP Volume Adjustment will then be used to calculate a "WNAP Dollar Adjustment" to each customer's billed delivery charge. The WNAP process is set forth below.

- Obtain and store in Southwest's billing system actual average temperature and 10-year average HDDs for each day of the winter season. Actual average temperature for each day will be input into the billing system the following day, e.g.., Monday's temperature must be input Tuesday for Wednesday's billing.

- Calculate "Cycle HDD Variance" as follows:

Normal Cycle HDD =	10-year average HDDs for each day
Actual Cycle HDD =	The number of degrees that any day's average temperature is less than 65
Cycle HDD Variance =	Normal Cycle HDDs for each day in the billing cycle less Actual Cycle HDDs for each day in the billing cycle

- Calculate each customer's non-temperature sensitive "Base Load Volume per Day" by determining the customer's lowest average daily use for the June thru September billing periods. Average daily use is the customer's total monthly use divided by the number of days in the billing cycle. For new customers, Base Load Volume per Day will be estimated based upon the average Base Load Volume for other customers in each district. If necessary, Company personnel will adjust customers' Base Load Volume per Day to reflect a more representative amount.

- Calculate each customer's "Cycle Usage per HDD" by subtracting the customer's Base Load Volume (Base Load Volume = Base Load Volume per Day X Number of Days in Billing Cycle) from actual usage and dividing the difference by the Actual Cycle HDDs.

PARAMETERS FOR SOUTHWEST GAS' WEATHER NORMALIZATION ADJUSTMENT PROVISION (WNAP)

- Calculate each customer's WNAP Volume Adjustment by multiplying the customer's Cycle Usage per HDD by the Cycle HDD Variance.

- Calculate each customer's WNAP Dollar Adjustment by multiplying the WNAP Volume Adjustment by Southwest's delivery charge rates.

- Add the WNAP Dollar Adjustment to the customer's "regular" bill calculated using metered volumes and calculate taxes on the total including the WNAP Dollar Adjustment.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PROPOSED ALLOCATION OF NON-GAS AND GAS COST RATE COMPONENTS FOR RESIDENTIAL GAS SERVICE
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Proposed Schedule Number	Billing Determinants: Number of Bills	Billing Determinants: Sales (Therms)	Delivery Charge Rates	Delivery Charges	Monthly Gas Cost [1]	Rate Adjustment	Monthly Gas Cost and Rate Adjustment Charges	Effective Sales Rate	Total Revenue	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
	Average Non-Gas and Gas Rate Components [2]											
	Basic Service Charge per Month											
1	Single-Family Residential Gas Service	G-5	10,298,030		$ 12.80	$131,814,784				$ 12.80	$ 131,814,784	1
2	Multi-Family Residential Gas Service	G-6	370,562		8.70	3,223,889				8.70	3,223,889	2
3	Low-Income Residential Gas Service	G-10, G-11	338,294		7.50	2,537,205				7.50	2,537,205	3
4	Special Residential Gas Service	G-15	1,296		12.80	16,589				12.80	16,589	4
	Commodity Charge per Therm											
5	Single-Family Residential Gas Service			289,056,115	$ 0.55376	$160,067,714	$ 0.92426	$ 0.01263	$ 270,813,784	$ 1.49065	$ 430,881,498	5
6	Multi-Family Residential Gas Service			6,508,059	0.55376	3,603,903	0.92426	0.01263	6,097,335	1.49065	9,701,238	6
7	Low-Income Residential Gas Service			9,211,615	0.55376	5,101,024	0.81426	0.00322	7,530,311	1.37124	12,631,335	7
8	Special Residential Gas Service			141,520	0.55376	78,368	0.92426	0.00322	131,257	1.48124	209,625	8
9	Total Residential Gas Service		11,008,182	304,917,309		$306,443,476			$ 284,572,687		$ 591,016,163	9
	Allocated Non-Gas and Gas Rate Components [3]											
	Basic Service Charge per Month											
10	Single-Family Residential Gas Service	G-5	10,298,030		$ 12.80	$131,814,784				$ 12.80	$ 131,814,784	10
11	Multi-Family Residential Gas Service	G-6	370,562		8.70	3,223,889				8.70	3,223,889	11
12	Low-Income Residential Gas Service	G-10, G-11	338,294		7.50	2,537,205				7.50	2,537,205	12
13	Special Residential Gas Service	G-15	1,296		12.80	16,589				12.80	16,589	13
	Commodity Charge per Therm											
	Single-Family Residential Gas Service											
14	First Block Usage			182,004,998	$ 0.88069	$160,289,981	$ 0.59733	$ 0.01263	$ 111,015,768	$ 1.49065	$ 271,305,749	14
15	Second Block Usage			107,051,117	0.00000	0	1.47802	0.01263	159,575,748	1.49065	159,575,748	15
	Multi-Family Residential Gas Service											
16	First Block Usage			3,677,522	$ 0.88069	$ 3,238,757	$ 0.59733	$ 0.01263	$ 2,243,141	$ 1.49065	$ 5,481,898	16
17	Second Block Usage			2,830,537	0.00000	0	1.47802	0.01263	4,219,340	1.49065	4,219,340	17
	Low-Income Residential Gas Service											
18	First Block Usage			6,017,376	$ 0.88069	$ 5,299,443	$ 0.48733	$ 0.00322	$ 2,951,824	$ 1.37124	$ 8,251,267	18
19	Second Block Usage			3,194,239	0.00000	0	1.36802	0.00322	4,380,068	1.37124	4,380,068	19
	Special Residential Gas Service											
20	First Block Usage			27,208	$ 0.88069	$ 23,962	$ 0.59733	$ 0.00322	$ 16,340	$ 1.48124	$ 40,302	20
21	Second Block Usage			114,312	0.00000	0	1.47802	0.00322	169,324	1.48124	169,324	21
22	Total Residential Gas Service		11,008,182	304,917,309		$306,444,610			$ 284,571,553		$ 591,016,163	22
	Allocated Non-Gas and Gas Rate Components Change From Average Ratemaking											
23	First Block Usage				$ 0.32693		$ (0.32693)	$ 0.00000				23
24	Second Block Usage				(0.55376)		0.55376	0.00000				24

[1] Monthly Gas Cost and Rate Adjustment effective May 1, 2007. Schedules G-5, G-6 and G-15 include $.11000 per therm Gas Cost Balancing Account adjustment.
[2] Rates without Southwest's proposed allocation of non-gas and gas cost components of the sales rate.
[3] Southwest's proposed rates reflecting its proposed allocation of non-gas and gas cost rate components.

Exhibit No. ____(ABC-3)
Sheet 1 of 1

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
CALCULATION OF MONTHLY FIXED COST OF SERVICE

Line No.	Description	Allocated Amount							Line No.
		Residential	Multi-Family Residential	MMMHP	Small General Service	Medium General Service	Large General Service	Transportation Eligible	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	
	Total Fixed Cost Revenue Requirement at Proposed System ROR								
1	Customer-Related Costs	$ 268,059,972	$ 7,234,834	$ 158,967	$ 7,086,260	$ 17,178,690	$ 14,192,418	$ 1,814,331	1
2	Demand-Related Costs	$ 64,893,565	$ 1,196,003	$ 462,686	$ 1,264,556	$ 6,827,127	$ 19,293,885	$ 13,426,359	2
3	Total Fixed Costs	$ 332,953,537	$ 8,430,837	$ 621,653	$ 8,350,815	$ 24,005,817	$ 33,486,303	$ 15,240,690	3
4	Total Number of Monthly Bills	10,610,232	397,950	1,968	201,805	193,790	85,510	2,222	4
5	Average Fixed Cost per Month	$ 31.38	$ 21.19	$ 315.88	$ 41.38	$ 123.88	$ 391.61	$ 6,859.00	5
6	Total Commodity Revenue Requirement at Proposed System ROR	$ 1,325,033	$ 31,410	$ 9,894	$ 22,335	$ 202,544	$ 663,827	$ 442,749	6
7	Total Annual Throughput	297,856,607	7,060,702	2,223,993	5,020,754	45,530,269	149,222,854	99,526,400	7
8	Average Commodity Cost per Therm	$ 0.00445	$ 0.00445	$ 0.00445	$ 0.00445	$ 0.00445	$ 0.00445	$ 0.00445	8
9	Average Demand Cost per Therm	$ 0.21787	$ 0.16939	$ 0.20804	$ 0.25187	$ 0.14995	$ 0.12930	$ 0.13490	9
10	Average Annual Cost per Customer	$ 378.06	$ 255.18	$ 3,850.90	$ 497.90	$ 1,499.05	$ 4,792.44	$ 84,699.04	10
11	Per Month	$ 31.51	$ 21.26	$ 320.91	$ 41.49	$ 124.92	$ 399.37	$ 7,058.25	11

Exhibit No. ___(ABC-4)
Sheet 1 of 8

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
CALCULATION OF MONTHLY FIXED COST OF SERVICE

Line No.	Description	Air Conditioning	CNG - Small	CNG - Large	CNG - Residential	Electric Generation	Small Essential Agriculture	Gas Engine	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	
	Total Fixed Cost Revenue Requirement at Proposed System ROR								
1	Customer-Related Costs	$ 10,698	$ 10,565	$ 94,707	$ 31,247	$ 103,343	$ 378,282	$ 1,305,476	1
2	Demand-Related Costs	$ 47,545	$ 12,146	$ 142,414	$ 5,650	$ 1,196,194	$ 1,245,080	$ 561,096	2
3	Total Fixed Costs	$ 58,243	$ 22,711	$ 237,121	$ 36,897	$ 1,299,537	$ 1,623,362	$ 1,866,572	3
4	Total Number of Monthly Bills	318	252	288	1,272	252	1,216	5,105	4
5	Average Fixed Cost per Month	$ 183.15	$ 90.12	$ 823.34	$ 29.01	$ 5,156.89	$ 1,335.00	$ 365.64	5
	Total Commodity Revenue Requirement at Proposed System ROR								
6		$ 4,975	$ 790	$ 9,165	$ 344	$ 95,742	$ 32,095	$ 58,147	6
7	Total Annual Throughput	1,118,252	177,495	2,060,152	77,361	21,521,946	7,214,684	13,070,981	7
8	Average Commodity Cost per Therm	$ 0.00445	$ 0.00445	$ 0.00445	$ 0.00445	$ 0.00445	$ 0.00445	$ 0.00445	8
9	Average Demand Cost per Therm	$ 0.04252	$ 0.06843	$ 0.06913	$ 0.07304	$ 0.05558	$ 0.17258	$ 0.04293	9
10	Average Annual Cost per Customer	$ 2,385.56	$ 1,119.06	$ 10,261.89	$ 351.33	$ 66,441.84	$ 16,336.74	$ 4,524.31	10
11	Per Month	$ 198.80	$ 93.26	$ 855.16	$ 29.28	$ 5,536.82	$ 1,361.40	$ 377.03	11

Exhibit No. ___(ABC-4)
Sheet 2 of 8

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
ALLOCATION OF PROPOSED MARGIN TO CUSTOMER CLASSES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Total	Single Family Residential	Multi-Family Residential	MMMHP	General Gas Service				Air-Conditioning	Line No.
						Small	Medium	Large	Trans. Eligible		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	
1	Margin at Requested System Rate of Return [1]	$ 449,454,506	$ 334,945,916	$ 8,589,901	$ 631,232	$ 8,497,194	$ 24,128,939	$ 33,785,216	$ 15,399,330	$ 63,059	1
2	Margin at Present Rates [2]	$ 399,234,678	$ 258,989,889	$ 7,115,596	$ 972,093	$ 7,867,642	$ 24,310,776	$ 53,003,981	$ 20,088,639	$ 123,697	2
3	Difference (Line 1 minus Line 2)	$ 50,219,828									3
4	System Average Percentage Increase (Line 3 / Line 2)	12.57902%									4
5	Ratio of Margin at System Return to Margin at Present Rates (Line 1 / Line 2)		1.29328	1.20719	0.64935	1.08002	0.99252	0.63741	0.76657	0.50979	5
6	Adjusted Percentage Increase (Line 4 X Line 5)		16.26818%	15.18532%	8.16823%	13.58557%	12.48494%	8.01798%	9.64269%	6.41260%	6
7	Adjusted Percentage Increase $ (Line 2 X Line 6)	$ 54,267,003	$ 42,132,929	$ 1,080,526	$ 79,403	$ 1,068,864	$ 3,035,185	$ 4,249,851	$ 1,937,085	$ 7,932	7
8	Adjusted Margin Requirement (Line 2 + Line 7)	$ 453,501,681	$ 301,122,818	$ 8,196,122	$ 1,051,496	$ 8,936,506	$ 27,345,961	$ 57,253,832	$ 22,025,724	$ 131,629	8
9	(Over) / Under Collection [3]	(4,047,175)	(2,798,669)	(76,176)	(9,773)	(83,057)	(254,156)	(532,123)	(204,710)	(1,223)	9
10	Proposed Class Margin Requirement (Line 8 plus Line 9)	$ 449,454,506	$ 298,324,149	$ 8,119,946	$ 1,041,723	$ 8,853,449	$ 27,091,805	$ 56,721,708	$ 21,821,015	$ 130,406	10
11	Proposed Dollar Increase in Margin	$ 50,219,828	$ 39,334,260	$ 1,004,350	$ 69,630	$ 985,807	$ 2,781,029	$ 3,717,727	$ 1,732,376	$ 6,709	11
12	Proposed Percentage Increase in Margin	12.58%	15.19%	14.11%	7.16%	12.53%	11.44%	7.01%	8.62%	5.42%	12
13	Rate of Return at Present Rates	6.68%	3.95%	5.69%	20.15%	7.80%	9.55%	21.08%	14.97%	28.63%	13
14	Present Rate of Return Indices	1.00	0.59	0.85	3.01	1.17	1.43	3.15	2.24	4.28	14
15	Rate of Return at Proposed Rates	9.45%	6.91%	5.09%	22.31%	11.01%	12.23%	23.35%	17.12%	30.72%	15
16	Proposed Rate of Return Indices	1.00	0.73	0.54	2.36	1.16	1.29	2.47	1.81	3.25	16

[1] Class margin required to earn proposed overall system rate of return on rate base.
[2] Schedule H-2, Sheets 1-4.
[3] Difference between total magin required and Line 8, Column (b) prorated to classes as a percentage of margin on Line 8.

Exhibit No. ____(ABC-4)
Sheet 3 of 8

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
ALLOCATION OF PROPOSED MARGIN TO CUSTOMER CLASSES
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Total	Street Lighting	Small CNG	Large CNG	Residential CNG	Electric Generation	Essential Agricultural	Gas Engines	Optional and Special Contract	Other Revenue	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
1	Margin at Requested System Rate of Return [1]	$ 449,454,506	$ 129,736	$ 23,454	$ 243,268	$ 37,732	$ 1,382,427	$ 1,640,387	$ 1,910,883	$ 5,784,028	$ 12,261,805	1
2	Margin at Present Rates [2]	$ 399,234,678	$ 55,850	$ 36,474	$ 404,946	$ 25,489	$ 2,529,330	$ 3,104,924	$ 2,559,519	$ 5,784,028	$ 12,261,805	2
3	Difference (Line 1 minus Line 2)	$ 50,219,828										3
4	System Average Percentage Increase (Line 3 / Line 2)	12.57902%										4
5	Ratio of Margin at System Return to Margin at Present Rates (Line 1 / Line 2)		2.32293	0.64305	0.60074	1.48034	0.54656	0.52832	0.74658	n/a	n/a	5
6	Adjusted Percentage Increase (Line 4 X Line 5)		29.22023%	8.08889%	7.55676%	18.62118%	6.87517%	6.64572%	9.39123%	n/a	n/a	6
7	Adjusted Percentage Increase $ (Line 2 X Line 6)	$ 54,267,003	$ 16,319	$ 2,950	$ 30,601	$ 4,746	$ 173,896	$ 206,345	$ 240,370	$ 0	$ 0	7
8	Adjusted Margin Requirement (Line 2 + Line 7)	$ 453,501,681	$ 72,169	$ 39,424	$ 435,547	$ 30,235	$ 2,703,226	$ 3,311,269	$ 2,799,889	$ 5,784,028	$ 12,261,805	8
9	(Over) / Under Collection [3]	(4,047,175)	(671)	(366)	(4,048)	(281)	(25,124)	(30,775)	(26,022)	0	0	9
10	Proposed Class Margin Requirement (Line 8 plus Line 9)	$ 449,454,506	$ 71,499	$ 39,058	$ 431,499	$ 29,954	$ 2,678,102	$ 3,280,493	$ 2,773,867	$ 5,784,028	$ 12,261,805	10
11	Proposed Dollar Increase in Margin	$ 50,219,828	$ 15,649	$ 2,584	$ 26,553	$ 4,465	$ 148,772	$ 175,569	$ 214,348	$ 0	$ 0	11
12	Proposed Percentage Increase in Margin	12.58%	28.02%	7.08%	6.56%	17.52%	5.88%	5.65%	8.37%	0.00%	0.00%	12
13	Rate of Return at Present Rates	6.68%	-0.71%	22.12%	23.21%	2.11%	25.45%	27.53%	17.22%	n/a	n/a	13
14	Present Rate of Return Indices	1.00	(0.11)	3.31	3.47	0.32	3.81	4.12	2.58	n/a	n/a	14
15	Rate of Return at Proposed Rates	9.45%	1.58%	23.00%	25.64%	4.83%	27.52%	29.68%	19.82%	n/a	n/a	15
16	Proposed Rate of Return Indices	1.00	0.17	2.43	2.71	0.51	2.91	3.14	2.10	n/a	n/a	16

[1] Class margin required to earn proposed overall system rate of return on rate base.
[2] Schedule H-2, Sheets 1-4.
[3] Difference between total magin required and Line 8, Column (b) prorated to classes as a percentage of margin on Line 8.

Exhibit No. ___(ABC-4)
Sheet 4 of 8

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
CALCULATION OF PROPOSED RATES AND REVENUES BY RATE COMPONENT
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Proposed Schedule Number	Billing Determinants		Revenue at Proposed Rates					Line No.
			Number of Bills	Sales (Therms)	Basic Service Charge	Commodity Charge	Basic Service Charge	Commodity Charge	Total Margin	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
	Single-Family Residential Gas Service	G-5								
	Summer (May - October)									
1	Basic Service Charge per Month		5,107,859		$ 12.80		$ 65,380,595		$ 65,380,595	1
	Commodity Charge per Therm									
2	First 15 Therms			48,048,640		$ 0.88069		$ 42,315,957	42,315,957	2
3	Over 15 Therms			16,007,105		0.00000		0	0	3
	Winter (November - April)									
4	Basic Service Charge per Month		5,190,171		$ 12.80		$ 66,434,189		$ 66,434,189	4
	Commodity Charge per Therm									
5	First 35 Therms			133,956,357		0.88069		117,974,024	117,974,024	5
6	Over 35 Therms			91,044,013		0.00000		0	0	6
7	Total Single-Family Residential Gas Service		10,298,030	289,056,115			$ 131,814,784	$ 160,289,981	$ 292,104,765	7
	Low Income Single-Family Residential Gas Service	G-10								
	Summer (May - October)									
8	Basic Service Charge		153,923		$ 7.50		$ 1,154,423		$ 1,154,423	8
	Commodity Charge per Therm									
	Summer (May - October)									
9	First 15 Therms			1,499,731		$ 0.88069		$ 1,320,798	1,320,798	9
10	Over 15 Therms			343,792		0.00000		0	0	10
	Winter (November - April)									
11	Basic Service Charge per Month		156,983		$ 7.50		$ 1,177,373		$ 1,177,373	11
	Commodity Charge per Therm									
12	First 35 Therms			4,229,842		0.88069		3,725,179	3,725,179	12
13	Next 115 Therms			2,532,839		0.00000		0	0	13
14	Over 150 Therms			52,769		0.00000		0	0	14
15	Total Low Income Single-Family Residential Gas Service		310,906	8,658,972			$ 2,331,796	$ 5,045,977	$ 7,377,773	15
	Multi-Family Residential Gas Service	G-6								
	Summer (May - October)									
16	Basic Service Charge per Month		182,409		$ 8.70		$ 1,586,958		$ 1,586,958	16
	Commodity Charge per Therm									
17	First 7 Therms			1,044,432		$ 0.88069		$ 919,821	919,821	17
18	Over 7 Therms			950,005		0.00000		0	0	18
	Winter (November - April)									
19	Basic Service Charge per Month		188,153		$ 8.70		$ 1,636,931		$ 1,636,931	19
	Commodity Charge per Therm									
20	First 18 Therms			2,633,090		0.88069		2,318,936	2,318,936	20
21	Over 18 Therms			1,880,532		0.00000		0	0	21
22	Total Multi-Family Residential Gas Service		370,562	6,508,059			$ 3,223,889	$ 3,238,757	$ 6,462,646	22

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
CALCULATION OF PROPOSED RATES AND REVENUES BY RATE COMPONENT
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Proposed Schedule Number	Billing Determinants		Revenue at Proposed Rates					Line No.
			Number of Bills	Sales (Therms)	Basic Service Charge	Commodity Charge	Basic Service Charge	Commodity Charge	Total Margin	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
	Low Income Multi-Family Residential Gas Service	G-11								
	Summer (May - October)									
1	Basic Service Charge per Month		13,560		$ 7.50		$ 101,700		$ 101,700	1
	Commodity Charge per Therm									
2	First 7 Therms			79,822		$ 0.88069		$ 70,298	70,298	2
3	Over 7 Therms			78,071		0.00000		0	0	3
	Winter (November - April)									
4	Basic Service Charge per Month		13,828		$ 7.50		$ 103,710		$ 103,710	4
	Commodity Charge per Therm									
5	First 18 Therms			207,982		0.88069		183,168	183,168	5
6	Next 132 Therms			186,423		0.00000		0	0	6
7	Over 150 Therms			345		0.00000		0	0	7
8	Total Low Income Multi-Family Residential Gas Service		27,388	552,643			$ 205,410	$ 253,466	$ 458,876	8
	Special Residential Gas Service for A/C	G-15								
	Summer (May - October)									
9	Basic Service Charge per Month		648		$ 12.80		$ 8,294		$ 8,294	9
	Commodity Charge per Therm									
10	First 15 Therms			7,899		$ 0.88069		$ 6,957	6,957	10
11	Over 15 Therms			65,327		$ 0.00000		0	0	11
	Winter (November - April)									
12	Basic Service Charge per Month		648		$ 12.80		$ 8,294		$ 8,294	12
	Commodity Charge per Therm									
13	First 35 Therms			19,309		$ 0.88069		17,005	17,005	13
14	Over 35 Therms			48,985		$ 0.00000		0	0	14
15	Total Special Residential Gas Service		1,296	141,520			$ 16,589	$ 23,962	$ 40,551	15
16	Total Residential Gas Service		11,008,182	304,917,309			$137,592,468	$168,852,143	$ 306,444,611	16
	Master Metered Mobile Home Park Gas Service	G-20								
17	Basic Service Charge per Month		1,968		$ 60.00		$ 118,080		$ 118,080	17
	Commodity Charge per Therm All Usage									
18	All Usage			2,223,993		$ 0.41531		$ 923,647	923,647	18
19	Total MMMHP Gas Service		1,968	2,223,993			$ 118,080	$ 923,647	$ 1,041,727	19
	General Gas Service - Small	G-25(S)								
20	Basic Service Charge		201,805		$ 25.00		$ 5,045,125		$ 5,045,125	20
	Commodity Charge per Therm All Usage									
21	Transportation Customers			10,138		$ 0.75852		$ 7,690	7,690	21
22	Sales Customers			5,010,616		0.75852		3,800,652	$ 3,800,652	22
23	Total Small General Gas Service		201,805	5,020,754			$ 5,045,125	$ 3,808,342	$ 8,853,467	23
	General Gas Service - Medium	G-25(M)								
24	Basic Service Charge		193,790		$ 43.50		$ 8,429,865		$ 8,429,865	24
	Commodity Charge per Therm All Usage									
25	Transportation Customers			172,365		$ 0.40988		$ 70,649	70,649	25
26	Sales Customers			45,357,904		0.40988		18,591,298	18,591,298	26
27	Total Medium General Gas Service		193,790	45,530,269			$ 8,429,865	$ 18,661,947	$ 27,091,812	27

Exhibit No. ____(ABC-4)
Sheet 6 of 8

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
CALCULATION OF PROPOSED RATES AND REVENUES BY RATE COMPONENT
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Proposed Schedule Number	Billing Determinants: Number of Bills	Billing Determinants: Sales (Therms)	Revenue at Proposed Rates: Basic Service Charge	Revenue at Proposed Rates: Commodity Charge	Revenue at Proposed Rates: Basic Service Charge	Revenue at Proposed Rates: Commodity Charge	Revenue at Proposed Rates: Total Margin	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
	General Gas Service - Large	G-25(L)								
1	Basic Service Charge		85,510		$ 160.00		$ 13,681,600		$ 13,681,600	1
	Commodity Charge per Therm All Usage									
2	Transportation Customers			3,556,829		0.28843		1,025,896	1,025,896	2
3	Sales Customers			145,666,025		0.28843		42,014,452	42,014,452	3
4	Total Large General Gas Service		85,510	149,222,854			13,681,600	43,040,348	56,721,948	4
	General Gas Service - Transportation Eligible	G-25(TE)								
5	Basic Service Charge		2,222		$ 950.00		$ 2,110,900		$ 2,110,900	5
6	Demand Charge per Month			12,803,712	0.064142			9,855,048	9,855,048	6
	Commodity Charge per Therm All Usage									
7	Transportation Customers			32,517,415		$ 0.09902		$ 3,219,874	3,219,874	7
8	Sales Customers			67,008,985		$ 0.09902		$ 6,635,230	6,635,230	8
9	Total Transportation Eligible General Gas Service		2,222	99,526,400			$ 2,110,900	$ 19,710,152	$ 21,821,052	9
10	Total General Gas Service		483,327	299,300,277			$ 29,267,490	$ 85,220,789	$ 114,488,279	10
	Air Conditioning Gas Service	G-40								
	Basic Service Charge									
11	W/ Other Service (No BSC)		60		$ 0.00		$ 0		$ 0	11
12	General Service - Small		198		25.00		4,950		4,950	12
13	General Service - Medium		0		43.50		0		0	13
14	General Service - Large		48		160.00		7,680		7,680	14
15	General Service -Transportation Eligible		12		950.00		11,400		11,400	15
16	Essential Agricultural		0		120.00		0		0	16
	Commodity Charge per Therm All Usage									
17	Transportation Customers			373,987		$ 0.09513		$ 35,577	35,577	17
18	Sales Customers			744,265		0.09513		70,802	70,802	18
19	Total Air Conditioning Gas Service		318	1,118,252			$ 24,030	$ 106,379	$ 130,409	19
	Street Lighting Gas Service	G-45								
	Commodity Charge per Therm of Rated Capacity									
20	All Usage		324	102,289		$ 0.69899		$ 71,499	71,499	20
21	Total Street Lighting Gas Service		324	102,289			$ 0	$ 71,499	$ 71,499	21
	Gas Service for Compression on Customer's Premises	G-55								
	Basic Service Charge									
22	Small		252		$ 25.00		$ 6,300		$ 6,300	22
23	Large		288		250.00		72,000		72,000	23
24	Residential		1,272		12.80		16,282		16,282	24
	Commodity Charge per Therm All Usage									
25	Transportation Customers			0		$ 0.17535		$ 0	0	25
	Sales Customers									
26	Small			177,495		0.17535		31,124	31,124	26
27	Large			2,060,152		0.17535		361,248	361,248	27
28	Residential			77,361		0.17535		13,565	13,565	28
29	Total CNG Gas Service		1,812	2,315,008			$ 94,582	$ 405,937	$ 500,519	29

Exhibit No. ____(ABC-4)
Sheet 7 of 8

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
CALCULATION OF PROPOSED RATES AND REVENUES BY RATE COMPONENT
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description	Proposed Schedule Number	Billing Determinants: Number of Bills	Billing Determinants: Sales (Therms)	Revenue at Proposed Rates: Basic Service Charge	Revenue at Proposed Rates: Commodity Charge	Revenue at Proposed Rates: Basic Service Charge	Revenue at Proposed Rates: Commodity Charge	Revenue at Proposed Rates: Total Margin	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
	Electric Generation Gas Service	G-60								
	Basic Service Charge									
1	General Service - Small		36		$ 25.00		$ 900		$ 900	1
2	General Service - Medium		36		43.50		1,566		1,566	2
3	General Service - Large		84		160.00		13,440		13,440	3
4	General Service - Transportation Eligible		84		0.00		0		0	4
5	Essential Agricultural		12		120.00		1,440		1,440	5
	Commodity Charge per Therm All Usage									
6	Transportation Customers			0		$ 0.12363		$ 0	0	6
7	Sales Customers			21,521,946		0.12363		2,660,758	2,660,758	7
8	Total Electric Generation Gas Service		252	21,521,946			$ 17,346	$ 2,660,758	$ 2,678,104	8
	Small Essential Agriculture User Gas Service	G-75								
9	Basic Service Charge		1,216		$ 120.00		$ 145,920		$ 145,920	9
	Commodity Charge per Therm All Usage									
10	Transportation Customers			6,217,976		$ 0.23335		$ 1,450,965	1,450,965	10
11	Sales Customers			7,214,684		0.23335		1,683,547	1,683,547	11
12	Total Essential Agricultural Gas Service		1,216	13,432,660			$ 145,920	$ 3,134,512	$ 3,280,432	12
	Natural Gas Engine Gas Service	G-80								
	Basic Service Charge									
13	Off-Peak Season (Oct. - March)		2,516		$ 0.00		$ 0		$ 0	13
14	Peak Season (April - September)		2,589		125.00		323,625		323,625	14
	Commodity Charge per Therm All Usage									
15	Transportation Customers			0		$ 0.18746		$ 0	0	15
16	Sales Customers			13,070,981		0.18746		2,450,286	2,450,286	16
17	Total Natural Gas Engine Gas Service		5,105	13,070,981			$ 323,625	$ 2,450,286	$ 2,773,911	17
18	Total Tariff Sales		11,502,504	658,002,715			$167,583,541	$263,825,950	$ 431,409,491	18
19	Optional Gas Service	G-30	84	49,447,344			$ 120,540	$ 3,135,458	3,255,998	19
20	Special Contract Service	B-1	244	35,660,859			$ 449,274	$ 2,078,755	$ 2,528,029	20
21	Other Operating Revenues						$ 12,261,805		$ 12,261,805	21
22	Total Revenue		11,502,832	743,110,918			$ 180,415,160	$ 269,040,163	$ 449,455,324	22
23	Total Revenue Requirement								$ 449,454,506	23
24	Over/(Under)								$818	24

Exhibit No. ____(ABC-4)
Sheet 8 of 8

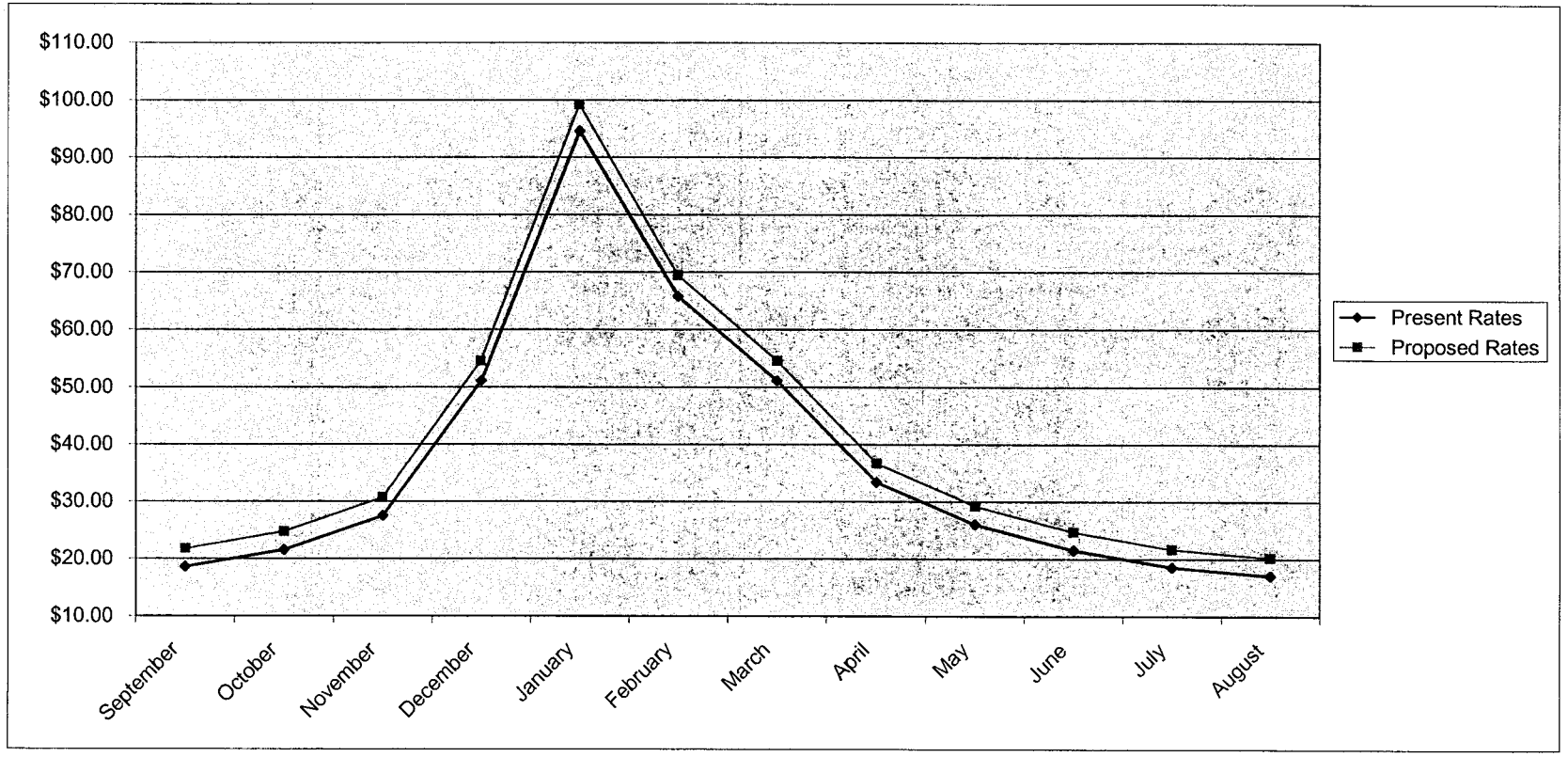
SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF PRESENT AND PROPOSED RATES BY RATE SCHEDULE
FOR RATE SCHEDULE NO. G-5 - SINGLE-FAMILY RESIDENTIAL GAS SERVICE

Line No.	Description	Billin Determinants Bills	Billin Determinants Volumes	Delivery Charge Rates	Distribution Service Revenue	Gas Cost Rate	Gas Cost Revenue	Effective Sales Rate	Total Revenue	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
	Revenues at Present Rates									
	Summer (May-October)									
1	Basic Service Charge	5,107,859		$ 9.70	$ 49,546,232			$ 9.70	$ 49,546,232	1
	Commodity Charge									
2	First 15 Therms		48,048,640	$ 0.54200	$ 26,042,363	$ 0.93689	$ 45,016,291	$ 1.47889	$ 71,058,654	2
3	Over 15 Therms		16,007,105	0.50100	8,019,559	0.93689	14,996,896	1.43789	23,016,456	3
	Winter (November-April)									
4	Basic Service Charge	5,190,171		$ 9.70	$ 50,344,659			$ 9.70	$ 50,344,659	4
	Commodity Charge									
5	First 35 Therms		133,956,357	$ 0.54200	$ 72,604,346	$ 0.93689	$ 125,502,371	$ 1.47889	$ 198,106,717	5
6	Over 35 Therms		91,044,013	0.50100	45,613,050	0.93689	85,298,225	1.43789	130,911,276	6
7	Total at Present Rates	10,298,030	289,056,115		$ 252,170,210		$ 270,813,784		$ 522,983,993	7
	Revenues at Proposed Rates									
	Summer (May-October)									
8	Basic Service Charge	5,107,859		$ 12.80	$ 65,380,595			$ 12.80	$ 65,380,595	8
	Commodity Charge									
9	First 15 Therms		48,048,640	$ 0.88069	$ 42,315,957	$ 0.60996	$ 29,307,749	$ 1.49065	$ 71,623,706	9
10	Over 15 Therms		16,007,105	0.00000	0	1.49065	23,860,990	1.49065	23,860,990	10
	Winter (November-April)									
11	Basic Service Charge	5,190,171		$ 12.80	$ 66,434,189			$ 12.80	$ 66,434,189	11
	Commodity Charge									
12	First 35 Therms		133,956,357	$ 0.88069	$ 117,974,024	$ 0.60996	$ 81,708,020	$ 1.49065	$ 199,682,044	12
13	Over 35 Therms		91,044,013	0.00000	0	1.49065	135,714,758	1.49065	135,714,758	13
14	Total at Present Rates	10,298,030	289,056,115		$ 292,104,765		$ 270,591,517		$ 562,696,282	14

Increase/(Decrease) Information	Present Rates	Proposed Rates	Dollar	Percent
Basic Charge				
Revenue	$ 99,890,891	$131,814,784	$ 31,923,893	31.96%
Average Rate	$ 9.70	$ 12.80	$ 3.10	31.96%
Commodity Charge				
Revenue	$152,279,319	$160,289,981	$ 8,010,663	5.26%
Average Rate	$ 0.52682	$ 0.55453	$ 0.02771	5.26%
Total Distribution Service Revenue				
Revenue	$252,170,210	$292,104,765	$ 39,934,556	15.84%
Average Rate	$ 0.87239	$ 1.01055	$ 0.13816	15.84%
Total Revenue				
Revenue	$522,983,993	$562,696,282	$ 39,712,289	7.59%
Average Rate	$ 1.80928	$ 1.94667	$ 0.13739	7.59%

Exhibit No. ___(ABC-5)
Sheet 1 of 8

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
MONTHLY BILL COMPARISON AT MODE USAGE
RATE SCHEDULE NO. G-5 - SINGLE-FAMILY RESIDENTIAL GAS SERVICE

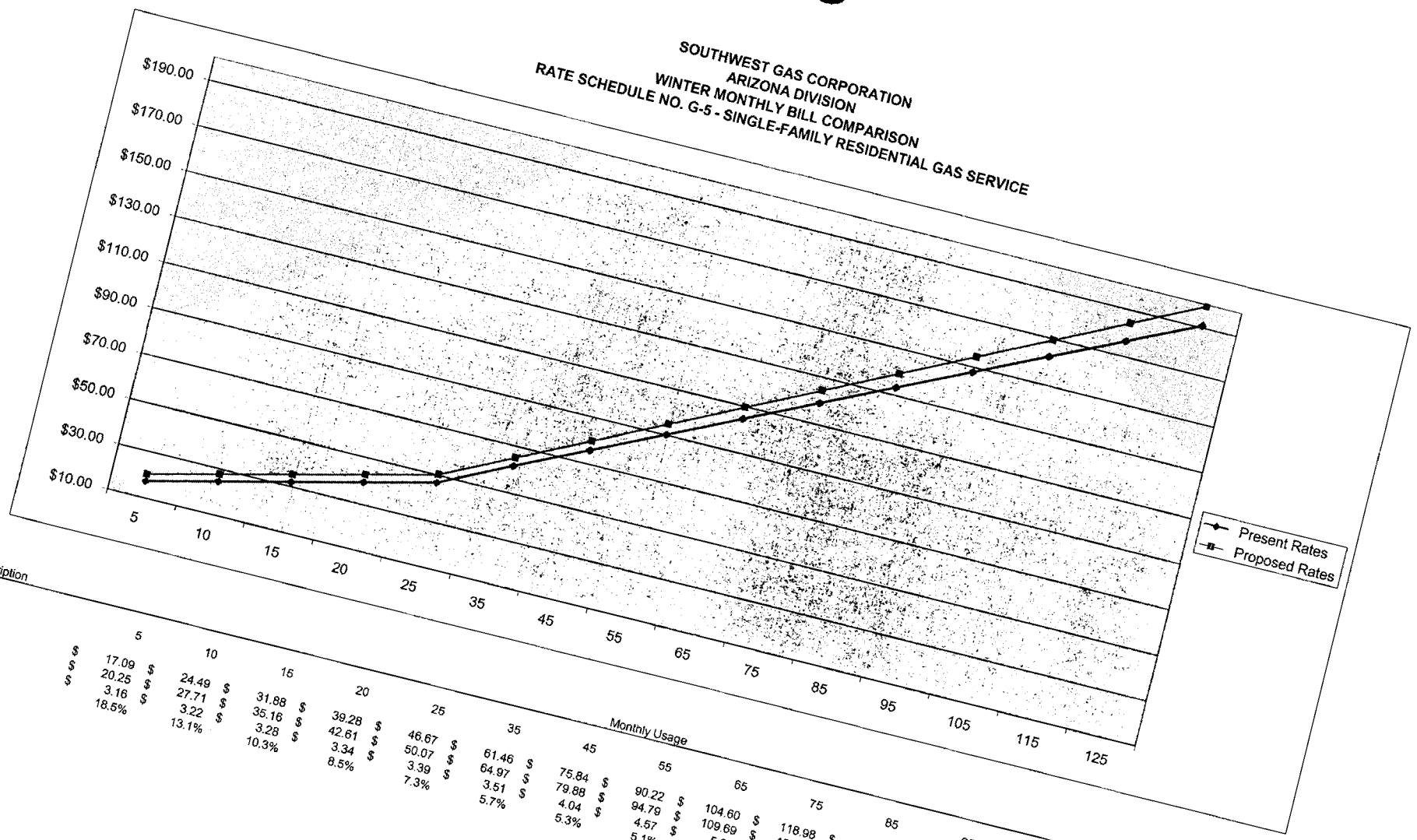


Description	September	October	November	December	January	February	March	April	May	June	July	August	Total
Mode Usage [1]	6	8	12	28	58	38	28	16	11	8	6	5	
Monthly Bill													
Present Rates	$ 18.57	$ 21.53	$ 27.45	$ 51.11	$ 94.53	$ 65.77	$ 51.11	$ 33.36	$ 25.97	$ 21.53	$ 18.57	$ 17.09	$ 446.61
Proposed Rates	$ 21.74	$ 24.73	$ 30.69	$ 54.54	$ 99.26	$ 69.44	$ 54.54	$ 36.65	$ 29.20	$ 24.73	$ 21.74	$ 20.25	$ 487.51
Dollar Change	$ 3.17	$ 3.19	$ 3.24	$ 3.43	$ 4.73	$ 3.67	$ 3.43	$ 3.29	$ 3.23	$ 3.19	$ 3.17	$ 3.16	$ 40.90
Percentage Change	17.1%	14.8%	11.8%	6.7%	5.0%	5.6%	6.7%	9.9%	12.4%	14.8%	17.1%	18.5%	9.2%

[1] Mode is the usage interval with the greatest number of monthly bills.

Exhibit No. ____(ABC-5)
Sheet 2 of 8

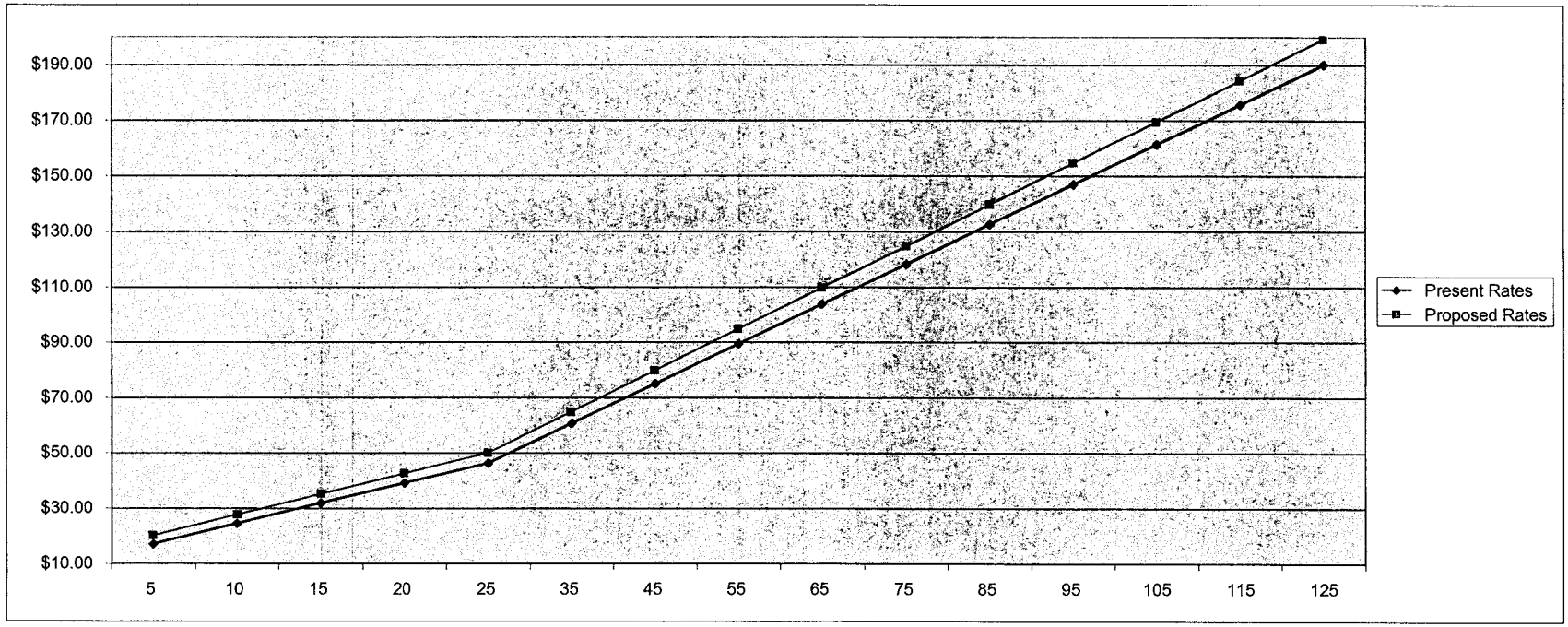
SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
WINTER MONTHLY BILL COMPARISON
RATE SCHEDULE NO. G-5 - SINGLE-FAMILY RESIDENTIAL GAS SERVICE



Description	Usage																							
Monthly Bill	5		10		15		20		25		35		45		55		65		75		85		95		105		115		125
Present Rates	$ 17.09		$ 24.49		$ 31.88		$ 39.28		$ 46.67		$ 61.46		$ 75.84		$ 90.22		$ 104.60		$ 118.98		$ 133.36		$ 147.73		$ 162.11		$ 176.49		$ 190.87
Proposed Rates	$ 20.25		$ 27.71		$ 35.16		$ 42.61		$ 50.07		$ 64.97		$ 79.88		$ 94.79		$ 109.69		$ 124.60		$ 139.51		$ 154.41		$ 169.32		$ 184.22		$ 199.13
Dollar Change	$ 3.16		$ 3.22		$ 3.28		$ 3.34		$ 3.39		$ 3.51		$ 4.04		$ 4.57		$ 5.09		$ 5.62		$ 6.15		$ 6.68		$ 7.20		$ 7.73		$ 8.26
Percentage Change	18.5%		13.1%		10.3%		8.5%		7.3%		5.7%		5.3%		5.1%		4.9%		4.7%		4.6%		4.5%		4.4%		4.4%		4.3%

Exhibit No. ___
Sheet 3 of 8 (ABC-5)

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMER MONTHLY BILL COMPARISON
RATE SCHEDULE NO. G-5 - SINGLE-FAMILY RESIDENTIAL GAS SERVICE



Description	Monthly Usage														
Usage	5	10	15	20	25	35	45	55	65	75	85	95	105	115	125
Monthly Bill															
Present Rates	$ 17.09	$ 24.49	$ 31.88	$ 39.07	$ 46.26	$ 60.64	$ 75.02	$ 89.40	$ 103.78	$ 118.16	$ 132.54	$ 146.91	$ 161.29	$ 175.67	$ 190.05
Proposed Rates	$ 20.25	$ 27.71	$ 35.16	$ 42.61	$ 50.07	$ 64.97	$ 79.88	$ 94.79	$ 109.69	$ 124.60	$ 139.51	$ 154.41	$ 169.32	$ 184.22	$ 199.13
Dollar Change	$ 3.16	$ 3.22	$ 3.28	$ 3.54	$ 3.80	$ 4.33	$ 4.86	$ 5.39	$ 5.91	$ 6.44	$ 6.97	$ 7.50	$ 8.02	$ 8.55	$ 9.08
Percentage Change	18.5%	13.1%	10.3%	9.1%	8.2%	7.1%	6.5%	6.0%	5.7%	5.5%	5.3%	5.1%	5.0%	4.9%	4.8%

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMARY OF PRESENT AND PROPOSED RATES BY RATE SCHEDULE
FOR RATE SCHEDULE NO. G-6 - MULTI-FAMILY RESIDENTIAL GAS SERVICE

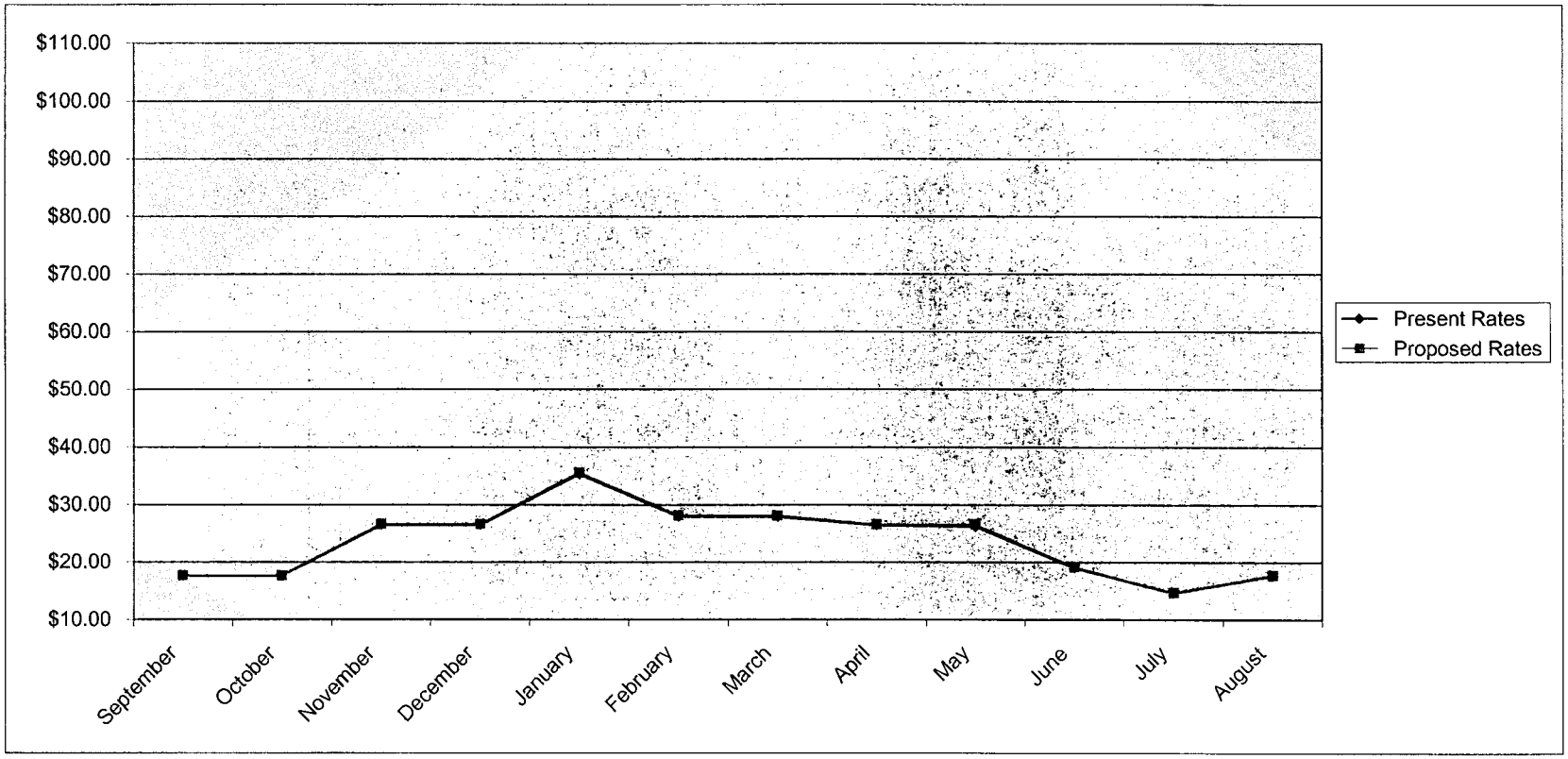
Line No.	Description	Billin Determinants Bills	Billin Determinants Volumes	Delivery Charge Rates	Distribution Service Revenue	Gas Cost Rate	Gas Cost Revenue	Effective Sales Rate	Total Revenue	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
	Revenues at Present Rates									
	Summer (May-October)									
1	Basic Service Charge	182,409		$ 8.70	$ 1,586,958			$ 8.70	$ 1,586,958	1
	Commodity Charge									
2	First 7 Therms		1,044,432	$ 0.54200	$ 566,082	$ 0.93689	$ 978,518	$ 1.47889	$ 1,544,600	2
3	Over 7 Therms		950,005	0.50100	475,953	0.93689	890,050	1.43789	1,366,003	3
	Winter (November-April)									
4	Basic Service Charge	188,153		$ 8.70	$ 1,636,931			$ 8.70	$ 1,636,931	4
	Commodity Charge									
5	First 18 Therms		2,633,090	$ 0.54200	$ 1,427,135	$ 0.93689	$ 2,466,916	$ 1.47889	$ 3,894,051	5
6	Over 18 Therms		1,880,532	0.50100	942,146	0.93689	1,761,851	1.43789	2,703,998	6
7	Total at Present Rates	370,562	6,508,059		$ 6,635,205		$ 6,097,335		$ 12,732,541	7
	Revenues at Proposed Rates									
	Summer (May-October)									
8	Basic Service Charge	182,409		$ 8.70	$ 1,586,958			$ 8.70	$ 1,586,958	8
	Commodity Charge									
9	First 7 Therms		1,044,432	$ 0.88069	$ 919,821	$ 0.60996	$ 637,062	$ 1.49065	$ 1,556,882	9
10	Over 7 Therms		950,005	0.00000	0	1.49065	1,416,125	1.49065	1,416,125	10
	Winter (November-April)									
11	Basic Service Charge	188,153		$ 8.70	$ 1,636,931			$ 8.70	$ 1,636,931	11
	Commodity Charge									
12	First 18 Therms		2,633,090	$ 0.88069	$ 2,318,936	$ 0.60996	$ 1,606,080	$ 1.49065	$ 3,925,016	12
13	Over 18 Therms		1,880,532	0.00000	0	1.49065	2,803,214	1.49065	2,803,214	13
14	Total at Present Rates	370,562	6,508,059		$ 6,462,646		$ 6,462,481		$ 12,925,128	14

Increase/(Decrease) Information

	Present Rates	Proposed Rates	Dollar	Percent
Basic Charge				
Revenue	$ 3,223,889	$ 3,223,889	$ -	0.00%
Average Rate	$ 8.70	$ 8.70	$ -	0.00%
Commodity Charge				
Revenue	$ 3,411,316	$ 3,238,757	$ (172,559)	-5.06%
Average Rate	$ 0.52417	$ 0.49765	$ (0.02652)	-5.06%
Total Distribution Service Revenue				
Revenue	$ 6,635,205	$ 6,462,646	$ (172,559)	-2.60%
Average Rate	$ 1.01954	$ 0.99302	$ (0.02651)	-2.60%
Total Revenue				
Revenue	$ 12,732,541	$ 12,925,128	$ 192,587	1.51%
Average Rate	$ 1.95643	$ 1.98602	$ 0.02959	1.51%

Exhibit No. ____(ABC-5)
Sheet 5 of 8

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
MONTHLY BILL COMPARISON AT MODE USAGE
RATE SCHEDULE NO. G-6 - MULTI-FAMILY RESIDENTIAL GAS SERVICE

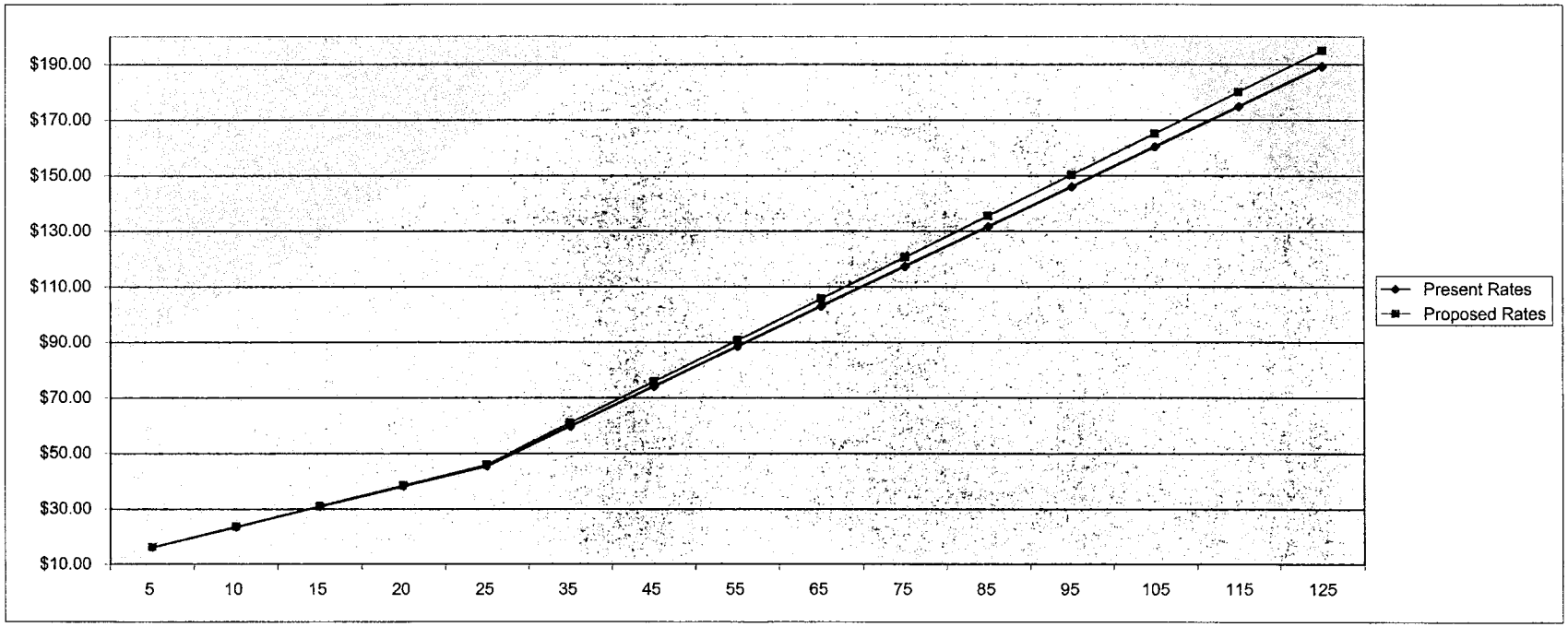


Description	September	October	November	December	January	February	March	April	May	June	July	August	Total
Mode Usage [1]	6	6	12	12	18	13	13	12	12	7	4	6	
Monthly Bill													
Present Rates	$ 17.57	$ 17.57	$ 26.45	$ 26.45	$ 35.32	$ 27.93	$ 27.93	$ 26.45	$ 26.24	$ 19.05	$ 14.62	$ 17.57	$ 283.14
Proposed Rates	$ 17.64	$ 17.64	$ 26.59	$ 26.59	$ 35.53	$ 28.08	$ 28.08	$ 26.59	$ 26.59	$ 19.13	$ 14.66	$ 17.64	$ 284.77
Dollar Change	$ 0.07	$ 0.07	$ 0.14	$ 0.14	$ 0.21	$ 0.15	$ 0.15	$ 0.14	$ 0.35	$ 0.08	$ 0.05	$ 0.07	$ 1.63
Percentage Change	0.4%	0.4%	0.5%	0.5%	0.6%	0.5%	0.5%	0.5%	1.3%	0.4%	0.3%	0.4%	0.6%

[1] Mode is the usage interval with the greatest number of monthly bills.

Exhibit No. ____(ABC-5)
Sheet 6 of 8

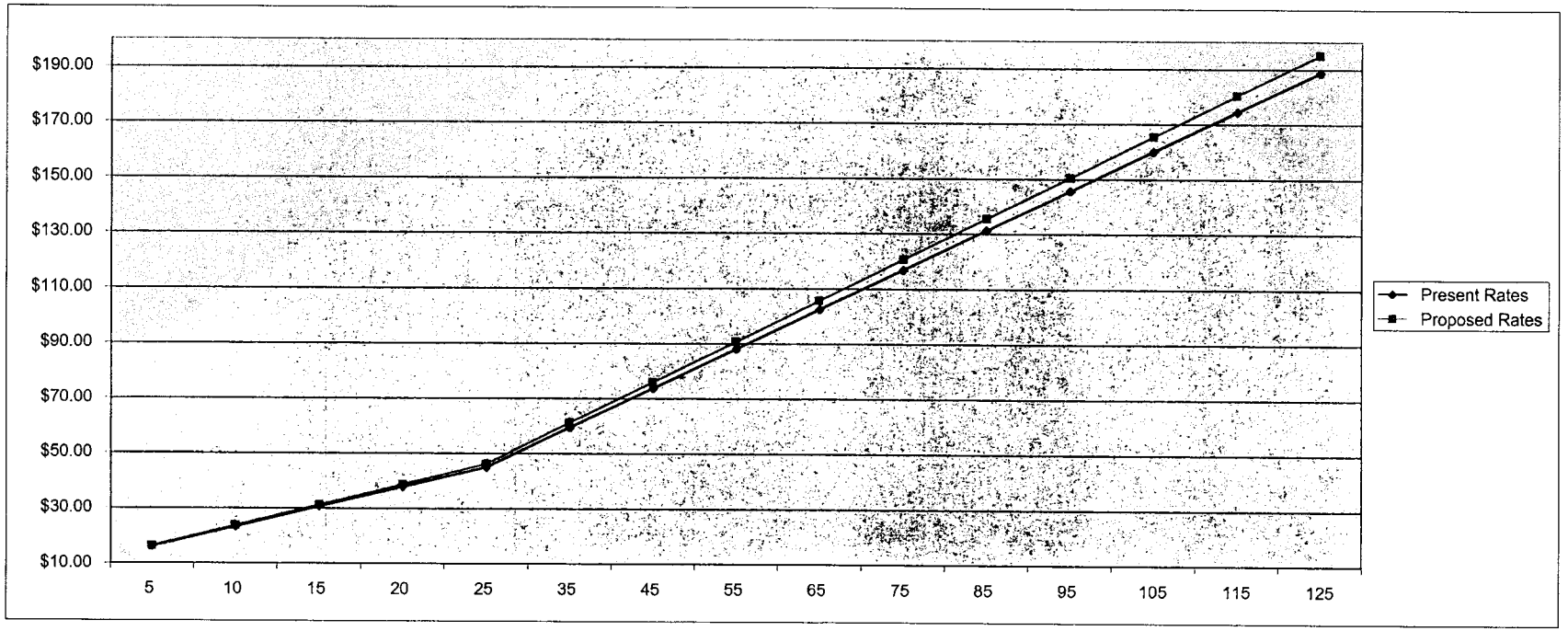
SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
WINTER MONTHLY BILL COMPARISON
RATE SCHEDULE NO. G-6 - MULTI-FAMILY RESIDENTIAL GAS SERVICE



Description	Monthly Usage														
Usage	5	10	15	20	25	35	45	55	65	75	85	95	105	115	125
Monthly Bill															
Present Rates	$ 16.09	$ 23.49	$ 30.88	$ 38.20	$ 45.39	$ 59.76	$ 74.14	$ 88.52	$ 102.90	$ 117.28	$ 131.66	$ 146.04	$ 160.42	$ 174.80	$ 189.17
Proposed Rates	$ 16.15	$ 23.61	$ 31.06	$ 38.51	$ 45.97	$ 60.87	$ 75.78	$ 90.69	$ 105.59	$ 120.50	$ 135.41	$ 150.31	$ 165.22	$ 180.12	$ 195.03
Dollar Change	$ 0.06	$ 0.12	$ 0.18	$ 0.32	$ 0.58	$ 1.11	$ 1.64	$ 2.16	$ 2.69	$ 3.22	$ 3.75	$ 4.27	$ 4.80	$ 5.33	$ 5.86
Percentage Change	0.4%	0.5%	0.6%	0.8%	1.3%	1.9%	2.2%	2.4%	2.6%	2.7%	2.8%	2.9%	3.0%	3.0%	3.1%

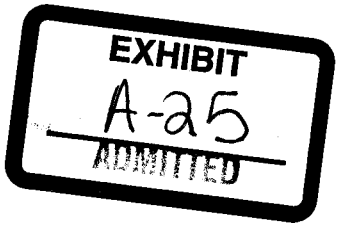
Exhibit No. ___(ABC-5)
Sheet 7 of 8

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
SUMMER MONTHLY BILL COMPARISON
RATE SCHEDULE NO. G-6 - MULTI-FAMILY RESIDENTIAL GAS SERVICE



Description	Monthly Usage														
Usage	5	10	15	20	25	35	45	55	65	75	85	95	105	115	125
Monthly Bill															
Present Rates	$ 16.09	$ 23.37	$ 30.56	$ 37.74	$ 44.93	$ 59.31	$ 73.69	$ 88.07	$ 102.45	$ 116.83	$ 131.21	$ 145.59	$ 159.97	$ 174.34	$ 188.72
Proposed Rates	$ 16.15	$ 23.61	$ 31.06	$ 38.51	$ 45.97	$ 60.87	$ 75.78	$ 90.69	$ 105.59	$ 120.50	$ 135.41	$ 150.31	$ 165.22	$ 180.12	$ 195.03
Dollar Change	$ 0.06	$ 0.24	$ 0.50	$ 0.77	$ 1.03	$ 1.56	$ 2.09	$ 2.61	$ 3.14	$ 3.67	$ 4.20	$ 4.73	$ 5.25	$ 5.78	$ 6.31
Percentage Change	0.4%	1.0%	1.7%	2.0%	2.3%	2.6%	2.8%	3.0%	3.1%	3.1%	3.2%	3.2%	3.3%	3.3%	3.3%

Exhibit No. ___(ABC-5)
Sheet 8 of 8



IN THE MATTER OF
SOUTHWEST GAS CORPORATION
Docket No. G-01551A-07-0504

PREPARED REBUTTAL TESTIMONY
OF
A. BROOKS CONGDON

ON BEHALF OF
SOUTHWEST GAS CORPORATION

May 9, 2008

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Of
Prepared Rebuttal Testimony
Of
A. BROOKS CONGDON

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Rebuttal Exhibit No.__(ABC-1)

Rebuttal Exhibit No.__(ABC-2)

Rebuttal Exhibit No.__(ABC-3)

Rebuttal Exhibit No.__(ABC-4)

Southwest Gas Corporation
Docket No. G-01551A-07-0504

BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rebuttal Testimony

of

A. BROOKS CONGDON

I. INTRODUCTION

Q. 1 Please state your name, occupation, and business address.

A. 1 My name is A. Brooks Congdon. I am the Manager/Pricing and Tariffs for Southwest Gas Corporation (Southwest or Company). My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150-0002.

Q 2 Are you the same A. Brooks Congdon who submitted prepared direct testimony in this Docket?

A. 2 Yes, I am.

Q. 3 What is the purpose of your rebuttal testimony?

A. 3 The purpose of my rebuttal testimony is to respond to the direct testimony presented by the Residential Utility Consumer Office (RUCO); the Arizona Corporation Commission Utilities Division Staff (Staff); and the Southwest Energy Efficiency Project (SWEEP) with respect to their recommendations and comments concerning Southwest's proposed rate design, tariff mechanisms, and revenue allocation to customer classes, and demand side management funding levels.

Q. 4 Did you prepare exhibits to support your rebuttal testimony?

A. 4 Yes. I prepared the exhibits identified as Rebuttal Exhibit No.__(ABC-1) through Rebuttal Exhibit No.__(ABC-4).

Q. 5 Please summarize your rebuttal testimony.

A. 5 My rebuttal testimony will address the following topics:

1) Southwest's continued financial pressure resulting from declining customer usage and sensitivity to variations in weather.

2) Southwest's participation in the rate design collaborative process following the Commission's decision in Southwest's last general rate case, including how Southwest applied what it learned to its rate design proposals in this general rate case.

3) Staff's critique of Southwest's residential rate design proposals.

4) The reasons why Staff's and RUCO's proposed rate designs do not sufficiently address the continued financial pressure facing Southwest as a result of declining customer usage and sensitivity to variations in weather.

5) Staff's allocation of non-gas revenue to customer classes.

6) Why Southwest's proposed residential rate design does not require any change to the Company's purchased gas adjustment mechanism.

7) Increased demand side management (DSM) spending and

the need for full revenue decoupling.

II. SOUTHWEST'S CONTINUED FINANCIAL PRESSURE FROM DECLINING CUSTOMER USAGE AND WEATHER SENSITIVITY

Q. 6 Please identify and explain the two primary issues presently facing Southwest with respect to rate design?

A. 6 The two primary issues presently facing Southwest with respect to rate design are: (1) declining usage per customer and (2) sensitivity to weather.

Q. 7 Do the parties to this docket recognize these two issues?

A. 7 Yes. In one form or another, the parties, with the exception of Staff, recognize the challenges Southwest faces due to declining customer usage and usage variability due to weather. For instance, RUCO witness William Rigsby states:

> "this is not to say that the issues and concerns the Company cites for wanting these decoupling mechanisms do not have some validity. . . . these concerns include the continued decline in average customer consumption, the relative proportion between SWG's fixed and variable costs to the Company's existing fixed and variable rates, and the resultant strain that puts on SWG's opportunity to recover its authorized rate of return.[1]

AIC witness Hansen acknowledges the problems when he states "decoupling will likely reduce the frequency of rate cases" and that decoupling will reduce "the

[1] Rigsby Rate Design Direct, p. 15, lns. 17-23 and p. 16, line1.

financial effects associated with changes in customer usage levels over time."[2] Mr. Hansen also recognizes the issue of sensitivity to weather when he notes that "when non-gas costs are recovered through volumetric rates, weather fluctuations lead to significant variability in customer payments for, and receipt of, non-gas revenue."[3] SWEEP witness Jeff Schlegel also recognizes the issue of declining use per customer when he states "The financial disincentive is particularly strong for natural gas utilities that have experienced an overall trend of declining gas usage per customer, which is the situation for Southwest Gas."[4]

Q. 8 Please explain how Southwest's rate design proposals provide the Commission with the tools necessary to address the two primary issues confronting Southwest?

A. 8 The Commission can use the rate design proposals presented by Southwest to achieve full revenue decoupling by implementing the WNAP and the RDAP. Implementation of the RDAP will protect Southwest and its customers from non-weather-related changes in cost recovery. Implementation of the WNAP eliminates weather-related risk for both Southwest and its customers equally, but does not protect customers or Southwest against non-weather-related variations in

[2] Hansen Rate Design Direct, p. 13, lns. 1-2.
[3] Id., p. 8, lns 8-10.
[4] Schlegel Direct, p. 4.

customer usage. Implementation of Southwest's proposed volumetric residential rate design methodology and increased basic service charge reduces, but does not eliminate, cost recovery variations due to weather-related and non-weather-related variations in customer use.

Q. 9. What do you mean by Southwest's proposed residential "Volumetric Rate Design"?

A. 9. By Volumetric Rate Design, I am referring to Southwest's proposal to combine a declining block rate for non-gas charges with an inverted block rate for gas costs for accounting purposes. The effect is that customers will see a single commodity rate applicable to all of their usage, while, through its accounting process, Southwest retains the benefit of a declining block rate to enhance its opportunity to recover its costs of providing service. These accounting changes, in conjunction with Southwest's proposals to flatten the commodity charge and increase the basic service charge constitute Southwest's proposed residential rate design.

Q. 10 You mentioned that in one form or another, all parties, except for Staff, recognize the challenges facing the Company with respect to declining customer usage and sensitivity to weather. Please explain.

A. 10 Staff's witness, Mr. Radigan, never acknowledges the problems, but instead summarily dismisses the Company's testimony, exhibits, and analysis by simply stating

disagreement with the Company, without offering any relevant evidence or information to invalidate the information he cites from the Company.

Unlike Mr. Radigan's testimony, Southwest, RUCO, SWEEP, and AIC all recognize the Company's challenges of declining customer usage and weather sensitivity, and presented rate design alternatives in response to the Commission's directive in Decision No. 68487. For example:

1) Although RUCO's residential rate design proposal does not adequately address the Company's rate design issues, in order to provide Southwest a better opportunity to recover its fixed cost of providing service, RUCO proposes significantly greater movement in Southwest's residential basic service charge than Staff.

2) SWEEP supports Southwest's proposed RDAP.

3) AIC supports Southwest's proposed full revenue decoupling through the RDAP and WNAP.

In other words, every party to the case, with the exception of Staff, believes changes to the status quo are warranted and have offered alternatives for the Commission's consideration in this regard.

Q. 11 Do you take exception to Mr. Radigan's statements that "[t]he Commission also wanted evidence that declining customer usage would continue, to what level and whether conservation efforts are the cause. No evidence on

either of these issues was presented in this case. No evidence was provided that showed that the Company needs 'full Revenue Decoupling.'"[5]

A. 11 Yes. Contrary to Mr. Radigan's contentions and conclusions, Southwest provided evidence that declining customer usage continues and to what level conservation is the cause. For example:

1) Company witness Jamie Cattanach presented direct testimony, at pages 9-14, demonstrating that average use per residential customer is continuing to decline at a rate of 6 therms per year and, for a variety of reasons, should be expected to continue to decline.

2) Company witness Robert Mashas presented direct testimony illustrating the significant dollar effect declining residential use per customer has had on the Company at pages 6-8 of his prefiled direct testimony.

3) Attached as Rebuttal Exhibit No.__(ABC-1) is an analysis Southwest performed and provided to all parties in the case in response to a RUCO data request which illustrates and quantifies the historical weather and conservation related losses experienced by the Company. Rebuttal Exhibit No.__(ABC-1) demonstrates that over the ten-year

[5] Radigan Decoupling Direct., p. 10, lns. 5-8.

period from 1998 thru 2007, Southwest experienced a $112.4 million shortfall in residential non-gas revenue from the amount rates were designed to recover. Of this amount, $118.2 million was non-weather-related (i.e., conservation and other possible variables). During this same time period, weather actually made a positive contribution to Southwest's recovery of margin in the amount of $5.8 million, which would have benefited customers if Southwest had a weather normalization adjustment mechanism similar to the WNAP.

4) Company witness Cattanach also filed rebuttal testimony indicating that since the close of the test period through the 12-month period ending March 2008, residential use per customer declined from an average of 332 therms to 319 therms on an annual basis.

Q. 12 Under Staff's or RUCO's proposed residential rate design, what will be the effect of using Southwest's as filed residential customer volumes to establish commodity rates?

A. 12 Under both Staff's and RUCO's proposed rate designs, residential commodity rates established using the filed customer volumes cannot reasonably be expected to recover the Commission's authorized cost of providing service. Therefore, from the day rates are placed into service, Southwest will be denied a reasonable opportunity to earn

its authorized rate of return.

Q. 13 Please quantify the effect of Mr. Cattanach's most recent twelve-month weather normalized residential volumes on Southwest's test period revenue at presently effective rates.

A. 13 The reduction in residential volumes results in a $6,292,707 decrease to test period revenue at present rates as quantified in Rebuttal Exhibit No.__(ABC-2).

Q. 14 What are the financial consequences to the Company associated with the known and measurable change in residential use per customer usage from 332 therms to 319 therms on a going-forward basis?

A. 14 If the Commission approves Southwest's proposed RDAP there would be no financial consequences as the test period RDAP would capture the differences between authorized and actual weather-adjusted non-gas revenue. However, without the RDAP, failure to recognize the reduction in residential usage, from 332 therms to 319 therms average use per customer, will deprive Southwest of the reasonable opportunity to recover $6,292,707, plus an additional amount associated with whatever increase is ultimately authorized, in residential revenue.

III. RATE DESIGN COLLABORATIVE PROCESS FOLLOWING DECISION No. 68487

Q. 15 Please respond to Staff's contention that the Company's proposals should be rejected due to the lack of

stakeholder support.[6]

A. 15 The fact that no consensus was reached in the collaborative should not be used as a basis to reject all of Southwest's rate design proposals in this case. Through the collaborative process, Southwest gained a better appreciation of the participating stakeholders' concerns and attempted to address those concerns in its rate design proposals.

Q. 16 Please describe how Southwest was able to utilitize the results of collaborative process in developing its rate design proposals.

A. 16 In response to RUCO's concern expressed during the collaborative that weather- and conservation-related changes in use per customer be separately addressed, Southwest proposed two separate and distinct tariff mechanisms to recover the non-gas portion of customer bills based on weather-adjusted volumes (the WNAP) and to recover or refund differences between actual and weather-adjusted non-gas revenues (the RDAP).

To respond to concerns expressed by Staff, RUCO and SWEEP (and the Commission in Decision No. 68487) regarding large increases in fixed charges, Southwest structured its Volumetric Rate Design proposal to include accounting changes for non-gas and gas costs. This rate design stabilizes residential cost recovery without large

[6] Id., p. 10, line 18.

increases to the basic service charge as would otherwise be required under traditional approaches to rate design in order to do so.

Q. 17 Do you believe the rate design collaborative process and Southwest's rate design proposals fully respond to the direction provided by the Commission in Decision No. 68487?

A. 17 Yes. In Decision No. 68487, the Commission clearly recognized the problems facing the Company when it stated that "Southwest Gas is facing increased financial pressure due to declining usage on a per customer basis."[7] The Commission also directed Southwest and other parties to seek rate design alternatives when it stated "We encourage the parties to this proceeding to seek rate design alternatives that will truly encourage conservation efforts, while at the same time providing benefits to all affected stakeholders."[8] As stated in my prepared direct testimony and more fully above, the Company considered the Commission's directives from Decision 68487 and the opinions expressed by the participating stakeholders at the rate design collaborative meetings when it developed its rate design proposals in this case. The Commission certainly has not stated that the inability of the stakeholders to reach settlement or consensus during the collaborative process

[7] Decision No. 68487, p. 33, lns 26-27.
[8] Id. at p. 34, lns 14-15.

would be a basis for the Commission to reject or not thoroughly consider proposals that mitigate or eliminate many concerns raised by the various stakeholders. Indeed, if a consensus of the collaborative group is required for the Commission to implement revenue decoupling then the Commission has in effect delegated its decision making authority to the participating stakeholders. The Company finds that possibility highly unlikely and believes that the Commission always intended to evaluate future proposals on their merits.

IV. RESPONSE TO STAFF'S CRITIQUE OF SOUTHWEST'S RESIDENTIAL RATE DESIGN PROPOSALS

Q. 18 What are the three reasons Staff provided as support for its recommendation to reject Southwest's proposed residential Volumetric Rate Design?

A. 18 Mr. Radigan states that Southwest's proposed Volumetric Rate Design should be rejected for three reasons: 1) current rates are almost flat now and customers currently have no reason not to invest in conservation; 2) the Company's proposed rate design is intended to eliminate virtually all risk from weather-related variation in usage; and 3) the specific line item where customers can see the commodity cost and track changes from month to month will no longer appear on the bill and, as such, may have the unintended effect of discouraging conservation.

Q 19 Do you agree with Mr. Radigan's reasons for rejecting Southwest's proposed Volumetric Rate Design?

A 19 No. I believe that Mr. Radigan's reasons for rejecting Southwest's proposed Volumetric Rate Design are flawed and should not be used as a basis to reject Southwest's proposal for the following reasons:

1) The record in Southwest's last general rate case is replete with discussion of the need for a rate design to send price signals to encourage conservation. This record includes discussion by Staff in direct testimony of moving to a flat rate design in Southwest's next rate case (the instant case) to eliminate a possible disincentive for energy conservation (Robert Gray, page 35, lines 2-5), and discussion during the hearing establishing that residential customers have "less of an opportunity to take actions to conserve their usage and thereby reduce their overall bills." as commodity rates are reduced (Hearing transcript, Decision No. 68487, Volume II, page 315, lines 22-24). Now that Southwest proposes a rate design in which the customer sees a flat rate design, Mr. Radigan's testimony suggests that Staff's previous concerns with Southwest's declining block rates were not relevant.

2) Mr. Radigan also suggests that the reduction or elimination of risk with respect to declining use per customer and variations in weather for the Company is a negative. However, as discussed by Mr.

Miller in his rebuttal testimony, reduction of risk can be a "win-win" proposal for both customers and the Company.

3) Under Southwest's proposed rate design, customers still see the commodity rate on their bill, and it will likely be easier for customers to track changes in their rate because there will be fewer line items on the bill. In addition, showing customers a single rate per therm may encourage greater conservation, as it indicates the total amount per therm saved if consumption is reduced.

Q. 20 Do you believe that Mr. Radigan mischaracterized, or misunderstands how the Commission can use Southwest's rate design proposals (the RDAP, WNAP, and its Volumetric Rate Design) to achieve full or partial revenue decoupling?

A. 20 Yes. While Mr. Radigan is correct that Southwest would like full revenue decoupling, full revenue decoupling can be accomplished by implementing the RDAP and the WNAP without Southwest's proposed Volumetric Rate Design. However, Southwest's proposed residential Volumetric Rate Design would serve to reduce the dollar amount of the adjustments made through the WNAP and, to a lesser extent, through the RDAP. Furthermore, if the Commission is reluctant to approve full revenue decoupling at this time, partial revenue decoupling can be accomplished by approving either one of the RDAP, the WNAP or the

proposed residential Volumetric Rate Design independently. Southwest specifically structured its rate design proposals to provide the Commission with as much flexibility as possible to address the Company's need for increased revenue stability without adversely affecting customers or the effective promotion of conservation and energy efficiency.

V. STAFF'S and RUCO's PROPOSED RESIDENTIAL RATE DESIGN PROPOSALS

Q. 21 Please comment on Staff's suggestion that most of the potential weather and conservation-related losses can be eliminated "by just adopting simple rate design changes such as increasing the customer charge."[9]

A. 21 While Staff is correct that increasing the customer charge can enhance the Company's ability to recover the authorized cost of service, Staff provides no analysis to demonstrate the level of increase that is necessary to achieve meaningful results. Southwest demonstrated to the participating stakeholders during the collaborative process that significant increases to the residential basic service charge were required to substantially affect fluctuations in margin associated with declining use per customer and weather. This analysis is included as Rebuttal Exhibit No.__(ABC-3). This exhibit quantifies the basic service charge that would be necessary to

[9] Radigan Decoupling Direct p. 10, Ins. 15-16.

eliminate most of weather- and conservation-related losses as Staff suggests can be accomplished by increasing the customer charge.

Q. 22 Staff and RUCO propose modest increases to the residential basic service charge and a flat commodity rate. What impact would such a rate design have on Southwest, if approved by the Commission in this rate case?

A. 22 As previously mentioned, Company witness Mr. Cattanach has demonstrated on rebuttal that, since the end of the test period in this case, through the 12-month period ending March 2008, Southwest's residential use per customer has declined on average from 332 therms to 319 therms. Staff's proposed commodity margin rate of $.56013 per therm results in an immediate shortfall of $6.7 million per year ($.56013 X 917,350 customers X 13 therms). This shortfall is almost 8.2 percent of Southwest's recorded net operating income during the test period, and is further compelling evidence that a significant change in rate design is necessary. RUCO's proposed residential rate design results in a $6.6 million shortfall at the time rates are implemented.

Q. 23 Has Southwest prepared an analysis similar to Rebuttal Exhibit No.__(ABC-3) reflecting the $6.7 million shortfall discussed above.

A. 23 Yes. Assuming Staff's proposed residential revenue requirement, the following table illustrates the effect

that increasing the basic service charge has on the above mentioned $6.7 million shortfall associated with the 13 therm decrease in residential use per customer.

Basic Charge	$10.70	$11.50	$12.80	$15.00	$17.50	$20.00
Commodity*	$.560	$.532	$.488	$.411	$.325	$.238
Shortfall	$6.7	$6.3	$5.8	$4.9	$3.9	$2.8
% Net Income	8%	8%	7%	6%	5%	3%

*Commodity rate is based upon Staff's proposed residential revenue requirement.

The table demonstrates that without very large increases to the basic service charge, Southwest is deprived of a fair and reasonable opportunity to recover its Commission-authorized cost of service. As such, Staff's and RUCO's proposed approach to residential rate design are not viable alternatives to address the issues presently facing the Company. Rather, Southwest's tariff mechanisms and rate design proposals to further decouple revenue from sales, which are supported by AIC and SWEEP to a limited extent, should be accepted by the Commission in this case as they are responsive to the Commission's Decision No. 68487, and there is no evidence of any other viable alternatives that would provide Southwest a reasonable opportunity to recover its Commission authorized cost of service.

VI. STAFF'S ALLOCATION OF NON-GAS REVENUE TO CUSTOMER CLASSES

Q. 24 Please comment on the reasonableness of Staff's revenue

allocation.

A. 24 Staff's position is that Southwest's proportional cost responsibility method (PCRM) allocation of revenues among customer classes should be "tempered," and Staff's allocation used. Three examples are cited to support this position: 1) the relatively large 12.2 percent increase proposed for Southwest's Special Residential Rate Schedule No. G-15; 2) the relatively small 1.5 percent increase proposed for Multi-Family Residential Rate Schedule No. G-6; and 3) the relatively large 10.4 percent increase proposed for Street Lighting Rate Schedule No. G-45.

Southwest's PCRM allocation methodology is intended to move class revenues closer to each class' allocated cost of service. Classes whose rates of return are further from the system average rate receive larger percentage changes in revenue than classes whose return is closer to the system average. Although Staff proposes a "two step process" where step-one is intended to bring class revenues closer to cost of service, the second step requires that no class receive an increase "more than 1 percent more or less than the overall increase."[10] As such, Staff's proposal effectively amounts to little more than an equal percentage increase to customer class revenue.

[10] Radigan Rate Design Direct, p. 4, ln 6.

Staff's proposal shifts more of the increase in non-gas costs to Southwest's high load factor customer classes, when these classes, in fact, cost less to serve on an average cents per therm basis. Thus, Staff's proposal effectively disregards Southwest's actual costs of providing service to its various classes of customers. In the long-run, mismatching the Company's cost of providing service with rates paid by customers increases the risk that customers will make uneconomical decisions with respect to their energy consumption.

Q. 25 Please explain why the examples Mr. Radigan cites do not provide a sufficient basis to reject Southwest's proposed allocation method.

A. 25 First, two of Mr. Radigan's three examples have nothing to do with Southwest's allocation methodology, but instead, result from how Southwest's residential rates are currently designed. Schedule G-15 currently has a steep declining block during the summer season. The 12.2 percent increase for Schedule G-15 results from Southwest's proposal to eliminate its declining block residential rate design. The relatively small 1.5 percentage increase for Schedule G-6 is the result of the design of Southwest's currently effective single-family and multi-family residential rates, which have identical commodity rates and Southwest's proposal not to change this relationship. These effects have nothing to do with Southwest's proposed revenue allocation methodology. The

10.4 percent increase to Schedule G-45 is necessary to increase that schedule's rate of return from -0.71 percent to (only) 0.17 percent at proposed rates, and demonstrates that Southwest's PCRM allocation method works as intended to move each customer class toward cost of service.

VII. SOUTHWEST'S PROPOSED RESIDENTIAL VOLUMETRIC RATE DESIGN AND ITS RELATIONSHIP TO THE PGA

Q. 26 Please comment on Staff witness Robert Gray's position that the existing PGA (PGA) mechanism must be changed prior to the implementation of any rate design decoupling mechanism (i.e., Southwest's proposed residential Volumetric Rate Resign).

A. 26 Southwest reviewed the structure and operation of the monthly PGA mechanism during the development of its Volumetric Rate Design proposal. Implementation of Southwest's Volumetric Rate Design would not require any changes to Southwest's current PGA process. Southwest's monthly gas cost will continue to be calculated exactly as it is today:

1) The current month's 12-month rolling average cost of gas will be calculated.

2) The current month's 12-month average cost of gas will be compared to the last twelve months, and the PGA bandwidth limit applied to determine the allowed cent per therm change in the monthly gas cost.

3) The resulting cent per therm change in gas cost will

be applied to the first and second tier gas costs in the rate design.

Q. 27 Has Southwest performed analyses showing the effects its proposed Volumetric Rate Design?

A. 27 Yes. Southwest performed analyses quantifying the dollar impacts of its proposal under both colder and warmer than normal weather conditions in response to Staff data request 6-28. Southwest also provided further explanation of its Volumetric Rate Design proposal in its response to RUCO Data Request 7-1. These responses are attached as Rebuttal Exhibit No.__(ABC-4).

Q. 28 Please describe the information reflected in Rebuttal Exhibit No.__(ABC-4).

A. 28 The dollar amounts reflected on Page 4 of 10 show that the Volumetric Rate Design's decoupling effect is significant in comparison to Southwest's net operating income but, at the same time, has a negligible percentage effect on Southwest's PGA mechanism. This is reflected in the table below which shows the rate design's decoupling effect as a percent of Southwest's recorded net operating income and recorded total purchased cost of gas.

$ Millions

	Colder Weather	Warmer Weather
Decoupling $ Amount	$1.0	$3.8
% Net Operating Income	1.2%	4.6%
% Total Gas Cost	0.2%	0.6%

It is also important to note that as long as no PGA surcharge is required to recover or return amounts in the PGA balancing account, the total amount of residential customers' bills is unaffected by the proposed Volumetric Rate Design. In that sense, Southwest's monthly PGA process compliments the proposed Volumetric Rate Design by limiting the need, except in periods of rapidly changing prices in the natural gas market place, for Southwest to have a surcharge to clear the gas cost balancing account.

Pages 6 through 10 of Rebuttal Exhibit No.__(ABC-4) discus how the Volumetric Rate Design impacts Southwest's accounting and also the benefits the rate design provides to the Company and to its customers.

VIII. INCREASED DSM PROGRAM SPENDING AND THE NEED FOR FULL REVENUE DECOUPLING

Q. 29 What is Southwest's position on increasing its DSM program spending to at least $12.0 million at this time as proposed by SWEEP?

A. 29 Southwest has not yet been authorized to spend the entire amount of its DSM program budget established in its last general rate case and therefore it would not be appropriate to significantly increase that budget prior to gaining additional experience under Southwest's current DSM programs.

Q. 30 In addition to SWEEP's proposal that Southwest increase its DSM program spending, SWEEP also supports Southwest's

proposed RDAP, and correctly points out that lower per customer revenues that result from successful energy efficiency measures create a financial disincentive for Southwest to enthusiastically support increased energy efficiency efforts. Is there an approach the Commission could consider that addresses both SWEEP's interests in maximizing DSM program spending and Southwest's attendant financial concerns?

A. 30 Yes. The record is very clear that without revenue decoupling, Southwest has a distinct financial disincentive to promote reductions in customer use. However, Southwest understands that reducing the amount of energy consumed by customers and reducing the amount of money spent by customers for their energy requirements is a goal all parties need to support for a variety of economic and environmental reasons. Therefore, Southwest suggests that the Commission entertain an alternative approach in addressing SWEEP's proposal to increase DSM spending and Southwest's proposed full revenue decoupling.

Q. 31 Please explain your proposed alternative approach to SWEEP's proposal?

A. 31 Southwest proposes the following:

1) Remove the determination of the level of DSM program spending from Southwest's general rate case process and allow the level of spending to be established annually or bi-annually by Commission order based on

recommendations from the previously established Southwest DSM Collaborative. This process will allow more time to evaluate the effectiveness of Southwest's currently-authorized DSM programs and study the effectiveness of new programs and/or increased spending on existing programs, rather than attempting to determine a level of spending in this rate case.

2) Implement Southwest's proposed revenue decoupling provisions, the RDAP and the WNAP, on a pilot basis for three years or until Southwest's next general rate case, which ever occurs first. During this pilot period, the parties can study the resulting impacts of the RDAP and WNAP, and Southwest can provide Staff with reports detailing the dollar amounts collected/refunded by the respective provisions.

3) At the conclusion of the three year pilot period or at the next rate case, Southwest will engage the services of an independent third party to conduct a review of the mechanisms and will provide the Commission a copy of the consultant's report. At that time the effectiveness of the RDAP and WNAP could be reviewed in Southwest's next rate case, and these mechanisms could be extended or eliminated at that time based on their respective performance.

Q. 32 Are you aware of other utilities and state regulatory

commissions that have utilized a similar approach?

A. 32 Yes. Questar Gas Company, cited by SWEEP in arriving at its proposed DSM spending for Southwest, had a revenue decoupling mechanism (the Conservation Enabling Tariff) approved on a three-year pilot basis as a part of that company's increased commitment to energy efficiency. Southwest believes that its alternative approach outlined above is a reasonable balance of the interests expressed to date by SWEEP, Staff, RUCO, and the Company.

Q. 33 Are there any other benefits associated with Southwest's decoupling proposals that the Commission should consider?

A. 33 Yes. Arizona Governor Janet Napolitano signed Executive Order 2005-02 establishing the Climate Change Advisory Group (CCAG) and directing the CCAG to, among other things, develop a climate change action plan. Page 50 of the climate change action plan discusses certain recommendations for energy savings goals for electricity and natural gas, and the implementation of the policy, program, and funding mechanisms that are needed to achieve these goals. One of the energy savings goals identified by CCAG for natural gas utility spending is to:

> ramp up to spending 1.5% of gas utility revenues on energy efficiency programs by 2015 pursuant to Arizona Corporation Commission (ACC) decoupling of gas sales and revenue. Further ***decisions by the ACC to decouple gas sales and revenues are viewed as central to achieving this target.*** Emphasis added.

Arizona Climate Change Action Plan, August 2006, p. 50.

As noted by the CCAG's recommendation, it is imperative that, despite the lack of support from RUCO and Staff for any form of decoupling, the Commission decouple gas sales and revenues as this is not only central to achieving the recommended target by CCAG, but it is also central to addressing the declining customer usage and weather sensitivity challenges that are negatively impacting Southwest.

Q. 34 Does this conclude your rebuttal testimony?

A. 34 Yes, it does.

305-001

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
* * *
RESIDENTIAL UTILITY CONSUMER OFFICE
DATA REQUEST NO. RUCO-8
(RUCO-8-1 THROUGH RUCO-8-2)

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 27, 2008

Request No. RUCO-8-1:

Declining Consumption Follow-up to RUCO 7.3. Please indicate if the Exhibit RAM-1 Sheet 4, provided in response to RUCO 7.3 measures both weather related as well as conservation related short-fall. If the referenced Exhibit is applicable to both phenomena please provide similar exhibits showing the shortfall effect of weather and conservation separately.

Respondent: Pricing/Demand Planning

Response:

Yes. The exhibit provided by Southwest in response to RUCO 7.3 measures both weather and conservation effects.

The attached schedule, for the calendar years 1998 (the first year of combined rates for Southwest's Arizona service areas) through 2007, and for the most currently available 12-month period ending February 2008, shows the shortfall effect of weather and conservation separately.

The format of the schedule is similar to the schedule provided by Southwest in response to RUCO's Question 1 in the Decoupling Work Group meetings and matches the average use per customer used to set rates and resulting average commodity rates in effect in each of the eleven 12-month periods with: 1) the actual average use per customer; 2) the weather-adjusted average use per customer; and 3) the average number of residential customers served for each 12-month period included in the study.

Schedule RUCO-8 attached shows that weather (see Line 11) actually made a positive contribution to revenue of approximately $0.8 million per year on average (Line 11, Col (m)). However, Line 11 also shows approximate $15 - $16 million weather-related swings in revenue from year-to-year. In contrast to weather,

(Continued on Page 2)

Response to RUCO-8-1: *(continued)*

conservation has resulted in lost revenue of approximately $12.2 million on average (Line 10, Col (m)). In total (weather plus conservation), Southwest lost approximately $11.4 million per year on average during the study period. This equates to a loss of approximately 8% (Line 18, Col (m)) of total authorized residential margin over the study period. (The after-tax impact of an $11.4 million loss in revenue as a percent of Southwest's recorded Net Operating Income is also approximately 8%.)

SOUTHWEST GAS CORPORATION
RESPONSE TO RUCO-8.1 and 8.2
($ MILLIONS)

Line No.	Description	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	Feb-08	Average Annual Impact	Weather/ Conservation % of Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	
	Total Arizona	**Rates Effective 9/1/1997**				**Rates Effective 11/1/2001**				**Rates Effective 3/1/2006**					
	Average Usage														
1	Actual	442.8	381.6	379.8	382.5	353.0	330.8	358.7	320.7	309.2	321.6	320.5			1
2	Weather Adjusted	375.8	378.6	375.6	341.8	362.6	354.3	338.4	343.0	342.3	318.1	313.4			2
3	GRC Authorized Amount	409.0	409.0	409.0	409.0	389.0	389.0	389.0	389.0	347.0	347.0	347.0			3
	Difference From Last GRC														
4	Weather + Conservation (Actual - GRC)	33.8	(27.4)	(29.2)	(26.5)	(36.0)	(58.2)	(30.3)	(68.3)	(37.8)	(25.4)	(26.5)			4
5	Conservation-Related (Weather Adj - GRC)	(33.2)	(30.4)	(33.4)	(67.2)	(26.4)	(34.7)	(50.6)	(46.0)	(4.7)	(28.9)	(33.6)			5
6	Weather-Related (Actual - Weather Adj)	67.0	3.0	4.2	40.7	(9.6)	(23.5)	20.3	(22.3)	(33.1)	3.5	7.1			6
7	Average No. of Customers	613,012	640,776	673,567	699,857	720,061	744,408	785,673	825,650	864,201	891,515	893,811			7
8	Average Commodity Rate	$ 0.42370	$ 0.42370	$ 0.42370	$ 0.42370	$ 0.45828	$ 0.45828	$ 0.45828	$ 0.45828	$ 0.52579	$ 0.52579	$ 0.52579			8
	Annual Dollar Impact of Change in Average Use														
9	Weather + Conservation (Actual - GRC)	$ 8.8	$ (7.4)	$ (8.3)	$ (7.9)	$ (11.9)	$ (19.9)	$ (10.9)	$ (25.8)	$ (17.2)	$ (11.9)	$ (12.5)	$ (11.4)	-100.0%	9
10	Conservation-Related (Weather Adj - GRC)	$ (8.6)	$ (8.3)	$ (9.5)	$ (19.9)	$ (8.7)	$ (11.8)	$ (18.2)	$ (17.4)	$ (2.1)	$ (13.5)	$ (15.8)	$ (12.2)	-107.3%	10
11	Weather-Related (Actual - Weather Adj)	$ 17.4	$ 0.8	$ 1.2	$ 12.1	$ (3.2)	$ (8.0)	$ 7.3	$ (8.4)	$ (15.0)	$ 1.6	$ 3.3	$ 0.8	7.3%	11
	Cumulative Dollar Impact of Change in Average Use [1]														
12	Weather + Conservation (Actual - GRC)	$ 8.8	$ 1.3	$ (7.0)	$ (14.9)	$ (26.7)	$ (46.6)	$ (57.5)	$ (83.3)	$ (100.5)	$ (112.4)			-100.0%	12
13	Conservation-Related (Weather Adj - GRC)	$ (8.6)	$ (16.9)	$ (26.4)	$ (46.3)	$ (55.0)	$ (66.9)	$ (85.1)	$ (102.5)	$ (104.6)	$ (118.2)			-105.1%	13
14	Weather-Related (Actual - Weather Adj)	$ 17.4	$ 18.2	$ 19.4	$ 31.5	$ 28.3	$ 20.3	$ 27.6	$ 19.2	$ 4.1	$ 5.8			5.1%	14
	GRC Authorized Residential Margin														
15	Basic Service Charge	$ 7.00	$ 7.00	$ 7.00	$ 7.00	$ 8.00	$ 8.00	$ 8.00	$ 8.00	$ 9.70	$ 9.70	$ 9.70			15
16	Average Commodity Rate	$ 0.42370	$ 0.42370	$ 0.42370	$ 0.42370	$ 0.45828	$ 0.45828	$ 0.45828	$ 0.45828	$ 0.52579	$ 0.52579	$ 0.52579			16
17	GRC Authorized Margin	$ 110.5	$ 115.5	$ 121.4	$ 126.2	$ 134.1	$ 138.7	$ 146.3	$ 153.8	$ 166.1	$ 171.3	$ 171.7	$ 141.4		17
18	Weather+Conservation % of Authorized Margin	7.9%	-6.4%	-6.9%	-6.2%	-8.9%	-14.3%	-7.5%	-16.8%	-10.3%	-7.0%	-7.3%	-8.0%		18

[1] For the 10-year period 1998 thru 2007 (excluding 12-months ended Februray 2008).
Note: Average usage and number of customers does not include Southwest's (approximately 30,000) low-income residential customers. This should not have significant effect on percent relationships.

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
CHANGE IN MARGIN AT PRESENT RATES AS A RESULT OF REDUCED RESIDENTIAL CUSTOMER USAGE

Line No.	Description (a)	Schedule Number (b)	As Filed (c)	As Adjusted [1] (d)	Change in Margin (e)	Line No.
1	Residential Gas Service	G-5	$ 252,170,209	$ 246,255,287	$(5,914,922)	1
2	Multi-Family Residential Gas Service	G-6	6,635,205	6,424,992	(210,213)	2
3	Low Income Residential Gas Service	G-10	6,749,399	6,601,781	(147,618)	3
4	Low Income Multi-Family Residential	G-11	480,391	460,437	(19,954)	4
5	Special Residential Gas Service	G-15	70,281	70,281	0	5
6	Total Residential		$ 266,105,485	$ 259,812,778	$ (6,292,707)	6
7	All Other Rate Schedules		118,339,358	118,339,358	0	7
8	Total Sales and Full Margin Transportation		$ 384,444,843	$ 378,152,136	$(6,292,707)	8
9	Special Contract Service	B-1	2,528,029	2,528,029	0	9
10	Other Operating Revenue		12,261,805	12,261,805	0	10
11	Total Arizona Revenue		$ 399,234,678	$ 392,941,971	$(6,292,707)	11

[1] Residential customer margin based on udated annual sales reflected in Rebuttal Exhibit No._(JLC-2).

Rebuttal Exhibit No.__(ABC-2)
Sheet 1 of 1

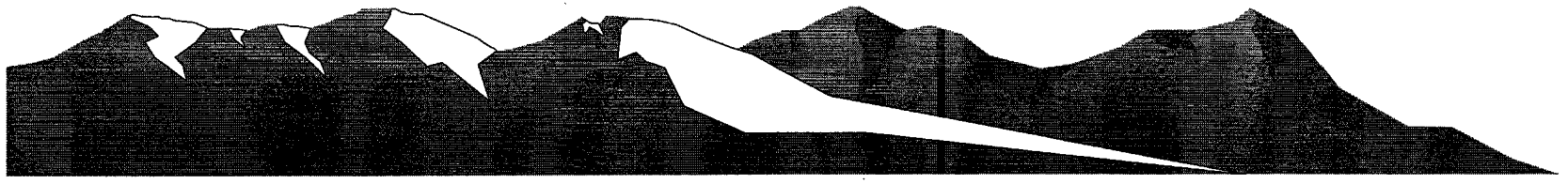
TRADITIONAL RATEMAKING AND SWG'S RESIDENTIAL COST RECOVERY DILEMMA

Monthly Basic Charge

Description	$10.00	$12.00	$15.00	$20.00
Margin Rate [1]	$.516	$.448	$.347	$.177
Lost SF Res Margin [2]	($16.1)	($14.0)	($10.8)	($5.5)
% Impact on ROE	(2.63)	(2.28)	(1.77)	(0.90)

[1] Rates calculated using GRC test year bills and volumes.

[2] Lost margin calculated using bills and volumes for 12 months ended August 2006.



Rebuttal Exhibit No.__(ABC-3)
Sheet 1 of 1

254-028

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-6
(ACC-STF-6-1 THROUGH ACC-STF-6-60)

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: DECEMBER 28, 2007

Request No. ACC-STF-6-28:

Please identify, quantify and explain in detail the "decoupling effect of a declining block rate for the recovery of non-gas costs" per Mr. Miller's testimony at page 14, line 3.

Respondent: Mr. Miller/Pricing & Tariffs

Response:

The above answer in Mr. Miller's testimony begins on page 13 and reads, "The important feature of this rate design is that the composite commodity charge for gas sales customers is a flat volumetric rate, but the offsetting block structures for the recovery of non-gas costs and gas costs provide Southwest with the partial decoupling effect of a declining block for its non-gas charges. This rate design is an innovative way of combining the desirable pricing features of a flat commodity charge rate with the desirable decoupling effect of a declining block rate for the recovery of non-gas costs." The partial decoupling effect for the recovery of non-gas costs of Southwest's proposed rate design is quantified in the Excel file on the enclosed CD. The calculations are based on Southwest's proposed single-family residential non-gas rates, bills and volumes.

Southwest's proposed rate design partially decouples the recovery of non-gas costs from both weather- and non-weather-related changes in sales. To quantify the decoupling effect of its proposed rate design, Southwest considered both the test year pro forma weather normalization adjustment to single-family residential customer volumes of <1,742,533> therms and the decline in weather adjusted use per residential customer of (approximately) 6 therms discussed by Southwest witness Mr. Cattanach. Southwest quantified the effects of 100% and 70% of the change in customer usage taking place in the second block of the rate design.

(Continued on Page 2)

Response to STF-6-28: *(continued)*

Page 1 of the spreadsheet analysis shows the adjusted single-family residential class test year volumes of 289,056,115 therms (line 1), the volumes purchased under the colder-than-normal test year weather conditions of 290,798,648 therms (lines 5-7), and the volumes customers would purchase in a warmer-than-normal year with an additional decrease of 6 therms per customer of 282,164,567 therms (lines 13-15).

Pages 2 and 3 show what customers would pay for non-gas delivery service in each of these three situations under Southwest's proposed rate design (Lines 1 - 6) and under a flat-rate commodity charge rate design (Lines 7 - 10). The difference between the two rate design approaches, which illustrates the partial decoupling effect of Southwest's proposed rate design for the recovery of non-gas costs, is shown on Line 11.

In the colder than normal test year, when customers used an additional 1,742,533 therms (page 1, line 2), their non-gas charges would increase by $966,287 with a flat commodity charge rate design for non-gas charges (pages 2 and 3, line 10). In contrast, under Southwest's proposed rate design, customers would not incur any additional non-gas charges if 100% of their additional usage is priced at the weather-sensitive rate (page 2, line 6), and their non-gas charges would increase by only $460,389 if 70% of the additional usage is priced at the weather-sensitive rate (page 3, line 6). Southwest's proposed rate design eliminates at least one-half or more of the additional non-gas charges customers would otherwise pay under a flat commodity charge rate design during colder than normal weather.

If usage per customer continues to decline by 6 therms and the weather is warmer than normal, then total usage would decrease by 6,891,548 therms (page 1, line 10). With a flat commodity charge rate design, Southwest's non-gas revenues would decrease by $3,821,570 (pages 2 and 3, line 10). However, the partial decoupling effect of Southwest's proposed rate design would completely eliminate the decrease in non-gas revenues if 100% of the decrease in usage is priced at the weather-sensitive rate (page 2, line 6), and would limit the decrease in non-gas revenues to $1,820,795 if 70% of the decrease in usage occurs in the weather-sensitive rate component (page 3, line 6). Southwest's proposed rate design reduces by at least one-half the decrease to non-gas revenue it would experience under a flat commodity rate design in warmer than normal weather.

SOUTHWEST GAS CORPORATION
PARTIAL DECOUPLING EFFECT OF SWG PROPOSED RATE DESIGN
G-5 SINGLE-FAMILY RESIDENTIAL GAS SERVICE VOLUMES

	Number of single-family residential bills			10,298,030	
	Number of single-family residential customers			858,169	
Line No.	Description	Weather-Sensitive Usage	Non-Weather-Sensitive Usage	Total	Line No.
1	Adjusted test year	182,004,997	107,051,118	289,056,115	1
2	Additional volumes for colder than normal weather			1,742,533	2
3	Assuming 70.000% in tail block	522,760	1,219,773		3
4	Assuming 100% in tail block	0	1,742,533		4
5	Total volumes for colder than normal weather			290,798,648	5
6	Assuming 70.000% of CTN increase in tail block	182,527,757	108,270,891		6
7	Assuming 100% of CTN increase in tail block	182,004,997	108,793,651		7
8a	Decremental volumes for additional conservation				8a
8b	of 6 therms per customer per year			(5,149,015)	8b
9	Decremental volumes for warmer than normal weather			(1,742,533)	9
10	Total decrement for WTN weather and conservation			(6,891,548)	10
11	Assuming 70.000% of decrement in tail block	(2,067,464)	(4,824,084)		11
12	Assuming 100% of decrement in tail block	0	(6,891,548)		12
13	Total volumes for WTN weather and conservation			282,164,567	13
14	Assuming 70.000% of decrement in tail block	179,937,533	102,227,034		14
15	Assuming 100% of decrement in tail block	182,004,997	100,159,570		15

SOUTHWEST GAS CORPORATION
PARTIAL DECOUPLING EFFECT OF SWG PROPOSED RATE DESIGN
G-5 SINGLE-FAMILY RESIDENTIAL GAS SERVICE
ASSUMING 100 PERCENT OF VOLUME CHANGE IS IN SECOND BLOCK OF RATE DESIGN

Line No.	Description	Non-Gas Charge Rates	Proposed Test Year, With Normal Weather		Colder Than Normal Weather		Warmer than Normal Weather and Additional Conservation		Line No.
			Bills/Volumes	Annual Cost	Bills/Volumes	Annual Cost	Bills/Volumes	Annual Cost	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	
	Proposed Rate Design								
1	Basic Service Charge	$ 12.80	10,298,030	$ 131,814,784	10,298,030	$ 131,814,784	10,298,030	$ 131,814,784	1
	Non-Gas Delivery Charge								
2	Weather-Sensitive Usage	$ 0.88069	182,004,997	160,289,981	182,004,997	160,289,981	182,004,997	160,289,981	2
3	Non-Weather-Sensitive Usage	0.00000	107,051,118	0	108,793,651	0	100,159,570	0	3
4	Total Commodity		289,056,115	$ 160,289,981	290,798,648	$ 160,289,981	282,164,567	$ 160,289,981	4
5	Total Non-Gas Revenue			$ 292,104,765		$ 292,104,765		$ 292,104,765	5
6	Change from Normal Weather			$ -		$ -		$ -	6
	Flat Commodity Charge Rate Design								
7	Basic Service Charge	$ 12.80	10,298,030	$ 131,814,784	10,298,030	$ 131,814,784	10,298,030	$ 131,814,784	7
8	Non-Gas Delivery Charge (Average Rate)	$ 0.55453	289,056,115	$ 160,290,287	290,798,648	$ 161,256,574	282,164,567	$ 156,468,717	8
9	Total Non-Gas Revenue			$ 292,105,071		$ 293,071,358		$ 288,283,501	9
10	Change from Normal Weather			$ -		$ 966,287		$ (3,821,570)	10
	Proposed Rate Design less								
11	Flat Commodity Charge Rate Design			$ (307)		$ (966,593)		$ 3,821,263	11

SOUTHWEST GAS CORPORATION
PARTIAL DECOUPLING EFFECT OF SWG PROPOSED RATE DESIGN
G-5 SINGLE-FAMILY RESIDENTIAL GAS SERVICE
ASSUMING 70.000% OF VOLUME CHANGE IS IN SECOND BLOCK OF RATE DESIGN

Line No.	Description	Non-Gas Charge Rates	Proposed Test Year, With Normal Weather		Colder Than Normal Weather		Warmer than Normal Weather and Additional Conservation		Line No.
			Bills/Volumes	Annual Cost	Bills/Volumes	Annual Cost	Bills/Volumes	Annual Cost	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	
	Proposed Rate Design								
1	Basic Service Charge	$ 12.80	10,298,030	$131,814,784	10,298,030	$131,814,784	10,298,030	$131,814,784	1
	Non-Gas Delivery Charge								
2	Weather-Sensitive Usage	$0.88069	182,004,997	160,289,981	182,527,757	160,750,370	179,937,533	158,469,186	2
3	Non-Weather-Sensitive Usage	0.00000	107,051,118	0	108,270,891	0	102,227,034	0	3
4	Total Commodity		289,056,115	$160,289,981	290,798,648	$160,750,370	282,164,567	$158,469,186	4
5	Total Non-Gas Revenue			$292,104,765		$292,565,154		$290,283,970	5
6	Change from Normal Weather			$ -		$ 460,389		$ (1,820,795)	6
	Flat Commodity Charge Rate Design								
7	Basic Service Charge	$ 12.80	10,298,030	$131,814,784	10,298,030	$131,814,784	10,298,030	$131,814,784	7
8	Non-Gas Delivery Charge (Average Rate	$0.55453	289,056,115	$160,290,287	290,798,648	$161,256,574	282,164,567	$156,468,717	8
9	Total Non-Gas Revenue			$292,105,071		$293,071,358		$288,283,501	9
10	Change from Normal Weather			$ -		$ 966,287		$ (3,821,570)	10
	Proposed Rate Design less								
11	Flat Commodity Charge Rate Design			$ (307)		$ (506,204)		$ 2,000,468	11

Rebuttal Exhibit No.__(ABC-4)
Sheet 5 of 10

302-001

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
* * *
RESIDENTIAL UTILITY CONSUMER OFFICE
DATA REQUEST NO. RUCO-7
(RUCO-7-1 THROUGH RUCO-7-10)

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 7, 2008

Request No. RUCO-7-1:

Allocation of Gas/Non-gas Costs

Please provide the following information related to the cost allocation discussion on pages 10 through 12 of the testimony of Brooks Congdon:

a) Explain in detail (including illustrative journal entries) how the proposed cost allocation affects SWG's income statement and balance sheet:

b) Explain in detail what benefit SWG perceives the Company derives from the proposed allocation; and

c) Explain in detail what benefit(s) customers receive from the proposed allocation.

Respondent: Pricing & Tariffs

Response:

a. The proposed allocation of the non-gas (margin) and gas cost components of residential sales rates has no effect on Southwest's current accounting and journal entry procedures. The proposal only impacts the relative amounts of non-gas and gas cost collected through residential rates as actual use per customer varies from the level (332 therms per customer per Southwest's proposal) used in setting rates. The effects of Southwest's proposed residential rate design on the recovery of non-gas and gas costs versus a more conventional average cost rate design are illustrated below using the rates reflected in the table on page 10 of Mr. Congdon's Direct Testimony.

(Continued on Page 2)

Response to RUCO-7-1: *(continued)*

	Non-Gas Rate	Gas Cost Rate	Total
Average Rate Design	$.55376	$.93689	$1.49065
Proposed Rate Design			
Non-Weather-Sensitive Use	$.88069	$ .60996	$1.49065
Weather-Sensitive Use	.00000	1.49065	1.49065
Number of Residential Customers			917,350

Scenario 1 - Assuming that average use increases as a result of colder than normal weather by 10 therms per customer and all of the increase is in the weather-sensitive 2nd block of the proposed rate design, the effects under the average and proposed rate designs in millions of dollars are summarized below.

	Non-Gas Rate	Gas Cost Rate	Total
Average Rate Design	$5.1	$8.6	$13.7
Proposed Rate Design	0.0	13.7	13.7
Difference	<$5.1>	$ 5.1	$ 0.0

In Scenario 1, Southwest's net after tax income would be $3.1 million less ($5.1 million X (1 - $0.395292 tax rate)) under its proposed rate design and an additional amount of $5.1 million (excluding interest) would accrue to Southwest's PGA Balancing Account resulting in a lower PGA balance than under an average cost rate design. Also, it is important to note that total gas cost incurred would not change; therefore, the PGA impact is merely a timing difference resulting from more timely collection of gas cost. No change in the accounts or methods used to record these ratemaking impacts in the accounting records would result, but the decrease in net income, net of tax, would result in a reduction to revenue on the income statement (vis-à-vis an average cost rate design) for that given period, with an associated decrease to cash on the balance sheet. The timing difference in collecting gas cost from customers would reduce the 191 account but also increase cash for the period, resulting in no net effect on the balance sheet and no ultimate impact on the income statement.

(Continued on Page 3)

Response to RUCO-7-1: *(continued)*

Scenario 2 - Assuming that average use decreases as a result of warmer than normal weather by 10 therms per customer with 50% of the decrease in the weather-sensitive 2nd block and 50% in the non-weather-sensitive block of the proposed rate design, the effects under the average and proposed rate designs in millions of dollars are summarized below.

	Non-Gas Rate	Gas Cost Rate	Total
Average Rate Design	<$5.1>	<$8.6>	<$13.7>
Proposed Rate Design	<4.1>	<9.6>	< 13.7>
Difference	$1.0	<$ 1.0>	$ 0.0

In Scenario 2, Southwest's net after tax income would be $0.6 million more ($1 million X (1 - $0.395292 tax rate)) under its proposed rate design and there would be an immediate $1 million impact (excluding interest) to PGA sales customers. Again, total gas cost incurred would not change and the PGA impact is only a timing difference resulting from the collection of gas cost over a longer period of time. No change in the accounts or methods used to record these ratemaking impacts in the accounting records would result, but the increase in net income, net of tax, would result in an increase in revenue on the income statement for that given period, with an associated increase in cash on the balance sheet. The timing difference in collecting gas cost from customers would have an immediate increase to the 191 account but also decrease cash for the period, resulting in no net effect on the balance sheet and no ultimate impact on the income statement. The $0.6 million addition to after-tax income represents almost 1% of Southwest's recorded Net Operating Income (see Volume II, Schedule A-1), while the $1.0 million impact to the PGA is less than 0.2% of Southwest's recorded gas cost (see Volume II, Schedule C-1, Sheet 3).

Southwest's proposed residential rate design will stabilize the recovery of its fixed costs of providing service when use-per-customer increases or decreases from the level used to set rates. As explained above, the effect of the proposed rate design is to shift over-recoveries of authorized margin per customer that would otherwise accrue to Southwest's shareholders when usage per customer is greater than the level used to set rates, to the PGA Balancing Account where the net dollar impact will be reduced interest on the resulting PGA balance. Conversely, when usage per customer is less than the level used to set rates, under-recoveries of authorized

(Continued on Page 4)

Response to RUCO-7-1: *(continued)*

margin that would otherwise reduce shareholder earnings, are also shifted to the PGA Balancing Account resulting in slightly greater interest expense. Over time, with both colder and warmer weather, the measurable effect of the proposed rate design on PGA interest expense should be de minimus in comparison to total gas cost expense.

Please also refer to the Company's response to Staff data request no. STF-6-28 for additional discussion of the effects of Southwest's proposed residential rate design.

b. Southwest will benefit from the proposed rate design because the adverse financial impact of declining use per customer on non-gas revenues, i.e., the recovery of Southwest's fixed costs of providing service, is less than under an average cost rate design. Southwest's proposed rate design also has the desirable feature of better matching cost recovery with cost incurrence: 1) recovery of Southwest's fixed costs of providing service (the cost of pipes, meters, property taxes, etc.) is less dependent on the total volume of gas delivered to customers than under a more traditional rate design, and 2) Southwest recovers more gas cost revenue when use per customer increases and gas prices would also be expected to be increasing (use per customer increases with cold weather and cold weather helps drive up winter gas prices) than under an average cost rate design.

c. Customers benefit from Southwest's proposed rate design because: 1) conservation-related savings are increased by the elimination of the lower priced second block in Southwest's current declining block rate design; 2) enhanced recovery of Southwest's fixed cost of providing service will extend the timing of Southwest's rate cases, all other factors being equal, and may result in reduced capital costs; 3) improved fixed cost recovery discussed in parts a. and b. above, is achieved through a single commodity charge effective sales rate with no significant shifting of costs between small and large volume customers, as would be the case with a traditional declining block rate design and/or large increases in the basic service charge; and 4) the only cost/savings to achieve these customer benefits is the dollar impact to the PGA Balancing Account interest accrual.

Because the fixed costs of providing service are recovered through the basic service charge and less usage-sensitive components of the rate structure as compared to Southwest's currently effect residential rates, fixed cost recovery would be more evenly distributed across small and large volume residential customers. This result would allow Southwest to economically provide service to

(Continued on Page 5)

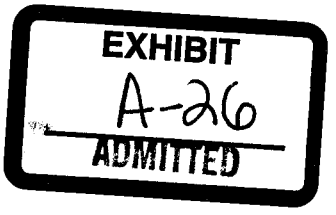
Response to RUCO-7-1: *(continued)*

residential customers whose volumes and resulting annual margin, given Southwest's current rate design, might not otherwise support the cost of establishing service. This effect is illustrated in the example below.

	Non-Gas Rate	Annual Usage [1]	Annual Non-Gas Revenue [2]
Average Rate Design	$.55376	300 therms	$166.13
Proposed Rate Design Non-Weather-Sensitive Use	$.88069	300 therms	$264.21
Difference			$ 98.08
Estimated Cost of Service Factor			20%
Additional Supportable Facilities Investment			$490.40

[1] 300 therms equals sum of proposed summer and winter rate blocks times six months (15 therms X 6 + 35 therms X 6).

[2] Excluding basic service charge revenue, which is assumed to be the same in both rate designs.



IN THE MATTER OF

SOUTHWEST GAS CORPORATION

Docket No. G-01551A-07-0504

PREPARED REJOINDER TESTIMONY

OF

A. BROOKS CONGDON

ON BEHALF OF

SOUTHWEST GAS CORPORATION

June 9, 2008

Southwest Gas Corporation
Docket No. G-01551A-07-0504

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Prepared Rejoinder Testimony
Of
A. BROOKS CONGDON

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BEFORE THE ARIZONA CORPORATION COMMISSION

Prepared Rejoinder Testimony
of
A. BROOKS CONGDON

INTRODUCTION

Q. 1 Please state your name and business address.

A. 1 My name is A. Brooks Congdon. My business address is 5241 Spring Mountain Road, Las Vegas, Nevada 89150.

Q. 2 Are you the same A. Brooks Congdon who sponsored prepared direct and rebuttal testimony in this Docket for Southwest Gas Corporation (Southwest or the Company)?

A. 2 Yes, I am.

Q. 3 What is the purpose of your rejoinder testimony?

A. 3 The purpose of my rejoinder testimony is to respond to the surrebuttal testimony presented by the following witnesses: Ms. Marylee Diaz Cortez, witness for the Residential Utility Consumer Office (RUCO); Messrs. Frank W. Radigan and Phillip S. Teumim, witnesses for the Arizona Corporation Commission Utilities Division Staff (Staff); and Mr. Jeffrey A. Schlegel, witness for the Southwest Energy Efficiency Project (SWEEP) regarding their recommendations and comments concerning Southwest's tariff and rate design proposals and the appropriate DSM funding level.

Q. 4 Did you prepare exhibits to support your rejoinder testimony?

A. 4 Yes. I prepared the exhibits identified as Rejoinder Exhibit No.__(ABC-1) and Rejoinder Exhibit No.__(ABC-2).

Q. 5 Please summarize your rejoinder testimony.

A. 5 My rejoinder testimony will address the following issues:

1) Staff's proposed revenue allocation.

2) Staff's and SWEEP's proposed DSM funding level.

3) RUCO's assertion that Southwest's proposed residential Volumetric Rate Design is not revenue neutral for customers.

4) Staff's assertion that Southwest's tariff and rate design proposals are "virtually the same proposals" as Southwest proposed in the last general rate case.

5) Staff's and RUCO's rejection of Southwest's RDAP, WNAP, and Volumetric Rate Design proposals.

STAFF'S PROPOSED REVENUE ALLOCATION

Q. 6 Mr. Radigan states in his surrebuttal testimony that revenue allocation should be done before rate design and the Company has it backwards. Please comment.

A. 6 Southwest has not performed rate design before revenue allocation. The Company used the results of its Class Cost of Service Study to allocate revenue responsibility to customer classes. The methodology that Southwest followed results in larger increases to those classes that are earning the lowest rates of return at present rates and smaller increases to those classes that are earning the highest rates of return at present rates. No party in this proceeding, including Staff, contested

Southwest's Class Cost of Service Study.

By comparison, Mr. Radigan has proposed a revenue allocation in which all customer classes receive a revenue increase within one percent of the system average increase. For all practical purposes, Mr. Radigan's revenue allocation gives no weight to the results of the Class Cost of Service Study and is an equal percent increase for all customer classes. It is Mr. Radigan, not Southwest, who has revenue allocation and rate design backwards.

STAFF'S AND SWEEP'S PROPOSED DSM FUNDING LEVEL

Q. 7 In your rebuttal testimony, you recommend that a Commission decision on the DSM funding level be removed from this rate case. How did the parties respond to this proposal?

A. 7 No party supported this proposal. Mr. Schlegel continues to propose that the Commission approve an increase in DSM funding to "at least $12 million annually". Mr. Teumim, who in his direct testimony did not propose any increase in the current DSM funding level of $4.4 million annually, proposed increased funding of $1 million per year for the years 2010 through 2012, bringing the DSM funding level to $7.4 million by 2012.

Q. 8 What is Southwest's response to these proposals?

A. 8 When Southwest proposed new DSM programs and a total funding level of $4.4 million in its last rate case, it did so with an expectation that the Commission would

approve the Company's proposed Conservation Margin Tracker (CMT) tariff, thereby removing the financial disincentives for Southwest to aggressively encourage its customers to conserve natural gas. That didn't happen. In this proceeding, Southwest has proposed a variety of new rate design and regulatory mechanisms that would remove or mitigate the financial harm to the Company when customers use less gas. Staff and RUCO are opposed to Southwest's proposed rate design and tariff mechanisms. Although Southwest is firmly committed to the goal of maximizing conservation and energy efficiency for its customers, Southwest is opposed to any increase in the current $4.4 million DSM funding level, without affirmative relief to the financial pressure Southwest faces due to declining average residential usage.

RUCO'S ASSERTION THAT SOUTHWEST'S PROPOSED RESIDENTIAL VOLUMETRIC RATE DESIGN IS NOT REVENUE NEUTRAL FOR CUSTOMERS

Q. 9 RUCO witness Marylee Diaz Cortez asserts that customers are not revenue neutral under Southwest's proposed Volumetric Rate Design compared with a traditional average cost rate design. Please comment.

A. 9 Very simply, Southwest's proposed residential Volumetric Rate Design, as RUCO itself correctly points out, has the same effective rate per therm for all natural gas consumed as a traditional average cost rate design. Consequently, it is impossible for the two rate designs not to be revenue neutral. Ms. Cortez's Surrebuttal

Exhibit A purportedly demonstrates how smaller users will pay more under Southwest's proposed Volumetric Rate Design than they would under a traditional average cost rate design. However, Ms. Diaz Cortez's exhibit contains a significant error.

Q. 10 Have you prepared an exhibit correctly displaying the differences between Southwest's proposed Volumetric Rate Design and a traditional average cost rate design?

A. 10 Yes. Rejoinder Exhibit No.___(ABC-1) shows a comparison of non-gas cost and gas cost amounts residential customers would be billed under Southwest's proposed Volumetric Rate Design and under a traditional average cost rate design. Rejoinder Exhibit No.__(ABC-1) demonstrates that customers are, in fact, revenue neutral under the two rate designs. RUCO is correct that there is a shifting of recovery of non-gas costs from large users to small users of gas. However, Ms. Diaz Cortez's exhibit fails to show the offsetting shift in the recovery of gas costs from small users to large users as demonstrated in Rejoinder Exhibit No.__(ABC-1).

Q. 11 Please explain how Southwest's proposed Volumetric Rate Design more accurately recovers the cost of providing service than a traditional rate design when the effective rate per therm is the same in both rate designs.

A. 11 Once customers are connected to the system, Southwest's non-gas cost of providing service is fixed, and does not vary with changes in customer use. In that regard, it

costs the Company the same amount to provide distribution service to a residential customer who uses 40 therms as it does to provide distribution service to a customer who uses 140 therms. Rejoinder Exhibit No.__(ABC-1) demonstrates that Southwest's proposed Volumetric Rate Design more accurately recovers the fixed cost of providing service to residential customers.

At the same time, Southwest's proposed Volumetric Rate Design shifts the amount of gas cost recovered from small users to large users. This shift in gas cost recovery is consistent with cost-based pricing principles because changes in the recovery of gas cost follow the movement in Southwest's cost of purchased gas associated with higher and lower gas demands. When gas demand increases, natural gas prices in the supply basins tend to increase, and the proposed Volumetric Rate Design will increase recovery of Southwest's gas cost as compared to a traditional average cost rate design.

STAFF'S ASSERTION THAT SOUTHWEST'S TARIFF AND RATE DESIGN PROPOSALS ARE "VIRTUALLY THE SAME PROPOSALS" AS SOUTHWEST PROPOSED IN THE LAST RATE CASE

Q. 12 Staff witness Mr. Radigan asserts, "In Southwest's last rate case, the Commission rejected virtually the same proposals, the Company is asking for here..." Please explain how Southwest's current proposals in this rate case differ substantially from the last case.

A. 12 Southwest's proposed WNAP and RDAP tariff mechanisms and

its proposed residential Volumetric Rate Design are similar to Southwest's CMT and rate design proposals in its last rate case only to the extent they are intended to address the same issues of weather and non-weather volatility in revenue. Southwest's proposals in this proceeding have been designed to be responsive to Commission Decision No. 68487 and are very different from its proposals in the last case. Southwest's proposals in its last rate case and in this case have been juxtaposed in Rejoinder Exhibit No.__(ABC-2) to illustrate the differences. Some of these differences are also set forth below:

1) Accounting for weather-related revenue variations with a real-time weather adjustment mechanism, and accounting for non-weather variations with a separate deferred accounting provision addresses the concern that there could be large swings in rates from year-to-year due to weather effects.

2) Limiting the proposed increase to the residential basic service charge to a much lower percentage increase than the 50 and 100 percent increases proposed by Southwest in the last case; an increase which is only 10 percent greater than the increase authorized in Southwest's last rate case.

3) Eliminating Southwest's declining block rate design to address concerns about sending appropriate price signals.

RUCO'S AND STAFF'S REJECTION OF SOUTHWEST'S RDAP, WNAP AND VOLUMETRIC RATE DESIGN PROPOSALS

Q. 13 Given that Southwest has again demonstrated that customer usage continues to decline and that the Company seeks to reduce weather-related volatility in customer bills, please provide your perspective on Staff's and RUCO's rejection of all of Southwest's proposed remedies.

A. 13 Staff's and RUCO's proposals are premised on the notion there is nothing wrong with the status quo, and therefore, there is no need to strive for improved rate design and tariff mechanisms. However, the record is very clear that Southwest and its customers continue to be exposed to weather-related volatility, and the Company continues to experience significant erosion in cost recovery due to declining use per customer. In my rebuttal testimony, I commented on the fact that average annual residential usage has declined by 13 therms in the 11 months since the close of the test year in this rate case. In his Rejoinder Testimony, Southwest witness James Cattanach provides analyses and historical data suggesting that there is a significant likelihood that residential usage per customer will continue to decline in the foreseeable future. The status quo is not an acceptable solution for Southwest.

Q. 14 What are the potential consequences if the Commission does not accept Southwest's proposals and agrees with Staff and RUCO to essentially maintain the status quo?

A. 14 In the short-run, customers will be denied immediate relief from high winter bills due to colder than normal weather that would otherwise be provided under Southwest's proposed WNAP. In the long-run, customers will be denied potential benefits including: 1) longer periods of time between general rate cases, 2) reduced average capital costs and 3) greater flexibility in rate design.

Q. 15 Please comment on Mr. Radigan's surrebuttal testimony at page 5, lines 15-26, wherein he discusses that while continued declines in use per customer from the test year level used to design rates will result in additional financial pressure on Southwest, the Company has presented only one piece of the puzzle because it will also be allowed to retain any revenues associated with new customer growth.

A. 15 Mr. Radigan's inference that growth in margin derived from new customers will compensate for the loss in margin due to declining customer usage is a fallacy. Mr. Radigan is correct when he observes that declining use per customer from the test year level used to design rates will place additional financial pressure on Southwest. However, the fallacy in Mr. Radigan's discussion is that he fails to mention that new customers are not gifted to the Company at zero cost. As a result, the margin derived from customer growth is necessary to pay for the capital investment and additional operating

expenses associated with serving those same new customers, and does not compensate Southwest for losses related to reduced customer usage. Thus, it is actually Mr. Radigan who presents only one piece of the puzzle.

Q. 16 Do you have any further comments?

A. 16 Yes. I completely agree with Mr. Schlegel's comment at page 3, lines 128 and 129 of his surrebuttal testimony, where he states "SWEEP suggests that the experience of pilot implementation will do more to resolve the differences among parties than continued debate in this or subsequent rate cases."

Q. 17 Does this conclude your rejoinder testimony?

A. 17 Yes, it does.

SOUTHWEST GAS CORPORATION
COMPARISON OF THE RESIDENTIAL BILL IMPACTS OF
AN AVERAGE RATE DESIGN AND SOUTHWEST'S PROPOSED RATE DESIGN
FOR WINTER SEASON BILLS

Description	Average (Normal) Rate Design	Southwest Proposed Rate Design	Difference Proposed less Average
Consumption			
20 Therms			
Monthly Minimum/Basic Charge	$ 12.80	$ 12.80	$ -
Base Commodity/Non-Gas Cost	11.08	17.61	6.54
PGA/Gas Cost	18.74	12.20	(6.54)
Total	$ 42.61	$ 42.61	$ -
40 Therms			
Monthly Minimum/Basic Charge	$ 12.80	$ 12.80	$ -
Base Commodity/Non-Gas Cost	22.15	30.82	8.67
PGA/Gas Cost	37.48	28.80	(8.67)
Total	$ 72.43	$ 72.43	$ -
55 Therms			
Monthly Minimum/Basic Charge	$ 12.80	$ 12.80	$ -
Base Commodity/Non-Gas Cost	30.46	30.82	0.37
PGA/Gas Cost	51.53	51.16	(0.37)
Total	$ 94.79	$ 94.79	$ -
60 Therms			
Monthly Minimum/Basic Charge	$ 12.80	$ 12.80	$ -
Base Commodity/Non-Gas Cost	33.23	30.82	(2.40)
PGA/Gas Cost	56.21	58.61	2.40
Total	$ 102.24	$ 102.24	$ -
80 Therms			
Monthly Minimum/Basic Charge	$ 12.80	$ 12.80	$ -
Base Commodity/Non-Gas Cost	44.30	30.82	(13.48)
PGA/Gas Cost	74.95	88.43	13.48
Total	$ 132.05	$ 132.05	$ -
100 Therms			
Monthly Minimum/Basic Charge	$ 12.80	$ 12.80	$ -
Base Commodity/Non-Gas Cost	55.38	30.82	(24.55)
PGA/Gas Cost	93.69	118.24	24.55
Total	$ 161.87	$ 161.87	$ -
120 Therms			
Monthly Minimum/Basic Charge	$ 12.80	$ 12.80	$ -
Base Commodity/Non-Gas Cost	66.45	30.82	(35.63)
PGA/Gas Cost	112.43	148.05	35.63
Total	$ 191.68	$ 191.68	$ -
140 Therms			
Monthly Minimum/Basic Charge	$ 12.80	$ 12.80	$ -
Base Commodity/Non-Gas Cost	77.53	30.82	(46.70)
PGA/Gas Cost	131.16	177.87	46.70
Total	$ 221.49	$ 221.49	$ -

	Average Rates	Proposed Rates
Basic Charge	$ 12.80	$ 12.80
Non-Gas Rates		
All Usage/First 35 Therms	$ 0.55376	$ 0.88069
Second Block		0.00000
Gas Cost Rates		
All Usage/First 35 Therms	$ 0.93689	$ 0.60996
Second Block		1.49065

	LAST RATE CASE		CURRENT RATE CASE
CMT:	1) Captures Weather plus Non-Weather-Related Changes in Usage 2) Applied Only to Residential Schedules 3) Deferred Accounting with One-Year Lag on Recovery/Refund	WNAP:	1) Captures Weather Only 2) Real-Time Adjustment to Customer Bills 3) Applied to Residential and Smaller General Service
		RDAP:	1) Captures Non-Weather Only 2) Deferred Accounting with One-Year Lag on Recovery/Refund 3) Applied to Residential and Smaller General Service
Rate Design With CMT:	1) 50% Increase to Basic Charge 2) $.59 Declining Block Rate with $.25 Tail Block	Rate Design:	1) 32% Increase to Basic Charge 2) Flat Rate, i.e. Eliminate Declining Block Rate 3) Accounting Changes for Non-Gas and Gas Cost Rate Components
Rate Design W/O CMT:	1) 100% Increase to Basic Charge 2) $.51 Declining Block Rate with $.15 Tail Block		