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

Exhibit # : 514-527

Arizona Corporation Commission
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EXHIBIT S-14

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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 THE SOUTHWEST GAS CORPORATION DEVOTED TO ITS OPERATIONS THROUGHOUT ARIZONA

DOCKET NO. G-01551A-07-0504

SURREBUTTAL

TESTIMONY

OF

RALPH C. SMITH

ON BEHALF OF

THE ARIZONA CORPORATION COMMISSION,

UTILITIES DIVISION STAFF

MAY 27, 2008

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EXECUTIVE SUMMARY
SURREBUTTAL TESTIMONY OF RALPH C. SMITH
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-07-0504

My Surrebuttal Testimony addresses the following issues, and responds to the testimony of Southwest Gas Corporation ("Company," or "SWG") witnesses Montgomery, Mashas, Aldridge and Hobbs on these issues:

- The Company's proposed revenue requirement
- Adjustments to test year data
- Rate base
- Test year revenues, expenses, and net operating income

My findings and recommendations for each of these areas are as follows:

- The Company's proposed revenue requirement of a base rate increase of $50.22 million is significantly overstated. On original cost rate base ("OCRB") my calculations show a jurisdictional revenue deficiency of $28.36 million. I recommend that SWG be authorized a base rate increase of $28.36 million on adjusted fair value rate base ("FVRB"). This amount is between the Staff's two options for the revenue requirement on FVRB. On adjusted FVRB under Staff's option 1, which uses a fair value rate of return of 6.79 percent, I show a base rate increase of $28.23 million. Similar to Staff's recommendations in a recent remand proceeding, Docket No. W-02113A-04-0616, concerning Chaparral City Water Company, Staff is also presenting the Commission with an option 2 for the fair value rate of return for SWG. Under option 2 the fair value rate of return for SWG is 7.08 percent, and the jurisdictional revenue deficiency is approximately $34.91 million. The testimony of Staff witness David Parcell addresses the determination of the fair value rate of return. In its filing, SWG calculated the same revenue deficiency under the OCRB and FVRB, and consequently has not requested an additional rate increase on FVRB.

- The following adjustments to SWG's proposed original cost and RCND rate base should be made:

Summary of Staff Adjustments to Rate Base			OCRB	RCND RB
Adj. No.	Description	Comment	Increase (Decrease)	Increase (Decrease)
B-1	Yuma Manors Pipe Replacement		$ (1,092,448)	$ (1,092,448)
B-2	Customer Advances for Construction		$ (7,399,425)	$ (7,399,425)
B-3	Cash Working Capital	Revised	$ (5,087,757)	$ (5,087,757)
B-4	Customer Deposits		$ (2,480,873)	$ (2,480,873)
B-5	Accumulated Deferred Income Taxes - Acct.190		$ (13,132,025)	$ (20,109,648)
B-6	Intangible Plant Added After the Test Year	Revised	$ (139,902)	$ (139,902)
B-7	Accumulated Deferred Income Taxes - RCND			$ (95,409,229)
B-8	Remove Net Plant Being Sold to TEP for Sundt Bypass	Added	$ -	$ -
	Total of Staff Adjustments		**$ (29,332,430)**	**$ (131,719,282)**
	SWGas Proposed Rate Base (Original Cost and RCND)		$ 1,094,790,047	$ 1,843,481,069
	Staff Proposed Rate Base (Original Cost and RCND)		**$ 1,065,457,617**	**$ 1,711,761,787**

- The following adjustments to SWG's proposed revenues, expenses and net operating income should be made (for comparison purposes, this table also shows the corresponding NOI adjustment amounts from Staff's direct filing):

Summary of Staff Adjustments to Net Operating Income			Pre-Tax Adj. to Revenue or Expense	Net Operating Income	NOI Adjustment in Staff's Direct Filing	Difference Between Staff Surreb. and Direct
Adj. No.	Description	Comment	Increase (Decrease)	Increase (Decrease)		
C-1	Yuma Manors Depreciation and Property Tax Expense		$ (83,315)	$ 50,381	$ 50,381	$ -
C-2	Gain on Sale of Property in Cave Creek, AZ		$ (69,700)	$ 42,148	$ 42,148	$ -
C-3	Management Incentive Program	Revised	$ (1,491,537)	$ 901,944	$ 1,130,012	$ (228,068)
C-4	Stock Based Compensation		$ (820,915)	$ 496,414	$ 496,414	$ -
C-5	Supplemental Executive Retirement Expense		$ (1,625,460)	$ 982,929	$ 982,929	$ -
C-6	American Gas Association Dues		$ (80,138)	$ 48,460	$ 48,460	$ -
C-7	TRIMP Surcharge		$ (920,914)	$ 556,884	$ 556,884	$ -
C-8	A&G Expenses - Annualized Paiute Allocation		$ (23,447)	$ 14,179	$ 14,179	$ -
C-9	Interest on Customer Deposits		$ 148,852	$ (90,012)	$ (90,012)	$ -
C-10	Interest Synchronization	Revised	$ -	$ 19,103	$ (237,509)	$ 256,612
C-11	Flow Back Excess Deferred Income Taxes		$ -	$ 147,345	$ 147,345	$ -
C-12	Injuries and Damages	Revised	$ (851,717)	$ 515,040	$ 521,087	$ (6,047)
C-13	Leased Aircraft Operating Costs		$ (32,814)	$ 19,843	$ 19,843	$ -
C-14	El Paso Natural Gas Rate Case Expense		$ (477,415)	$ 288,697	$ 288,697	$ -
C-15	New Intangible Plant Annualized Amortizations	Revised	$ (46,633)	$ 28,199	$ 109,494	$ (81,295)
C-16	Gain on Sale of Utility Property Related to TEP Sundt Bypass	Added	$ (101,600)	$ 61,438		$ 61,438
C-17	Depreciation for Plant Sold to TEP for Sundt Bypass	Added	$ (5,117)	$ 3,094		$ 3,094
Total of Staff's Adjustments to Net Operating Income			$ (6,481,870)	$ 4,086,086	$ 4,080,352	$ 5,734
	Adjusted Net Operating Income per Southwest Gas			$ 73,180,098	$ 73,180,098	$ -
	Adjusted Net Operating Income per Staff			$ 77,266,184	$ 77,260,450	$ 5,734

- The following table reconciles the differences between SWG's requested and Staff's adjusted revenue deficiency, and provides an estimated revenue requirement impact for each Staff adjustment:

	Reconciliation of Revenue Requirement (Thousands of Dollars)	ACC Jurisdictional Original Cost	Conversion Factor	Estimated Revenue Requirement Impact	Comment
	Rate of Return Difference				
	Utility Proposed Rate Base	$ 1,094,790,047			
	ROR Difference	-0.5932%	1.6586	$ (10,770,929)	Staff ROE at 10.0%
	Staff ROR (x GRCF for the RB to Revenue Requirement Conversion Factor)		8.86%		
Adj.	**Staff Rate Base Adjustments**		0.146901008		
No.	Description				
B-1	Yuma Manors Pipe Replacement	$ (1,092,448)	0.146901008	$ (160,482)	
B-2	Gain on Sale of Property in Cave Creek, AZ	$ (7,399,425)	0.146901008	$ (1,086,983)	
B-3	Cash Working Capital	$ (5,087,757)	0.146901008	$ (747,397)	
B-4	Customer Deposits	$ (2,480,873)	0.146901008	$ (364,443)	
B-5	Accumulated Deferred Income Taxes - Acct.190	$ (13,132,025)	0.146901008	$ (1,929,108)	
B-6	Intangible Plant Added After the Test Year	$ (139,902)	0.146901008	$ (20,552)	
B-7	Accumulated Deferred Income Taxes - RCND	$ -	0.146901008	$ -	
B-8	Remove Net Plant Being Sold to TEP for Sundt Bypass	$ -	0.146901008	$ -	
	Total of Staff Adjustments	$ (29,332,430)			
	The Utility's Proposed Rate Base	$ 1,094,790,047			
	Rounding	$ -			
	Staff Proposed Original Cost Rate Base	$ 1,065,457,617			
	Staff Net Operating Income Adjustments				
Adj.	Description	NOI Adjustment	GRCF		
C-1	Yuma Manors Depreciation and Property Tax Expense	$ 50,381	1.6586	$ (83,562)	
C-2	Gain on Sale of Property in Cave Creek, AZ	$ 42,148	1.6586	$ (69,907)	
C-3	Management Incentive Program	$ 901,944	1.6586	$ (1,495,964)	
C-4	Stock Based Compensation	$ 496,414	1.6586	$ (823,352)	
C-5	Supplemental Executive Retirement Expense	$ 982,929	1.6586	$ (1,630,286)	
C-6	American Gas Association Dues	$ 48,460	1.6586	$ (80,376)	
C-7	TRIMP Surcharge	$ 556,884	1.6586	$ (923,648)	
C-8	A&G Expenses - Annualized Paiute Allocation	$ 14,179	1.6586	$ (23,517)	
C-9	Interest on Customer Deposits	$ (90,012)	1.6586	$ 149,294	
C-10	Interest Synchronization	$ 19,103	1.6586	$ (31,684)	
C-11	Flow Back Excess Deferred Income Taxes	$ 147,345	1.6586	$ (244,386)	
C-12	Injuries and Damages	$ 515,040	1.6586	$ (854,245)	
C-13	Leased Aircraft Operating Costs	$ 19,843	1.6586	$ (32,912)	
C-14	El Paso Natural Gas Rate Case Expense	$ 288,697	1.6586	$ (478,833)	
C-15	New Intangible Plant Annualized Amortizations	$ 28,199	1.6586	$ (46,771)	
C-16	Gain on Sale of Utility Property Related to TEP Sundt Bypass	$ 61,438	1.6586	$ (101,901)	
C-17	Depreciation for Plant Sold to TEP for Sundt Bypass	$ 3,094	1.6586	$ (5,132)	
	Total of Staff's Adjustments	$ 4,086,086			
	Adjusted Net Operating Income per Utility	$ 73,180,098			
	Rounding	$ -			
	Adjusted Net Operating Income per Staff	$ 77,266,184			
1	**STAFF REVENUE REQUIREMENT ADJUSTMENTS IDENTIFIED ABOVE**			$ (21,857,076)	sum of above
2	**Utility Requested Base Rate Revenue Increase**			$ 50,218,363	Staff Schedule A
3	Adjusted revenue requirement, per above			$ 28,361,287	Line 1 + Line 2
4	GRCF difference (see below)			$ -	Line 12 below
5	**Staff Adjusted revenue increase (decrease) on OCRB**			$ 28,363,105	Staff Schedule A
6	Dollar Difference (unidentified)			$ (1,818)	
7	Percentage Difference			-0.006%	
	GRCF difference:				
8	Per Staff	1.6586	Sch A-1		No diff for SWG
9	Per the Utility	1.6586	Sch A-1		
10	Difference	0			
11	Utility's adjusted NOI deficiency	$ 30,277,561	Sch A, Col A		
12	GRCF difference	$ -			

INTRODUCTION

Q. Please state your name, position and business address.

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Are you the same Ralph C. Smith who previously filed Direct Testimony in this proceeding on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff")?

A. Yes, I am.

Q. What is the purpose of the Surrebuttal Testimony you are presenting?

A. The purpose of my testimony is to address the rate base, adjusted net operating income and revenue requirement proposed by Southwest Gas Corporation ("SWG," or "Company"), and to present Staff's updated revenue requirement recommendations.

Q. Have you prepared any exhibits to be filed with your testimony?

A. Yes. Attachments RCS-7 through RCS-8 contain the results of my analysis and copies of selected documents that are referenced in my testimony, respectively.

REVENUE REQUIREMENT

Q. What issues are addressed in your Surrebuttal Testimony?

A. My Surrebuttal Testimony responds to the Company's Rebuttal Testimony concerning various issues affecting the revenue requirement, rate base and net operating income.

Q. As a result of information received after your Direct Testimony was completed, have you revised Staff's recommended revenue increase?

A. Yes. As shown on Attachment RCS-7, I have revised Staff's recommended revenue increase for information received after my direct testimony was completed. Staff recommends a revenue increase of $28.36 million on adjusted fair value rate base. This amount is between the Staff's two options for the revenue requirement on FVRB. As shown on Schedule A, on original cost rate base ("OCRB") my calculations show a jurisdictional revenue deficiency of $28.36 million. On adjusted fair value rate base ("FVRB") under Staff's option 1, which uses a fair value rate of return of 6.79 percent, I show a base rate increase of $28.23 million. Similar to Staff's recommendations in a recent Chaparral City Water Company remand proceeding, Docket No. W-02113A-04-0616, Staff is also presenting the Commission with an option 2 for the fair value rate of return for SWG. While Staff is not recommending that the Commission adopt option 2 in this case, under option 2 the fair value rate of return for SWG is 7.08 percent, and the jurisdictional revenue deficiency is approximately $34.91 million. Attachment RCS-2, Schedule D, revised, shows the development of Staff's recommended fair value rate of return to be applied to FVRB. The direct and surrebuttal testimony of Staff witness David Parcell addresses the determination of the fair value rate of return.

ADJUSTMENTS TO ORIGNAL COST RATE BASE

Q. Please discuss Staff's adjustments to SWG's proposed original cost rate base.

A. Staff has made seven adjustments to SWG's proposed original cost rate base. These have been designated as Staff Adjustments B-1 through B-6 and Adjustment B-8. Staff Adjustment B-8 to address plant that Southwest is selling to TEP related to the TEP's Sundt plant bypass. has been added in surrebuttal, and is described below. As described in my Direct Testimony, I have also made an adjustment to SWG's proposed RCND rate base, for trending the Accumulated Deferred Income Tax ("ADIT") component, which is also discussed below and shown in Staff Adjustment B-7. My rebuttal to Southwest concerning each adjustment follows.

B-1 Yuma Manors Pipe Replacement

Q. How is Staff responding to SWG's Rebuttal concerning Staff's recommended adjustment for the Yuma Manors Pipe Replacement?

A. Staff witness, Corky Hanson, is responding to the Rebuttal Testimony of SWG witness Jerome T. Schmitz. I am responding to the Rebuttal Testimony of SWG witness Robert Mashas, which addresses, at pages 8-14, regarding ratemaking standards and precedents that the Commission has applied in past SWG rate proceedings to determine the appropriate level of pipe replacement costs in rate base.

Q. Mr. Mashas cites four prior Commission Decisions. Are any of those directly on point with the Yuma Manors pipe replacement issue in the current rate case?

A. No. As explained in Mr. Hanson's testimony, Staff views the Yuma Manors pipe replacement issue 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. Consequently, as applied to the Yuma Manors pipe replacement issue that is being addressed in the current SWG rate case, Staff has a different perspective of the regulatory history, and the appropriate regulatory treatment of the Yuma Manors cost, than Mr. Mashas apparently does.

Q. Please explain Staff's perspective of the regulatory history and the appropriate treatment of the Yuma Manors pipe replacement cost, and how that differs with the views and interpretations expressed in Mr. Mashas' Rebuttal Testimony.

A. At pages 9-10, Mr. Mashas states that:

> *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.*

Staff notes the following facts with respect to the Yuma Manors steel pipe at issue in the current SWG rate case. First, as noted in the above quoted portion of Mr. Mashas' Rebuttal Testimony, the Commission has found that, under the appropriate circumstances, the remedial portion of the pipe replacement cost was the sole responsibility of SWG's shareholders. In regards to the Yuma Manors pipe replacement, based on the circumstances that lead to that pipe failure, as described by Staff witness Hanson, the responsibility for the cost should be with SWG's shareholders, rather than being shared with ratepayers.

Second, as far as Staff can tell, that specific Yuma Manors steel pipe had not previously been replaced. Thus, the pipe replacement costs for Yuma Manors that occurred in 2006, which are at issue in the current SWG rate case, was not specifically addressed in the 19 percent write-off of steel pipe that was discussed in Decision No. 58693.

Third, the current SWG rate case represents the first SWG rate case where the issue of the Yuma Manors pipe replacement is being addressed. The issues concerning the questionable maintenance of that pipe, as described in Staff witness Hanson's testimony, first came to Staff's attention in the context of the current SWG rate case.

Q. At page 10, lines 12-13 of his Rebuttal, Mr. Mashas states that each of the five previously addressed pipe replacement programs shared the following characteristic in common: "All five pipe replacement programs resulted in the premature replacement of pipe resulting from either defective material and/or installation." Is the Yuma Manors pipe replacement issue in the current SWG case directly attributable to either defective material or installation?

A. 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. Consequently, where there was a sharing of cost between shareholders and ratepayers in prior SWG rate cases where the premature replacement was attributed to either defective material and/or installation, Staff attributes the premature replacement of Yuma Manors not to those factors but rather to negligent maintenance by SWG. As such, based on Staff's analysis in the current SWG rate case, the cost of the premature replacement of the Yuma Manors pipe should be borne by shareholders and not shared between shareholders and ratepayers.

Q. At pages 11-12 of his Rebuttal Testimony, Mr. Mashas comments on the Commission's previous rulings concerning the replacement of steel pipe. He cites Decision No. 58693, wherein the Commission adopted and approved a settlement that addressed the appropriate level of steel pipe replacement that would be included in rate base. Please discuss Mr. Mashas' view of Decision No. 58693 and describe how and why Staff's interpretation of that decision, as applied to the issue of Yuma Manors pipe replacement cost in the current SWG rate case differs.

A. Mr. Mashas states at page 11, lines 20-22, of his Rebuttal that:

> *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 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__*. (Emphasis in original.)

At page 12, Mr. Mashas claims that Staff's proposal is not consistent with any of the above Commission rulings on pipe replacement. He seems to believe that the settlement that was approved in Decision No. 58693 somehow provided SWG with "100 percent recovery of replacement cost for steel pipe that was first installed prior to 1960."[1]

Staff has a different view of Decision No. 58693 and concludes that it does not preclude Staff from pursuing the issues related to the Yuma Manors pipe replacement in the context of SWG's current rate case, based on the facts that Staff has identified in the current case.

[1] See, e.g., Mashas' rebuttal testimony, page 12, lines 24-26.

Decision No. 58693, at page 3, paragraph B, specified that SWG shall write off the following amounts of gross plant-in-service on its books as of June 30, 1993, which included an amount of $906,000 for steel pipe. With respect to steel pipe, paragraph B provides further that:

> *In future Southwest rate cases for the Southern Division gas properties, Southwest shall exclude from rate base an additional portion of capitalized expenditures associated with replacements of ... steel installed in the 1960's ... related to defective materials and/or installation. For such capitalized expenditures during the period July 1, 1993 through June 30, 1994, the rate base exclusion shall be based on the following percentages: ... 19 percent for steel installed in the 1960's .... During each successive twelve month period following June 30, 2004, the foregoing percentages shall be reduced incrementally by one percent.*

Clearly, this provision relates to capitalized expenditures associated with replacements of steel pipe that was installed in the 1960s that is related to defective materials and/or installation. The issue concerning Yuma Manors in the current SWG rate case relates to questionable maintenance and an error made by SWG personnel in 2006 related to wiring the cathodic protection. Additionally, what Mr. Mashas fails to acknowledge is that the maintenance issues related to the Yuma Manors pipe replacement issue in the current rate case were not known in the 1993-1994 time frame when the case addressed by Decision No. 58693 was processed[2]. Moreover, Mr. Mashas fails to mention paragraph F on page 5 of Decision 58693, which provides that:

> *... nothing in this Agreement shall be construed as prohibiting Staff or any other party from pursuing new issues related to expenditures made or actions taken after June 30, 1993, except for the treatment of pipe replacement and repair costs, which will be governed by paragraph B. However, Staff or any other party shall not be precluded from pursuing*

[2] As described in the direct testimony of Staff witness Corky Hanson, a need for Southwest to correct deficiencies in the cathodic protection was identified in a 2006 inspection report and remedial action, which included connecting the wiring backwards, was not completed until February 28, 2006.

> *issues related to pipe replacement, pipe repair, leak surveys or any other matter related to pipe replacement, pipe repair, or leak surveys not specifically covered by Paragraph B.*

From Staff's perspective, nothing in Decision No. 58693 precludes Staff from addressing in the current SWG rate case the concerns over SWG's questionable maintenance of the Yuma Manors pipe, including the reverse wiring of the cathodic protection[3], or the resulting costs of the pipe replacement that resulted from those maintenance issues.

Q. Has SWG offered to make a lesser adjustment related to the Yuma Manors pipe replacement?

A. Yes. At page 13 of his Rebuttal Testimony, Mr. Mashas offers to reduce rate base by $320,779 ($123,397 for mains and $197,382 for services) for additional costs that were incurred by the Company due to the urgency required to replace the Yuma Manors steel pipe system in a relatively short period of time. In response to Staff data request STF-13-21, SWG identifies related adjustments to decrease depreciation expense by $15,175 and property taxes by $8,499, that should be made if SWG's offer to make a lesser adjustment for Yuma Manors were to be accepted.[4]

Q. Does Staff agree with SWG's proposed offer for a lower adjustment for Yuma Manors?

A. No. Staff views SWG's offer to reduce rate base by only $320,779 for the Yuma Manors pipe replacement (plus the related adjustments to depreciation expense and property taxes) as the absolute minimum adjustment that should be made. As noted above, Staff does not agree with Mr. Mashas' interpretation of the prior SWG rate case orders as precluding the adjustment recommended by Staff in the current SWG rate case.

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[3] See, e.g., Staff witness Corky Hanson's direct testimony at page 2.
[4] See Attachment RCS-8 for copies of data request responses referenced in this testimony.

Q. What adjustment does Staff recommend for Yuma Manors?

A. Staff recommends the adjustment that was shown on Schedule B-1[5], that reduces rate base by $1,092,448. This adjustment restates test year rate base as if the pipe replacement project undertaken by SWG in the Manors subdivision in Yuma, Arizona, did not exist. Plant in Service accounts for Mains (Account 376) and Services (Account 380) are restated to effectively eliminate the costs related to the Company's failure to adequately maintain the pipe which led to its replacement. Accumulated Depreciation as of April 30, 2007, the end of the test year, is also restated similarly. The components of the adjustment are summarized on Schedule B-1. Plant in Service is reduced by $1.232 million. Accumulated Depreciation is increased by $139,314. Net rate base is decreased by $1.092 million. As was noted in my Direct Testimony, the source for the amounts used in the adjustment was SWG's response to Staff data requests STF-7-1 and LA-11-6.[6]

Related adjustments for depreciation expense and property taxes should also be made. As described in my Direct Testimony, Staff Adjustment C-1 is related to this adjustment and reduces test year Depreciation Expense and Property Tax Expense, based on the adjustment to Plant in Service and Net Plant, respectively.

B-2 Customer Advances for Construction

B-4 Customer Deposits

Q. Does SWG disagree with Staff's Adjustments B-2 or B-4?

A. No. However, SWG witness Randi Aldridge suggests at page 6, lines 7-16, that accepting these Staff adjustments should somehow be contingent upon making an adjustment to Uncollectibles expense.

[5] In Attachment RCS-2, attached to my direct testimony.
[6] See Attachment RCS-5 for copies of data request responses referenced in this testimony.

Q. Has SWG changed its request for Uncollectibles Expense?

A. No. As stated in the Company's response to data request STF-13-11(a): "Southwest's request for uncollectibles expense is unchanged from its initial filing. Southwest continues to request test year recorded uncollectibles expense of $2,977,729."

Q. Are Staff's Adjustments B-2 or B-4 to rate base contingent in any way upon whether an adjustment is made to Uncollectibles Expense?

A. No. Staff Adjustments B-2 and B-4 affect rate base and are not dependent upon whether test year uncollectibles expense is adjusted or not. Staff Adjustment B-2 decreases rate base by $11.285 million to reflect the end-of-test-year balance for Customer Advances. Rate base is also increased by $3.885 million for the related impact on Accumulated Deferred Income Taxes ("ADIT"). Similarly, Staff Adjustment B-4 decreases rate base by $2.48 million to reflect the end-of-test-year balance for Customer Deposits. Neither of these rate base adjustments is dependent in any way on Uncollectibles Expense.

Q. Please summarize why Staff Adjustment B-2 is necessary.

A. As explained in my Direct Testimony, the end-of-test-year balance for Customer Advances should be used for at least two reasons.

First, Customer Advances are related to Plant, and the end-of-test-year balances for Plant in Service and Accumulated Depreciation are used in rate base. Revenues have been annualized to year-end conditions, and expenses, such as Depreciation and Property Taxes have also been adjusted to year-end conditions, to properly "match" with the use of year-end plant in rate base.

Second, and perhaps more importantly, the end-of-test-year balance for Customer Advances is more representative of current and ongoing conditions than would be an average test year balance. As shown on Schedule B-2[7], the monthly balance of Customer Advances has increased in each month of the test year. Thus, unlike some other rate base components, where the balances fluctuate up and down from month to month, the steady upward trend in Customer Advances indicates that this is a growing balance. Consequently, the average balance is not representative of conditions at the end of the test year, or on a going-forward basis.

Q. Please summarize why Staff Adjustment B-4 is necessary.

A. The end-of-test-year balance for Customer Deposits should be used for at least two reasons.

First, Customer Deposits are related to the number of customers that the utility is serving. End-of-test-year balances for Plant in Service and Accumulated Depreciation are used in the determination of SWG's rate base. Revenues have been annualized to year-end conditions, and expenses, such as Depreciation and Property Taxes have also been adjusted to year-end conditions, to properly "match" with the use of year-end plant in rate base. Using the end-of-test-year balance of Customer Deposits thus better matches that balance with the use of year-end customer levels that were used to annualize utility revenues to test year-end conditions.

Second, and perhaps more importantly, the end-of-test-year balance for Customer Deposits is more representative of current and ongoing conditions than would be an average test year balance. As shown on Schedule B-4, the monthly balance of Customer

[7] In Attachment RCS-2, attached to my direct testimony.

Deposits has increased in each month of the test year. Thus, unlike some other rate base components, where the balances fluctuate up and down from month to month, the steady upward trend in Customer Deposits indicates that this is a growing upward trend, and the average balance is not representative of conditions at the end of the test year, or on a going-forward basis. Perhaps even more compelling regarding the trend of steady growth SWG has experienced in the monthly balances of Customer Deposits is shown on Schedule B-4, page 2. In the 61 months from September 2002 through September 2007, the Company's balance of Customer Deposits has increased in every single month. A graph of the monthly Customer Deposit balances from September 2002 through September 2007, which illustrates this trend of steady growth to (and even beyond) the end of the test year, is presented on Schedule B-4, page 3.

B-3 Cash Working Capital

Q. What issues relating to Cash Working Capital are addressed in SWG's Rebuttal Testimony?

A. SWG witness Robert Mashas' Rebuttal Testimony addresses two issues related to cash working capital:

(1) Southwest agreed with RUCO on the inclusion of an interest lag for preferred securities.[8]

(2) The derivation of a payment lag for revenue-based taxes.[9]

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[8] See the rebuttal testimony of Mr. Mashas, at pages 15-16. He also states that Southwest disagrees with RUCO concerning the inclusion of a lag for interest on customer deposits in the lead-lag study.

[9] Id., pages 16-17.

Q. Does Staff agree that the cash working capital should reflect the lag for the payment of interest on preferred securities?

A. Yes. Interest on preferred securities is included in the cost of capital and should be afforded similar ratemaking treatment to other interest expense included in the cost of capital. As shown on Schedule B-3, revised, page 1 of 2, line 7, column D, I have used the same quarterly payment lag of 45.25 days for the preferred securities payment lag proposed by SWG[10] and used by RUCO[11] to reflect this.

Q. In your Direct Testimony, had you identified any revisions to SWG's cash working capital request that were not quantified at that time?

A. Yes. I noted that SWG had omitted reflecting the additional cash payment lag associated with revenue-based taxes and assessments. I noted that the lead-lag studies for other Arizona utilities, including UNS Gas ("UNSG"), UNS Electric("UNSE") and Tucson Electric Power Company ("TEP") had each included a component in the cash working capital allowance for the additional cash payment lag related to the payment of revenue-based taxes and assessments.

Q. Have you incorporated a lag for the payment of revenue-based taxes into the calculation of cash working capital?

A. Yes. This is shown on Attachment RCS-7, Schedule B-3, page 2. As shown there, incorporation of a net payment lag for revenue-based taxes of 18.10 days reduces SWG's cash working capital and rate base by approximately $5 million. As explained below, and shown on Schedule B-3, page 2, the net lag of 18.10 days is based on the difference in the

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[10] See Mr. Mashas' Rebuttal Exhibit __(RAM-3), sheet 1 of 2, preferred equity lag days of 45.25 days.
[11] See RUCO witness Rodney Moore's Schedule RLM-6, page 3 of 5, which shows the preferred equity lag of 45.25 days.

weighted payment lag of 57.63 days for revenue-based taxes and SWG's revenue lag of 39.53 days.

Q. Please explain why a net payment lag for revenue-based taxes should be reflected in the determination of cash working capital.

A. During the period between (1) when the utility collects the revenue based taxes from ratepayers and (2) when the utility remits those funds to the taxing or assessing authority, the Company has use of the ratepayer-provided funds. Because the revenue based taxes are directly related to the provision of utility service and because there is a cash payment and the utility typically has the use of ratepayer-provided funds for some period, it is appropriate to reflect the payment lag associated with such taxes in the determination of cash working capital using a lead-lag study.

Q. What payment lag for revenue-based taxes does SWG propose?

A. As described in the Rebuttal Testimony of SWG witness Robert Mashas and shown on his Rebuttal Exhibit __(RAM-3), sheet 2, the Company proposes a revenue-based payment lag of 45.24 days. Mr. Mashas derived this by calculating a payment lag for quarterly and annually paid revenue-based taxes and by assuming that the lag related to the monthly payments of revenue-based taxes was identical to the Company's 39.53-day revenue lag. The latter, however, is an incorrect assumption.

Q. Is Mr. Mashas' derivation of the lag for the revenue taxes that are paid monthly consistent with what you have seen in other recent Arizona energy utility rate cases?

A. No, it is not. As shown on Mr. Mashas' Rebuttal Exhibit __(RAM-3), sheet 2, the monthly paid revenue taxes consist of franchise fees (which were approximately $6.448 million for SWG) and the State of Arizona privilege/sales tax (approximately $84.412

million). The payment lag assumed by Mr. Mashas for each of these is too short, and is inconsistent with the revenue tax payment information in other recent Arizona energy utility rate cases, where those utilities are paying the same or similar types of revenue-based taxes that Southwest is paying.

For example, the revenue tax payment lag workpapers for UNSG, UNSE and TEP each include the following explanation of the derivation of the lag for the payment of the Arizona State sales tax:

> *The Arizona Transaction Privilege Tax is required to be paid by the 20th day of the month following the applicable revenue month. Consistent with the development of the revenue lag, the tax payment should be measured from the midpoint of the customer service period underlying the revenue being taxes to the actual tax payment date. For example, if January revenues include a billing cycle extending from December 10th through January 9th, the tax payment should be measured from the midpoint of that period, and not from the midpoint of January.*

An examination of some of the Arizona Department of Revenue, Transaction Privilege, Use and Severance Tax Returns (TPE-1), as filed by SWG (which were provided in response to data request STF-11-3) indicate that the returns are due on the 20th day of the following month.[12] The information shown on SWG's returns for the Arizona Transaction Privilege Tax thus appears to be consistent with the analysis used by UNSG, UNSE and TEP, but is inconsistent with the monthly payment lag analysis shown on Mr. Mashas' Rebuttal Exhibit __(RAM-3), sheet 2.

[12] Illustrative copies of such returns are included in Attachment RCS-8.

Q. What payment lag did UNSG, UNSE and TEP use for the Arizona State Transaction Privilege Tax, and how did that compare with the respective revenue lag for those utilities?

A. The payment lags used by UNSG, UNSE and TEP for the Arizona State Transaction Privilege Tax (aka the state sales tax), and how that compared with the respective revenue lags used by those utilities in their most recent lead-lag studies is summarized in the following table:

Additional Lag in Payment of Arizona State Sales Tax
Beyond the Utility's Revenue Lag

Utility	Revenue Lag Days	AZ State Sales Tax Payment Lag Days	Additional Lag for Payment of Sales Tax
UNSG	38.95	52.36	13.41
UNSE	35.59	50.58	14.99
TEP	33.79	58.6	24.81

As shown above, there is a notable additional lag for the monthly payment of the state sales tax beyond the utility's revenue lag.

Q. What does the information in SWG's response to data request STF-11-3 show for monthly paid city franchise taxes?

A. For franchise taxes paid monthly, the returns are due on the 20th day of the next month. A review of SWG's actual returns, including those for the cities of Phoenix, Scottsdale, Tempe, Tucson, Chandler, Glendale, Mesa, Peoria, and Avondale support this. Illustrative copies of such returns are included in Attachment RCS-8 to my Surrebuttal Testimony.

Q. What net lag did SWG assume for monthly paid city franchise taxes?

A. Mr. Mashas used the Company's revenue lag, without any adjustment, as his assumed payment lag for monthly paid city franchise taxes.

Q. How does that compare with what TEP and its affiliates used for similar monthly-paid franchise taxes?

A. The payment lag used by SWG for monthly paid city franchise taxes is much too short. When TEP and its affiliates paid monthly franchise fees to some of the same cities (such as Tucson to which Southwest also pays such taxes) TEP concluded, for example, that: "the required payments of taxes are due the 20th day of the following month. Accordingly, the same 58.6-day computed lag for AZ Sales Taxes would apply to these various revenue-driven taxes."

Q. What lag for revenue-based taxes have you used for SWG?

A. As shown on Schedule B-3 (Revised), page 2, I have used a net lag of 18.1 days. My derivation of the net lag for the payment of revenue-based taxes is similar to that of SWG; however, I have revised the payment lag related to the monthly payment of city franchise fees and the Arizona State Transaction Privilege Tax (aka the Arizona state sales tax) by adding 14 days to SWG's revenue lag. This is consistent with how such taxes are actually paid, as well as being reasonably consistent with the approach used, and results obtained, by the most current lead-lag studies of other major Arizona energy utilities including UNSG, UNSE and TEP.

Q. What is the result of your revised cash working capital calculation?

A. As shown on Schedule B-3 (Revised), I have decreased SWG's filed cash working capital by approximately $5 million.

B-6 New Intangible Plant Placed Into Service by December 31, 2007

Q. What does SWG's Rebuttal state concerning Staff's adjustment for new intangible plant placed into service by December 31, 2007?

A. SWG witness Randi Aldridge addresses this at pages 14-15 of her Rebuttal Testimony. The Company disagrees with Staff's adjustment because it used information from SWG's responses to data requests STF-6-49 and STF-11-4. SWG had provided updated and/or revised responses to those data requests, which had not been considered in Staff's adjustment.

Q. Have you revised Staff's adjustment for new intangible plant placed into service by December 31, 2007 to incorporate SWG's supplemental response to data requests STF-6-49 and STF-11-4?

A. Yes. Incorporating the information provided in the Company's supplemental/revised response to those Staff data requests should bring the Staff adjustment into agreement with the Company's revised amount of $1,449,530, which was further clarified in SWG's response to Staff data request STF-13-12.

Q. Please explain Staff's revised adjustment for new intangible plant placed into service by December 31, 2007.

A. SWG's filing included an adjustment (Company Adjustment No. 14) to add to rate base $1,696,000 for new intangible plant that the Company projected would be placed into service by December 31, 2007. Staff Adjustment B-6, revised, adjusts the Company's estimate for actual new intangible plant that was placed into service by December 31, 2007 to the amount of $1,449,260 shown in SWG's revised responses. As shown on Schedule B-6, Intangible Plant allocated to Arizona is reduced by $139,902.

Q. Is there a related adjustment for the annualized amortization?

A. Yes. A related adjustment for the impact upon annualized amortization expense is presented in Staff Adjustment C-15, revised. As shown there, SWG's originally requested Arizona jurisdictional expense for the amortization of new intangible plant is reduced by $46,633.

B-8 Remove Net Plant Being Sold to TEP for Sundt Bypass

Q. Please explain the adjustment to remove the net plant that is being sold to TEP related to the Sundt Plant bypass.

A. SWG has removed revenue related to TEP bypassing SWG with respect to providing gas supply to TEP's Sundt generating station. SWG's May 14, 2008 supplemental response to data request RUCO-7-2 states that:

> *A) A high pressure metering facility and 1,867 feet of 12-inch steel pipe will be retired as a result of the TEP bypass. The original amount for the metering facility to be retired is $182,093 and the retirement amount for the piping to be retired is $28,526. The net book value as of April 30, 2007, for the metering facility is $151,351 and the net book value of the piping is $25,429. The net book value as of March 31, 2008, the expected sales date, for the metering facility is $144,156 and the net book value of the piping is $24,440.*
>
> *B) The facilities described in the response to a) are anticipated to be sold as a result of the TEP bypass. Although the sales agreement between Southwest, TEP, and El Paso is not final, the tentative sales prices are $398,381 and $350,000 for the Alternative Feed Line (pipe) and Meter Set Assembly (MSA), respectively.*

Staff adjustment B-8 removes the plant from rate base. Based on the standard accounting for a retirement of plant, the same amount is credited to Plant and is debited to Accumulated Depreciation. Consequently, this adjustment has a net impact on rate base of zero.

Q. Is there a related adjustment for the sharing of the gain realized on the sale of that plant between shareholders and ratepayers?

A. Yes. A related Staff Adjustment, C-16, discussed below, reflects the sharing of the gain between ratepayers and shareholders.

ADJUSTMENTS TO OPERATING INCOME

Q. What adjustments to operating income do you discuss in your Surrebuttal Testimony?

A. I discuss adjustments which have been revised or added based on the receipt of additional information from SWG. I also respond to SWG's Rebuttal Testimony concerning certain adjustments to operating expenses that Staff has recommended.

Q. Have you revised Staff's recommended net operating income?

A. Yes. Attachment RCS-7, Schedule C, revised, summarizes Staff's recommended net operating income. Schedule C.1, revised, presents Staff's recommended adjustments to Arizona test year revenues and expenses. The impact on state and federal income taxes associated with each of the recommended adjustments to operating income are also reflected on Schedule C.1. Staff's revised adjusted net operating income is $77.266 million. The recommended adjustments to operating income are discussed below in the same order as they appear on Schedule C.1.

C-1 Yuma Manors Depreciation and Property Tax Expense

Q. In response to SWG's Rebuttal Testimony have you revised Staff Adjustment C-1?

A. No. As described above, in conjunction with the related rate base adjustment, Adjustment B-1, Staff disagrees with SWG witness Robert Mashas' interpretation of prior Commission orders, which addressed historic pipe replacement issues related to defective materials and/or installation. As described in the Direct Testimony of Staff witness Hanson, Staff believes that the issue with Yuma Manors in the current SWG rate case relates to questionable maintenance actions by SWG personnel in 2006. Consequently, Staff recommends that the replacement costs should be borne fully by the Company and not by ratepayers. As described in Mr. Mashas' Rebuttal Testimony at page 13 and in the Company's response to data request STF-13-21, SWG has offered to make a lower adjustment to depreciation and property tax expense. Staff views that offer by SWG as representing the absolute minimum amounts of adjustment for the Yuma Manors replacement, but not the most appropriate or most reasonable amounts for this adjustment, based on the facts of the current case. Consequently, Staff continues to recommend that $54,370 of Depreciation Expense and $28,945 of Property Tax Expense related to the adjustment to Plant in Service for the Yuma Manors pipe replacement project be removed from test year operating expenses.

C-3 Management Incentive Program Expense

Q. Please explain Staff Adjustment C-3, revised.

A. This adjustment provides for the allocation of 50 percent of the test year expense for the Management Incentive Program ("MIP") to shareholders. Test year expense for the MIP proposed by SWG is reduced by $1.612 million. Related payroll tax expense is increased by $120,186. The amounts have been revised for corrections made by SWG in its March 25, 2008 supplemental responses to data requests STF-1-78, and RUCO-1-10.

Q. Please explain why payroll tax expense is being increased in Staff Adjustment C-3, revised.

A. SWG's response to data request STF-11-15 states that SWG's annualized labor (shown on the Company's workpaper for Schedule C-2, Adjustment No. 3) does not include MIP compensation or stock based compensation.[13] Consequently, the cost of service filed by SWG did not include annualized payroll taxes related to these two items of compensation. This adjustment, therefore, provides for annualized payroll tax expense on the portion of MIP that is being allowed in rates.

Q. SWG witness Laura Hobbs claims, at page 3, lines 9-11, of her Rebuttal Testimony that: "The sharing concept relating to the Company's MIP expenses is premised upon a false assumption that the program is an additional cost to customers." Please respond.

A. First, SWG has not presented information showing how employee salaries were reduced when MIP was first implemented. SWG's employee salaries have continued to increase each year. Thus, the MIP is an additional expense. Second, the sharing concept is based upon a premise that the incentive compensation program provides benefits both to ratepayers and to shareholders.

Q. SWG witness Laura Hobbs claims, at page 3, lines 20-24, of her Rebuttal Testimony that: "The goals or targets of the current MIP are also heavily weighted toward providing benefit to customers. Identifying which of the goals is a greater benefit to whom in deciding cost recovery is irrelevant." Please explain why a 50 percent allocation to shareholders is appropriate for an incentive compensation program, such as SWG's MIP.

A. In general, incentive compensation programs can provide benefits to both shareholders and ratepayers. The removal of 50 percent of the MIP expense, in essence, provides an equal sharing of such cost, and therefore provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Both shareholders and ratepayers

[13] See Attachment RCS-5.

stand to benefit from the achievement of performance goals; however, there is no assurance that the award levels included in the Company's proposed expense for the test year will be repeated in future years.

Q. How are the MIP awards related to shareholder dividends?

A. Two of the five MIP award criteria relate to return on equity. Additionally, no annual incentive awards will be payable unless the Company's dividends equal or exceed the prior year's dividends. This is an important factor because, if shareholder dividends are decreased from the prior year, there are no incentive awards under the MIP for that year.

Q. Does SWG recognize that its proposed treatment of MIP expense in the current case represents a conscious deviation from principles and policies established in prior Commission Orders?

A. Yes.

Q. How was SWG's MIP cost shared between shareholders and ratepayers in SWG's last rate case and what criteria did the Commission's decision appear to find important in deciding issues concerning utility incentive compensation in recent cases?

A. In SWG's last rate case the Commission in Decision No. 68487 (issued February 23, 2006), the Commission adopted Staff's recommendation for an equal sharing of costs associated with the Company's MIP expense. In reaching its conclusion regarding SWG's MIP, the Commission stated in part on page 18 of Order 68487 that:

> *We believe that Staff's recommendation for an equal sharing of the costs associated with MIP compensation provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Although achievement of the performance goals in the MIP, and the*

> *benefits attendant thereto, cannot be precisely quantified there is little doubt that both shareholders and ratepayers derive some benefit from incentive goals. Therefore, the costs of the program should be borne by both groups and we find Staff's equal sharing recommendations to be a reasonable solution.*

Ms. Hobbs has not refuted the fact that both shareholders and ratepayers derive some benefit from incentive goals.

Q. Do SWG's shareholders and customers both benefit from its MIP goals?

A. Yes. Ms. Hobbs stated in her Direct Testimony at page 5, lines 4-8 that:

> *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.*

Shareholders benefit from the achievement of financial goals. Additionally, shareholders benefit from the achievement of expense reduction and expense containment goals between rate cases. Shareholders and ratepayers can both benefit from the achievement of customer service goals.

Q. Have the facts changed materially since the last SWG rate case that a different result concerning the sharing of MIP expense should occur?

A. No, I don't believe so. The Company's MIP expense is significantly higher in the current rate case than it was in the prior SWG rate case. However, the rationale for the 50 percent allocation to shareholders of the MIP expense in the current case appears to be consistent with the Commission's findings concerning MIP in Decision No. 68487.

Q. Did SWG appeal Decision No. 68487?

A. No.

Q. Should the 50/50 ratepayer/shareholder sharing that the Commission has applied to utility incentive compensation in SWG's last rate case be modified to a 100 percent ratepayer responsibility for such cost based on the analysis presented by Ms. Hobbs or by anything in her Rebuttal Testimony?

A. No. The 50/50 sharing of Southwest's MIP program cost ordered by the Commission in Decision No. 68487 should continue to apply in the current SWG rate case.

Q. Was an equal sharing of utility incentive compensation expense also ordered in the Commission's recent decision in a rate case involving another Arizona gas distribution utility?

A. Yes, it was. In Decision No. 70011 (November 27, 2007), in the recent UNS Gas rate case, Docket No. G-04204-06-0463 et al, the Commission stated in part on page 27 that:

> *We believe that Staff's recommendation provides a reasonable balancing of the interests between ratepayers and shareholders by requiring each group to bear half the cost of the incentive program.*

A similar decision was also reached with respect to UNS Electric's incentive compensation in Docket No. E-04204A-06-0783:

> *Consistent with our finding in the UNS Gas rate case (Decision No. 70011, at 26-27), we believe that Staff's recommendation provides a reasonable balancing of the interests between ratepayers and shareholders by requiring each group to bear half the cost of the incentive program.*[14]

[14] Recommended Decision at page 21, as adopted by the Commission at the May 14, 2008 open meeting.

Q. How does the amount of SWG's MIP expense in the current case compare with the amount from SWG's prior rate case?

A. The following table summarizes SWG's MIP expense in the current case, and Staff's recommended adjustment for MIP expense from Staff's Surrebuttal Testimony in SWG's last rate case, Docket No. G-0551A-04-0876:

Management Incentive Program Expense
Staff Proposed Treatment in Current SWG Rate Case
Compared with Staff Recommendation in Last SWG Rate Case

Line	Description	Current Case	SWG's Last Rate Case	Dollar Increase	Percent Increase
1	Test Year amount of Management Incentive Program Expense (Corporate)	$5,919,502	$ 3,366,667	$ 2,552,835	76%
2	Allocation to Paiute (MMF)	$ (234,412)			
3	Net of Allocation to Paiute	$5,685,090	$ 3,366,667		
4	Arizona Four Factor allocation rate per SWG Schedule C-1, sheet 17	56.70%	57.58%		
5	Test Year amount of Management Incentive Program Expense (Arizona)	$3,223,446	$ 1,938,518		
6	Ratepayerer allocation percentage	50%	50%		
7	50% Allocation of MIP Expense to Ratepayers	$1,611,723	$ 969,259	$ 642,464	66%

Source:
Current case amounts - Attachment RCS-7, Schedule C-3, Revised
Prior case amounts - Docket No. G-0551A-04-0876, James Dorf surrebuttal, Schedule JJD-16 Revised

As shown in the above table, which reflects a Company correction to the test year amounts shown in the corrected response to RUCO-1-10 and STF-1-78, SWG's MIP expense in the current rate case is 76 percent higher than in the prior case. Also, Staff's proposed 50 percent allowance of MIP expense for Arizona operations of $1.612 million in the current case is 66 percent higher than the $969,259 amount from SWG's last rate case.

Q. Is a significant portion of SWG's MIP expense related to stock-based compensation?

A. Yes. SWG's response to data request STF-10-12 identifies $3,587,416 as MIP stock-based compensation expense.[15] Thus, over half[16] of SWG's total test year MIP expense is related to stock-based compensation.

Q. Did the Commission recently disallow another utility's stock based compensation in a recent decision?

A. Yes. In Decision No. 69663, from a recent APS rate case, the Commission adopted a Staff recommendation in that case where cash-based incentive compensation expense was allowed and stock-based compensation was disallowed. Additionally, page 36 of Decision No. 69663 indicates that the Commission rejected an argument by APS that the Commission not look at how compensation is determined or its individual components:

> *"APS argues that the issue is whether APS compensation, including incentives, is reasonable. APS does not believe that the Commission should look at how that compensation is determined or its individual components, but rather should just look at the total compensation. The Company argues that the interests of investors and consumers are not in fundamental conflict over the issue of financial performance, because both want the Company to be able to attract needed capital at a reasonable cost."*
>
> *"We agree with Staff that APS' stock-based compensation expense should not be included in the cost of service used to set rates. Contrary to APS' argument that we should not look at how compensation is determined, we do not believe rates paid by ratepayers should include costs of a program where an employee has an incentive to perform in a manner that could negatively affect the Company's provision of safe, reliable utility service at a reasonable rate." As testified to by Staff witness Dittmer and set out in Staff's Initial brief, "enhanced earnings levels can sometimes be achieved by short-term management decisions that may not encourage the development of safe and reliable utility service at the lowest long-term cost. ... For example, some maintenance can be temporarily deferred,*

[15] See Attachment RCS-5.
[16] $3.587 million of stock-based / $5.919 million total (revised) = 60.60 percent.

> *thereby boosting earnings. ... But delaying maintenance can lead to safety concerns or higher subsequent 'catch-up' costs." [cite omitted] To the extent that Pinnacle West shareholders wish to compensate APS management for its enhanced earnings, they may do so, but it is not appropriate for the utility's ratepayers to provide such incentive and compensation."*

Thus, in Decision No. 69663, the Commission made an adjustment to disallow a portion of that utility's incentive compensation expense, specifically the stock-based compensation.

Additionally, in the recent UNS Electric rate case, Docket No. E-04204A-06-0783, the Commission disallowed that utility's stock based compensation expense, stating that:

> *... we agree with Staff that test year expenses should be reduced to remove stock-based compensation to officers and employees. As Staff witness Ralph Smith stated, the expense of providing stock options and other stock-based compensation beyond normal levels of compensation should be borne by shareholders rather than ratepayers ... The disallowance of stock-based compensation is consistent with the most recent rate case for Arizona Public Service Company (Decision No. 69663).*[17]

Q. Please summarize Staff's recommendation concerning SWG's MIP expense.

A. Staff recommends continuing the 50 percent allocation to shareholders ordered for SWG by the Commission in Decision No. 68487. This results in a reduction to test year expense of $1,611,723, as shown on Schedule C-3, revised.

C-4 Stock-Based Compensation (Other than MIP)

Q. Please describe SWG's Stock Incentive Plan.

A. As noted in my Direct Testimony, SWG has two stock-based compensation plans: (1) the stock incentive plan ("SIP") and the management incentive plan ("MIP"). The stock-

[17] Recommended decision at page 22, as adopted by the Commission at the May 14, 2008 open meeting.

based compensation addressed in Staff Adjustment C-4 is for stock-based compensation other than MIP. As described above, SWG's MIP incentive compensation also includes a stock-based component. Under the SIP, the Company may grant options to purchase shares of common stock to key employees and outside directors. Each option has an exercise price equal to the market price of Company 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.

Q. Please respond to SWG witness, Ms. Hobbs' Rebuttal Testimony concerning SWG's stock-based compensation expense.

A. At pages 4-5 of her Rebuttal Testimony, Ms. Hobbs addresses SWG's stock-based compensation program. She takes exception to a suggestion that a stock based incentive compensation program could incent utility employees to perform in a manner that could negatively affect the Company's provision of safe, reliable utility service at a reasonable rate. I have not seen evidence that the SWG management is performing in a manner that could negatively affect the quality of service. However, the potential for such an incentive was cited in Decision No. 69663 involving APS. As noted above, a utility's stock-based compensation was disallowed in the last APS rate case, and was disallowed in the recent decision in the UNS Electric rate case.

Q. Did SWG have stock option expense in its prior rate case?

A. No. Prior to 2006, SWG only recognized compensation expense in its financial statements for restricted shares issued from the MIP. In accordance with changes in financial accounting requirements, such as Statement of Financial Accounting Standards No. 123, as Revised in 2004, (SFAS 123R), SWG began expensing stock options in 2006, as described in the Company's response to data request STF 10-12 and in an internal

Company memo dated December 29, 2005 regarding: "SFAS No. 123 (Revised 2004) Share-Based Payment."[18] Those documents indicate that the provisions of SFAS 123R became effective for the Company in January 2006. SWG's response to STF 10-12 states that, in May 2007, a restricted stock unit plan replaced SWG's stock option plan (and were also required to be expensed). SWG expenses stock-based compensation over a three-year vesting period. Grants to retirement-eligible employees are immediately expensed.

Q. Please explain Staff Adjustment C-4.

A. As shown on Schedule C-4, this adjustment decreases test year expense by $820,915 to reflect the removal of SWG's stock option compensation expense that is allocated to Arizona operations. The expense of providing stock options and other stock-based compensation to officers and employees beyond their other compensation should be borne by shareholders and not by ratepayers. As noted above, the stock-based compensation addressed in Staff Adjustment C-4 is for stock-based compensation other than MIP.

C-5 Supplemental Executive Retirement Plan Expense ("SERP")

Q. Please address SWG witness Hobbs' Rebuttal Testimony concerning SERP.

A. At pages 5-7 of her Rebuttal Testimony, Ms. Hobbs' presents arguments, similar to those presented by SWG in its last rate case and by other utilities arguing, for instance that providing SERP to officers is a necessary cost of providing service.

The SERP provides supplemental retirement benefits for select executives. Generally, SERPs are implemented for executives to provide retirement benefits that exceed amounts limited in qualified plans by Internal Revenue Service ("IRS") limitations. Companies usually maintain that providing such supplemental retirement benefits to executives is

[18] See Attachment RCS-5 (attached to my direct testimony), pages 33-49 for a copy of SWG's accounting memo concerning this.

necessary in order to ensure attraction and retention of qualified employees. Typically, SERPs provide for retirement benefits in excess of the limits placed by IRS regulations on pension plan calculations for salaries in excess of specified amounts. IRS restrictions can also limit the Company 401(k) contributions such that the Company 401(k) contribution as a percent of salary may be smaller for a highly paid executive than for other employees.

In Decision No. 68487, February 23, 2006, in the most recent SWG rate case, the Commission adopted a recommendation by RUCO to remove SERP expense. In reaching its conclusion regarding SERP, the Commission stated on page 19 of Order 68487 that:

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

Q. Was SERP expense also disallowed in the Commission's recent decision in the rate case involving UNS Gas, Inc?

A. Yes, it was. See Decision No. 70011 at pages 27-29. Notably, at page 28 of that Decision, the Commission stated:

> *... the issue is not whether UNS may provide compensation to select executives in excess of the retirement limits allowed by the IRS, but whether ratepayers should be saddled with costs of executive benefits that*

> *exceed the treatment allowed for all other employees. If the Company chooses to do so, shareholders rather than ratepayers should be responsible for the retirement benefits afforded only to those executives. We see no reason to depart from the 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.*

Q. Was SERP expense also disallowed in the Commission's recent decision in the rate case involving UNS Electric, Inc?

A. Yes, it was.[19]

Q. What adjustment related to SWG's SERP expense do you recommend?

A. I recommend the adjustment to remove SWG's expense for the SERP, which is shown on Schedule C-5 and reduces O&M expense by $1.625 million.

C-6 American Gas Association Dues

Q. What does SWG witness Randi Aldridge's Rebuttal Testimony state concerning Staff's proposed adjustment for American Gas Association dues.

A. Ms. Aldridge addresses Staff's proposed disallowance of a portion of AGA dues at pages 6-9 of her Rebuttal. She claims at pages 6-7 that the NARUC audits of AGA dues cannot be relied upon because they are too old. She claims at page 7 that a Florida decision, disallowing a similar portion of AGA dues is outdated. She claims at page 7, lines 22-25, that "Staff provides no current information supporting the disallowance of a portion of any category other than advertising or lobbying." She attaches the AGA 2007 budget. Additionally, in her Rebuttal Exhibit __(RLA-1), she attaches testimony of Kevin

[19] See, e.g., page 22 of the proposed Decision in Docket No. E-04204A-06-0783, as adopted by the Commission at the May 14, 2008 open meeting.

Hardardt, the Chief Financial & Administrative Officer of the AGA, touting the benefits of the AGA.[20]

Q. Please respond to SWG's Rebuttal concerning Staff's proposed adjustment for American Gas Association dues.

A. Decision No. 68487, at page 14, provided a clear directive from the Commission at page 14 of that order stating that: "in its next rate case filing the Company should provide a clearer picture of AGA functions and how the AGA's activities provide specific benefits to the Company and its Arizona ratepayers." In response to that directive, SWG has provided only selective self-serving material, some of it apparently prepared by the AGA itself, such as the attachments to Ms. Aldridge's Rebuttal Testimony, and/or which contained claims of benefits that Staff has been unable to independently verify or confirm.[21]

In contrast with SWG's urging that the NARUC audit report and Florida Cities Gas decisions regarding AGA dues be ignored, Staff believes that the Commission should consider all of the available information in determining the appropriate percentage of AGA dues that should be excluded from operating expenses in the current SWG rate case. While NARUC no longer sponsors an annual audit of the AGA expenditures, the categories of AGA expenditures in the NARUC-sponsored audit report remain useful to state regulatory commissions. Moreover, Attachment RCS-2, Schedule C-6, page 2,

[20] It is unclear if Mr. Hardardt is being presented as a witness in the current Southwest rate case (by attaching his "testimony" as an exhibit, it appears he is not) or if he has ever been cross examined on such testimony. Staff has asked Southwest additional discovery about such matters. As of the date of this writing, responses have not yet been received.

[21] For example, Southwest witness Randi Aldridge addressed AGA activities in her direct testimony at page 12 and pages 21-24. At page 24 of that testimony she claimed that the AGA's efforts provide its members with $479 million in outright savings or avoided costs in 2006, in comparison with $18 million in total membership dues. However, she did not provide the source document from which such claimed benefits were taken, and it is not clear whether AGA claimed benefits have ever been independently audited or verified.

which was filed with my Direct Testimony, showed the recommended percentage of AGA dues exclusion based on the 2007 and 2008 AGA budgets, would be 43.29 percent and 46.19 percent, respectively. This is a larger exclusion than the 40 percent Staff has recommended. An AGA dues exclusion of approximately 40 percent appears to have been consistently utilized in Florida Cities Gas Company gas utility rate cases[22], and the exclusion based on the most recent NARUC sponsored audit of AGA expenditures would be 39.64 percent.[23]

Q. How does Staff's proposed adjustment for AGA dues compare with SWG's proposed treatment of such dues?

A. As noted above, Staff's adjustment reflects the removal of 40 percent of AGA core dues, SWG's filing reflected the removal of only 3.39 percent of the AGA dues. The 3.39 percent exclusion proposed by Southwest only reflects a 1.39 percent exclusion for advertising and 2 percent for lobbying. However, as shown on Schedule C-6, page 2, the lobbying percentage identified by the AGA for its 2008 budget has doubled, from the 2 percent identified for 2007, to 4 percent in 2008.[24] Yet SWG wants to continue to use the now outdated AGA lobbying percentage of only 2 percent. Based on the NARUC audits, the Florida Cities Gas case and other information presented, an exclusion of AGA dues of 40 percent would appear to be more reasonable.

Moreover, SWG's use of the 1.39 percent for advertising, based on a 2007 AGA budget, understates that exclusion percentage by failing to recognize an allocation of AGA general and administrative ("G&A") expense to the advertising function. When the AGA G&A

[22] See, e.g., Attachment RCS-4 to my direct testimony.
[23] As shown on Attachment RCS-2, Schedule C-6, page 2, that was based upon the March 2005 NARUC Audit Report of AGA expenditures for the Year Ended 12/31/02.
[24] The AGA identification of lobbying is based on a definition from Internal Revenue Code Section 162, which is one of the most narrow definitions available.

expense is allocated to the other functions it supports, the percentage of the disallowable categories is increased, as shown on Schedule C-6, page 2. In the NARUC audits of AGA expenditures the AGA's G&A expense has consistently been allocated to the other supported functions.

Q. What amount of AGA membership dues expense has Staff removed from test year expense?

A. As shown on Schedule C-6, Staff has removed $80,138 in test year expense for AGA membership dues.

C-7 Transmission Integrity Management Program ("TRIMP")

Q. What is Staff's recommendation with regard to the TRIMP issue in the instant proceeding?

A. As described in my direct testimony, Staff recommends that:

1) The current TRIMP deferral and surcharge mechanism that was ordered by the Commission in Decision No. 68487 for a 36-month period will continue for the remainder of the 36-month period. This surcharge, which SWG has indicated it will be updating in the near future, would continue the 50/50 sharing ordered by the Commission in Decision No. 68487. Any over- or under-recovery of the 50 percent of TRIMP costs as of February 28, 2009 (the end of the 36-month period), would be addressed in the TRIMP surcharge for the subsequent period.

2) After the TRIMP surcharge ordered by the Commission in Decision No. 68487 is completed (which is currently expected to occur by February 28, 2009), a new TRIMP surcharge would replace it. The new TRIMP surcharge would be designed to recover

$921,000 of TRIMP costs over the initial twelve-month period (currently expected to be March 2009 through February 2010). Providing for an annual recovery of $921,000 of TRIMP costs, divided by a test year rate case volume of 743,110,918 therms would produce a DOT TRIMP surcharge of $0.00124 per therm. TRIMP surcharge revenue and TRIMP costs would be recorded by SWG into Account 182.3. Starting with the March 2009 TRIMP surcharge period, the 50 percent shareholder responsibility for TRIMP costs would cease.

3) The TRIMP revenue and costs in SWG's base rate filing should be removed, since prospective recovery would continue to be governed by the existing and the replacement TRIMP surcharge mechanisms, described above.

Q. Has SWG offered any Rebuttal to Staff's proposals concerning the Transmission Integrity Management Program?

A. No.

C-10 Interest Synchronization

Q. Have you updated Staff's interest synchronization adjustment for the impact of revisions affecting rate base?

A. Yes. The interest synchronization adjustment applies the weighted cost of debt to the calculation of test year income tax expense. After adjustments, my proposed rate base differs from that of the Company. This results in an adjustment to the amount of synchronized interest included in the tax calculation. The calculation of the interest synchronization adjustment is shown on Schedule C-10, revised. This adjustment decreases income tax expense by the amount shown on Schedule C-10, revised, and increases the Company' achieved operating income by a similar amount.

C-11 Flow-back of Excess Deferred Taxes

Q. Has SWG offered any rebuttal to Staff's recommendation concerning the flow-back of excess deferred taxes.

A. No. SWG has offered no rebuttal to Staff's adjustment which reduces federal income tax expense by $147,345 to flow back excess deferred federal income taxes over a three-year period. The three-year period used is the same period SWG has used in this case to normalize the allowance for rate case expense.

C-12 Injuries and Damages

Q. Have you revised Staff's adjustment for Injuries and Damages expense?

A. Yes. The revised adjustment is shown on Schedule C-12, revised, and reduces SWG's proposed expense for Injuries and Damages in Account 925 by $851,717. The revision relates to the use of full year 2007 information on Schedule C-12, line 10, which was provided by SWG in a supplemental response to a Staff data request.

Q. What does SWG's rebuttal state concerning Staff's adjustment for Injuries and Damages expense?

A. SWG witness Robert Mashas addresses this at pages 2-8 of his Rebuttal Testimony.

At page 8, he claims that SWG, Staff and RUCO agreed upon a methodology in the Company's last general rate case and that agreed-upon methodology continues to be appropriate. He claims that nothing has changed except for the lowering of SWG's self-insured aggregate exposure.

At pages 3-4, he claims that Staff's ten-year average 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 SWG's $5 million aggregate level of self-insurance.

At page 6, lines 8-15, he states that RUCO proposes no adjustment to the Company's calculation of the Arizona portion of the self-insured $1 million per incident or the $5 million aggregate.

At page 6, line 13, through page 8, line 9, he claims that Staff's proposed level of self-insurance for the "Arizona direct" component would need to be increased by $1,596,611. This is apparently based on an attempt by Mr. Mashas to take his calculated amount of $15,966,105 of losses for the "$5 million aggregate above $1,000,000 self-insurance per claim" (per his Rebuttal Exhibit ___(RAM-2), sheet 2) and directly assign them to Arizona, based on a ten-year average. However, a direct assignment to Arizona of such extreme losses is inconsistent with Southwest's accounting and its treatment of such self-insurance costs as a "common" component of Injuries and Damages.

Q. In addition to Mr. Mashas' rebuttal testimony, did you consider any additional information in re-evaluating SWG's estimate of self-insured expense in the current rate case and Staff's proposed adjustment?

A. Yes. I reviewed additional information requested by Staff and provided by Southwest in response to a number of data requests in Staff set 13, including response to STF-13-13 through 17, STF-13-19 and STF-13-20. Copies of those responses are provided in Attachment RCS-8.

Q. Do you agree with Mr. Mashas' assertion that the parties agreed upon a methodology for estimating SWG's self-insured expense in that case?

A. Yes, for purposes of that case, it appears that SWG, Staff and RUCO each used a similar methodology to ultimately derive an amount in that case for SWG's self-insured expense.

Q. Does that mean there is only one valid method for estimating SWG's self-insured expense in the current case?

A. No. The use of a particular calculation to derive a pro forma expense adjustment in SWG's last rate case does not mean that there is no other reasonable way of estimating SWG's self-insured expense for ratemaking purposes. Nor does it mean that the method used in that one rate case is the best one or must necessarily be applied in all future rate cases, especially in situations where there is a different fact situation.

Q. Notwithstanding the particular method used in Southwest's last rate case for estimating the pro forma amount of self-insurance expense, was there a concern that the amount originally proposed by Southwest in that case was too high?

A. Yes. In the last Southwest rate case, the Company had proposed an increase of $1,598,744 and Staff recommended a downward adjustment of $429,985.[25]

Q. If Mr. Mashas' recommendations concerning the pro forma amount self-insurance expense were to be adopted by the Commission, what adjustment to Staff's case would be needed?

A. Pre-tax operating expenses would be increased by approximately $1.135 million as summarized in the following table:

[25] See, e.g., SWG's response to STF-13-14, sheet 4 of 6, which reproduces Staff's adjustment to self-insurance from SWG's last rate case, Docket No. G-01551A-04-0876.

Self-Insured Retention Normalization Adjustment to Staff's Case if SWG's Recommendation is Adopted

Description	Amount	Reference
Proposed by Southwest Gas:		
As corrected by SWG:	$ 2,512,119	Rsp to STF-13-14, sheet 4
In its direct filing	$ 2,228,455	SWG Sch C-2, Adj. 10
Adjustment to increase expense	$ 283,664	
Remove Staff adjustment C-12 to decrease expense	$ 851,717	Staff Sch C-12, revised
Increase to pre-tax operating expense	$ 1,135,381	

Essentially, the correction identified above, to increase expense, would need to be substituted for Staff's adjustment that decreases Southwest's as-filed expense. However, as I explain below, Southwest's proposed expense level is too high and should not be accepted. Moreover, Staff's proposed adjustment actually reflects a significant increase over the test year recorded amount of Injuries and Damages Expense.

Q. Why is SWG's self-insured expense reviewed and adjusted in a rate case?

A. The test year recorded expense is reviewed and, if necessary, adjusted in order to determine a normal and recurring expense level that is reflective of the expense that would be incurred by the Company during the rate effective period.

Q. Is there a concern in the current Southwest rate case that the Company's proposed self-insured expense is overstated?

A. Yes. Southwest proposes a "corrected" amount of increase to test year expense of $2,512,119.[26] This is a significant increase over the test year recorded amount.

[26] See, e.g., Southwest's response to STF-13-14, sheet 4 of 6.

Q. Is the method proposed by Southwest necessarily the best way of estimating SWG's self-insured expense prospectively?

A. No, it is not. The method used by Southwest in its last rate case would have significantly overstated the expense amounts recorded in 2006 and 2007, respectively. In Southwest's last rate case, Docket No. G-0551A-04-0876, a test year ending August 31, 2004 was used. Based on the estimating method used in that docket, as shown on Southwest's response to Staff data request, STF-13-14, a pro forma expense for Arizona operations of $1,731,312 was allowed. As shown in the following table, however, this allowed amount has substantially exceeded Southwest's recorded expenses for self insurance in each year, 2006 and 2007 (from Staff Schedule C-12, page 2):

Reserve for Self-Insurance Expense
Amount allowed in last SWG rate case (G-01551A-04-0876) $ 1,731,312 (2)

Arizona and Common Actual Recorded Expense Amounts

Year	Arizona Direct	Total Common	Common Allocated to Arizona (1)	Total Arizona	Overstatement of Actual
	(A)	(B)	(C)	(D)	(E)
				A + C	Above - Col.D
2006	$ (975,540)	$ 200,000	$ 108,909	$ (866,631)	$ 2,597,943
2007	$ 713,629	$ (25,500)	$ (13,886)	$ 699,743	$ 1,031,569

Notes and Source
(1) Based on the Paiute and AZ percentages shown on Sch C-12, p.2
(2) SWG response to STF-13-14, sheet 4 of 6

Southwest is proposing to use a similar estimation method in the current case. The concern that such an estimation method would continue to significantly overstate Southwest's actual recorded expense for self-insurance thus persists.

Q. Was the same method for estimating injuries and damages expense that SWG proposes to use in the current case, used by other major Arizona energy utilities in their most recent rate cases?

A. No. Based on a review of the recent rate cases of UNSE, UNSG and TEP, a different method was used, to fit the circumstances and concerns of each case. The method proposed by Southwest is not fool proof and can result in substantial overstatements of actual recorded expense, as identified above for 2006 and 2007.

Q. Please respond to Mr. Mashas' assertion that Staff's proposed level of "Arizona Direct" self-insurance would need to be increased by $1,596,611.

A. I disagree with Mr. Mashas' assertion that the ten-year average of Arizona direct recorded amounts shown on Schedule C-12, page 2, needs to be increased by $1,596,611. His attempt to impose what is clearly a system allocable or "common" amount that consists of some the most extreme events onto Arizona ratepayers as a "direct" Arizona expense should be rejected. Mr. Mashas' Rebuttal appears to be heavily reliant upon a particular methodology being used in SWG's last general rate case. In the current case, Staff has taken a different approach by looking at the actual recorded Arizona direct and common amounts to produce a normalized allowance for self-insurance expense. As explained below, Staff's proposed allowance reflects a normalized amount of $200,000 per year for "common" self-insurance and an $830,000 per year allowance for Arizona direct recorded self-insurance expense.

Q. Did SWG experience an extreme and unprecedented expense since its last rate case?

A. Yes. SWG experienced an extreme and unprecedented self insured expense in 2005. As a result of a May 2005 leaking gas line fire, the Company incurred an extremely large and unprecedented expense totaling $30 million, including the portion that was covered by insurance. The insurance coverage SWG had at that time covered some of that expense, but the Company was left with a self-insured expense of over $10 million. This is shown on Schedule C-12, page 2, line 8, for 2005 in column B. This expense of over $10 million related to that leaking gas line fire is totally out-of-line with the expense in all other years of the 1998 through 2007 period where the "common" expense ranged from a high of $500,000 per year in 1998 to a low of negative $300,000 (i.e., a $300,000 credit) in 2003.

Q. Was the May 2005 gas leak fire found to be the result of non-compliance with state minimum standards for the transportation of natural gas by pipeline?

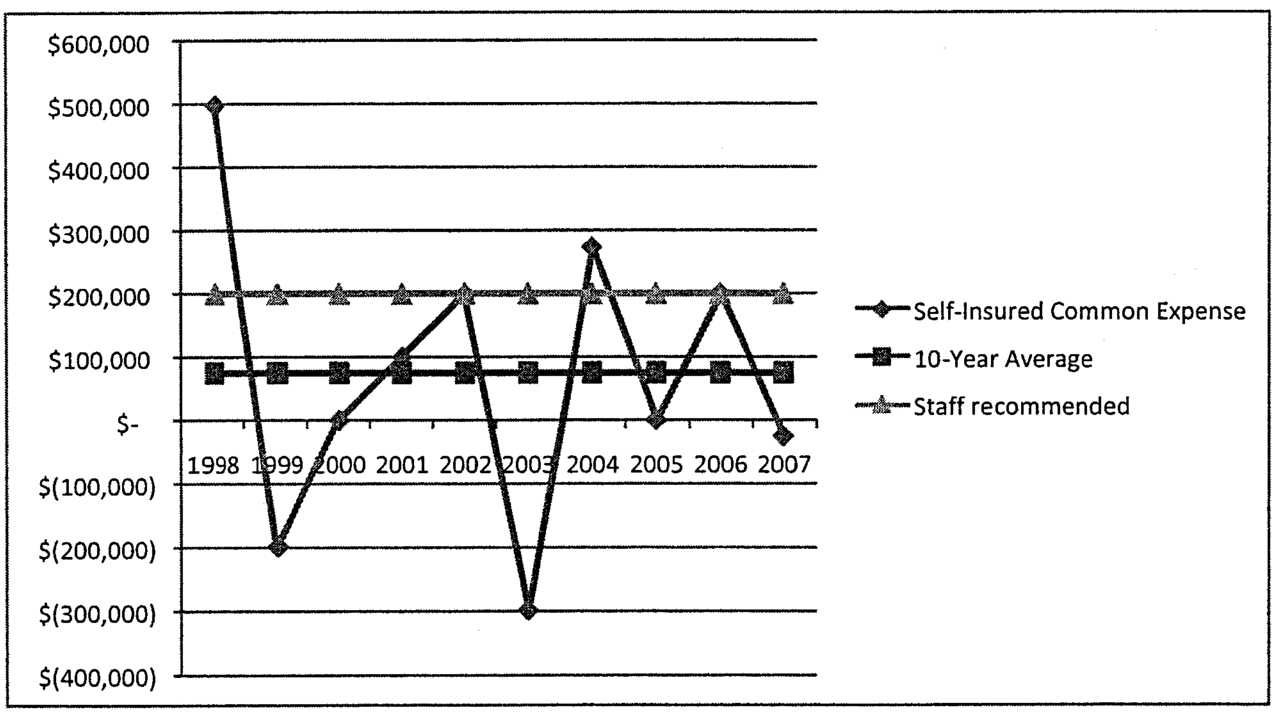
A. No. Staff conducted an investigation, the details of which are provided in the response to data request STF-13-20 (provided in Attachment RCS-8) which concluded that the cause of the explosion and fire was natural gas leaking from a buried main in the alley behind a duplex apartment in Tucson; however, no non-compliance issues were noted as a result of Staff's investigation.

Q. Should the impact of that extraordinary expense be excluded in establishing an expense allowance for self-insurance to be included in rates prospectively?

A. Yes. The over $10 million in self insured expense in 2005 should be excluded for ratemaking purposes because it is extremely abnormal past event and is not expected to recur. The objective is to determine a level of self-insured expense that is reflective of a level of expense that will be incurred by the Company during the rate effective period. In other words, a normal level of expense should be reflected for ratemaking purposes. Because of the distortive impact of the extremely abnormal self-insurance expense incurred by SWG in 2005, the recorded "common" self-insurance expense for 2005 is abnormally high, and therefore is inappropriate for ratemaking purposes. SWG's approach would essentially build into future rates, a portion of the costly May 2005 gas-leak fire related cost.

Q. Is Staff's recommended allowance for the "common" portion of self-insurance that is to be included in rates prospectively consistent with an analysis of Southwest's recorded amounts?

A. Yes. Staff's proposed annual allowance for the "common" portion of SWG's self insurance expense is $200,000. As shown on Schedule C-12, page 2, this excludes the abnormal 2005 amount of over $10 million. Moreover, Staff's allowance is reasonable in comparison with the actual levels incurred by SWG in all years in the 1998 through 2007 period (excluding the extreme amount incurred in 2005), as shown in the following comparison:



As shown in the above chart, Staff's recommended annual allowance for common self-insured expense of $200,000 per year (before jurisdictional allocations) exceeds the ten-year average of $74,950 (without the $10,367,500 extreme amount from 2005), and is reasonable within the overall annual fluctuations of this expense. Staffs allowance of $200,000 per year also equals SWG's actual expense in two of the ten years, 2002 and 2006. Moreover, SWG's actual recorded common self-insurance expense was zero in 2000, and negative in the years 1999, 2003, and in 2007, the most current year available. Consequently, as shown on Schedule C-12, page 2, removing the $10,367,500 extreme and unprecedented amount incurred in 2005 (related to the May 2005 gas leak fire) and using zero for 2005 is reasonable, perhaps conservative. As such, I believe that Staff's proposed allowance does properly reflect the cost of self insurance that is reflective of what the Company will experience during the rate effective period.

Q. Please summarize why SWG's Arizona ratepayers should not be responsible for the impact on Injuries and Damages expense relating to the Company's settlement of litigation related to the May 2005 leaking gas line fire.

A. Arizona ratepayers should not be responsible for the massive expense incurred by the Company to settle litigation related to the May 2005 leaking gas line fire. That "common" self-insurance expense, which produced the abnormal recorded "common" amount in excess of $10 million in 2005, shown on Schedule C-12, page 2, is abnormal and was incurred in a prior period. Rates in the current case are being established for prospective application. While historical information may be useful to address normalized expenses, an extremely abnormal event like the over $10 million in recorded "common" expense related to the May 2005 leaking gas line fire-related settlement expense, is not expected to reoccur and should therefore not be built into pro forma operating expenses.

Q. Please explain why you believe that SWG has proposed an excessive total increase to Injuries and Damages expense in the current rate case.

A. As shown on Schedule C-12, page 1, in column A, on line 18, during the test year, SWG recorded an expense for Injuries and Damages of $5.679 million for Arizona. As shown in Column B of that Schedule, SWG's filing included three pro forma adjustments that attempted to increase this expense to $8.169 million, for an increase of approximately $2.490 million. That is an increase of approximately 44 percent.

In response to various Staff data requests, SWG identified errors in its filed calculation. SWG now proposes a pro forma Injuries and Damages expense for Arizona of $8.259 million, as shown on Schedule C-12, page 1, column C, line 18. This represents an increase of $2.580 million or 45 percent, over the test year recorded amount.

Q. Does Staff's recommendation result in a reasonable going-forward allowance for Injuries and Damages expense, while still allowing a substantial increase over the test year recorded amount?

A. Yes, I believe it does. In contrast with SWG's proposals, as shown on Schedule C-12, revised, page 1, column D, line 18, Staff recommends a normalized allowance for Injuries and Damages expense for Arizona of $7.317 million. This represents an increase of $1.638 million or 29 percent, over the test year recorded amount of $5.679 million shown on Schedule C-12, column A, line 18.

Q. How does Staff's recommended going-forward allowance for Injuries and Damages expense reflect the $300,000 correction that Southwest identified as being necessary to its original rate filing?

A. In terms of Account 925, Injuries and Damages, the $300,000 correction identified by Southwest decreased the Company's Arizona direct expense for the self-insurance reserve from negative $558,765 to negative $858,765. This is shown on Schedule C-12, page 1, line 2. As also shown on Schedule C-12, in column D, Staff's adjustment reflects an allowance for Arizona direct self-insurance of $830,000 per year. The difference between Staff's recommended allowance of positive $830,000 and SWG's recorded negative $558,765 comprises Staff's adjustment to increase the annual Arizona direct self-insurance allowance by $1.389 million, as shown on Schedule C-12, page 1, line 2, column D. If the Company's $300,000 correction were reflected as a separate adjustment to decrease the test year recorded expense in Account 925, then Staff's adjustment on Schedule C-12, page 1, line 2, column D, would be increased by this same amount of $300,000, and would be a $1.689 million over the corrected test year recorded amount.

Q. How does Staff's recommended going-forward allowance for Injuries and Damages expense compare with the pro forma increase requested by Southwest in its original rate filing?

A. As shown on Schedule C-12, revised, page 1, Staff's recommended allowance for Injuries and Damages expense in Account 925 is $851,717 lower than the pro forma adjusted amount in SWG's original filing. This $851,717 reduction to SWG's originally filed pro forma adjusted amount is shown on Schedule C-12, revised, page 1, columns D and E.

Q. What adjustment to Injuries and Damages expense do you recommend?

A. Southwest's originally filed amount for Account 925, Injuries and Damages Expense, should be decreased by $851,717 as shown on Schedule C-12, revised, page 1, columns D and E.

C-13 Leased Aircraft Operating Costs

Q. Did SWG present any rebuttal to Staff's adjustment for Leased Aircraft Operating Costs?

A. No. As shown on Schedule C-13, the test year expense for leased aircraft is adjusted downward by $32,814 to a normalized amount based on the four-year period, 2004 through 2007.

C-14 El Paso Pipeline Rate Case Litigation Cost

Q. Did SWG present any rebuttal to Staff's adjustment for El Paso Pipeline Rate Case Litigation Cost?

A. No. As shown on Schedule C-14, the abnormally high test year expense for the El Paso Pipeline Rate Case Litigation is adjusted downward by $477,415, to a normalized level, based on the average for 2005 through 2007.

C-15 Annualized Amortization for New Intangible Plant

Q. Please explain Staff's revised adjustment for the annualized amortization for new intangible plant that was placed into service by December 31, 2007.

A. SWG's filing included an adjustment (Company Adjustment No. 14) to add to test year amortization expense $565,333 for the annualized amortization on new intangible plant that the Company projected would be placed into service by December 31, 2007. As noted above, Staff has made a related adjustment to rate base in Staff Adjustment B-6, revised. Staff Adjustment C-15, revised, adjusts the Company's estimated amounts. As shown on Schedule C-15, revised, to reflect actual new intangible plant that was placed into service by December 31, 2007, the estimated annualized amortization for new Intangible Plant allocated to Arizona that had been reflected in SWG's filing is reduced by $46,633.

C-16 Gain on Sale of Utility Property Related to TEP Sundt Bypass

Q. Please explain Staff Adjustment C-16.

A. This adjustment reflects ratepayer sharing of 50 percent of the gain realized by SWG on the sale of the metering facilities and pipe related to TEP's bypass of SWG for gas supply to TEP's Sundt generating station. SWG's May 14, 2008 supplemental response to data request RUCO 7-2 provides information used to compute the net gain. As described in SWG's response to Staff data request STF-1-96[27]:

> *Historically, the Commission has amortized, over a multiple-year period, the gain or loss on Southwest's disposition of property previously included in rate base, 50 percent above-the-line to ratepayers and 50 percent below-the-line to shareholders.*

Staff Adjustment C-16 reflects this treatment. A normalization period of three years was used. Three years is the same period that SWG has used for normalizing its proposed allowance for rate case costs. A shown on Schedule C-16, pre-tax operating income is increased by $101,600.

[27] See Attachment RCS-5, attached to my direct testimony, for a copy of that response.

C-17 Depreciation for Plant Sold to TEP for Sundt Bypass

Q. Please explain Staff Adjustment C-17.

A. This adjustment reduces depreciation expense by $5,117 to recognize that portions of Southwest's plant, including metering and piping, serving TEP's Sundt generating station have now been sold to TEP in conjunction with TEP's Sundt plant bypass.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes, it does.

Southwest Gas Corporation
Docket No. G-01551A-07-0504
Attachment RCS-7
Staff Accounting Schedules
Accompanying the Surrebuttal Testimony of Ralph C. Smith

Schedule	Description	Pages	Note
	Revenue Requirement Summary Schedules		
A	Calculation of Revenue Deficiency (Sufficiency)	1	Revised
A-1	Gross Revenue Conversion Factor	1	Revised
B	Adjusted Rate Base	1	Revised
B.1	Summary of Rate Base Adjustments	2	Revised
C	Adjusted Net Operating Income	1	Revised
C.1	Summary of Net Operating Income Adjustments	3	Revised
D	Capital Structure and Cost Rates	1	Revised
	Rate Base Adjustments		
B-1	Yuma Manors Pipe Replacement	1	
B-2	Gain on Sale of Property in Cave Creek, AZ	1	
B-3	Cash Working Capital	2	Revised
B-4	Customer Deposits	3	
B-5	Accumulated Deferred Income Taxes - Acct.190	2	
B-6	Intangible Plant Added After the Test Year	1	Revised
B-7	Accumulated Deferred Income Taxes - RCND	1	
B-8	Remove Net Plant Being Sold to TEP for Sundt Bypass	1	Added
	Net Operating Income Adjustments		
C-1	Yuma Manors Depreciation and Property Tax Expense	2	
C-2	Gain on Sale of Utility Property	1	
C-3	Management Incentive Program	1	Revised
C-4	Stock Based Compensation	1	
C-5	Supplemental Executive Retirement Expense	1	
C-6	American Gas Association Dues	2	
C-7	TRIMP Surcharge	3	
C-8	A&G Expenses - Annualized Paiute Allocation	1	
C-9	Interest on Customer Deposits	1	
C-10	Interest Synchronization	1	Revised
C-11	Flow Back Excess Deferred Income Taxes	1	
C-12	Injuries and Damages	2	Revised
C-13	Leased Aircraft Operating Costs	1	
C-14	El Paso Natural Gas Rate Case Expense	1	
C-15	New Intangible Plant Annualized Amortizations	1	Revised
C-16	Gain on Sale of Utility Property Related to TEP Sundt Bypass	1	Added
C-17	Depreciation for Plant Sold to TEP for Sundt Bypass	1	Added
	Total Pages (including Contents page)	45	

Southwest Gas Corporation
Computation of Increase in Gross Revenue Requirement

Test Year Ended April 30, 2007

Docket No. G-01551A-07-0504
Schedule A Revised
Page 1 of 1

Line No.	Description	Reference	SWG Proposed Original Cost (A)	SWG Proposed Fair Value (B)	Staff Proposed Original Cost (C)	Staff Proposed Fair Value Option 1 (D)	Staff Proposed Fair Value Option 2 (E)
1	Adjusted Rate Base	Sch. B	$ 1,094,790,047	$ 1,469,135,559	$ 1,065,457,617	$ 1,388,609,702	$ 1,388,609,702
2	Rate of Return	Sch. D	9.45%	7.04%	8.86%	6.79%	7.08%
3	Operating Income Required		$ 103,457,659	$ 103,457,659	$ 94,366,814	$ 94,286,599	$ 98,313,567
4	Net Operating Income Available	Sch. C	$ 73,180,098	$ 73,180,098	$ 77,266,184	$ 77,266,184	$ 77,266,184
5	Operating Income Excess/Deficiency		$ 30,277,561	$ 30,277,561	$ 17,100,630	$ 17,020,415	$ 21,047,383
6	Gross Revenue Conversion Factor	Sch. A-1	1.6586	1.6586	1.6586	1.6586	1.6586
7	Overall Revenue Requirement		$ 50,218,363	$ 50,218,363	$ 28,363,105	$ 28,230,061	$ 34,909,190

Notes and Source
Cols. A & B taken from SWG filing, Schedule A-1

Southwest Gas Corporation
Computation of Gross Revenue Conversion Factor

Test Year Ended April 30, 2007

Docket No. G-01551A-07-0504
Schedule A-1 Revised
Page 1 of 1

Line No.	Description	Rate (A)	Company Proposed (B)	Staff Proposed (C)
1	Gross Revenue		1.0000000	1.0000000
2	Less: Uncollectible Revenue		0.0029890	0.0029890
3	State Taxable Income		0.9970110	0.9970110
4	Less: State Income Taxes	6.9680%	0.0694720	0.0694720
5	Federal Taxable Income		0.9275390	0.9275390
6	Federal Income Tax	35.0000%	0.3246390	0.3246390
7	Change in Net Operating Income		0.6029000	0.6029000
8	Gross Revenue Conversion Factor		1.6586	1.6586

Notes and Source
Cols.A&B: SWG Filing, Schedule C-3

	Components of Revenue Requirement Increase	Percent	OCRB-Based Amount	FVROR Option 1 Amount
9	Net Income	60.29000%	$ 17,100,116	$ 17,019,904
10	Federal and State Income Taxes	39.41110%	$ 11,178,212	$ 11,125,778
11	Uncollectibles	0.29890%	$ 84,777	$ 84,380
12	Total Revenue Increase	100.00000%	$ 28,363,105	$ 28,230,062
13	Computation of State and Federal Income Tax Rate		L.10 / L.3	39.5293%
14	Per SWG Schedule C-3, page 2 of 2			39.5292%

Southwest Gas Corporation
Original Cost and RCND Adjusted Rate Base

Test Year Ended April 30, 2007

Docket No. G-01551A-07-0504
Schedule B Revised

Line No.	Description	Original Cost: As Adjusted by SWG (A)	Original Cost: Staff Adjustments (B)	Original Cost: As Adjusted by Staff (C)	RCND: As Adjusted by SWG (D)	RCND: Staff Adjustments (E)	RCND: As Adjusted by Staff (F)
1	Gross Utility Plant in Service	$ 2,053,847,890	$ (1,582,283)	$ 2,052,265,607	$ 3,224,193,614	$ (1,579,978)	$ 3,222,613,636
2	Less: Accumulated Depreciation	$ (752,275,563)	$ 349,933	$ (751,925,630)	$ (1,173,930,265)	$ 347,628	$ (1,173,582,637)
3	Net Utility Plant in Service	$ 1,301,572,327	$ (1,232,350)	$ 1,300,339,977	$ 2,050,263,349	$ (1,232,350)	$ 2,049,030,999
4	Customer Advances for Construction	$ (37,910,017)	$ (11,284,772)	$ (49,194,789)	$ (37,910,017)	$ (11,284,772)	$ (49,194,789)
							$ -
5	Customer Deposits	$ (31,921,898)	$ (2,480,873)	$ (34,402,771)	$ (31,921,898)	$ (2,480,873)	$ (34,402,771)
							$ -
6	Accumulated Deferred Income Taxes	$ (142,632,297)	$ (9,246,678)	$ (151,878,975)	$ (142,632,297)	$ (111,633,530)	$ (254,265,827)
7	Total Deductions	$ (212,464,212)	$ (23,012,323)	$ (235,476,535)	$ (212,464,212)	$ (125,399,175)	$ (337,863,387)
8	Allowance for Working Capital	$ 5,681,932	$ (5,087,757)	$ 594,175	$ 5,681,932	$ (5,087,757)	$ 594,175
9	Total Rate Base	$ 1,094,790,047	$ (29,332,430)	$ 1,065,457,617	$ 1,843,481,069	$ (131,719,282)	$ 1,711,761,787

Notes and Source
Cols. A and D: SWG filing, Schedule B

Fair Value Calculation (Per Company)

Original Cost	$ 1,094,790,047	
RCND	$ 1,843,481,069	
Total	$ 2,938,271,116	
Average (Fair Value)	$ 1,469,135,559	See Sch. A

Fair Value Calculation (Per Staff)

Original Cost	$ 1,065,457,617	
RCND	$ 1,711,761,787	
Total	$ 2,777,219,404	
Average (Fair Value)	$ 1,388,609,702	See Sch. A

Southwest Gas Corporation
Summary of Rate Base Adjustments
Original Cost
Test Year Ended April 30, 2007

Docket No. G-01551A-07-0504
Schedule B.1 (OCRB)
Page 1 of 1 Revised

Line No.	Description	Staff Adjustments	Yuma Manors Pipe Replacement	Customer Advances for Construction	Cash Working Capital	Customer Deposits	Accumulated Deferred Income Taxes - Acct.190	Intangible Plant Added After the Test Year	Accumulated Deferred Income Taxes - RCND	Remove Net Plant Being Sold to TEP for Sundt Bypass
			B-1	B-2	B-3	B-4	B-5	B-6	B-7	B-8
1	Gross Utility Plant in Service	$ (1,582,283)	$ (1,231,762)					$ (139,902)		$ (210,619)
2	Less: Accumulated Depreciation	$ 349,933	$ 139,314							$ 210,619
3	Net Utility Plant in Service	$ (1,232,350)	$ (1,092,448)	$ -	$ -	$ -	$ -	$ (139,902)	$ -	$ -
4	Customer Advances for Construction	$ (11,284,772)		$ (11,284,772)						
5	Customer Deposits	$ (2,480,873)				$ (2,480,873)				
6	Accumulated Deferred Income Taxes	$ (9,246,678)		$ 3,885,347			$ (13,132,025)			
7	Total Deductions	$ (23,012,323)	$ -	$ (7,399,425)	$ -	$ (2,480,873)	$ (13,132,025)	$ -	$ -	$ -
8	Allowance for Working Capital	$ (5,087,757)			$ (5,087,757)					
9	Total Rate Base	$ (29,332,430)	$ (1,092,448)	$ (7,399,425)	$ (5,087,757)	$ (2,480,873)	$ (13,132,025)	$ (139,902)	$ -	$ -

Southwest Gas Corporation
Summary of Rate Base Adjustments
Reconstruction Cost New Depreciated
Test Year Ended April 30, 2007

Docket No. G-01551A-07-0504
Schedule B.1 (RCND)
Page 1 of 1 Revised

Line No.	Description	Staff Adjustments	Yuma Manors Pipe Replacement B-1	Customer Advances for Construction B-2	Cash Working Capital B-3	Customer Deposits B-4	Accumulated Deferred Income Taxes - Acct.190 B-5	Intangible Plant Added After the Test Year B-6	Accumulated Deferred Income Taxes - RCND B-7	Remove Net Plant Being Sold to TEP for Sundt Bypass B-8
1	Gross Utility Plant in Service	$ (1,579,978)	$ (1,229,457)					$ (139,902)		$ (210,619)
2	Less: Accumulated Depreciation	$ 347,628	$ 137,009							$ 210,619
3	Net Utility Plant in Service	$ (1,232,350)	$ (1,092,448)	$ -	$ -	$ -	$ -	$ (139,902)	$ -	$ -
4	Customer Advances for Construction	$ (11,284,772)		$ (11,284,772)						
5	Customer Deposits	$ (2,480,873)				$ (2,480,873)				
6	Accumulated Deferred Income Taxes	$ (111,633,530)		$ 3,885,347			$ (20,109,648)		$ (95,409,229)	
7	Total Deductions	$ (125,399,175)	$ -	$ (7,399,425)	$ -	$ (2,480,873)	$ (20,109,648)	$ -	$ (95,409,229)	$ -
8	Allowance for Working Capital	$ (5,087,757)			$ (5,087,757)					
9	Total Rate Base	$ (131,719,282)	$ (1,092,448)	$ (7,399,425)	$ (5,087,757)	$ (2,480,873)	$ (20,109,648)	$ (139,902)	$ (95,409,229)	$ -

Southwest Gas Corporation
Adjusted Net Operating Income

Test Year Ended April 30, 2007

Docket No. G-01551A-07-0504
Schedule C Revised

Line No.	Description	As Adjusted by Company	Staff Adjustments	As Adjusted by Staff
		(A)	(B)	(C)
	Operating Revenues			
1	Revenues	$ 399,234,678	$ -	$ 399,234,678
2	Total Operating Revenues	$ 399,234,678	$ -	$ 399,234,678
	Operating Expenses			
3	Purchased Gas	$ -	$ -	$ -
4	Other O&M Expenses	$ 187,034,455	$ (6,444,543)	$ 180,589,912
5	Interest on Customer Deposits	$ 1,915,314	$ 148,852	$ 2,064,166
6	Depreciation & Amortization	$ 87,887,713	$ (277,420)	$ 87,610,293
7	Taxes Other Than Income Taxes	$ 33,124,880	$ 91,241	$ 33,216,121
8	Income Taxes	$ 16,092,218	$ 2,395,784	$ 18,488,002
9	Total Operating Expenses	$ 326,054,580	$ (4,086,086)	$ 321,968,494
10	Net Operating Income	$ 73,180,098	$ 4,086,086	$ 77,266,184

Notes and Source
Col. A: SWG filing, Schedule C-1
Col. B: Staff Schedule C.1

Southwest Gas Corporation
Summary of Net Operating Income Adjustments

Test Year Ended April 30, 2007

Line No.	Description	Staff Adjustments	Yuma Manors Depreciation and Property Tax Expense	Gain on Sale of Utility Property	Management Incentive Program	Stock Based Compensation	Supplemental Executive Retirement Expense
			C-1	C-2	C-3 Revised	C-4	C-5
	Operating Revenues						
1	Gas Retail Revenues	$ -					
2	Other Operating Revenues	$ -					
3	Total Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Expenses						
4	Purchased Gas	$ -					
5	Other O&M Expenses	$ (6,444,543)			$ (1,611,723)	$ (820,915)	$ (1,625,460)
6	Interest on Customer Deposits	$ 148,852					
7	Depreciation & Amortization	$ (277,420)	$ (54,370)	$ (69,700)			
8	Taxes Other Than Income Taxes	$ 91,241	$ (28,945)		$ 120,186		
9	PRE-TAX OPERATING EXPENSES	$ (6,481,870)	$ (83,315)	$ (69,700)	$ (1,491,537)	$ (820,915)	$ (1,625,460)
10	PRE-TAX OPERATING INCOME	$ 6,481,870	$ 83,315	$ 69,700	$ 1,491,537	$ 820,915	$ 1,625,460
11	Income Taxes	$ 2,395,784	$ 32,934	$ 27,552	$ 589,593	$ 324,501	$ 642,531
12	TOTAL OPERATING EXPENSES	$ (4,086,086)	$ (50,381)	$ (42,148)	$ (901,944)	$ (496,414)	$ (982,929)
13	OPERATING INCOME	$ 4,086,086	$ 50,381	$ 42,148	$ 901,944	$ 496,414	$ 982,929

Notes and Source

Combined Effective Tax Rate 39.5292%
Per SWG Schedule C-3, page 2

Southwest Gas Corporation
Summary of Net Operating Income Adjustments

Test Year Ended April 30, 2007

Line No.	Description	American Gas Association Dues	TRIMP Surcharge	A&G Expenses - Annualized Paiute Allocation	Interest on Customer Deposits	Interest Synchronization	Flow Back Excess Deferred Income Taxes
		C-6	C-7	C-8	C-9	C-10 Revised	C-11
	Operating Revenues						
1	Gas Retail Revenues						
2	Other Operating Revenues						
3	Total Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Expenses						
4	Purchased Gas						
5	Other O&M Expenses	$ (80,138)	$ (920,914)	$ (23,447)			
6	Interest on Customer Deposits				$ 148,852		
7	Depreciation & Amortization						
8	Taxes Other Than Income Taxes						
9	PRE-TAX OPERATING EXPENSES	$ (80,138)	$ (920,914)	$ (23,447)	$ 148,852	$ -	$ -
10	PRE-TAX OPERATING INCOME	$ 80,138	$ 920,914	$ 23,447	$ (148,852)	$ -	$ -
11	Income Taxes	$ 31,678	$ 364,030	$ 9,268	$ (58,840)	$ (19,103)	$ (147,345)
12	TOTAL OPERATING EXPENSES	$ (48,460)	$ (556,884)	$ (14,179)	$ 90,012	$ (19,103)	$ (147,345)
13	OPERATING INCOME	$ 48,460	$ 556,884	$ 14,179	$ (90,012)	$ 19,103	$ 147,345

Notes and Source

Combined Effective Tax Rate 39.5292%

Per SWG Schedule C-3, page 2

Southwest Gas Corporation
Summary of Net Operating Income Adjustments

Test Year Ended April 30, 2007

Line No.	Description	Injuries and Damages	Leased Aircraft Operating Costs	El Paso Natural Gas Rate Case Expense	New Intangible Plant Annualized Amortizations	Gain on Sale of Utility Property Related to TEP Sundt Bypass	Depreciation for Plant Sold to TEP for Sundt Bypass
		C-12 Revised	C-13	C-14	C-15 Revised	C-16 Added	C-17 Added
	Operating Revenues						
1	Gas Retail Revenues						
2	Other Operating Revenues						
3	Total Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Expenses						
4	Purchased Gas						
5	Other O&M Expenses	$ (851,717)	$ (32,814)	$ (477,415)			
6	Interest on Customer Deposits						
7	Depreciation & Amortization				$ (46,633)	$ (101,600)	$ (5,117)
8	Taxes Other Than Income Taxes						
9	PRE-TAX OPERATING EXPENSES	$ (851,717)	$ (32,814)	$ (477,415)	$ (46,633)	$ (101,600)	$ (5,117)
10	PRE-TAX OPERATING INCOME	$ 851,717	$ 32,814	$ 477,415	$ 46,633	$ 101,600	$ 5,117
11	Income Taxes	$ 336,677	$ 12,971	$ 188,718	$ 18,434	$ 40,162	$ 2,023
12	TOTAL OPERATING EXPENSES	$ (515,040)	$ (19,843)	$ (288,697)	$ (28,199)	$ (61,438)	$ (3,094)
13	OPERATING INCOME	$ 515,040	$ 19,843	$ 288,697	$ 28,199	$ 61,438	$ 3,094

Notes and Source

Combined Effective Tax Rate	39.5292%
Per SWG Schedule C-3, page 2	

Southwest Gas Corporation
Capital Structure & Cost Rates
Cost of Service Methodology

Docket No. G-01551A-07-0504
Schedule D Revised
Page 1 of 1

Test Year Ended April 30, 2007

Line No.	Capital Source	Capitalization Amount (A)	Capitalization Percent (B)	Cost Rate (C)	Weighted Avg. Cost of Capital (D)
	SWG - Proposed				
1	Long-Term Debt		51.00%	7.96%	4.06%
2	Preferred Equity		4.00%	8.20%	0.33%
3	Common Stock Equity		45.00%	11.25%	5.06%
4	Total Capital		100.00%		9.45%
	ACC Staff - Proposed for OCRB	**Supporting OCRB**			
5	Long-Term Debt	$ 554,890,327	52.08%	7.96% [b]	4.15%
6	Preferred Equity	$ 47,732,501	4.48%	8.20% [b]	0.37%
7	Common Stock Equity	$ 462,834,789	43.44%	10.00% [b]	4.34%
8	Total Capital	$1,065,457,617	100.00%		8.86%
9	Difference				-0.59%
10	Weighted Cost of Debt				4.51%
	ACC Staff - Proposed Cost of Capital for Fair Value Rate Base - Option 1				
11	Long-Term Debt	$ 554,890,327	39.96%	7.96% [b]	3.18%
12	Preferred Equity	$ 47,732,501	3.44%	8.20% [b]	0.28%
13	Common Stock Equity	$ 462,834,789	33.33%	10.00% [b]	3.33%
14	Capital financing OCRB	$1,065,457,617			
15	Appreciation above OCRB not recognized on utility's books	$ 323,152,085	23.27%	0% [a]	0.00%
16	Total capital supporting FVRB	$1,388,609,702	100.00%		6.79%
	ACC Staff - Proposed Cost of Capital for Fair Value Rate Base - Option 2				
17	Long-Term Debt	$ 554,890,327	39.96%	7.96%	3.18%
18	Preferred Equity	$ 47,732,501	3.44%	8.20%	0.28%
19	Common Stock Equity	$ 462,834,789	33.33%	10.00%	3.33%
20	Capital financing OCRB	$1,065,457,617			
21	Appreciation above OCRB not recognized on utility's books	$ 323,152,085	23.27%	1.25% [b]	0.29%
22	Total capital supporting FVRB	$1,388,609,702	100.00%		7.08%

Notes and Source

Lines 11-15, Col.A:

23	Fair Value Rate Base	$1,388,609,702	Schedule A
24	Original Cost Rate Base	$1,065,457,617	Schedule A
25	Difference	$ 323,152,085	

Difference is appreciation of Fair Value over Original Cost that is not recognized on the utility's books.

[a] The appreciation of Fair Value over Original Cost has not been recognized on the utility's books. Such off-book appreciation has not been financed by debt or equity capital recorded on the utility's books. The appreciation over Original Cost book value is therefore recognized for cost of capital purposes at zero cost.

[b] Per Staff witness David Parcell

Southwest Gas Corporation
Yuma Manors Pipe Replacement

Docket No. G-01551A-07-0504
Schedule B-1
Page 1 of 1

Test Year Ended April 30, 2007

Line No.	Description	Account	Account 376 Mains Amount (A)	Account 380 Services Amount (B)	Total Amount (C)	Reference	
	I. Costs Recorded by Company Though End of Test Year						
	A. For New Plant Replacing the Original Plant						
1	Costs incurred prior to and during the test year	101	$ 737,377	$ 494,385	$ 1,231,762	Note A	
2	Accumulated Depreciation	108	$ (1,099)	$ (1,206)	$ (2,305)	Note A	
3	Net Plant in Service - replacement plant		$ 736,278	$ 493,179	$ 1,229,457	Note A	L.1 - L.2
	B. For the Original Cost of Plant Installed 1954-1958						
	1. Plant in Service						
4	Gas Plant in Service	101	$ 151,539	$ 27,462	$ 179,001	Note A	
5	Gas Plant Retired	101	$ (151,539)	$ (27,462)	$ (179,001)	Note A	
6	Gas Plant in Service After Retirement	101	$ -	$ -	$ -	Note A	
	2. Accumulated Depreciation						
7	Accumulated Depreciation recorded at April 2007	108	$ (271,280)	$ (57,198)	$ (328,478)	Note A	
8	Gas Plant Retired	108	$ 151,539	$ 27,462	$ 179,001	Note A	
9	Removal costs incurred prior to and during the test year	108	$ 4,137	$ 8,331	$ 12,468	Note A	
10	Impact on Accumulated Depreciation	108	$ (115,604)	$ (21,405)	$ (137,009)	Note A	
11	Impact on Net Plant		$ 115,604	$ 21,405	$ 137,009	Note A	L6 - L10
	III. Staff Adjustment						
12	Remove impact on test year of replacement plant		$ (736,278)	$ (493,179)	$ (1,229,457)	- Line 3	
13	Remove impact on test year of original plant retired		$ 115,604	$ 21,405	$ 137,009	- Line 11	
14	Adjustment to Test Year Net Plant		$ (620,674)	$ (471,774)	$ (1,092,448)		
15	Adjustment to Test Year Plant in Service		$ (737,377)	$ (494,385)	$ (1,231,762)	- Line 1 less Line 6	
16	Adjustment to Test Year Accumulated Depreciation		$ 116,703	$ 22,611	$ 139,314	- Line 2 less Line 10	
17	Adjustment to Test Year Net Plant		$ (620,674)	$ (471,774)	$ (1,092,448)		

Notes and Source

A Responses to ACC-STF-7-1 and STF-11-6
Also see the direct testimony of Staff engineer Corky Hanson

Southwest Gas Corporation
Customer Advances for Construction

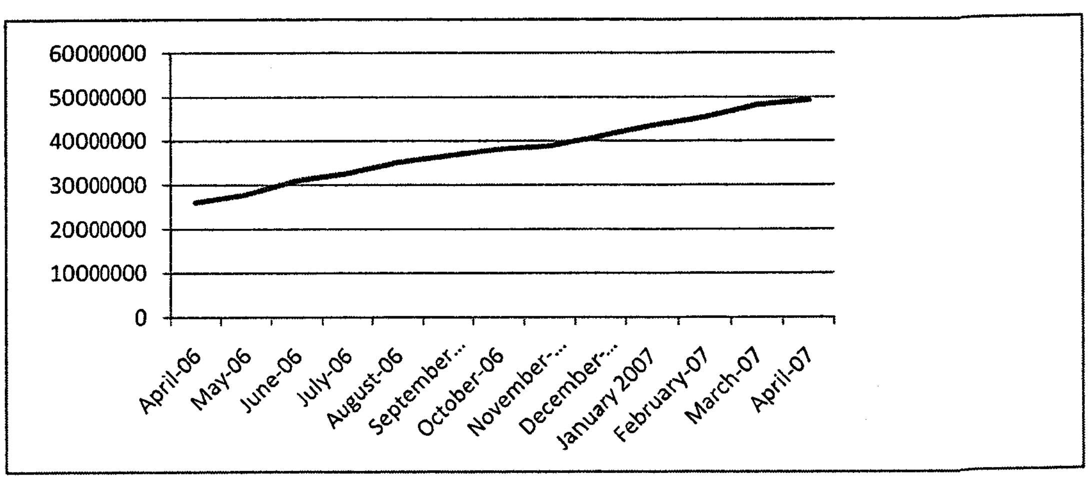
Test Year Ended April 30, 2007

Docket No. G-01551A-07-0504
Schedule B-2

Line No.	Description		Amount (A)	Reference
1	Staff proposed		$ (49,194,789)	See below
2	Company proposed		$ (37,910,017)	See below
3	Staff adjustment to rate base		$ (11,284,772)	Account 252
	Related Accumulated Deferred Income Taxes:			
4	Related ADIT	34.43%	$ 3,885,347	Response to STF 1.25, Customer Advances Account 2830 2100

Notes and Source
From Southwest Excel workpapers

	Month	Account 252 Amount (B)	Monthly Change (C)
5	April-06	$ 25,965,151.95	
6	May-06	$ 27,771,678.00	$ 1,806,526.05
7	June-06	$ 30,949,083.64	$ 3,177,405.64
8	July-06	$ 32,596,096.25	$ 1,647,012.61
9	August-06	$ 35,041,274.23	$ 2,445,177.98
10	September-06	$ 36,572,842.62	$ 1,531,568.39
11	October-06	$ 38,058,790.21	$ 1,485,947.59
12	November-06	$ 38,732,669.00	$ 673,878.79
13	December-06	$ 41,078,965.78	$ 2,346,296.78
14	January 2007	$ 43,365,611.50	$ 2,286,645.72
15	February-07	$ 45,355,426.19	$ 1,989,814.69
16	March-07	$ 48,147,845.19	$ 2,792,419.00
17	April-07	$ 49,194,789.04	$ 1,046,943.85
18	Average	$ 37,910,017.20	
19	Year-End	$ 49,194,789.04	
20	Adjustment	$ 11,284,771.84	



Southwest Gas Corporation

Cash Working Capital
Test Year Ended April 30, 2007

Docket No. G-01551A-07-0504
Schedule B-3 Revised
Page 1 of 2

Line No.	Description	Per Company Cost (A)	Staff Adjustments (B)	Staff Adjusted (C)	Lag Days (D)	Dollar Days (E)
1	Cost of Gas	$ 540,064,385	$ -	$ 540,064,385	42.30	$ 22,842,405,297
2	Labor Cost	$ 117,038,570	$ (4,058,098)	$ 112,980,472	12.33	$ 1,393,594,232
3	Provision for Uncollected Accounts	$ 2,977,729	$ -	$ 2,977,729	120.00	$ 357,327,523
4	Other O & M Expenses	$ 54,826,860	$ (2,237,593)	$ 52,589,268	8.40	$ 441,887,570
5	Total O & M Expenses	$ 714,907,545	$ (6,295,691)	$ 708,611,854	35.02	$ 25,035,214,622
6	Interest	$ 48,035,008	$ 48,327	$ 48,083,335	84.65	$ 4,070,393,157
7	Peferred Securities			$ 7,722,141	45.25	$ 349,426,880
8	Taxes Other Than Income Taxes	$ 33,124,880	$ 91,241	$ 33,216,121	185.34	$ 6,156,275,784
9	Income Taxes-Current	$ 21,699,571	$ 2,543,129	$ 24,242,700	37.00	$ 896,979,888
10	Total Operating Expenses, Interest and Preferred	$ 817,767,003	$ 2,634,370	$ 821,876,150	44.64	$ 36,508,290,331
11	Number of Days in Test Period	365		365		
12	Average Daily Operating Expense	$ 2,240,458		$ 2,251,715		
13	Lag in Receipt of Revenue				39.53	
14	Net Difference Revenue-Expense Lag	(5.11)		(5.11)	(5.11)	
	Cash Working Capital:					
15	Per Staff			$ (11,512,918)		
16	Lag for Revenue Based Taxes			$ (5,030,195)		
17	Per Staff adjusted			$ (16,543,113)		
18	Per Company	$ (11,455,356)		$ (11,455,356)		
19	Staff Adjustment			$ (5,087,757)		
20	Staff Adjustment (rounded to thousands)			$ (5,088,000)		

Notes and Source

Col.A: SWG Sch B-5, page 2 of 4
Col.B: Staff Schedule B-3 workpaper
Col.C: Col. A + Col.B
L.6: Schedule C-10, L.3, Synchronized interest
L.7: Southwest Gas rebuttal Exhibit __(RAM-3) (Mashas)
L.16 Page 2 of 2
Col.D: SWG Sch B-5, page 2 of 4, except as noted
Col.E: Col. C x Col.D

Southwest Gas Corporation
Cash Working Capital - Revenue Based Taxes for Lead Lag Study

Test Year Ended April 30, 2007

Line No.	Description	Paid Monthly (A)	Paid Quarterly (B)	Paid Annually (C)	Total (D)
	I. Per Southwest Gas				
1	Franchise Fees	$ 6,448,399	$ 10,717,071		$ 17,165,470
2	Privilege/Sales Taxes	$ 82,412,358		$ 354	$ 82,412,712
3	Business Occupational Taxes		$ 85,768		$ 85,768
4	Mill Assessments (ACC/RUCO)			$ 1,757,145	$ 1,757,145
5	Totals	$ 88,860,757	$ 10,802,839	$ 1,757,499	$ 101,421,095
6	Ratio to Totals	87.62%	10.65%	1.73%	100.00%
7	Lag days	39.53	66.43	203.93	
8	Weighted lag days	34.63	7.08	3.53	45.24
	II. Per Staff				
9	Lag days	53.53	67.43	204.93	
10	Weighted lag days	46.90	7.18	3.55	57.63
	III. Staff Adjustment	Reference			
11	Revenue-based taxes payment lag	Line 10			57.63
12	Revenue lag	Schedule B-3			39.53
13	Net lag for payment of revenue based taxes	Line 12 - Line 11			(18.10)
14	Revenue-based taxes	Line 5, column D			$ 101,421,095
15	Average daily amount of revenue-based taxes	Line 14 / 365 days			$ 277,866
16	Cash working capital impact of revenue-based taxes	Line 13 x Line 15			$ (5,030,195)

Notes and Source

Part I: SWG did not include a lag for revenue based taxes in its direct filing. Souwthest rebutal Exhibit __(RAM-3), page 2

Part II: Staff has added 14 days after receipt of revenue for payment of monthly-paid revenue-based taxes

Southwest Gas Corporation
Customer Deposits

Docket No. G-01551A-07-0504
Schedule B-4
Page 1 of 3

Test Year Ended April 30, 2007

Line No.	Description	Amount	Reference
		(A)	
1	Staff proposed	$ (34,402,771)	See below
2	Company proposed	$ (31,921,898)	See below
3	Staff adjustment to rate base	$ (2,480,873)	

Notes and Source
From Southwest Excel workpapers

	Month	Amount	Monthly Change
		(B)	(C)
4	April-06	$ 29,940,533.00	
5	May-06	$ 30,244,307.00	$ 303,774.00
6	June-06	$ 30,534,168.00	$ 289,861.00
7	July-06	$ 30,907,667.00	$ 373,499.00
8	August-06	$ 31,068,422.00	$ 160,755.00
9	September-06	$ 31,294,649.00	$ 226,227.00
10	October-06	$ 31,925,334.07	$ 630,685.07
11	November-06	$ 32,387,659.54	$ 462,325.47
12	December-06	$ 32,677,847.19	$ 290,187.65
13	January 2007	$ 32,866,854.83	$ 189,007.64
14	February-07	$ 33,171,594.71	$ 304,739.88
15	March-07	$ 33,562,861.81	$ 391,267.10
16	April-07	$ 34,402,770.85	$ 839,909.04
17	Average	$ 31,921,897.62	
18	Year-End	$ 34,402,770.85	
19	Adjustment	$ 2,480,873.23	

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

Southwest Gas Corporation
Customer Deposits

Docket No. G-01551A-07-0504
Schedule B-4

Test Year Ended April 30, 2007

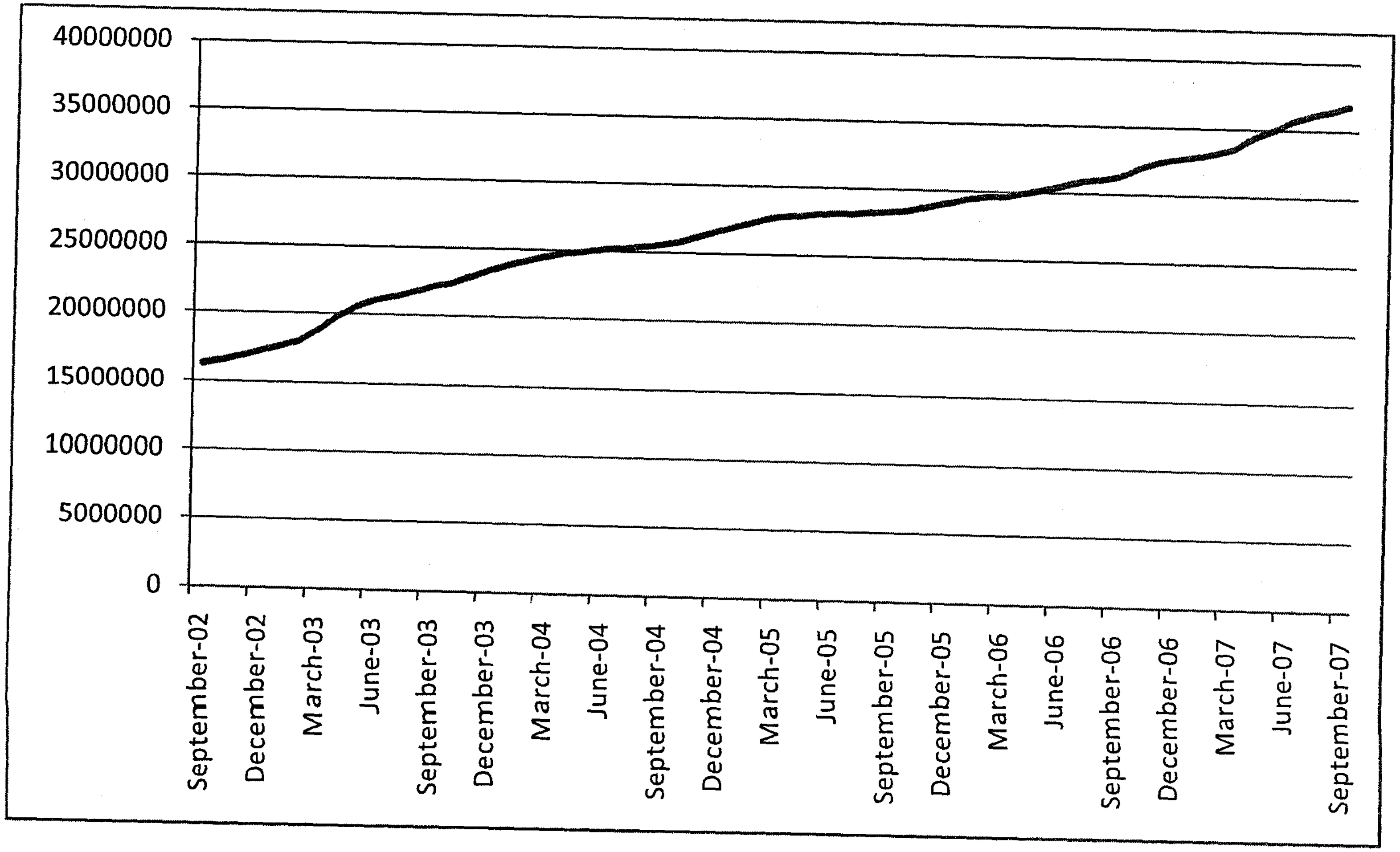
Line No.	Month		Amount		Monthly Change
			(A)		(B)
1	September-02	$	16,250,822		
2	October-02	$	16,492,184	$	241,362
3	November-02	$	16,804,948	$	312,764
4	December-02	$	17,151,007	$	346,059
5	January-03	$	17,539,415	$	388,408
6	February-03	$	17,955,206	$	415,791
7	March-03	$	18,771,907	$	816,701
8	April-03	$	19,779,385	$	1,007,478
9	May-03	$	20,563,887	$	784,502
10	June-03	$	21,068,603	$	504,716
11	July-03	$	21,361,867	$	293,264
12	August-03	$	21,697,818	$	335,951
13	September-03	$	22,116,629	$	418,811
14	October-03	$	22,421,280	$	304,651
15	November-03	$	22,915,023	$	493,743
16	December-03	$	23,429,731	$	514,708
17	January-04	$	23,858,508	$	428,777
18	February-04	$	24,244,633	$	386,125
19	March-04	$	24,547,955	$	303,322
20	April-04	$	24,807,840	$	259,885
21	May-04	$	24,958,957	$	151,117
22	June-04	$	25,170,362	$	211,405
23	July-04	$	25,267,247	$	96,885
24	August-04	$	25,421,849	$	154,602
25	September-04	$	25,552,621	$	130,772
26	October-04	$	25,848,938	$	296,317
27	November-04	$	26,282,708	$	433,770
28	December-04	$	26,682,829	$	400,121
29	January-05	$	27,087,182	$	404,353
30	February-05	$	27,467,386	$	380,204
31	March-05	$	27,823,958	$	356,572
32	April-05	$	27,893,262	$	69,304
33	May-05	$	28,063,139	$	169,877
34	June-05	$	28,169,344	$	106,205
35	July-05	$	28,186,789	$	17,445
36	August-05	$	28,307,776	$	120,987
37	September-05	$	28,394,707	$	86,931
38	October-05	$	28,538,698	$	143,991
39	November-05	$	28,856,769	$	318,071
40	December-05	$	29,139,638	$	282,869
41	January-06	$	29,453,967	$	314,329
42	February-06	$	29,642,993	$	189,026
43	March-06	$	29,683,090	$	40,097
44	April-06	$	29,940,535	$	257,445
45	May-06	$	30,244,306	$	303,771
46	June-06	$	30,534,170	$	289,864
47	July-06	$	30,907,669	$	373,499
48	August-06	$	31,068,422	$	160,753
49	September-06	$	31,294,651	$	226,229
50	October-06	$	31,925,334	$	630,683
51	November-06	$	32,387,660	$	462,326
52	December-06	$	32,677,847	$	290,187
53	January-07	$	32,866,855	$	189,008
54	February-07	$	33,171,595	$	304,740
55	March-07	$	33,562,862	$	391,267
56	April-07	$	34,402,771	$	839,909
57	May-07	$	34,944,231	$	541,460
58	June-07	$	35,653,565	$	709,334
59	July-07	$	36,066,017	$	412,452
60	August-07	$	36,447,849	$	381,832
61	September-07	$	36,827,715	$	379,866

Source: Response to STF-1-9

All are positive, i.e., increases

Southwest Gas Corporation
Customer Deposits

Test Year Ended April 30, 2007



Southwest Gas Corporation
Accumulated Deferred Income Taxes

Test Year Ended April 30, 2007

Line No.	Description	Southwest Proposed Amount (A)	Staff Proposed Amount (B)	Staff Adjustment (C)	Reference
	Original Cost Rate Base Adjustment				
1	Account 190\Deferred Tax Asset	$ 20,877,149	$ 7,745,124	$(13,132,025)	See below
	Corresponding RCND Adjustment				
2	RCND Factor for Account 190 ADIT			1.531344	Page 2 of 2
3	Corresponding RCND Rate Base Adjustment			$(20,109,648)	L.1 x L.2

Notes and Source

Col.A: Company Schedule B-6, Sheet 3 of 3
Line 1, Account 190 ADIT Debit balance item:

		Per Southwest	Per Staff	Going-Forward Adjustment	
4	Debit balance ADIT relating to Alternative Minimum Tax Carryforward	$ 36,820,369	$ 13,659,830	$(23,160,539)	Notes A and B
5	Arizona Four-Factor Allocation	56.70%	56.70%	56.70%	
6	Arizona Allocation	$ 20,877,149	$ 7,745,124	$(13,132,026)	

A Per the Company's response to STF-11-10(a), the $36.82 million represents the total Alternative Minimum Tax Credit (AMTC) for Southwest Gas Corporation as of 12/31/06. Sub-account 19002110 for $25 million is the current portion of the AMTC that is expected to be utilized during the next 12 months, i.e., during the 2007 tax year. Sub-account 19002115 is the non-current portion of the AMTC and represents the amount that is expected to be utilized sometime after the 2007 tax year.

B AMT carryfoward used in 2007 (per 3-15-08 estimate for 2007 corporate tax return extension filing)
This amount is therefore no longer being carried as an ADIT balance in Account 190 on a going-forward basis. Southwest currently expects to be able to apply an additional amount of its AMT carry-forward to reduce income tax in tax year 2009 (but not in tax year 2008); therefore, the remaining Account 190 balance is expected to remain during 2008 and beyond until utilized.
Source: Southwest Gas Tax Department, Lisa Moses

Southwest Gas Corporation
Account 190 Deferred Taxes by Vintage
At April 30, 2007

Line No.	Year	System Allocable: Total Acct 190 Deferred Tax Asset at 4/30/07	System Allocable: 4-Factor	System Allocable: Total Acct 190 Deferred Tax Asset at 4/30/07 for Arizona	RCN Deferred Taxes for Acct 190: H -W Index	RCN Deferred Taxes for Acct 190: Ratio to Current Index	RCN Deferred Taxes for Acct 190: Acct 190 RCN Deferred Taxes for Arizona
1	1993	(33,127)	56.70%	(18,783)	291	1.76	(33,058)
2	1994	(1,180,873)	56.70%	(669,555)	307	1.67	(1,118,157)
3	1995	(2,033,739)	56.70%	(1,153,130)	309	1.66	(1,914,196)
4	1996	0	56.70%	0	312	1.64	0
5	1997	0	56.70%	0	320	1.60	0
6	1998	(7,175,288)	56.70%	(4,068,388)	323	1.58	(6,428,053)
7	1999	(18,722,588)	56.70%	(10,615,708)	332	1.54	(16,348,190)
8	2000	0	56.70%	0	346	1.48	0
9	2001	(6,360,549)	56.70%	(3,606,431)	352	1.45	(5,229,325)
10	2002	(647,026)	56.70%	(366,864)	358	1.43	(524,615)
11	2003	0	56.70%	0	373	1.37	0
12	2004	0	56.70%	0	439	1.17	0
13	2005	(667,179)	56.70%	(378,291)	517	0.99	(374,508)
14	2006	0	56.70%	0	529	0.97	0
15	2007	0	56.70%	0	512	1.00	0
16	Total	(36,820,369)		(20,877,149)			(31,970,102)
17						RCND value	(31,970,102)
18						Original cost value	(20,877,149)
19						RCND factor for Account 190	1.531344

Southwest Gas Corporation
Intangible Plant Added After the Test Year
That Was In Service by December 31, 2007
Test Year Ended April 30, 2007

Docket No. G-01551A-07-0504
Schedule B-6 Revised

Line No.	Description	Southwest Proposed Amount	Staff Proposed Amount	Staff Adjustment	Reference
		(A)	(B)	(C)	
	Original Cost Rate Base Adjustment				
1	New Intangible Plant	$ 1,696,000	$ 1,449,260	$ (246,740)	See below
2	Arizona Four-Factor Allocation	56.70%	56.70%	56.70%	
3	Arizona Allocation	$ 961,632	$ 821,730	$ (139,902)	

Notes and Source

Col.A: Company Proposed Per Southwest Gas Adjustment No. 14

Col.B: Staff Proposed per Company's Supplemental Responses to STF-11-4 nd STF-6-49
Also see Schedule C-15, columns B and E

Southwest Gas Corporation
Deferred Taxes By Vintage
At April 30, 2007

Docket No. G-01551A-07-0504
Schedule B-7
Page 1 of 1

Line No.	Year	Arizona: Total Federal 282 Deferred Tax Liability at 4/30/07	Arizona: Total State 282 Deferred Tax Liability at 4/30/07	Arizona: Total Arizona Recorded Deferred Tax Liability at 4/30/07	System Allocable: Total Federal 282 Deferred Tax Liability at 4/30/07	System Allocable: Total Acct 190 Deferred Tax Asset at 4/30/07	System Allocable: Total System Allocable at 4/30/07	System Allocable: 4-Factor	System Allocable: Total Recorded Deferred Tax Liability at 4/30/07	Total: Total AZ Recorded Deferred Tax Liability at 4/30/07	RCN Deferred Taxes: H-W Index	RCN Deferred Taxes: Ratio to Current Index	RCN Deferred Taxes: RCN Deferred Taxes fro Arizona
1	1953	1,859	291	2,150	0	0	0	56.70%	0	2,150	47	10.89	23,414
2	1654	(271)	(42)	(313)	0	0	0	56.70%	0	(313)	49	10.45	(3,271)
3	1955	162	25	187	0	0	0	56.70%	0	187	51	10.04	1,877
4	1956	(2,532)	(396)	(2,928)	0	0	0	56.70%	0	(2,928)	56	9.14	(26,762)
5	1957	(753)	(118)	(871)	0	0	0	56.70%	0	(871)	59	8.68	(7,560)
6	1958	(2,308)	(361)	(2,669)	0	0	0	56.70%	0	(2,669)	61	8.39	(22,393)
7	1959	2,432	381	2,813	0	0	0	56.70%	0	2,813	63	8.13	22,870
8	1960	(7,620)	(1,193)	(8,813)	0	0	0	56.70%	0	(8,813)	65	7.88	(69,446)
9	1961	10,750	1,683	12,433	(5)	0	(5)	56.70%	(3)	12,430	66	7.76	96,458
10	1962	(12,403)	(1,942)	(14,345)	0	0	0	56.70%	0	(14,345)	67	7.64	(109,596)
11	1963	(25,672)	(4,020)	(29,692)	19	0	19	56.70%	11	(29,681)	68	7.53	(223,500)
12	1964	(47,772)	(7,480)	(55,252)	0	0	0	56.70%	0	(55,252)	69	7.42	(409,970)
13	1965	(33,707)	(5,278)	(38,985)	(49)	0	(49)	56.70%	(28)	(39,013)	71	7.21	(281,282)
14	1966	(17,230)	(2,698)	(19,928)	0	0	0	56.70%	0	(19,928)	72	7.11	(141,688)
15	1967	5,885	921	6,806	(40)	0	(40)	56.70%	(23)	6,783	74	6.92	46,941
16	1968	(36,933)	(5,783)	(42,716)	(5)	0	(5)	56.70%	(3)	(42,719)	76	6.74	(287,925)
17	1969	(11,023)	(1,726)	(12,749)	0	0	0	56.70%	0	(12,749)	79	6.48	(82,614)
18	1970	(11,601)	(1,816)	(13,417)	0	0	0	56.70%	0	(13,417)	84	6.10	(81,844)
19	1971	3,506	549	4,055	48	0	48	56.70%	27	4,082	90	5.69	23,228
20	1972	(2,118)	(332)	(2,450)	93	0	93	56.70%	53	(2,397)	95	5.39	(12,921)
21	1973	21,291	3,334	24,625	(81)	0	(81)	56.70%	(46)	24,579	100	5.12	125,845
22	1974	81,690	12,791	94,481	0	0	0	56.70%	0	94,481	115	4.45	420,440
23	1975	1,228	192	1,420	108	0	108	56.70%	61	1,481	133	3.85	5,703
24	1976	60,416	9,460	69,876	(9)	0	(9)	56.70%	(5)	69,871	143	3.58	250,138
25	1977	23,368	3,659	27,027	(11,351)	0	(11,351)	56.70%	(6,436)	20,591	155	3.30	67,950
26	1978	46,293	7,248	53,541	326	0	326	56.70%	185	53,726	169	3.03	162,789
27	1979	1,333,385	208,774	1,542,159	0	0	0	56.70%	0	1,542,159	184	2.78	4,287,202
28	1980	1,012,547	158,539	1,171,086	(1,756)	0	(1,756)	56.70%	(996)	1,170,090	198	2.59	3,030,534
29	1981	478,969	74,994	553,963	38	0	38	56.70%	22	553,985	223	2.30	1,274,164
30	1982	193,572	30,308	223,880	1,449	0	1,449	56.70%	822	224,702	235	2.18	489,849
31	1983	632,984	99,109	732,093	3,709	0	3,709	56.70%	2,103	734,196	241	2.12	1,556,496
32	1984	7,838,504	1,227,307	9,065,811	335	0	335	56.70%	190	9,066,001	246	2.08	18,857,282
33	1985	3,351,835	524,810	3,876,645	18,321	0	18,321	56.70%	10,388	3,887,033	241	2.12	8,240,510
34	1986	6,108,046	956,362	7,064,408	(10,952)	0	(10,952)	56.70%	(6,210)	7,058,198	234	2.19	15,457,454
35	1987	4,331,907	678,264	5,010,171	(1,716)	0	(1,716)	56.70%	(973)	5,009,198	242	2.12	10,619,500
36	1988	5,289,269	828,162	6,117,431	(44,225)	0	(44,225)	56.70%	(25,076)	6,092,355	255	2.01	12,245,634
37	1989	3,939,340	616,799	4,556,139	781,665	0	781,665	56.70%	443,204	4,999,343	264	1.94	9,698,726
38	1990	4,708,170	737,177	5,445,347	32,590	0	32,590	56.70%	18,479	5,463,826	271	1.89	10,326,630
39	1991	2,001,984	313,459	2,315,443	89,422	0	89,422	56.70%	50,702	2,366,145	278	1.84	4,353,707
40	1992	2,352,840	368,394	2,721,234	24,138	0	24,138	56.70%	13,686	2,734,920	283	1.81	4,950,206
41	1993	2,821,601	441,790	3,263,391	21,122	(33,127)	(12,005)	56.70%	(6,807)	3,256,584	291	1.76	5,731,588
42	1994	2,998,550	469,495	3,468,045	78,585	(1,180,873)	(1,102,288)	56.70%	(624,997)	2,843,048	307	1.67	4,747,890
43	1995	3,825,639	598,996	4,424,635	191,218	(2,033,739)	(1,842,521)	56.70%	(1,044,710)	3,379,925	309	1.66	5,610,676
44	1996	4,082,540	639,220	4,721,760	82,646	0	82,646	56.70%	46,860	4,768,620	312	1.64	7,820,537
45	1997	3,903,337	611,161	4,514,498	123,485	0	123,485	56.70%	70,016	4,584,514	320	1.60	7,335,222
46	1998	6,753,167	1,057,371	7,810,538	346,634	(7,175,288)	(6,828,654)	56.70%	(3,871,847)	3,938,691	323	1.58	6,223,132
47	1999	8,728,276	1,366,622	10,094,898	504,506	(18,722,588)	(18,218,082)	56.70%	(10,329,653)	(234,755)	332	1.54	(361,522)
48	2000	7,310,098	1,144,572	8,454,670	344,295	0	344,295	56.70%	195,215	8,649,885	346	1.48	12,801,830
49	2001	7,028,031	951,099	7,979,130	796,497	(6,360,549)	(5,564,052)	56.70%	(3,154,817)	4,824,313	352	1.45	6,995,253
50	2002	16,104,379	1,448,826	17,553,205	1,313,889	(647,026)	666,863	56.70%	378,111	17,931,316	358	1.43	25,641,783
51	2003	17,138,584	1,195,708	18,334,292	8,082,682	0	8,082,682	56.70%	4,582,881	22,917,173	373	1.37	31,396,527
52	2004	23,408,345	1,045,414	24,453,759	1,018,923	0	1,018,923	56.70%	577,729	25,031,488	439	1.17	29,286,841
53	2005	1,844,435	288,791	2,133,226	1,705,754	(667,179)	1,038,575	56.70%	588,872	2,722,098	517	0.99	2,694,877
54	2006	(5,514,649)	(863,451)	(6,378,100)	1,081,147	0	1,081,147	56.70%	613,010	(5,765,090)	529	0.97	(5,592,137)
55	2007	(5,987,497)	(937,487)	(6,924,984)	(424,624)	0	(424,624)	56.70%	(240,762)	(7,165,746)	512	1.00	(7,165,746)
56	Total	138,065,125	16,287,934	154,353,059	16,148,831	(36,820,369)	(20,671,538)		(11,720,762)	142,632,297			238,041,526
									check	142,632,297		RCND Adjustment	95,409,229

Notes and Source
Southwest Gas-provided Excel file workpaper

Southwest Gas Corporation
Remove Net Plant Being Sold to TEP for Sundt Bypass

Test Year Ended April 30, 2007

Line No.	Description	Adjustment to Plant in Serice (A)	Adjustment to Accumulated Depreciation (B)	Net Adjustment to Rate Base (C)	Reference
	Original Cost Rate Base Adjustment				
1	Metering facility	$ (182,093)	$ 182,093	$ -	See below
2	Piping	$ (28,526)	$ 28,526	$ -	
3	Total	$ (210,619)	$ 210,619	$ -	

Notes and Source
Southwest's May 14, 2008 supplemental response to RUCO 7-2

Southwest Gas Corporation
Yuma Manors Depreciation and Property Tax Expense

Test Year Ended April 30, 2007

Line No.	Description	Plant Amount (A)	Depreciation Rate (B)	Adjustment to Depreciation Expense (C)
1	Account 376, Mains	$ (737,377)	3.82%	$ (28,168)
2	Account 380, Services	$ (494,385)	5.30%	$ (26,202)
3	Adjustment to Annualized Depreciation Expense	$ (1,231,762)		$ (54,370)

Notes and Source
Col.A: Schedule B-1
Col.B: Response to ACC-STF-7-1
Col.C: Also see SWG's response to STF-11-6

FERC 403

Southwest Gas Corporation
Yuma Manors Depreciation and Property Tax Expense

Docket No. G-01551A-07-0504
Schedule C-1

Test Year Ended April 30, 2007

Line No.	Description	Amount	Reference
	Adjustment to Property Tax Expense		
1	Adjustment to Net Plant in Service	$ (1,092,448)	Note A
2	Statutory Assessment Ratio	23.0%	Note A
3	Taxable Value	$ (251,263)	Note A
4	Property Tax Rate	11.52%	Notes A and B
5	Property Tax Expense Adjustment	$ (28,945)	Note A

Notes and Source

A Schedule B-1 and SWG's response to STF-11-6

B Also see Company's Schedule C-2, Adj. No. 15

FERC 408.1

Southwest Gas Corporation

Gain on Sale of Property in Cave Creek, AZ
Test Year Ended April 30, 2007

Line No.	Description	Amount	Reference
1	Gain on Sale of Property in Cave Creek, AZ which had been included in gas plant in service	$ 418,196	A
2	Ratepayer sharing percent	50.0%	A
3	Ratepayer sharing amount of gain	$ 209,098	
	Normalization period, in years	3	B
4	Adjustment to pre-tax NOI for gain sharing	$ (69,700)	

Notes and Source

A SWG response to STF 1-96

B Same period used by SWG for normalization of rate case cost, see SWG Sch C-2, Adj. No. 13

Southwest Gas Corporation
Management Incentive Program

Docket No. G-01551A-07-0504
Schedule C-3 Revised

Test Year Ended April 30, 2007

Line No.	Description	Amount	Reference	
1	Adjustment to Management Incentive Program Expense	$ (1,611,723)	A	
2	Related Adjustment to Payroll Tax Expense	$ 120,186	B	

Notes and Source

A	Adjustment to Management Incentive Program Expense			
	Amount below from SWG's corrected responses to STF-1-78 and RUCO-1-10			
3	Test Year amount of Management Incentive Program Expense (Corporate)	$ 5,919,502		
4	Allocation to Paiute (MMF)	$ (234,412)	3.96%	C
5	Net of Allocation to Paiute	$ 5,685,090		
6	Arizona Four Factor allocation rate per SWG Schedule C-1, sheet 17	56.70%		C
7	Test Year amount of Management Incentive Program Expense (Arizona)	$ 3,223,446		
8	Shareholder allocation percentage	50%		
9	50% Allocation of MIP Expense to Shareholders	$ 1,611,723	FERC 920	
B	Adjustment to Payroll Tax Expense			
10	Adjustment to Test Year MIP Expense	$ 1,611,723	D	
11	Payroll Tax Expense Rate	7.457%	E	
12	Adjustment to Payroll Tax Expense	$ 120,186		

C SWG's response to STF-11-15 states that Southwest's annualized labor (shown in WP Sch C-2, Adj. No. 3) does not include MIP compensation or stock based compensation. Therefore, the cost of service filed by SWG does not include annualized payroll taxes related to these two items of compensation.
This adjustment, therefore, provides for annualized payroll tax expense on the portion of MIP allowed in rates.

D SWG's response to STF-9-10

E Estimated based on SWG's annualized payroll tax expense; is a Staff DR in Set 11 to ID specific info

Southwest Gas Corporation
Stock Based Compensation (Other Than MIP)

Docket No. G-01551A-07-0504
Schedule C-4

Test Year Ended April 30, 2007

Line No.	Description	Amount	Reference
1	Adjustment to remove expense for Stock Based Compenation (other than MIP)	$ (820,915)	A

Notes and Source

A	Test Year amount of Stock Based Compensation (Other than MIP)		
2	Test Year amount of Stock Based Compensation (Other than MIP)	$ 1,507,520	STF-10-12
3	Allocation to Paiute (FERC via MMF)	$ (59,698)	3.96% B
4	Net of Allocation to Paiute	$ 1,447,822	
5	Arizona Four Factor allocation rate per SWG Schedule C-1, sheet 17	56.70%	B
6	Test Year amount of Stock Based Compensation (Other than MIP) - Arizona	$ 820,915	

B SWG's response to STF-9-10
SWG's supplemental response to STF-6-41 that was referenced in SWG's response to STF-10-12(c)

Southwest Gas Corporation
Supplemental Executive Retirement Expense

Test Year Ended April 30, 2007

Line No.	Description	Amount	Reference
1	Test Year Supplemental Executive Retirement Expense (Arizona)	$ (1,117,881)	A
2	Test Year Supplemental Executive Retirement Expense (Corporate Direct Arizona)	$ (54,102)	A
3	System Allocable Amount of SERP (Arizona)	$ (453,477)	A
4	Adjustment to Remove Supplemental Executive Retirement Expense	$ (1,625,460)	B

Notes and Source

A SWG Filing, WP Schedule C-2, page 8, line 11 as referenced by SWG's responses to STF-1-49 and RUCO 1.20 and STF-9-8

B Amount confirmed in SWG's response to STF-10-6

SERP is recorded by SWG in FERC 926 and then allocated to other expense accounts via SWG's labor loading.

Southwest Gas Corporation
American Gas Association Dues

Test Year Ended April 30, 2007

Docket No. G-01551A-07-0504
Schedule C-6

Line No.	Description	Staff Adjustment (A)	Company Adjustment (B)	Net Staff Adjustment (C)	Reference
1	2007 AGA Dues per Filing	$ 401,975	$ 401,975		A
2	Recommended disallowance percentage	40%	3.39%		B
3	Recommended disallowance	$ (160,790)	$ (13,627)		L1 x L2
4	Less: Paiute & SGTC Allocation at 3.96%	$ 6,367	$ 540		C
5	Adjustment to AGA Dues Before Four-Factor	$ (154,423)	$ (13,087)		
6	Arizona Four-Factor Allocation	56.70%	56.70%		D
7	Adjustment to Arizona Related AGA Dues	$ (87,558)	$ (7,420)	$ (80,138)	

Notes and Source

A: SWG Filing, Schedule C-2, Adjustment No. 9, line 1

B: See testimony of Staff witness Ralph C. Smith and page 2 of this schedule

C: SWG Filing, Schedule C-1, sheet 18, which indicates a Modified Massachusetts Formula of 3.92% for Paiute and .04% for SGTC

D: SWG Filing, Schedule C-1, sheet 17

FERC Account 930.2

Southwest Gas Corporation
American Gas Association
Schedule of Expenses by NARUC Category

Docket No. G-01551A-07-0504
Schedule C-6

Line No.	NARUC Operating Expense Category	March 2005 NARUC Audit Report for Year Ended 12/31/02 % of Dues (A)	Recommended Disallowance (B)	AGA 2007 Budget % of Dues (C)	With G&A Allocated (D)	Recommended Disallowance (E)	AGA 2008 Budget % of Dues (F)	With G&A Allocated (G)	Recommended Disallowance (H)
1	Public Affairs	24.13%	24.13%	23.29%	28.67%	28.67%	24.44%	30.63%	30.63%
2	Advertising			1.39%	1.71%	1.71%	1.18%	1.48%	1.48%
3	Communications	15.53%							
4	Corporate Affairs and International	10.54%	10.54%	8.44%	10.39%	10.39%	9.14%	11.46%	11.46%
5	General Counsel & Corp Secretary	5.20%	2.60%	4.09%	5.04%	2.52%	4.17%	5.23%	2.62%
6	Regulatory Affairs	15.51%							
7	Policy Planning & Regulatory Affairs			14.76%	18.17%		15.78%	19.78%	
8	Marketing Department	2.37%	2.37%						
9	Operating & Engineering Services	15.85%		24.11%	29.68%		21.71%	27.21%	
10	Policy & Analysis	12.94%							
11	Industry Finance & Admin. Programs	4.75%		5.16%	6.35%		3.36%	4.21%	
12	General & Administrative			18.77%			20.22%		
13	Total Expenses	106.82%	39.64%	100.01%	100.01%	43.29%	100.00%	100.00%	46.19%
14	Lobbying per IRC Section 162			2%			4%		

Notes and Source
Col.A: March 2005 Annual Audit Report on the Expenditures of the American Gas Association for the 12 month period ended December 31, 2002
Col.C: Southwest's Response to Staff data request STF-6-52
Col.F: Southwest's Response to Staff data request STF-6-50(b)

Southwest Gas Corporation
TRIMP Surcharge

Test Year Ended April 30, 2007

Line No.	Description	Account	Test Year Recorded Amount (A)	Company Adjustment (B)	Company Adjusted (C)	Reference
1	TRIMP Related Regulatory Amortization	407.3	$ 551,530	$ (551,530)	$ -	A
2	TRIMP Costs Written Off	887	$ 348,690	$ (348,690)	$ -	A
3	Test Year TRIMP Costs	887		$ 920,914	$ 920,914	A
4	Adjustment to O&M Expense		$ 348,690	$ 572,224	$ 920,914	
5	Staff adjustment to remove SWG pro forma TRIMP expense				$ (920,914)	- Line 4

Notes and Source

A SWG Filing, Schedule C-2, Adjustment No. 9
SWG response to data request STF-10-2

Southwest Gas Corporation
Test Year Ending April 30, 2007
Comparison of TRIMP Expense Proposed by Company
With Annual Average for First Five Years of TRIMP

Docket No. G-01551A-07-0504
Schedule C-7

Line No.	Month	Year	TRIMP Cost	Average	
1	January	2004	$ -		
2	February		$ -		
3	March		$ -		
4	April		$ -		
5	May		$ 471.82		
6	June		$ 6,544.60		
7	July		$ 5,129.14		
8	August		$ 34,505.15		
9	September		$ 26,727.58		
10	October		$ 43,458.93		
11	November		$ 47,645.50		
12	December		$ 249,744.24		
13	January	2005	$ 3,287.69		
14	February		$ 10,172.00		
15	March		$ 112,724.24		
16	April		$ 74,840.59		
17	May		$ 34,496.78		
18	June		$ 153,864.86		
19	July		$ 59,016.31		
20	August		$ 37,807.80		
21	September		$ 74,315.00		
22	October		$ 57,342.53		
23	November		$ 81,834.80		
24	December		$ 116,930.64		
25	January	2006	$ 3,399.49		
26	February		$ 112,185.46		
27	March		$ 89,027.76		
28	April		$ 14,517.99		
29	May		$ 78,760.70		
30	June		$ 25,798.91		
31	July		$ 11,716.63		
32	August		$ 25,738.65		
33	September		$ 61,415.65		
34	October		$ 40,789.65		
35	November		$ 53,181.82		
36	December		$ 184,304.68		
37	January	2007	$ 1,696.82		
38	February		$ 89,940.27		
39	March		$ 51,725.37		
40	April		$ 295,844.74		
41	May		$ 219,060.96		
42	June		$ 563,459.42		
43	July		$ 161,869.56		
44	August		$ 382,430.01		
45	September		$ 606,095.91		
46	October		$ 211,299.88		
47	November		$ 145,226.48		
48	December		$ 17,512.58		
49	GRAND TOTAL		$ 4,677,859.59	$ 935,571.92	Average for First Five Year TRIMP Period
	ANNUAL TOTALS				
50		2003	$ -		
51		2004	$ 414,226.96		
52		2005	$ 816,633.24		
53		2006	$ 700,837.39		
54		2007	$ 2,746,162.00		
55	GRAND TOTAL		$ 4,677,859.59	$ 935,571.92	Average for First Five Year TRIMP Period
	Compare:				
56	Test Year Ending 4/30/07			$ 920,913.89	Normalized O&M Expense for TRIMP Proposed by Southwest Gas

Notes and Source
Response to STF-9-18 and STF-10-2

Southwest Gas Corporation
Test Year Ending April 30, 2007
Estimated Replacement TRIMP Surcharge

Line No.	Description	Amount	Reference
1	Normalized TRIMP Costs per Year	$ 921,000	STF-10-2
2	Test Year rate case volumes	743,110,918	STF-10-2(B)
3	Estimated Replacement TRIMP Surcharge, $/therm	$ 0.00124	Line 1 / Line 2

Southwest Gas Corporation
A&G Expenses - Annualized Paiute Allocation

Test Year Ended April 30, 2007

Line No.	Description	FERC Account	12 Months Ended April 30, 2007 Net Recorded	Charged to Paiute	Gross Recorded	MMF Allocation Paiute	Paiute Annualized	Paiute's A&G Expenses	Amount Allocated to Arizona
			(A)	(B)	(C) (A) + (B)	(D)	(E)	(F) (B) - (E)	(G)
1	Administrative and General Salaries	920	56,785,724	2,402,071	59,187,795	3.92%	2,322,351	79,720	45,201
2	Office Supplies	921	10,322,576	438,378	10,760,954	3.92%	422,228	16,150	9,157
3	Outside Services Employed	923	8,919,827	378,579	9,298,406	3.92%	364,842	13,738	7,789
4	Property Insurance	924	373,578	91,630	465,208	21.09%	98,118	(6,487)	(3,563)
5	Injuries and Damages	925	9,299,361	395,033	9,694,394	3.92%	380,379	14,654	8,309
6	Miscellaneous General Expenses	930.2	5,507,176	233,944	5,741,120	3.92%	225,264	8,680	4,922
7	Rents	931	4,453,278	190,026	4,643,304	3.92%	182,189	7,836	4,443
8	Maintenance of General Plant	935	1,833,689	77,859	1,911,548	3.92%	75,003	2,855	1,619
9	Total		97,495,209	4,207,520	101,702,729		4,070,374	137,146	77,877
10	Revised Paiute Allocation Annualization per STF-1-53								$ 77,877
11	Paiute Allocation Annualization as Filed								$ 101,324
12	Adjustment to Paiute Allocation Annualization								$ (23,447)

Notes and Source

Amounts from SWG's filing, Schedule C-2, Adjustment No. 12 except for line 6, which was revised per SWG's response to STF-1-53

Col. G: All accounts except FERC 924 - Property Insurance are allocated using the 56.70% four-factor. FERC 924 uses 54.92% from WP Schedule C-2, sheet 17

Southwest Gas Corporation
Interest on Customer Deposits

Test Year Ended April 30, 2007

Line No.	Description	Amount	Reference
1	Staff Adjustment to Customer Deposits	$ (2,480,873)	A
2	Interest rate on Customer Deposits	6.0%	B
3	Adjustment to increase interest expense	$ 148,852	L2 - L1

Notes and Source

A Schedule B-4

B Customer Deposit interest rate from SWG Adjustment No. 16

Southwest Gas Corporation
Interest Synchronization

Docket No. G-01551A-07-0504
Schedule C-10 Revised
Page 1 of 1

Test Year Ended April 30, 2007

Line No.	Description		Amount	Reference	
1	Adjusted rate base	$	1,065,457,617	Schedule B	Revised
2	Weighted cost of debt		4.51%	Schedule D	Revised
3	Synchronized interest deduction	$	48,083,335	Line 1 x Line 2	
4	Synchronized interest deduction per Company	$	48,035,008	Note A	
5	Difference (decreased) increased interest deduction	$	48,327	Line 3 - Line 4	
6	Combined federal and state income tax rates		39.529%	Schedule A-1	
7	Increase (decrease) to income tax expense	$	(19,103)		

Notes and Source

A SWG Excel file, "A Scheds.xls"
Arizona, Summary Of Results Of Operations
and SWG Supporting Schedule C-1.

Southwest Gas Corporation
Flow Back Excess Deferred Income Taxes

Test Year Ended April 30, 2007

Docket No. G-01551A-07-0504
Schedule C-11

Line No.	Description		Amount	Reference
1	Excess Deferred Income Taxes for SWG-Arizona	$	(442,035)	A
2	Amortization period, in years		3.0	B
3	Adjustment to income tax expense	$	(147,345)	L2 / L1

Notes and Source

A Southwest Gas Tax Department workpaper
Amount is as of 12/31/07

B Same period as used by SWG to normalize rate case expense

Southwest Gas Corporation
Injuries and Damages, Account 925

Test Year Ended April 30, 2007

Docket No. G-01551A-07-0504
Schedule C-12 Revised
Page 1 of 2

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) Col.D - Col.B
	Arizona Direct						
1	Legal and Other Costs		$ 467,269	$ 467,269	$ 467,269	$ 467,269	$ -
2	Reserve for Self Insurance		$ (558,765)	$ (558,765)	$ (858,765)	$ 830,000 c	$ 1,388,765
3	Self-Insured Workmen's Comp		$ 497,524	$ 497,524	$ 497,524	$ 497,524	$ -
4	Total Arizona Direct		$ 406,028	$ 406,028	$ 106,028	$ 1,794,793	$ 1,388,765
	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	$ 7,317,136	$ (851,717)
19	Company's proposed adjustments to Account 925 in its filing			$ 2,490,088 Col.B - Col.A	$ 2,579,781 Col.C - Col.A	$ (851,717)	
	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	$ 1,376,738	
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	$ 1,638,371	
24	Percentage increase over test year recorded amount			44%	45%	29%	
25	Staff proposed adjustment to SWG as-filed pro forma expense for Account 925					$ (851,717) L.23, Col.D - Col.B	$ (851,717)

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)	$ 830,000	$ 1,388,765
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	$ 943,400	$ (839,690)
29	Net SWG Proposed Adjustment, before change in Paiute allocation		$ 2,228,455 L.27, Col.B - Col.A To Line 21	$ 2,438,624 L.27, Col.C - Col.A	$ 1,388,765	
				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 To Line 21		$ (851,717) c
33	Staff adjustment to Southwest recorded, net of change in Paiute allocation				$ 1,376,738 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 Revised
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	$ 713,629	$ (25,500)	$ 713,629	$ (25,500)		
11	Total		$ 8,302,405	$ 11,117,000	$ 8,302,405	$ 749,500		
12	Ten Year Average		$ 830,241	$ 1,111,700	$ 830,241	$ 74,950	$ 830,000 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		$ 830,241	$ 605,373	$ 830,241	$ 40,814	$ 830,000	$ 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	$ 1,389,006	$ (1,736,482)	$ 1,389,006	$ (2,301,041)	$ 1,388,765	$ (2,232,946)
19	Net adjustment to Arizona expense		$ (347,477)		$ (912,036)		$ (844,181)	
			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	$ 1,689,006	$ (2,246,651)	$ 1,689,006	$ (2,811,210)	$ 1,688,765	$ (2,743,115)
22	Net adjustment to Arizona expense		$ (557,646)		$ (1,122,205)		$ (1,054,350)	
			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.

Southwest Gas Corporation
Leased Aircraft Operating Costs

Test Year Ended April 30, 2007

Docket No. G-01551A-07-0504
Schedule C-13

Line No.	Description	Amount	Reference
		(A)	
	Leased Aircraft Expense Allocated to Arizona		
1	Normalized expense	$ 272,533	See line 13, below
2	Test year expense	$ 305,347	Note A
3	Adjustment to test year expense	$ (32,814)	Line 2 - Line 1

Notes and Source

A Response to STF-10-26

	Account	2004	2005	2006	2007	Average
		(B)	(C)	(D)	(E)	(F)
4	908				$ 1,800	$ 450
5	920	$ 208,306	$ 220,273	$ 259,841	$ 231,208	$ 229,907
6	921	$ 181,231	$ 225,338	$ 216,448	$ 193,086	$ 204,026
7	930.2	$ 28,500	$ 42,210	$ 53,300	$ 35,950	$ 39,990
8	931	$ 24,101	$ 27,026	$ 24,049	$ 25,134	$ 25,078
9	935	$ 679	$ 924	$ 4,297		$ 1,475
10	Totals	$ 442,817	$ 515,771	$ 557,935	$ 485,378	$ 500,476
11	Allocation to Paiute Pipeline				3.96%	$ (19,819)
12	Aircraft Expense Net of PP/SGTC					$ 480,657
13	Arizona allocation factor and normalized leased aircraft expense				56.70%	$ 272,533

Southwest Gas Company
El Paso Natural Gas Rate Case Expense

Docket No. G-01551A-07-0504
Schedule C-14

Test Year Ended April 30, 2007

Line No.	Year	Arizona Direct	System Allocable	Net of Paiute/SGTC Allocation of 3.96%	Arizona 4 Factor	Allocable to Arizona	Total Arizona
		(A)	(B)	(C)	(D)	(E)	(F) (A) + (E)
1	2005	$ 117,761	$ 37,438	$ 35,955	56.70%	$ 20,387	$ 138,148
2	2006	$ 800,809	$ 47,363	$ 45,487	56.70%	$ 25,791	$ 826,600
3	2007	$ 167,675	$ -	$ -	56.70%	$ -	$ 167,675
4	Total	$ 1,086,245	$ 84,801	$ 81,443		$ 46,178	$ 1,132,423

5	Total Arizona Amount of El Paso Natural Gas Rate Case Legal & Consulting Expense	$ 1,132,423
6	Normalized Over 3 years	3
7	Normalized Amount of El Paso Natural Gas Rate Case Legal & Consulting Expense	$ 377,474
8	Test Year Amount of El Paso Natural Gas Rate Case Legal & Consulting Expense	$ 854,889
9	Staff Adjustment to El Paso Natural Gas Rate Case Legal & Consulting Expense	$ (477,415)

Notes and Source

Amounts from SWG's response to ACC-STF-10-1

FERC 923

Southwest Gas Corporation
Depreciation and Amortization Annualization
New Intangible Plant Annualized Amortizations

New Amortizations Beginning Before 12/31/07

		Company Proposed Per Southwest Gas Adjustment No. 14				Per Staff - SWG Supp Rsps to STF-6-49 and STF-11-4			Staff Adjustments	
Line No.	Description	Estimated In-Service Date (A)	Estimated Asset Amount (B)	Service Life (C)	Annual Amortization (D)	Asset Amount (E)	Actual In-Service Date (F)	Annual Amortization (H)	Plant (I) E - B	Annual Amortization (J) H - D
1	Autocad Map 3D 2007	6/30/2007	$ 180,000	3 years	$ 60,000	$ 128,129	6/29/2007	$ 42,710	$ (51,871)	$ (17,290)
2	Pi Data Access	6/30/2007	$ 24,000	3 years	$ 8,000	$ 25,900	6/27/2007	$ 8,633	$ 1,900	$ 633
3	Receivables Software	6/30/2007	$ 105,000	3 years	$ 35,000	$ 76,084	6/29/2007	$ 25,361	$ (28,916)	$ (9,639)
4	Load Balancer	6/30/2007	$ 38,000	3 years	$ 12,667	$ 37,781	5/24/2007	$ 12,594	$ (219)	$ (73)
5	MacKinney VS/Cobol License	6/30/2007	$ 10,500	3 years	$ 3,500	$ 10,149	5/24/2007	$ 3,383	$ (351)	$ (117)
6	Citrix Presentation License	6/30/2007	$ 83,000	3 years	$ 27,667	$ 82,628	5/24/2007	$ 27,543	$ (372)	$ (124)
7	San Lefthand Network Expansion	6/30/2007	$ 15,500	3 years	$ 5,167	$ 15,489	5/24/2007	$ 5,163	$ (11)	$ (4)
8	EMRS/LMR Software Module	12/31/2007	$ 430,000	3 years	$ 143,333	$ -	N/A	$ -	$ (430,000)	$ (143,333)
9	EMRS Software	12/31/2007	$ 350,000	3 years	$ 116,667	$ -	after 12/31/07	$ -	$ (350,000)	$ (116,667)
10	Oracle UPK Licenses	12/31/2007	$ 250,000	3 years	$ 83,333	$ 189,398	12/17/2007	$ 63,133	$ (60,602)	$ (20,200)
11	Oracle PUI Licenses	12/31/2007	$ 210,000	3 years	$ 70,000	$ 172,400	8/27/2007	$ 57,467	$ (37,600)	$ (12,533)
11.01	Per Supplemental Response to STF-6-49							$ -		
11.02	ACD Reporting License					$ 20,678	8/27/2007	$ 6,893	$ 20,678	$ 6,893
11.03	Powerbroker License					$ 10,926	10/31/2007	$ 3,642	$ 10,926	$ 3,642
11.04	Tivoli Workload Scheduler					$ 110,638	10/31/2007	$ 36,879	$ 110,638	$ 36,879
11.05	Powerbroker License					$ 11,960	11/30/2007	$ 3,987	$ 11,960	$ 3,987
11.06	Trident OS/EM Licenses					$ 55,300	11/30/2007	$ 18,433	$ 55,300	$ 18,433
11.07	MAPX GIS Software					$ 35,030	12/17/2007	$ 11,677	$ 35,030	$ 11,677
11.08	Oracle Internet Licenses					$ 49,177	12/22/2007	$ 16,392	$ 49,177	$ 16,392
11.09	HP Licenses					$ 54,728	12/22/2007	$ 18,243	$ 54,728	$ 18,243
11.10	Ops Mgr Server Licenses					$ 61,285	12/22/2007	$ 20,428	$ 61,285	$ 20,428
11.11	WMS Test Project					$ 301,580	12/31/2007	$ 100,527	$ 301,580	$ 100,527
12	Total New Amortizations		$ 1,696,000		$ 565,333	$ 1,449,260		$ 483,088	$ (246,740)	$ (82,245)
13	4-Factor [2]		56.70%		56.70%	56.70%		56.70%	56.70%	56.70%
14	Net Adjustment after 4-Factor		$ 961,632		$ 320,544	$ 821,730		$ 273,911	$ (139,902)	$ (46,633)

Notes and Source
SWG amounts: Southwest's W/P Schedule C-2, Sheet 89, Adjustment No. 14
Staff amounts: Company's response to STF-11-4 and its supplemental responses to STF-6-49 and STF-11-4

Line 8: Per SWG's resposne to STF-1-4, the EMRS/LMR Module is still in CWIP
Line 9: EMRS Software not in service by 12/31/07 $ 195,120 1/28/2008

Southwest Gas Corporation
Gain on Sale of Utility Property Related to TEP Sundt Bypass

Test Year Ended April 30, 2007

Line No.	Description	Recorded Plant in Serice (A)	Recorded Accumulated Depreciation (B)	Net Book Value At Sales Date (C)	Tentative Sales Price (D)	Net Gain (E)
	Gain on Sale of Utility Property					
1	Metering facility	$ 182,093	$ (67,937)	$ 114,156	$ 398,381	$ 284,225
2	Piping	$ 28,526	$ (4,126)	$ 24,400	$ 350,000	$ 325,600
3	Total	$ 210,619	$ (72,063)	$ 138,556	$ 748,381	$ 609,825
	Sharing of Gain with Ratepayers					
4	Ratepayer sharing percent					50.0%
5	Ratepayer sharing amount of gain					$ 304,913
6	Normalization period, in years					3
7	Adjustment to pre-tax NOI for gain sharing					$ (101,600)

Notes and Source

Southwest's May 14, 2008 supplemental response to RUCO 7-2

Col.B: At March 31, 2008, the expected sales date. Derived based on the difference between Col.C and Col.A

Col.C: NBV at March 31, 2008, the expected sales date, per Southwest's supplemental response to RUCO 7-2

Col.E: Col.D - Col.C

L.4&5: Same gain sharing percent and normalization period as reflected for other gains on sale of utility property in Staff Schedule C-2

Southwest Gas Corporation
Depreciation for Plant Sold to TEP for Sundt Bypass

Test Year Ended April 30, 2007

Line No.	Description	Plant Amount (A)	Depreciation Rate (B)	Adjustment to Depreciation Expense (C)
1	Metering facility	$ (182,093)	1.98%	$ (3,605)
2	Piping	$ (28,526)	5.30%	$ (1,512)
3	Adjustment to Depreciation Expense	$ (210,619)		$ (5,117)

Notes and Source
Col.A: Schedule B-8
Col.B: SWG workpapers for Schedule C-2, Adj. 14, sheet 81 of 90
Col.C: Col.A x Col.B

FERC 403

Southwest Gas Corporation
Docket No. G-01551A-07-0504
Attachment RCS-8
Copies of SWG's Responses to Data Requests, Workpapers and Other Documents Referenced in the Surrebuttal Testimony and Schedules of Ralph C. Smith

Data Request/ Workpaper No.	Subject	Confidential	No. of Pages	Page No.
STF-13-21	Yuma Manors System Improvement Project	No	2	2 - 3
STF-13-11	Uncollectibles	No	1	4
STF-6-49	Intangible Plant (03/20/08 Supp)	No	4	5 - 8
STF-11-4	Amortizations	No	3	9 - 11
STF-13-12	Intangible Plant	No	1	12
RUCO-7-2	TEP Bypass without attachments (05/14/08 Supp)	No	2	13 - 14
STF-1-78	Payroll, Incentive Programs (03/25/08 Supp)	No	2	15 - 16
RUCO-1-10	Employee Incentives (03/25/08 Supp)	No	2	17 - 18
STF-13-13	Injuries and Damages	No	6	19 - 24
STF-13-14	Injuries and Damages	No	8	25 - 32
STF-13-15	Injuries and Damages	No	1	33
STF-13-16	Injuries and Damages	No	1	34
STF-13-17	Injuries and Damages	No	1	35
STF-13-19	Injuries and Damages	No	6	36 - 41
STF-13-20	Injuries and Damages	No	23	42 - 64
STF-6-42	Management Incentive Compensation (3/25/08 Supp)	No	2	65 - 66
	UNS Gas-AZ Sales Tax Payment Lag	No	1	67
	UNS Electric-AZ Sales Tax Payment Lag	No	1	68
	TEP Lead/Lag Study-AZ Sales Tax Payment Lag	No	1	69
STF-11-3 Attach	Illustrative Samples of SWG's AZ City Sales Tax Returns	No	10	70 - 79
STF-11-3 Attach	Illustrative Samples of SWG's AZ State Use and Severance Tax Return	No	4	80 - 83
	Total Pages Including this Page		83	

313-021

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
*** * ***
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-13
(ACC-STF-13-1 THROUGH ACC-STF-13-25)

DOCKET NO.:	G-01551A-07-0504
COMMISSION:	ARIZONA CORPORATION COMMISSION
DATE OF REQUEST:	MAY 13, 2008

Request No. ACC-STF-13-21:

Yuma Manors. Please identify all of the rate base and operating expense adjustments that Southwest would propose relating to the $320,779 identified in Mr. Mashas' rebuttal testimony at page 13.

Respondent: Revenue Requirements

Response:

Attached is the calculation of the reduction to rate base ($320,779), depreciation ($15,175) and property tax ($8,499) associated with the $320,779 of overtime, shift premiums, etc., incurred in replacing the Yuma Manors steel pipe system that were identified in the rebuttal testimony of Robert Mashas.

SOUTHWEST GAS CORPORATION
ARIZONA
YUMA MANORS
ADJUSTMENT TO RATE BASE, DEPRECIATION AND PROPERTY TAX EXPENSE
RESPONE TO STAFF DATA REQUEST 13.21

Line No.	Description		Rate Base	Deprection Rate		Deprection Expense	Line No.
	(a)		(b)	(c)		(d)	
	Distribution Plant						
1	Mains	$	(123,397)	3.82%	$	(4,714)	1
2	Services		(197,382)	5.30%		(10,461)	2
3	**Reduction to Gross Plant In-Service (Rate Base)**	$	**(320,779)**				3
4	**Reduction to Depreciation Expense**				$	**(15,175)**	4
5	Reduction to Property Taxable Plant	$	(320,779)				5
6	Property Tax Assessment Ratio		23%				6
7	Assessed Property	$	(73,779)				7
8	Property Tax Rate		0.1152				8
9	**Reduction to Property Tax Expense**	$	**(8,499)**				9

313-011

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-13
(ACC-STF-13-1 THROUGH ACC-STF-13-25)

DOCKET NO.:	G-01551A-07-0504
COMMISSION:	ARIZONA CORPORATION COMMISSION
DATE OF REQUEST:	MAY 13, 2008

Request No. ACC-STF-13-11:

Uncollectibles. Refer to Randi Aldridge's rebuttal testimony at page 5-6. (a) Please identify the amount of Uncollectibles Expense SWG is now recommending. (b) Please include all supporting documentation and calculations for that amount. (c) Does SWG agree with Staff's adjustments for Customer Deposits and Customer Advances? If not, explain fully why not.

Respondent: Revenue Requirements

Response:

a. Southwest's request for uncollectibles expense is unchanged from its initial filing. Southwest continues to request the test year recorded uncollectibles expense of $2,977,729.

b. Please see Schedule C-1, Sheet 3, Line 26.

c. Southwest agrees with the rationale employed by Staff, in that Staff is using a number for customer deposits and customer advances that it believes best reflects the conditions on a going-forward basis, which is the same rationale used by the Company with respect to its uncollectibles expense. Furthermore, the Company believes the Commission should be consistent with respect to these adjustments and the rationale used by the parties. As such, if the Commission approves Southwest's rationale for its uncollectibles expense, Southwest would not object to the rationale of Staff with respect to the adjustments for customer deposits and customer advances.

254-049

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-6-49:

System Allocable miscellaneous intangible plant (Account 303). Refer to Ms. Aldridge's direct testimony at page 18.

a. Please provide a detailed itemization, with amounts and descriptions, of all of the actual projects closed to plant after the end of the test year and by December 31, 2007.

b. For each project listed in response to part a, please provide the Company's proposed amortization period, and the basis for such amortization period.

c. Please provide a detailed listing of all projects with an amortization period expiring December 31, 2007 or earlier that the Company has removed from rate base.

d. Please provide a detailed listing of all projects with an amortization period scheduled to expire between December 31, 2007 and June 30, 2008.

e. Please provide a listing and descriptions of all amortizable projects budgeted to be placed into service between December 31, 2007 and June 30, 2008, and the estimated in-service cost and date of each.

Respondent: Revenue Requirements

Response: ***SUPPLEMENTAL ATTACHMENT – MARCH 20, 2008***

a. and b. Southwest's books for December 2007 have not yet been closed. Southwest will provide a supplemental response after the data becomes available in late-February or early-March 2008.

(Continued on Page 2)

<u>Response to STF-6-49</u>: *(continued)*

c. A detailed listing of the projects with an amortization period expiring December 31, 2007 or earlier, that the Company removed from rate base was provided in WP Schedule C-2, Adjustment No. 14, Sheet 86, Lines 24-50, and Sheet 87, Lines 1-11.

d. A list of all projects with an amortization period scheduled to expire between December 31, 2007 and June 30, 2008 was provided in WP Schedule C-2, Adjustment No. 17, Sheet 87. The projects are sorted by expiration date; please see the "Expiration Date" column.

e. There are several projects that were budgeted to be placed into service during 2008, but whether these projects will close before or after June 30, 2008 is unknown at this time. Southwest will update this response if and when more information becomes available.

Attachment Supplemental STF-6-49a Sheet 1 of 1

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
ACCOUNT 303 - PROJECTS CLOSED BETWEEN 5/1/07 THROUGH 12/31/07
UPDATE: RESPONSE TO STF-6-49

Description	Asset ID	In-Service Date	Asset Balance	Monthly Expense	Annual Expense
Load Balancers	07001151	05/24/07	$ 37,781	$ 1,049	$ 12,588
Comm Vault Licences	07001149	05/24/07	10,419	289	3,468
Citrix Presentation Licenses	07001152	05/24/07	82,628	2,295	27,540
Lefthand Network Expansion	07001150	05/24/07	15,489	430	5,160
PI Data Access	07001456	06/27/07	25,900	719	8,628
Autocad Training	07001455	06/29/07	128,129	3,559	42,708
Receivables Software	07001457	06/29/07	76,084	2,113	25,356
Oracle E Business Licenses	07002004	08/27/07	172,400	4,789	57,468
ACD Reporting License	07002005	08/27/07	20,678	574	6,888
Powerbroker License	07002910	10/31/07	10,926	304	3,648
Tivoli Workload Scheduler	07002911	10/31/07	110,638	3,073	36,876
Powerbroker License	07002913	11/30/07	11,960	332	3,984
Trident OS/EM Licenses	07002914	11/30/07	55,300	1,536	18,432
UPK Software	07002912	12/17/07	189,398	5,261	63,132
MAPX GIS Software	07002915	12/22/07	35,030	973	11,676
Oracle Internet Licenses	07003142	12/22/07	49,177	1,366	16,392
HP Licenses	07003143	12/22/07	54,728	1,520	18,240
Ops Mgr Server Licenses	07003144	12/22/07	61,285	1,702	20,424
WMS Test Project	07003141	12/31/07	301,580	8,377	100,524
			$ 1,449,530	$ 40,261	$ 483,132

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
ACCOUNT 303 - PROJECTS IN CWIP EXPECTED TO CLOSE BY 6/30/08
UPDATE: RESPONSE TO STF-6-49

	Work Order	CWIP Balance @ 2/29/08	Est Amount	Est Service
EMRS/LMR Software Module	52-C5100055	$ 88,406	$ 430,000	3 years
Purchase Chardware Software	52-C7100056	103,854	300,000	3 years
Purchase Questionmark Software	52-C7100067	26,130	12,500	3 years
WMS/EMRS Interface Phase III	52-C8100004	43,395	300,000	3 years
Sun Memory for Oracle	61-C7100131	9,138	9,000	3 years
Microsoft Licenses	61-C7100132	74,937	105,970	3 years
Visco and Office Licenses	61-C7100133	106,726	106,726	3 years
		$ 452,586	$ 1,264,196	

298-004

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504

* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-11
(ACC-STF-11-1 THROUGH ACC-STF-11-15)

DOCKET NO.:	G-01551A-07-0504
COMMISSION:	ARIZONA CORPORATION COMMISSION
DATE OF REQUEST:	MARCH 3, 2008

Request No. ACC-STF-11-4:

Amortizations. Refer to Southwest's W/P Schedule C-2, Sheet 89, Adjustment No. 14. For each item of new amortization listed in the following table, please provide the following information: (1) the actual cost, (2) the actual date placed into service, and (3) the documentation relied upon for the amortization period/service life:

New Amortizations beginning before 12/31/07

Description [1]	Annual Amortization	CWIP Balance @4/30/07	Estimated In-Service Date	Estimated Asset Amount	Service Life
(a)	(b)	(c)	(d)	(e)	(f)
Autocad Map 3D 2007	$ 60,000	$ 125,879	6/30/2007	$ 180,000	3 years
Pi Data Access	8,000	25,900	6/30/2007	24,000	3 years
Receivables Software	35,000	57,238	6/30/2007	105,000	3 years
Load Balancer	12,667	37,780	6/30/2007	38,000	3 years
MacKinney VS/Cobol License	3,500	10,420	6/30/2007	10,500	3 years
Citrix Presentation License	27,667	82,628	6/30/2007	83,000	3 years
San Lefthand Network Expansion	5,167	15,489	6/30/2007	15,500	3 years
EMRS/LMR Software Module	143,333	88,406	12/31/2007	430,000	3 years
EMRS Software	116,667	99,510	12/31/2007	350,000	3 years
Oracle UPK Licenses	83,333	0	12/31/2007	250,000	3 years
Oracle PUI Licenses	70,000	0	12/31/2007	210,000	3 years
Total New Amortizations	$ 565,333	$ 543,250		$ 1,696,000	

Respondent: Revenue Requirements

Response:

Please see the attached worksheet for the actual in-service amounts and dates for the projects in the above table. The EMRS/LMR Module is still in CWIP.

(Continued on Page 2)

Response to STF-11-4: *(continued)*

Generally, Southwest assigns a three-year service life to small software projects or software license purchases under $1 million. This assignment is based on seasoned professional judgment, and there is no documentation Southwest relied upon to determine a service life for the above projects.

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
INTANGIBLE PLANT IN CWIP AT 4/30/07
ACTUAL COST AND IN-SERVICE DATE

	Description [1]	In-Service Date	Asset Amount	
	(a)	(b)	(c)	
1	Autocad Map 3D 2007	6/29/2007	$ 128,129	1
2	Pi Data Access	6/27/2007	25,900	2
3	Receivables Software	6/29/2007	76,084	3
4	Load Balancer	5/24/2007	37,781	4
5	MacKinney VS/Cobol License	5/24/2007	10,149	5
6	Citrix Presentation License	5/24/2007	82,628	6
7	San Lefthand Network Expansion	5/24/2007	15,489	7
8	EMRS/LMR Software Module	N/A	[1]	8
9	EMRS Software	1/28/2008	195,120	9
10	Oracle UPK Licenses	12/17/2007	189,398	10
11	Oracle PUI Licenses	8/27/2007	172,400	11

[1] This project is still in CWIP.

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-13
(ACC-STF-13-1 THROUGH ACC-STF-13-25)

<u>DOCKET NO.</u>: G-01551A-07-0504
<u>COMMISSION</u>: ARIZONA CORPORATION COMMISSION
<u>DATE OF REQUEST</u>: MAY 13, 2008

<u>Request No. ACC-STF-13-12</u>:

Intangible plant. Refer to Aldridge rebuttal Q/A 31. (a) Please identify which intangible projects recorded as Plant as of December 31, 2007 by SWG that SWG alleges that Staff did not include. (b) For each such not included intangible project, please state fully SWG's understanding of why it was not included by Staff.

<u>Respondent</u>: Revenue Requirements

<u>Response</u>:

a. Please refer to the Company's response to STF-6-49 for a complete list of miscellaneous intangible plant projects closed from May 1, 2007 through December 31, 2007. The items that Staff did not include when updating intangible plant through December 31, 2007 were: ACD Reporting, Powerbroker (2 line items), Tivoli Workload, Trident, MAPX GIS, Oracle Internet, HP, Ops Mgr Server, and WMS Test Project, totaling $738,228. Southwest originally requested to include $1,696,000 in its adjustment. After the update to actual, that amount is reduced to $1,449,530, not $737,958 as Staff proposes (amounts are original asset balances, before allocation to Arizona).

b. Southwest does not understand why Staff did not include these projects in its update of miscellaneous intangible plant to December 31, 2007, as they were included in the response to STF-6-49.

302-002

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-7-2:

TEP Bypass

Refer to the testimony on page 8 of the testimony of James Cattanach regarding the TEP bypass and provide the following information:

a) Identify each plant item that will be retired as a result of the TEP bypass. Provide dollar amounts as well as plant account numbers;

b) Identify each plant item that will be sold as a result of the TEP bypass. Provide book value, plant account numbers and actual or estimated sales price; and

c) Identify all test year O&M costs that will be avoided as a result of the bypass.

Respondent: Plant Accounting, Key Accounts, Pricing

Response: ***SUPPLEMENTAL RESPONSE – MAY 14, 2008***

Please find attached the signed Sundt Generating Station Interconnect Purchase and Sale Agreement between TEP, El Paso, and Southwest. This document completed the sale of the interconnection facilities from Southwest to TEP and El Paso for the bypass of the Sundt Generating Station from Southwest's system. As of April 1, 2008, Southwest no longer provided service to TEP's Sundt Generating Station.

(Continued on Page 2)

Response to RUCO-7-2: *(continued)*

Original Response:

A) A high pressure metering facility and 1,867 feet of 12-inch steel pipe will be retired as a result of the TEP bypass. The original amount for the metering facility to be retired is $182,093 and the retirement amount for the piping to be retired is $28,526. The net book value as of April 30, 2007, for the metering facility is $151,351 and the net book value of the piping is $25,439. The net book value as of March 31, 2008, the expected sales date, for the metering facility is $144,156 and the net book value of the piping is $24,440.

B) The facilities described in the response to a) are anticipated to be sold as a result of the TEP bypass. Although the sales agreement between Southwest, TEP, and El Paso is not final, the tentative sales prices are $398,381 and $350,000 for the Alternate Feed Line (pipe) and Meter Set Assembly (MSA), respectively.

C) Attached is a worksheet that provides the estimated annual maintenance related to the facilities to be sold as a result of the TEP bypass.

241-078

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504

* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 THROUGH ACC-STF-1-99)

DOCKET NO.:	G-01551A-07-0504
COMMISSION:	ARIZONA CORPORATION COMMISSION
DATE OF REQUEST:	NOVEMBER 9, 2007

Request No. STF-1-78:

Payroll, Incentive Programs. Please provide complete copies of any bonus programs or incentive award programs in effect at the Company for the most recent three years. Identify all incentive and bonus program expense incurred in 2005, 2006 and 2007. Identify the accounts charged. Identify all incentive and bonus program expense charged or allocated to the Company from affiliates in 2005, 2006 and 2007.

Respondent: Human Resources / Revenue Requirements

Response: ***CORRECTED SUPPLEMENTAL ATTACHMENT – MARCH 25 2008***

SUPPLEMENTAL ATTACHMENT - DECEMBER 17, 2007

The Management Incentive Plan and Special Incentive Plan are discussed in the Company's response to data request no. STF-1-49. The current document for the Service Planning Quality Incentive Award is attached as Attachment A. The expense incurred in 2005, 2006, and for the test year ended April 2007 for each program is attached as Attachment B. Please note the amounts shown for "Corporate" are before 4-Factor allocation to Arizona.

There are no incentive or bonus program expenses allocated from affiliates.

Attachment
STF-1-78

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
INCENTIVE PROGRAMS
IN RESPONSE TO DATA REQUEST NO. STF-1-78
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

243-010

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
*** * ***

RESIDENTIAL UTILITY CONSUMER OFFICE
DATA REQUEST NO. RUCO-1
(RUCO-1-1 THROUGH RUCO-1-22)

DOCKET NO.:	G-01551A-07-0504
COMMISSION:	ARIZONA CORPORATION COMMISSION
DATE OF REQUEST:	NOVEMBER 27, 2007

Request No. RUCO-1-10:

Employee Incentives

Please provide a description of each current employee incentive program. For each program offered, provide the following additional information:

a) Employee eligibility;

b) Cost incurred in each year 2004, 2005, 2006, and the test year; and

c) The account where each expense identified in part b) was recorded.

Respondent: Human Resources

Response: ***SUPPLEMENTAL ATTACHMENT – MARCH 25, 2008***

A description of each current employee incentive program was provided in the Company's response to data request nos. STF-1-49 and STF-1-78, provided in response to data request no. RUCO-1-6.

Please see the attached schedule for the information requested in parts a) through c). Please note that amounts shown for "Corporate" are before 4-Factor allocation to Arizona.

**Attachment
RUCO-1-10
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 exempts with at least 6 mos. service	2004	$ 150,700		920
	2005	148,450		920
	2006	154,500		920
	12ME Apr 07	151,250		920
Service Planning Quality Incentive Award	2004	$ 168,035	$ 431,425	903
Eligiblity: service planners, their supvs and managers, industrial gas engineers	2005	140,171	465,150	903
	2006	143,865	367,534	903
	12ME Apr 07	137,522	290,004	903
Stock Option Expense				
Expense that must be recognized on Southwest's books	2004	-		n/a
	2005	-		n/a
	2006	1,493,694		920
	12ME Apr 07	1,507,520		920

313-013

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
***
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-13
(ACC-STF-13-1 THROUGH ACC-STF-13-25)

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MAY 13, 2008

Request No. ACC-STF-13-13:

Injuries and damages. Refer to Bob Mashas rebuttal testimony at page 3, lines 1-3: However, Staff excludes a $10 million dollar expense recorded in 2006 related to an incident that occurred in Arizona in 2005. For purposes of responding to this question, please assume that the cost to SWG for the May 2005 incident should be excluded. Under that hypothetical, please show in detail what amount of self-insurance expense SWG would propose.

Respondent: Revenue Requirements

Response:

Attached is a file that calculates the Company's filed proposed Adjustment No. 10, Injuries and Damages, excluding the May 2005 incident as requested above.

The Company's filed Adjustment No. 10, would have been $1,901,727 in place of the $2,228,455 shown on filed Schedule C-2, Sheet 1, Line 15, Column (f). The difference is $326,728 and is calculated as follows:

Self-Insured Retention (Up to $1 million per incident)	$1,000,000
Amount of claim included in calculation ($5 million maximum)	5,000,000
Total Impact of May 2005 Incident	$6,000,000
Number of Years	10
Ten Year Average	$600,000
Less: Paiute Allocation @ 3.96%	23,760
Net Subject to "4" Factor Allocation	$576,240
Arizona "4" Factor Allocation	56.70%
Arizona Allocation	$326,728

SOUTHWEST GAS CORPORATION
ARIZONA
SELF-INSURED RETENTION NORMALIZATION
(TEN YEAR AVERAGE $5.0 MILLION AGGREGATE)
ADJUSTMENT NO. 10 EXCLUDING MAY 2005 INCIDENT
RESPONSE TO STF-13.13

Line No.	Description (a)	Reference (b)	Allocation Percent (c)	System Allocable (d)	10-Year Total (d)	Total Arizona Accrual (e)	Line No.
	Claims Paid	WP C-2, Adj. 10					
1	< $1,000,000				$ 7,698,138		1
2	At $1,000,000				7,000,000		2
3	> $1,000,000 < $5,000,000				11,963,879		3
4	Total Claims Paid				$ 26,662,017		4
5	10 Year Average					$ 2,666,202	5
6	Less FERC Allocation @ 3.96%	C-1, Sh 18	3.96%			(105,582)	6
7	System Allocable					$ 2,560,620	7
8	Arizona 4-Factor	C-1, Sh 19	56.70%			$ 1,451,872	8
9	Recorded Amounts			$ 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 19	56.70%			$ 108,909	12
	Arizona Direct (Reclass from Acct 923)		100.00%				
13	Arizona Direct		100.00%			(558,765)	13
14	Total Recorded Arizona					$ (449,856)	14
15	Total Adjustment Including May 2005 Incident and $300,000 reclass.					$ 1,901,727	15

SOUTHWEST GAS CORPORATION
ARIZONA
ALLOCATION OF SELF-INSURANCE (10 YEAR AVERAGE)
ADJUSTMENT NO. 10 EXCLUDING MAY 2005 INCIDENT
RESPONSE TO STF-13.13

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	4,000,000	0	7,000,000	2
3	At $5MM Aggregate	0	0	0	0	997,774	10,966,105	0	11,963,879	3
4		$ 0	$ 177,500	$ 24,375	$ 2,350,143	$ 3,192,774	$ 20,775,970	$ 141,255	$ 26,662,017	4
	Total Company Experience									
5	10 Year Average	$ 0	$ 17,750	$ 2,438	$ 235,014	$ 319,277	$ 2,077,597	$ 14,126	$ 2,666,202	5
6	Less: Paiute & SGTC at 3.96%								(105,582)	6
7	Net System Allocable								$ 2,560,620	7
8	Four Factor %		7.94%	2.32%	27.29%	5.74%	56.70%			8
9	Allocation of Self-Insurance	$ 105,582	$ 203,313	$ 59,406	$ 698,793	$ 146,980	$ 1,451,872	$	$ 2,560,620	9
10					Arizona Allocation Percent				56.70%	10
11					Arizona Allocation				$ 1,451,872	11
					Less: Test Year Reclass Acct 923					
					Less: Recorded Sytem Allocable				108,909	
12					Less: Test Year Recorded Arizona Direct				(558,765)	12
13					**Arizona Adj. to Exclude May 2005 Incident**				$ 1,901,727	13

SOUTHWEST GAS CORPORATION
ARIZONA
TEN YEAR HISTORY OF LIABILITY CLAIMS
ADJUSTMENT NO. 10 EXCLUDING MAY 2005 INCIDENT
RESPONSE TO STF-13.13

Line No.	Year (a)	Paiute (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	2006	**Acctg. Reclass**							0	11
12	2007				5,001		129,059		134,060	12
13		$ 0	$ 177,500	$ 24,375	$ 1,350,143	$ 195,000	$ 5,809,865	$ 141,255	$ 7,698,138	13
					$1,000,000 Self-Insurance Per Claim					
14	1997						1,000,000		1,000,000	14
15	1998					1,000,000	2,000,000		3,000,000	15
16	1999								0	16
17	2000					1,000,000			1,000,000	17
18	2001								0	18
19	2002								0	19
20	2003						1,000,000		1,000,000	20
21	2004						0		0	21
22	2005				1,000,000		**May 2005**		1,000,000	22
23	2006								0	23
24	2007								0	24
25		$ 0	$ 0	$ 0	$ 1,000,000	$ 2,000,000	$ 4,000,000	$ 0	$ 7,000,000	25
					$5 Million Agregate above $1,000,000 Self-Insurance Per Claim					
26	1997						2,726,235		2,726,235	26
27	1998					6,272	1,739,870		1,746,142	27
28	1999								0	28
29	2000					991,502			991,502	29
30	2001								0	30
31	2002								0	31
32	2003						5,000,000		5,000,000	32
33	2004						1,500,000		1,500,000	33
34	2005						**May 2005**		0	34
35	2006								0	35
36	2007								0	36
37		$ 0	$ 0	$ 0	$ 0	$ 997,774	$ 10,966,105	$ 0	$ 11,963,879	37
38	Total	$ 0	$ 177,500	$ 24,375	$ 2,350,143	$ 3,192,774	$ 20,775,970	$ 141,255	$ 26,662,017	38

[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
ARIZONA
SELF-INSURANCE FOR THE FIRST $5 MILLION ABOVE $1 MILLION OF SELF-INSURED RETENTION
APPLICABLE CLAIMS FOR THE PERIOD 1997 THROUGH APRIL 2007
HYPOTHETICAL RESTATEMENT OF HISTORY AS IF NEW POLICY AND PRACTICE WAS IN PLACE
ADJUSTMENT NO. 10 EXCLUDING MAY 2005 INCIDENT
RESPONSE TO STF-13.13

Line No.	Description	District	Year	Incident Date	Total Payout	Less Expense	Indemnity Payments	SWG SIR < $1MM	SWG SIR SIR @$1MM	$5MM Pool	Insurance Carrier	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
1	Arizona	42	1997	12-Sep-97	$ 3,726,235	$ 1,226,235	$ 2,500,000	$ 0	$ 1,000,000	$ 2,726,235	$ 0	1
2	Arizona	42	1998	15-Jan-98	1,320,903	475,904	844,999	0	1,000,000	320,903	0	2
3	Northern Nevada	26	1998	04-Feb-98	1,006,272	309,029	697,243	0	1,000,000	6,272	0	3
4	Arizona	36	1998	14-Sep-98	2,418,967	638,235	1,780,732	0	1,000,000	1,418,967	0	4
6	Northern Nevada	23	2000	26-Oct-00	1,991,502	756,278	1,235,224	0	1,000,000	991,502	0	6
9	Arizona	42	2003	02-Jan-03	16,604,129	0	16,604,129	0	1,000,000	5,000,000	10,604,129	9
10	Arizona	42	2004	02-Jan-03	1,500,000	0	1,500,000	0	0	1,500,000	0	10
11	Southern Nevada	21	2005	01-Dec-99	1,000,000	0	1,000,000	0	1,000,000	0	0	11
12	**Removed Per ACC Request**	36	2005	27-May-05			0	0			0	12
13	10 Yr. Total				$ 29,568,008	$ 3,405,681	$ 26,162,327	$ 0	7,000,000	$ 11,963,879	$ 10,604,129	13
14	10 Yr. Average				$ 2,956,801	$ 340,568	$ 2,616,233	$ 0	$ 700,000	$ 1,196,388	$ 1,060,413	14
					Southwest Gas Liability							
	Rate Jurisdiction				Total Payout	Less Expense	Indemnity Payments	< $1MM	$1MM SIR	$5MM S-I	Insurance Carrier	
15	Paiute				$ 0	$ 0	$ 0	$ 0	0	$ 0	$ 0	15
16	So. Ca.				0	0	0	0	0	0	0	16
17	No. Ca.				0	0	0	0	0	0	0	17
18	No. Nv.				2,997,774	1,065,307	1,932,467	0	2,000,000	997,774		18
19	So. Nv.				1,000,000	0	1,000,000	0	1,000,000	0		19
20	Az.				25,570,234	2,340,374	23,229,860	0	4,000,000	10,966,105	10,604,129	20
21	Total				$ 29,568,008	$ 3,405,681	$ 26,162,327	0	7,000,000	$ 11,963,879	$ 10,604,129	21
22	Arizona Percent of Total				86.5%	68.7%	88.8%	0.0%	57.1%	91.7%	100.0%	22

Docket No. G-01551A-07-0504
Attachment RCS-[illegible]
Page 23 of [illegible]

STF-13-13
Sheet 4 of 5

SOUTHWEST GAS CORPORATION
ARIZONA
SELF-INSURANCE FOR THE FIRST $5 MILLION ABOVE $1 MILLION OF SELF-INSURED RETENTION
APPLICABLE CLAIMS FOR THE PERIOD MAY 1997 THROUGH APRIL 2007
HYPOTHETICAL RESTATEMENT OF HISTORY AS IF NEW POLICY AND PRACTICE WAS IN PLACE
ADJUSTMENT NO. 10 EXCLUDING MAY 2005 INCIDENT

RESPONSE TO STF-13.13

Line No.	Description	District	Incident Date	Total Payout	Less Expense	Indemnity Payments	SWG SIR	$5MM Pool	Insurance Carrier	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
1	Arizona	42	12-Sep-97	3,726,235	1,226,235	2,500,000	1,000,000	2,726,235	0	1
2	Arizona	42	15-Jan-98	1,320,903	475,904	844,999	1,000,000	320,903	0	2
3	Northern nevada	26	4-Feb-98	1,006,272	309,029	697,243	1,000,000	6,272	0	3
4	Arizona	36	14-Sep-98	2,418,967	638,235	1,780,732	1,000,000	1,418,967	0	4
5	Northern nevada	23	26-Oct-00	1,991,502	756,278	1,235,224	1,000,000	991,502	0	5
6	Arizona	42	2-Jan-03	16,604,129		16,604,129	1,000,000	5,000,000	10,604,129	6
7	Arizona	42	1-May-04	1,500,000		1,500,000		1,500,000	0	7
	Southern Nevada	21	1-Dec-99	1,000,000	0	1,000,000	1,000,000	0	0	
8	**Removed Per ACC Request**	36				0			0	8
9	10 Yr Total			$ 29,568,008	$ 3,405,681	$ 26,162,327	$ 7,000,000	$ 11,963,879	$ 10,604,129	9

Line No.	Rate Jurisdiction	Southwest Gas Liability: Total Payout	Less Expense	Indemnity Payments	$1MM SIR	$5MM S-I	Insurance Carrier	Line No.
10	Paiute	$ 0	$ 0	$ 10	$ 0	$ 0	$ 0	10
11	So. Ca.	0	0	11	0	0	0	11
12	No. Ca.	0	0	12	0	0	0	12
13	No. Nv.	2,997,774	1,065,307	1,932,467	2,000,000	997,774	0	13
14	So. Nv.	1,000,000	0	1,000,000	1,000,000	0	0	14
15	Az.	25,570,234	2,340,374	23,229,860	4,000,000	10,966,105	10,604,129	15
16	Total	$ 29,568,008	$ 3,405,681	$ 26,162,360	7,000,000	$ 11,963,879	$ 10,604,129	16
17	Arizona Percent of Total	86.5%	68.7%	88.8%	57.1%	91.7%	100.0%	17

313-014

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
*** * ***
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-13
(ACC-STF-13-1 THROUGH ACC-STF-13-25)

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MAY 13, 2008

Request No. ACC-STF-13-14:

Injuries and damages. Refer to Bob Mashas' rebuttal testimony on injuries and damages. (A) Please identify exactly where in the prior Southwest rate case, the Company informed the Commission about the cost of the May 2005 incident. (B) Please identify the last time prior to May 2005 when the Company had experienced a similar level of cost to the self-insured cost that was incurred by Southwest for the May 2005 incident. (C) Please identify about how many years, on average, when Southwest anticipates experiencing another incident as costly to the company as the May 2005 gas leak fire. (D) Does the Company view the May 2005 gas leak fire cost as a nonrecurring event? If not, please identify approximately when and in what amounts the Company anticipates such an incident will reoccur in the future.

Respondent: Revenue Requirements

Response:

(a) Please see response ot Staff Data Request No STF-13.20.

(b) January 2003.

(c) Including the May 2005 incident, the actual experience during the 17-year period (1991-2007) included four such major incidents, or one every four years.

(d) No. Please reference (b) and (c) above. The issue is not whether an incident as large as the May 2005 will occur, but whether there is a likelihood of an incident(s) with an expense greater than $1 million with an aggregate additional expense up to $5 million above the $1 million self-insured retention. The three incidents referenced above, along with the May 2005 incident, are examples of such occurrences.

(Continued on Page 2)

Response to Request No. ACC-STF-13-14: *(continued)*

Attached are two files that provide the information included in the Company's last general rate case, where the treatment of using all jurisdictional self-insured retentions as System Allocable expense and the introduction of the self-insured aggregate was first presented in Southwest ratemaking. The first file includes the Company's filed Schedule C-2, Adjustment No. 10, (14-year average) and the workpapers supporting that adjustment. Workpaper Sheet No. 2, shows that there were ten incidents that exceed the $1 million self-insured retention, two exceeded $10 million aggregate (one in 1993 and one in 2003) and another one in 1993 $8.8 million) exceed $5 million but less than $10 million. All of the above are examples of costs that are likely to occur within this component of the injuries and damages expense. The schedule clearly shows that no one specific year is indicative of a going forward expectation of expense. Thus it is reasonable to use a 10-year average in order to smooth the expense to a reasonably expected level during the going-forward rate effective period.

The second file recalculates the Company's adjustment using a 10-year average. The Staff proposed, and the Company agreed, that a 10-year average was reasonable. Also attached are copies of Staff witness James Dorf's Surrebuttal and Surrebuttal Schedule JJD-15, where he proposed a 10-year average of all jurisdictional self-insured claims as System Allocable including a restatement of the 10-year year experience to reflect the then $10 million aggregate. Finally, attached is a file that restates the Company's history using only the most recent 10-years. This schedule ties to the Staff's proposed adjustment. Please note that the January 2003 claim was restated to reflect the $10 million aggregate used in the last rate case. In the Company's current application, the January 2003 claim is restated to reflect the current $5 million aggregate.

The file that restates the prior rate case to the Staff's 10-year average includes additional information in the Adjustment No. 10 format that compares the numbers used in the current case to those that were used in the prior rate case. In both instances the total claims shown on line 4 (claims below $1 million, $1 million and the $10 million/$5 million aggregate) are nearly indentical. The FERC and Arizona allocations have decreased slightly, but the Arizona allocated amount shown on line 8 are nearly the same. The 2004 number was $1,731,312 while the 2007 is $1,762,263. The number that has changed dramatically is the recorded number shown on line 14. During the last test year the recorded was a positive $562,552, while the current test year is a negative $749,856. Using accrual accounting it is possible to have one 12-month period with a negative number and another period with a large positive number. This is why the Company believes that using a relatively large (10-year) period of actual claims paid rather than recorded accrual periods is the appropriate method to establish a normalized level for a potential volatile year-to-year expense. In the last rate case the required adjustment was $1,168,760 since the recorded number was a positive $562,552. In the current case, the $2,512,119 adjustment to recorded expense appears to be significantly larger when in fact the end result ($1,762,263) is only $30,951 ($1,762,263 - $1,731,312) larger than the last rate case.

SOUTHWEST GAS CORPORATION
ARIZONA
SELF-INSURED RETENTION NORMALIZATION
ADJUSTMENT NO. 10
DOCKET NO. G-01551A-04-0876
RESPONSE TO STAFF-13.14

Line No.	Description (a)	Reference (b)	Allocation Percent (c)	System Allocable (d)	14-Year Total (d)	Total Arizona Accrual (e)	Line No.
	Claims Paid	WP C-2, Adj. 10					
1	< $1,000,000				$ 8,557,891		1
2	At $1,000,000				10,000,000		2
3	> $1,000,000 < $10,000,000				36,347,300		3
4	**Total Claims Paid**				**$ 54,905,191**		4
5	**14 Year Average**					**$ 3,921,799**	5
6	Less FERC Allocation @4.29%	C-1, Sh 18	4.29%			(168,245)	6
7	**System Allocable**					**$ 3,753,554**	7
8	**Arizona 4-Factor**	C-1, Sh 19	57.58%			**$ 2,161,296**	8
9	Recorded Amounts			$ 275,000			9
10	Less FERC Allocation @4.29%	C-1, Sh 18	4.29%	(11,798)			10
11	Net System Allocable			$ 263,203			11
12	Arizona 4-Factor	C-1, Sh 19	57.58%			$ 151,552	12
13	Arizona Direct		100.00%			411,000	13
14	**Total Recorded Arizona**					**$ 562,552**	14
15	**Total Adjustment**					**$ 1,598,744**	15

Note: This sheet was included in the rate case filing as Schedule C-2, Adjustment C-10. The bolding in lines 1-15 was not included in the original filing.

SOUTHWEST GAS CORPORATION
ARIZONA
ALLOCATION OF SELF-INSURANCE
DOCKET NO. G-01551A-04-0876
RESPONSE TO STAFF-13.14

Line No.	Claims Paid	FERC	So. Ca.	No. Ca.	So. Nv.	No. Nv.	Arizona	System Allocable	Total	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	
1	< $1MM Per Claim	$ 30,262	$ 361,500	$ 24,375	$ 2,072,392	$ 956,025	$ 4,925,937	$ 187,400	$ 8,557,891	1
2	At $1MM Per Claim	0	0	0	1,000,000	1,000,000	8,000,000	0	10,000,000	2
3	At $10MM Aggregate	0	0	0	185,500	997,800	35,164,000	0	36,347,300	3
4		$ 30,262	$ 361,500	$ 24,375	$ 3,257,892	$ 2,953,825	$ 48,089,937	$ 187,400	$ 54,905,191	4
	Total Company Experience									
5	14 Year Average	$ 2,162	$ 25,821	$ 1,741	$ 232,707	$ 210,988	$ 3,434,996	$ 13,386	$ 3,921,799	5
6	Less: Palute & SGTC at 4.29%	161,200							(168,245)	6
7	Net System Allocable								$ 3,753,554	7
8	Four Factor %		7.9%	1.5%	26.9%	6.2%	57.6%			8
8	Allocation of Self-Insurance	$ 161,200	$ 295,780	$ 55,553	$ 1,009,331	$ 231,594	$ 2,161,296	$	$ 3,914,754	8

SOUTHWEST GAS CORPORATION
ARIZONA
FOURTEEN YEAR HISTORY OF LIABILITY CLAIMS
FOR AMOUNTS LESS THAN ONE MILLION AND TEN MILLION AGGREGATE PER YEAR
DOCKET NO. G-01551A-04-0876
RESPONSE TO STAFF-13.14

Year	Paiute	So. Ca.	No. Ca.	So. Nv.	No. Nv.	Arizona	Syst Alloc.	Total
Less Than $1,000,000 Self-Insurance Per Claim								
1991	$ 30,262	$	$	$ 164,750	$ 85,568	$ 716,732	$	$ 997,312
1992		3,000		583,500	293,000	116,396		995,896
1993				36,000	252,813	407,500		696,313
1994		65,000				35,000		100,000
1995		100,000		285,000		96,183		481,183
1996		43,500			50,000	265,998	63,645	423,143
1997					79,644	618,384		698,028
1998						1,494,253	123,755	1,618,008
1999			6,250	256,333		37,545		300,128
2000			18,125	208,216	195,000			421,341
2001		100,000		415,093		609,455		1,124,548
2002						400,000		400,000
2003		50,000		31,000		95,491		176,491
2004				92,500		33,000		125,500
	$ 30,262	$ 361,500	$ 24,375	$ 2,072,392	$ 956,025	$ 4,925,937	$ 187,400	$ 8,557,891
$1,000,000 Self-Insurance Per Claim								
1991	$	$	$	$	$	$	$	$ 0
1992								0
1993						2,000,000		2,000,000
1994								0
1995				1,000,000				1,000,000
1996						1,000,000		1,000,000
1997						1,000,000		1,000,000
1998					1,000,000	2,000,000		3,000,000
1999								0
2000						1,000,000		1,000,000
2001								0
2002						1,000,000		1,000,000
2003								0
2004								0
	$ 0	$ 0	$ 0	$ 1,000,000	$ 1,000,000	$ 8,000,000	$ 0	$ 10,000,000
$10 Million Agregate above $1,000,000 Self-Insurance Per Claim								
1991	$	$	$	$	$	$	$	$ 0
1992								0
1993						18,800,000		18,800,000
1994								0
1995				185,500				185,500
1996						1,898,000		1,898,000
1997						2,726,000		2,726,000
1998					6,300	1,740,000		1,746,300
1999								0
2000					991,500			991,500
2001								0
2002								0
2003						10,000,000		10,000,000
2004								0
	$ 0	$ 0	$ 0	$ 185,500	$ 997,800	$ 35,164,000	$ 0	$ 36,347,300

SOUTHWEST GAS CORPORATION
ARIZONA
SELF-INSURED RETENTION NORMALIZATION USING A TEN-YEAR AVERAGE
ADJUSTMENT NO. 10
DOCKET NO. G-01551A-04-0876 COMPARED TO STAFF/SWG DOCKET NO. G-01551A-07-0504
RESPONSE TO STAFF-13.14

		Docket No G-01551A-04-0876					Docket No. G-01551A-07-0504		
Line No.	Description (a)	Reference (b)	Allocation Percent (c)	System Allocable (d)	10-Year Total (d)	Total Arizona Accrual (e)	10-Year Total (d)	Total Arizona Accrual (e)	Line No.
	Claims Paid	WP C-2, Adj. 10							
1	< $1,000,000				$ 5,868,370		$ 7,398,138		1
2	At $1,000,000				8,000,000		8,000,000		2
3	> $1,000,000 < $10,000,000				17,547,300		16,963,879		3
4	**Total Claims Paid**				**$ 31,415,670**		**$ 32,362,017**		4
5	**10 Year Average**					$ 3,141,567		$ 3,236,202	5
6	Less FERC Allocation @4.29%	C-1, Sh 18	4.29%			(134,773)	3.96%	(128,154)	6
7	**System Allocable Staff Surrebuttal Sch JDD-15 Line 8 (A)**					**$ 3,006,794**		**$ 3,108,048**	7
8	**Arizona 4-Factor**	**C-1, Sh 19**	**57.58%**			**$ 1,731,312**	**56.70%**	**$ 1,762,263**	8
9	Recorded Amounts			$ 275,000				200,000	9
10	Less FERC Allocation @4.29%	C-1, Sh 18	4.29%	(11,798)				(7,920)	10
11	Net System Allocable			$ 263,203				192,080	11
12	Arizona 4-Factor	C-1, Sh 19	57.58%			$ 151,552		$ 108,909	12
13	Arizona Direct		100.00%			411,000		(858,765)	13
14	Total Recorded Arizona					$ 562,552		$ (749,856)	14
15	**Total Adj. Staff Surrebuttal/SWG Rejoinder**					**$ 1,168,760**		**$ 2,512,119**	15
16	SWG Original Filing Adj. C-10					1,598,744			16
17	Staff Adjustment					(429,985)			17

Note: Staff Surrebuttal Schedule JDD-15 Revised 9/13/2005 Line 11 (A)
Staff agreed with SWG and treated claims as System Allocable and determined Arizona's portion using the Four Factor

SOUTHWEST GAS CORPORATION
ARIZONA
ALLOCATION OF SELF-INSURANCE USING A TEN-YEAR AVERAGE
DOCKET NO. G-01551A-04-0876
RESPONSE TO STAFF-13.14

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	$ 358,500	$ 24,375	$ 1,288,142	$ 324,644	$ 3,685,309	$ 187,400	$ 5,868,370	1
2	At $1MM Per Claim	0	0	0	1,000,000	1,000,000	6,000,000	0	8,000,000	2
3	At $10MM Aggregate	0	0	0	185,500	997,800	16,364,000	0	17,547,300	3
4		$ 0	$ 358,500	$ 24,375	$ 2,473,642	$ 2,322,444	$ 26,049,309	$ 187,400	$ 31,415,670	4
	Total Company Experience									
5	10 Year Average	$ 0	$ 35,850	$ 2,438	$ 247,364	$ 232,244	$ 2,604,931	$ 13,386	$ 3,141,567	5
6	Less: Paiute & SGTC at 4.29%	161,200							(134,773)	6
7	Net System Allocable								$ 3,006,794	7
8	Four Factor %		7.9%	1.5%	26.9%	6.2%	57.6%			8
8	Allocation of Self-Insurance	$ 161,200	$ 236,935	$ 44,501	$ 808,527	$ 185,519	$ 1,731,312	$	$ 3,167,994	8

SOUTHWEST GAS CORPORATION
ARIZONA
FOURTEEN YEAR HISTORY OF LIABILITY CLAIMS
FOR AMOUNTS LESS THAN ONE MILLION AND TEN MILLION AGGREGATE PER YEAR
DOCKET NO. G-01551A-04-0876
RESPONSE TO STAFF-13.14

Year	Paiute	So. Ca.	No. Ca.	So. Nv.	No. Nv.	Arizona	Syst Alloc.	Total
	Less Than $1,000,000 Self-Insurance Per Claim							
1991	$	$	$	$	$	$	$	$ 0
1992								0
1993								0
1994		65,000				35,000		100,090
1995		100,000		285,000		96,183		481,183
1996		43,500			50,000	265,998	63,645	423,143
1997					79,644	618,384		698,028
1998						1,494,253	123,755	1,618,008
1999			6,250	256,333		37,545		300,128
2000			18,125	208,216	195,000			421,341
2001		100,000		415,093		609,455		1,124,548
2002						400,000		400,000
2003		50,000		31,000		95,491		176,491
2004				92,500		33,000		125,500
	$ 0	$ 358,500	$ 24,375	$ 1,288,142	$ 324,644	$ 3,685,309	$ 187,400	$ 5,868,370
	$1,000,000 Self-Insurance Per Claim							
1991	$	$	$	$	$	$	$	$ 0
1992								0
1993								0
1994								0
1995				1,000,000				1,000,000
1996						1,000,000		1,000,000
1997						1,000,000		1,000,000
1998					1,000,000	2,000,000		3,000,000
1999								0
2000						1,000,000		1,000,000
2001								0
2002						1,000,000		1,000,000
2003								0
2004								0
	$ 0	$ 0	$ 0	$ 1,000,000	$ 1,000,000	$ 6,000,000	$ 0	$ 8,000,000
	$10 Million Agregate above $1,000,000 Self-Insurance Per Claim							
1991	$	$	$	$	$	$	$	$ 0
1992								0
1993								0
1994								0
1995				185,500				185,500
1996						1,898,000		1,898,000
1997						2,726,000		2,726,000
1998					6,300	1,740,000		1,746,300
1999								0
2000					991,500			991,500
2001								0
2002								0
2003						10,000,000		10,000,000
2004								0
	$ 0	$ 0	$ 0	$ 185,500	$ 997,800	$ 16,364,000	$ 0	$ 17,547,300

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504

* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-13
(ACC-STF-13-1 THROUGH ACC-STF-13-25)

DOCKET NO.:	G-01551A-07-0504
COMMISSION:	ARIZONA CORPORATION COMMISSION
DATE OF REQUEST:	MAY 13, 2008

Request No. ACC-STF-13-15:

Injuries and damages. Refer to Bob Mashas' rebuttal testimony at page 5, lines 25-27: This exercise is necessary to calculate a ten-year average that is reflective of a level of expense that will be incurred during the rate effective period. (A) Does the Company agree that the objective of this rate case is to derive a level of expense that will be incurred during the rate effective period? If not, explain fully why not. (B) Does the Company agree that a backward-looking period which contained an extreme event - the cost of the May 2005 gas leak fire - might not always be the best way to derive a level of expense that will be incurred during the rate effective period? If not, explain fully why not. (C) Please clarify exactly what is the rate effective period referred to on page 5, line 27. Identify the years and months in such rate effective period.

Respondent: Revenue Requirements

Response:

(a) Please reference the Company's response to Staff Data Request No. STF-13.14 (d).

(b) The Company disagrees. Please reference the Company's response to Staff Data Request No. STF-13.14 (d).

(c) The rate effective period is the time that the rates pursuant to this proceeding are in effect. The Company anticipates the rates pursuant to this proceeding to be in effect during the fourth quarter 2008 and be in effect for at least three years.

313-016

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
***
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-13
(ACC-STF-13-1 THROUGH ACC-STF-13-25)

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MAY 13, 2008

Request No. ACC-STF-13-16:

Injuries and damages. Refer to Mr. Mashas' rebuttal testimony at page 6, lines 3-7. (A) Please identify the cost of the additional layer of insurance. (B) Would the cost of that additional layer of insurance be borne by ratepayers as a result of the SWG recommendation in the current rate case? If not, explain fully why not. (C) Based on SWG's understanding, would the cost of that additional layer of insurance be borne by ratepayers as a result of the Staff's recommendation in the current rate case? If not, explain fully why not.

Respondent: Revenue Requirements

Response:

(a) The cost of the $5 million buydown from the $10 million aggregate (expense in any given plan year above the $5 million aggregate up to the $10 million) cost $1,500,000 and is included in System Allocable insurance expense.

(b) Yes.

(c) Yes.

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
*** * ***
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-13
(ACC-STF-13-1 THROUGH ACC-STF-13-25)

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MAY 13, 2008

Request No. ACC-STF-13-17:

Injuries and damages. Is Mr. Mashas attempting to shift the cost of the May 2005 gas leak fire from (1) a system allocated self-insured amount, to (2) an Arizona direct self-insurance amount? If so, explain fully how that would be consistent with Southwest's direct filing.

Respondent: Revenue Requirements

Response:

For ratemaking, Southwest treats all self-insured amounts (self-insured retentions and aggregate amounts) as System Allocable. However, for accounting purposes Southwest charges the rate jurisdiction where the incident occurred up to the $1 million self-insured retention. The aggregate portion of self-insurance is accounted for as System Allocable regardless of the rate jurisdiction where the event occurred. The aggregate portion of self-insurance is not jurisdictional specific. In a given plan year, one or more incidents, from multiple jurisdictions, can use up the current $5 million aggregate. Once the aggregate is reached, all additional amounts, from one or more incidents, or rate jurisdictions, would be indemnified by insurance carriers. The payment of the up to $1 million is the responsibility of the Company and the amounts above the $5 million is the responsibility of the insurance carriers. For both accounting and ratemaking, it is appropriate to treat the aggregate amounts as System Allocable.

Since the establishment of the aggregate component of self-insurance, the May 2005 incident was the only event where the aggregate component was used and accounted for as a System Allocable amount. Prior to the establishment of the aggregate component of self-insurance August 1, 2004, all expense above the $1 million self-insured retention was indemnified by the Company's insurance carriers and therefore, not recorded on the Company's books, Thus, the need to restate history to reflect a reasonable level of aggregate self-insurance that would be expected during the rate effective period.

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
*** * ***
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-13
(ACC-STF-13-1 THROUGH ACC-STF-13-25)

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MAY 13, 2008

Request No. ACC-STF-13-19:

Injuries and damages. (A) As of its rebuttal filing, what amount of expense is Southwest claiming for injuries and damages? Show in detail how that amount is derived. (B) As of its rebuttal filing, what amount of expense is Southwest claiming for the self-insurance portion of injuries and damages? Show in detail how that amount is derived.

Respondent: Revenue Requirements

Response:

(a) Please see the response to Staff Data Request STF-1-53(2). For Account 923, Outside Services, Arizona direct the recorded $768,490 should be increased by $300,000 to $1,068,490. For Account 925, Injuries and Damages, Arizona Direct the recorded $406,029 should be decreased by $300,000 to $106,029. Schedule C-2, Adjustment No. 10, Line 13 (f) is a negative $558,765 and should be changed to a negative $858,765.

(b) As of its rebuttal filing the Company is proposing to adjust, by $2,512,119, the recorded self-insured component of the injuries and damages expense. This amount is modified to reflect the accounting error referred to in the direct testimony of RUCO witness Rodney Moore and shown on RUCO Schedule RLM-8 Adjustment No. 2. Attached is a file that calculates the Company's revised Adjustment No. 10, which includes the impact of the $300,000 adjustment. Company witness Randi Aldridge also addresses this issue in her rebuttal testimony.

The accounting error occured in June 2006. An adjustment to Arizona direct self-insurance was erroneously credited $300,000 to Account 923 thus understating that account. The $300,000 should have been credited to Account 925, Injuries and Damages, Arizona direct thus reducing the recorded Arizona direct from a minus $558,765 to a minus $858,765.

SOUTHWEST GAS CORPORATION
ARIZONA
SELF-INSURED RETENTION NORMALIZATION
(TEN YEAR AVERAGE $5.0 MILLION AGGREGATE)
ADJUSTMENT NO. 10 INCLUDING MAY 2005 ACCIDENT AND $300,000 RECLASS
RESPONSE TO STF-13.13

Line No.	Description (a)	Reference (b)	Allocation Percent (c)	System Allocable (d)	10-Year Total (d)	Total Arizona Accrual (e)	Line No.
	Claims Paid	WP C-2, Adj. 10					
1	< $1,000,000				$ 7,398,138		1
2	At $1,000,000				8,000,000		2
3	> $1,000,000 < $5,000,000				16,963,879		3
4	Total Claims Paid				$ 32,362,017		4
5	10 Year Average					$ 3,236,202	5
6	Less FERC Allocation @ 3.96%	C-1, Sh 18	3.96%			(128,154)	6
7	System Allocable					$ 3,108,048	7
8	Arizona 4-Factor	C-1, Sh 19	56.70%			$ 1,762,263	8
9	Recorded Amounts			$ 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 19	56.70%			$ 108,909	12
	Arizona Direct (Reclass from Acct 923)		100.00%			(300,000)	
13	Arizona Direct		100.00%			(558,765)	13
14	Total Recorded Arizona					$ (749,856)	14
15	Total adjustment including May 2005 incident and $300,000 reclass.					$ 2,512,119	15

SOUTHWEST GAS CORPORATION
ARIZONA
ALLOCATION OF SELF-INSURANCE (10 YEAR AVERAGE)
ADJUSTMENT NO. 10 INCLUDING MAY 2005 ACCIDENT AND $300,000 RECLASS
RESPONSE TO STF-13.13

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	$ 5,509,865	$ 141,255	$ 7,398,138	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	$ 26,475,970	$ 141,255	$ 32,362,017	4
	Total Company Experience									
5	10 Year Average	$ 0	$ 17,750	$ 2,438	$ 235,014	$ 319,277	$ 2,647,597	$ 14,126	$ 3,236,202	5
6	Less: Paiute & SGTC at 3.96%								(128,154)	6
7	Net System Allocable								$ 3,108,048	7
8	Four Factor %		7.9%	2.3%	27.3%	5.7%	56.7%			8
9	Allocation of Self-Insurance	$ 128,154	$ 246,779	$ 72,107	$ 848,186	$ 178,402	$ 1,762,263	$	$ 3,108,048	9
10					Arizona Allocation Percent				56.70%	10
11					Arizona Allocation				$ 1,762,263	11
12					**Less: Test Year Reclass Acct 923**				**(300,000)**	12
13					Less: Net Recorded System Allocable As Recorded				108,909	13
14					Less: Recorded Direct Arizona				(558,765)	14
15					**Arizona Revised Adj. With $300,000 Reclass**				**$ 2,512,119**	15

Note: An Arizona direct test year credit to self-insured retention was erroneously charged to Account 923, Outside Services, thus understating that account. Account 923, Outside Services Arizona direct should be increased by $300,000.
Account 925, Injuries and Damages, Arizona direct self-insured retention should be **decreased** by $300,000. The adjusted recorded minus $750,132 ($300,000 + $450,132) needs to be adjusted to reflect the 10-Year average of self-insured retention calculated above $1,762,263
The required adjustment is $2,512,219 which excludes the may 2005 accident.

SOUTHWEST GAS CORPORATION
ARIZONA
TEN YEAR HISTORY OF LIABILITY CLAIMS
ADJUSTMENT NO. 10 INCLUDING MAY 2005 ACCIDENT AND $300,000 RECLASS
RESPONSE TO STF-13.13

Line No.	Year (a)	Paiute (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	2006	**Acctg. Reclass**					**(300,000)**		**(300,000)**	11
12	2007				5,001		129,059		134,060	12
13		$ 0	$ 177,500	$ 24,375	$ 1,350,143	$ 195,000	$ 5,509,865	$ 141,255	$ 7,398,138	13
		$1,000,000 Self-Insurance Per Claim								
14	1997						1,000,000		1,000,000	14
15	1998					1,000,000	2,000,000		3,000,000	15
16	1999								0	16
17	2000					1,000,000			1,000,000	17
18	2001								0	18
19	2002								0	19
20	2003						1,000,000		1,000,000	20
21	2004						0		0	21
22	2005				1,000,000		1,000,000		2,000,000	22
23	2006								0	23
24	2007								0	24
25		$ 0	$ 0	$ 0	$ 1,000,000	$ 2,000,000	$ 5,000,000	$ 0	$ 8,000,000	25
		$5 Million Agregate above $1,000,000 Self-Insurance Per Claim								
26	1997						2,726,235		2,726,235	26
27	1998					6,272	1,739,870		1,746,142	27
28	1999								0	28
29	2000					991,502			991,502	29
30	2001								0	30
31	2002								0	31
32	2003						5,000,000		5,000,000	32
33	2004						1,500,000		1,500,000	33
34	2005						5,000,000		5,000,000	34
35	2006								0	35
36	2007								0	36
37		$ 0	$ 0	$ 0	$ 0	$ 997,774	$ 15,966,105	$ 0	$ 16,963,879	37
38	Total	$ 0	$ 177,500	$ 24,375	$ 2,350,143	$ 3,192,774	$ 26,475,970	$ 141,255	$ 32,362,017	38

[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
ARIZONA
SELF-INSURANCE FOR THE FIRST $5 MILLION ABOVE $1 MILLION OF SELF-INSURED RETENTION
APPLICABLE CLAIMS FOR THE PERIOD 1997 THROUGH APRIL 2007
HYPOTHETICAL RESTATEMENT OF HISTORY AS IF NEW POLICY AND PRACTICE WAS IN PLACE
ADJUSTMENT NO. 10 INCLUDING MAY 2005 ACCIDENT AND $300,000 RECLASS
RESPONSE TO STF-13.13

Line No.	Description	District	Year	Incident Date	Total Payout	Less Expense	Indemnity Payments	SWG SIR < $1MM	SWG SIR SIR @$1MM	$5MM Pool	Insurance Carrier	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
1	Arizona	42	1997	Sep-97	$ 3,726,235	$ 1,226,235	$ 2,500,000	$ 0	$ 1,000,000	$ 2,726,235	$ 0	1
2	Arizona	42	1998	Jan-98	1,320,903	475,904	844,999	0	1,000,000	320,903	0	2
3	Northern Nevada	26	1998	Feb-98	1,006,272	309,029	697,243	0	1,000,000	6,272	0	3
4	Arizona	36	1998	Sep-98	2,418,967	638,235	1,780,732	0	1,000,000	1,418,967	0	4
6	Northern Nevada	23	2000	Oct-00	1,991,502	756,278	1,235,224	0	1,000,000	991,502	0	6
9	Arizona	42	2003	Jan-03	16,604,129	0	16,604,129	0	1,000,000	5,000,000	10,604,129	9
10	Arizona	42	2004	Jan-03	1,500,000	0	1,500,000	0	0	1,500,000	0	10
11	Southern Nevada	21	2005		1,000,000	0	1,000,000	0	1,000,000	0	0	11
12	Arizona	36	2005	May-05	30,000,000		30,000,000	0	1,000,000	5,000,000	24,000,000	12
13	10 Yr. Total				$ 59,568,008	$ 3,405,681	$ 56,162,327	$ 0	8,000,000	$ 16,963,879	$ 34,604,129	13
14	10 Yr. Average				$ 5,956,801	$ 340,568	$ 5,616,233	$ 0	$ 800,000	$ 1,696,388	$ 3,460,413	14

Line No.	Rate Jurisdiction	Southwest Gas Liability: Total Payout	Less Expense	Indemnity Payments	< $1MM	$1MM SIR	$5MM S-I	Insurance Carrier	Line No.
15	Paiute	$ 0	$ 0	$ 0	$ 0	0	$ 0	$ 0	15
16	So. Ca.	0	0	0	0	0	0	0	16
17	No. Ca.	0	0	0	0	0	0		17
18	No. Nv.	2,997,774	1,065,307	1,932,467	0	2,000,000	997,774		18
19	So. Nv.	1,000,000	0	1,000,000	0	1,000,000	0		19
20	Az.	55,570,234	2,340,374	53,229,860	0	5,000,000	15,966,105	34,604,129	20
21	Total	$ 59,568,008	$ 3,405,681	$ 56,162,327	0	8,000,000	$ 16,963,879	$ 34,604,129	21
22	Arizona Percent of Total	93.3%	68.7%	94.8%	0.0%	62.5%	94.1%	100.0%	22

Docket No. G-01551A-07-0504
Attachment RCS-8
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Sheet 4 of 5

SOUTHWEST GAS CORPORATION
ARIZONA
SELF-INSURANCE FOR THE FIRST $5 MILLION ABOVE $1 MILLION OF SELF-INSURED RETENTION
APPLICABLE CLAIMS FOR THE PERIOD MAY 1997 THROUGH APRIL 2007
HYPOTHETICAL RESTATEMENT OF HISTORY AS IF NEW POLICY AND PRACTICE WAS IN PLACE
ADJUSTMENT NO. 10 INCLUDING MAY 2005 ACCIDENT AND $300,000 RECLASS
RESPONSE TO STF-13.13

Line No.	Description (a)	District (b)	Incident Date (c)	Total Payout (d)	Less Expense (e)	Indemnity Payments (f)	SWG SIR (g)	$5MM Pool (h)	Insurance Carrier (i)	Line No.
1	Arizona	42	12-Sep-97	3,726,235	1,226,235	2,500,000	1,000,000	2,726,235	0	1
2	Arizona	42	15-Jan-98	1,320,903	475,904	844,999	1,000,000	320,903	0	2
3	Northern nevada	26	4-Feb-98	1,006,272	309,029	697,243	1,000,000	6,272	0	3
4	Arizona	36	14-Sep-98	2,418,967	638,235	1,780,732	1,000,000	1,418,967	0	4
5	Northern nevada	23	26-Oct-00	1,991,502	756,278	1,235,224	1,000,000	991,502	0	5
6	Arizona	42	2-Jan-03	16,604,129		16,604,129	1,000,000	5,000,000	10,604,129	6
7	Arizona	42	1-May-04	1,500,000		1,500,000		1,500,000	0	7
8	Arizona	**36**	May-05	30,000,000		30,000,000	1,000,000	5,000,000	24,000,000	8
9	10 Yr Total			$ 58,568,008	$ 3,405,681	$ 55,162,327	$ 7,000,000	$ 16,963,879	$ 34,604,129	9

Line No.	Rate Jurisdiction	Southwest Gas Liability: Total Payout	Less Expense	Indemnity Payments	$1MM SIR	$5MM S-I	Insurance Carrier	Line No.
10	Paiute	$ 0	$ 0	$ 10	$ 0	$ 0	$ 0	10
11	So. Ca.	0	0	11	0	0	0	11
12	No. Ca.	0	0	12	0	0	0	12
13	No. Nv.	2,997,774	1,065,307	1,932,467	2,000,000	997,774	0	13
14	So. Nv.	0	0	0	0	0	0	14
15	Az.	55,570,234	2,340,374	53,229,860	5,000,000	15,966,105	34,604,129	15
16	Total	$ 58,568,008	$ 3,405,681	$ 55,162,360	7,000,000	$ 16,963,879	$ 34,604,129	16
17	Arizona Percent of Total	94.9%	68.7%	96.5%	71.4%	94.1%	100.0%	17

313-020

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
*** * ***
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-13
(ACC-STF-13-1 THROUGH ACC-STF-13-25)

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MAY 13, 2008

Request No. ACC-STF-13-20:

Injuries and damages. Refer to Mr. Mashas' Q/A 14. (A) Was the cost of the May 2005 gas leak fire known when the Commission issued Decision No. 68487? If so, please provide the documentation showing that that cost was known at that time. (b) Isn't the unprecedentedly large cost resulting from the May 2005 gas leak fire something that has changed, which the Commission should take into consideration in the current SWG rate case to determine an expense that would be representative of the rate effective period? If not, explain fully why not.

Respondent: Revenue Requirements

Response:

(a) The ACC Safety Division was informed telephonically of the incident within hours of its occurrence. The Safety Division conducted a year long investigation of the incident and concluded that no non-compliance issues were noted. Attached is a copy of the ACC Pipeline Safety Section report on the incident. Also attached is the Company's June 16, 2005 copy of the US DOT Form RSPA F 7100.1 filed with the ACC Safety Division. In addition is a copy of the report filed with the US DOT on June 17, 2005. Also attached is a copy of the relevant pages of the SEC Form 10Q the Company filed on August 9, 2005 which included details on the incident. The Company also included detail of the incident in its 2005 SEC 10K and its 2005 Annual Report to Shareholders; attached are copies of the relevant pages detailing the occurance and possible dollar impact. The hearing pursuant to the last general rate case commenced on October 3, 2005, with Commission ruling on the case in February 2006. Based on these public filings, in addition to the Company's same day notification to the Safety Division of the accident, there is reason to believe that the Commission was aware of the May 2005 incident. The incident occurred after the test year and was not subject to the establishment of injuries and damages expense in that proceeding. However, it was an example of an incident where the $10 million aggregate was actually met, which added validity to the January 2003 incident that was valued as $10 million in the Adjustment No. 10 in that proceeding.

(b) Please refer to the Company's response to Staff Data Req. No. ACC-STF-13.14 (d).

ARIZONA CORPORATION COMMISSION

April 21, 2006

CERTIFIED MAIL

Ms. Debra Jacobson
Manager of Regulatory Affairs
Southwest Gas Corporation
5241 Spring Mountain Road
Las Vegas, Nevada 89193-8510

RE: INCIDENT – 1841 South Campbell Avenue, Tucson, Arizona

Dear Ms. Jacobson:

The Arizona Corporation Commission's (Commission) Office of Pipeline Safety has the responsibility to enforce the Arizona Revised Statue Section 40-441. The Commission has adopted Title 49, Code of Federal Regulations, Parts 191, 192, 199, 40 and the Arizona Administrative Code R-14-5-202 and R14-5-203 as the minimum standards for the transportation of natural gas by pipeline. Southwest Gas Corporation (SWG) is transporting natural gas and is required to meet these minimum standards.

Larry Ayers of the Commission's Office of Pipeline Safety conducted a specialized inspection at 1841 South Campbell Avenue, Tucson, Arizona. Mr. Ayers was assigned this investigation on May 27, 2005 after a telephonic report from SWG indicated that an explosion and fire had occurred at the apartment complex noted above. The cause of the explosion and fire was natural gas leaking from a buried main in the alley behind this facility. No non-compliance issues were noted as a result of this investigation.

Thank you for your continued interest in pipeline safety. Should you have any questions regarding this matter, you may contact Robert Miller at (602) 262-5601.

Sincerely,

Alan Bohnenkamp
Chief of Pipeline Safety
Pipeline Safety Section

AB:RW:vbg

Enclosures:

CC: Robert Clarillos
Jason Gellman

PL2005-0228
1841 SOUTH CAMPBELL AVENUE, APT. #2
TUCSON, ARIZONA
PROBABLE NON-COMPLIANCES

There were no probable non-compliances noted as a result of this incident.

ARIZONA CORPORATION COMMISSION

PIPELINE SAFETY STAFF
INVESTIGATIVE REPORT
MAY 27, 2005
1841 SOUTH CAMPBELL AVENUE
APARTMENT # 2
TUCSON, ARIZONA

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B. Statements of Facts

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J. Photos

K. Data Request

SYNOPSIS

On May 27, 2005, at approximately 16:55 p.m., the Arizona Corporation Commission's Office of Pipeline Safety (OPS) was notified by Southwest Gas Corporation (SWG) of an explosion at 1841 South Campbell Avenue, Tucson, Arizona, a duplex apartment. Larry Ayers (OPS) was assigned to investigate this incident.

The cause of the explosion was natural gas leaking from a two inch (2") PE main owned and operated by SWG. The main was operating at 60 PSIG, when the explosion occurred. The maximum allowable operating pressure (MAOP) of this section of main is 60 PSIG. A rock in contact with the main at the 6 o-clock position caused a crack 1.5 inches in length. The gas migrated approximately 20' from the gas main in the alley to the residence. The explosion caused damage to both apartments, (Numbers 1 and 2), in this duplex..

There was one individual injured, a resident of Apartment Number 2. He was transported to Saint Mary's Hospital for emergency treatment and admitted.

STATEMENTS OF FACT

1. Southwest Gas Corporation (SWG) was notified on May 27, 2005 at 15:52 p.m. of an apparent gas explosion at 1841 South Campbell Avenue Apartment #2, Tucson, Arizona.

2. The cause of the explosion was natural gas leaking from the gas main approximately twenty feet (20') from the outside wall of the residence at 1841 S. Campbell.

3. SWG system maps showed several types of piping material in this alley where this incident occurred.

4. The maximum allowable operating pressure (MAOP) for the two (2) inch PE main was 60 PSIG.

5. The operating pressure of the distribution pipeline system at the time of the incident was 60 PSIG.

6. The tenant, Arnold H. Valenzuela was transported and admitted for emergency treatment at Saint Mary's Hospital with extensive burns

7. The explosion and fire caused extensive damage to both apartments in this duplex.

8. The gas was shut off by squeezing the two (2) inch PE main just east of Barleycorn Street.

9. The leak was the result of rock impingement of the two (2) inch PE main at the 6 o'clock position, causing a crack approximately 1.5 inches in length.

10. The isolation of the distribution pipeline system resulted in the outage of natural gas service to 28 customers.

11. The riser at 1841 South Campbell had a reading of 92% gas.

12. The two inch (2") PE main was manufactured by Dupont (ADLYL-HD) and installed by SWG in 1981.

INVESTIGATION REPORT

On May 27, 2005, Southwest Gas Corporation (SWG) was contacted by The City of Tucson Fire Department, (TFD) of a natural gas (gas) explosion that occurred at a duplex apartment located at 1841 South Campbell Avenue, Apartment No. 2, Tucson, Arizona. SWG responded arriving on scene at 4:14 p.m. The Arizona Corporation Commission's Office of Pipeline Safety (OPS) was notified at 4:55 p.m by (SWG) of the explosion with one person injured and transported to the hospital for emergency treatment. Larry Ayers was assigned the investigation.

SWG crews arriving on scene began conducting leak surveys to establish the presence of gas and then to determine the size of the gas spread. A reading of 92% gas was noted at the service riser to Apartment No. 2. SWG crews exposed the two inch (2") gas main north of Barleycorn Street and with squeeze off equipment controlled the flow of gas to the incident site at 6:22 p.m.

The explosion and fire caused extensive damage to the duplex apartment. One resident was injured. Mr. Arnold H Valenzuela, the tenant of Apartment No. 2, was burned in the explosion. He was transported and admitted to Saint Mary's Hospital for emergency treatment.

The gas leak was determined to be on the 2" gas main located east of 1841 South Campbell in the alley. The gas had migrated from the main in the alley to the structure at 1841 South Campbell. The cause of the leak was rock impingement at the 6 o-clock position of the 2" Polyethelene ALDYL HD pipe. The impingement caused a 1½ inch crack. SWG system mapping identified several types of piping material in this section of the alley where the gas leak occurred.

The maximum allowable operating pressure (MAOP) for this segment of the gas distribution system is 60 PSIG. At the time of the explosion the operating pressure was 60 PSIG.

SWG personnel conducted bar hole leak surveys starting at 4:30 p.m. on May 27, 2005 continuing until June 8, 2005. Daily leak surveys of the ALDYL HD pipe in the general area commenced on May 29, 2005 and continued until June 15, 2005.

June 15, 2005, SWG and Arizona Pipeline finished replacing all the ALDYL HD, ALDYL "A" main and other types of piping material in the alley behind 1841 South Campbell Avenue. The 2" main where the leak occurred was installed in 1981. The service line to Apartment No. 2 was installed in 2002 when the building was upgraded.

Visual inspections of the existing backfill indicated that a "sandy type soil" was used as bedding and shading as required by Arizona Administrative Code R14-5-202 (O) when the 2" main was installed in 1981. The native soil in the area was very rocky.

CONCLUSION

Southwest Gas Corporation (SWG) received initial notification of this incident from the Tucson Fire Department and began arriving on site at 4:14 p.m. The natural gas leak was secured using squeeze off tools at 6:22 p.m. There was one individual injured, transported and admitted to Saint Mary's Hospital for emergency treatment. The actions taken by the Tucson Fire Department and SWG led to the safe control and termination of this natural gas leak.

The cause of the natural gas main failure was rock impingement. A rock contacting the main at the six (6) o-clock position caused a one and a half inch (1 ½") crack. The soil condition in this area was rocky (river rock) but visual inspection of the backfill around the pipe was a sandy type soil indicating that the native soil was not used as backfill. The gas migrated from the crack in the main through the soil to the duplex where it was ignited, causing the explosion.

The maximum Allowable Operating Pressure (MAOP) of the main is 60 PSIG.. The operating pressure at the time of the explosion was 60 psig.

SWG and Arizona Pipeline crews replaced all of the ALDYL HD, ALDYL "A", as well as other types of piping material in the alley directly behind the incident site. The main where the leak occurred was installed in 1981. The service line to 1841 South Campbell was replaced in 2002 when the building was upgraded. .

As a result of this investigation, Arizona Corporation Commission's Office of Pipeline Safety (OPS) concludes that there were no probable noncompliance issues that contributed to the cause of this incident.

SOUTHWEST GAS CORPORATION

June 16, 2005 **HAND DELIVERED ON 06/16/05**

Arizona Corporation Commission
Mr. Alan Bohnenkamp
Interim Chief, Pipeline Safety
2200 N. Central Ave Suite #300
Phoenix, AZ 85004

Dear Mr. Bohnenkamp:

RE: ***1841 South Campbell Ave Units 1 & 2 – Tucson, Arizona***
May 27, 2005

Attached is a copy of the written report for the incident that occurred ***in Tucson, Arizona,*** as reported by telephone to your office on May 27, 2005. (Note: The original report has been forwarded to DOT, as it has met their reporting requirements). Please reference the attached report for details related to this incident.

Please contact Vern Sullivan at (520) 794-6034 if you have any questions regarding this incident.

Sincerely,

Randy Ortlinghaus
Director, Gas Operations

attachment

c R. Clarillos
G. Denio
D. Jacobson
J. Kane
G. Clark
J. Schmitz
R. Smith
V. Sullivan
J. Wunderlin

NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed $100,000 for each violation for each day the violation continues up to a maximum of $1,000,000 for any related series of violations as provided in 49 USC 60122. Form Approved OMB No. 2137-0

STF-13-20
Sheet 10 of 22

U.S. Department of Transportation
Research and Special Programs Administration

INCIDENT REPORT - GAS DISTRIBUTION SYSTEM

[redacted]

INSTRUCTIONS

Important: *Please read the separate instructions for completing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions, you can obtain one from the Office Of Pipeline Safety Web Page at* http://ops.dot.gov.

PART A – GENERAL REPORT INFORMATION Check: ☒ Original Report ☐ Supplemental Report ☐ Final Report

1. Operator Name and Address

a. Operator's 5-digit Identification Number / 1 / 8 / 5 / 3 / 6 /

b. If Operator does not own the pipeline, enter Owner's 5-digit Identification Number / / / / / /

c. Name of Operator Southwest Gas

d. Operator street address P. O. Box 98510

e. Operator address Las Vegas, Clark, Nevada 89193-8510
City, County or Parish, State and Zip Code

2. Time and date of the incident

/ 1 / 5 / 5 / 2 / hr. / 0 / 5 / month / 2 / 7 / day / 0 / 5 / year

3. Incident Location

a. 1841 South Campbell Avenue, Units 1 & 2
Street or nearest street or road

b. Tucson, Pima
City and County or Parish

c. Arizona 85713
State and Zip Code

d. Latitude: /3/2/ /2/0/0/0/1/3 Longitude:- /1/1/0/ /9/4/3/0/9/1/
(if not available, see instructions for how to provide specific location)

e. Class location description
○ Class 1 ○ Class 2 ⊙ Class 3 ○ Class 4

f. Incident on Federal Land ○ Yes ⊙ No

4. Type of leak or rupture

⊙ Leak: ○Pinhole ○Connection Failure *(complete sec. F5)*

⊙ Puncture, diameter or cross section *(inches)* crack of 1.5

○ Rupture (if applicable):

○ Circumferential – Separation

○ Longitudinal

- Tear/Crack, length *(inches)* ____

- Propagation Length, total, both sides *(feet)* ______

○ N/A

○ Other: ______

5. Consequences *(check and complete all that apply)*

a. ☐ Fatality N/A Total number of people: / / / /

Employees: / / / / *General Public:* / / / /

Non-employee Contractors: / / / /

b. ☒ Injury requiring inpatient hospitalization

Total number of people: / / / 1 /

Employees: / / / / *General Public:* / / / 1 /

Non-employee Contractors: / / / /

c. ☒ Property damage/loss *(estimated)* Total $ 225,000.00

Gas loss $ 0 Operator damage $ 25,000.00

Public/private property damage $ 200,000.00

d. ☒ Gas ignited ⊙ Explosion ○ No Explosion

e. ☐ Gas did not ignite ○ Explosion ○ No Explosion

f. ☒ Evacuation *(general public only)* / / / / 4 / people

Evacuation Reason:

○ Unknown

⊙ Emergency worker or public official ordered, precautionary

○ Threat to the public

○ Company policy

6. Elapsed time until area was made safe:

/ / 2 / hr. / 3 / 0 / min.

7. Telephone Report

760-206 NRC Report Number / 0 / 5 / month / 2 / 7 / day / 0 / 5 / year

8. a. Estimated pressure at point and time of incident:

60 *PSIG*

b. Max. allowable operating pressure *(MAOP)*: 60. *PSIG*

c. MAOP established by:

⊙ Test Pressure 100 psig

○ 49 CFR § 192. 619 (a)(3)

PART B – PREPARER AND AUTHORIZED SIGNATURE

Vernon Sullivan Specialist/Compliance
(type or print) Preparer's Name and Title

(520) 794-6034
Area Code and Telephone Number

Vernon.sullivan@swgas.com
Preparer's E-mail Address

(520) 794-6034
Area Code and Facsimile Number

Authorized Signature

Randy Ortlinghaus Director/Gas Operations
(type or print) Name and Title

6/16/05
Date

(520) 794-6053
Area Code and Telephone Number

PART C – ORIGIN OF THE INCIDENT

1. Incident occurred on
   - ⦿ Main ○ Meter Set
   - ○ Service Line ○ Other: ____________
   - ○ Pressure Limiting and Regulating Facility
2. Failure occurred on
   - ⦿ Body of pipe ○ Pipe Seam
   - ○ Joint ○ Component
   - ○ Other: ____________
3. Material involved *(pipe, fitting, or other component)*
   - ○ Steel
   - ○ Cast/Wrought Iron
   - ⦿ Polyethelene Plastic (complete all items that apply in a-c)
   - ○ Other Plastic (complete all items that apply in a-c)
   - Plastic failure was: ☐ a.ductile ☒ b.brittle ☐ c.joint failure
   - ○ Other material: ____________
4. Year the pipe or component which failed was installed: / 1 / 9 / 8 / 1/

PART D – MATERIAL SPECIFICATION (if applicable)

1. Nominal pipe size *(NPS)* / 2 / . / 0 / 0 / in.
2. Wall thickness / . / 2 / 1 / 6 / in.
3. Specification ASTM D 2513 SMYS / / / / / / /
4. Seam type N/A
5. Valve type N/A
6. Pipe or valve manufactured by DuPont in year / 1 / 9 / 8 / 1 /

PART E – ENVIRONMENT

1. Area of incident
   - ○ Under pavement
   - ⦿ Under ground
   - ○ Inside/under building
   - ○ In open ditch
   - ○ Above ground
   - ○ Under water
   - ○ Other: ____________
2. Depth of cover: 28 inches

PART F – APPARENT CAUSE

***Important:* There are 25 numbered causes in this section. Check the box to the left of the primary cause of the incident. Check one circle in each of the supplemental items to the right of or below the cause you indicate. See the instructions for this form for guidance.**

F1 – CORROSION N/A

1. ☐ External Corrosion
2. ☐ Internal Corrosion

If either F1 (1) External Corrosion, or F1 (2) Internal Corrosion is checked, complete all subparts a – e.

a. Pipe Coating
   - ○ Bare
   - ○ Coated
   - ○ Unknown

b. Visual Examination
   - ○ Localized Pitting
   - ○ General Corrosion
   - ○ Other: ____________

c. Cause of Corrosion
   - ○ Galvanic ○ Stray Current
   - ○ Improper Cathodic Protection
   - ○ Microbiological
   - ○ Other: ____________

d. Was corroded part of pipeline considered to be under cathodic protection prior to discovering incident?
   ○ No ○ Yes ○ Unknown Year Protection Started: / / / / /

e. Was pipe previously damaged in the area of corrosion?
   ○ No ○ Yes ○ Unknown How long prior to incident: / / / *years* / / / *months*

F2 – NATURAL FORCES N/A

3. ☐ Earth Movement ⇒ ○ Earthquake ○ Subsidence ○ Landslide ○ Other: ____________
4. ☐ Lightning
5. ☐ Heavy Rains/Floods ⇒ ○ Washouts ○ Flotation ○ Mudslide ○ Scouring ○ Other: ____________
6. ☐ Temperature ⇒ ○ Thermal stress ○ Frost heave ○ Frozen components ○ Other: ____________
7. ☐ High Winds

F3 – EXCAVATION N/A

8. ☐ Operator Excavation Damage *(including their contractors)* / Not Third Party
9. ☐ Third Party Excavation Damage *(complete a-d)*
   - a. Excavator group
     ○ General Public ○ Government ○ Excavator other than Operator/subcontractor
   - b. Type: ○ Road Work ○ Pipeline ○ Water ○ Electric ○ Sewer ○ Phone/Cable/Fiber ○ Landowner ○ Railroad ○ Building Construction ○ Other: ____________
   - c. Did operator get prior notification of excavation activity?
     ○ No ○ Yes: Date received: / / / mo. / / / day / / / yr.
     Notification received from: ○ One Call System ○ Excavator ○ General Contractor ○ Landowner
   - d. Was pipeline marked?
     ○ No ○ Yes *(If Yes, check applicable items i – iv)*
     - i. Temporary markings: ○ Flags ○ Stakes ○ Paint
     - ii. Permanent markings: ○ Yes ○ No
     - iii. Marks were *(check one)* ○ Accurate ○ Not Accurate
     - iv. Were marks made within required time? ○ Yes ○ No

F4 – OTHER OUTSIDE FORCE DAMAGE N/A

10. ☐ Fire/Explosion as primary cause of failure ⇒ Fire/Explosion cause: ○ Man made ○ Natural *Describe in Part G*
11. ☐ Car, truck or other vehicle not relating to excavation activity damaging pipe
12. ☐ Rupture of Previously Damaged Pipe
13. ☐ Vandalism

F5 – MATERIAL OR WELDS N/A

Material

14. ☐ Body of Pipe ⇒ O Dent O Gouge O Wrinkle Bend O Arc Burn O Other: ______
15. ☐ Component ⇒ O Valve O Fitting O Vessel O Extruded Outlet O Other: ______
16. ☐ Joint ⇒ O Gasket O O-Ring O Threads O Fusion O Other: ______

Weld N/A

17. ☐ Butt ⇒ O Pipe O Fabrication O Other: ______
18. ☐ Fillet ⇒ O Branch O Hot Tap O Fitting O Repair Sleeve O Other: ______
19. ☐ Pipe Seam ⇒ O LF ERW O DSAW O Seamless O Flash Weld O HF ERW O SAW O Spiral O Other: ______

Complete a-f if you indicate any cause in part F5. N/A

a. Type of failure:
☐ Construction Defect ⇒ O Poor Workmanship O Procedure not followed O Poor Construction Procedures
☐ Material Defect

b. Was failure due to pipe damage sustained in transportation to the construction or fabrication site? O Yes O No

c. Was part which leaked pressure tested before incident occurred? O Yes, *complete d-f, if known* O No

d. Date of test: /__/__/ mo. /__/__/ day /__/__/ yr.

e. Time held at test pressure; /__/__/ hr.

f. Estimated test pressure at point of incident: ______________ *PSIG*

F6 – EQUIPMENT OR OPERATIONS N/A

20. ☐ Malfunction of Control/Relief Equipment ⇒ O Valve O Instrumentation O Pressure Regulator O Other: ______
21. ☐ Threads Stripped, Broken Pipe Coupling ⇒ O Nipples O Valve Threads O Mechanical Couplings O Other: ______
22. ☐ Leaking Seals

23. ☐ Incorrect Operation

a. Type: O Inadequate Procedures O Inadequate Safety Practices O Failure to Follow Procedures O Other: ______

b. Number of employees involved in incident who failed post-incident drug test: /__/__/__/ Alcohol test /__/__/__/

c. Was person involved in incident qualified per OQ rule? O Yes O No d. Hours on duty for person involved: /__/__/

F7 – OTHER

24. ☒ Miscellaneous, *describe:* See Part G
25. ☐ Unknown

☐ Investigation Complete ☒ Still Under Investigation *(submit a supplemental report when investigation is complete)*

PART G – NARRATIVE DESCRIPTION OF FACTORS CONTRIBUTING TO THE EVENT *(Attach additional sheets as necessary)*

Brief Description:
At 1552 hours on May 27, 2005, Southwest Gas was notified of a fire at 1841 South Campbell Avenue. Upon arrival at 1614 hours, two apartment units were found to be damaged by the reported fire. A leak investigation was initiated and the presence of gas was detected below ground. Gas control of the main and services in the vicinity of the fire was achieved at 1822 hours by digging and squeezing, which resulted in an outage of 28 services. One person required inpatient hospitalization. Further investigation determined that the leak was on a 2" polyethylene main. The leak was due to rock impingement. There is a possibility that previous third party excavation in the immediate area was a contributing factor to the incident. An investigation is ongoing.

RECEIVED

JUN 2 1 2005

ENGINEERING STAFF

SOUTHWEST GAS CORPORATION

June 17, 2005

Information Resources Manager
Office of Pipeline Safety
Research and Special Programs Administration
U. S. Department of Transportation
400 Seventh Street SW, Room 7128
Washington, DC 20590

Dear Sirs:

RE: Report Date: ***May 27, 2005***
No. *760-206*
Ignition of Natural Gas – ***1841 South Campbell Avenue Units 1 & 2***
Tucson, Arizona – May 27, 2005

Attached is a written report for the incident that occurred in ***Tucson, Arizona***, as reported by telephone to your office on ***May 27, 2005***. Please reference the attached report for details related to this incident.

Please contact Vern Sullivan at (520) 794-6034 if you have any questions regarding this incident.

Sincerely,

Randy Ortlinghaus
Director, Gas Operations

attachment

cf

c A. Bohnenkamp, ACC
R. Clarillos, SWG
G. Denio, SWG
D. Jacobson, SWG
J. Kane, SWG
G. Clark, SWG
J. Schmitz, SWG
R. Smith, SWG
V. Sullivan, SWG
J. Wunderlin, SWG

3401 East Gas Road / Tucson, Arizona 85714-1994
P.O. Box 26500 / Tucson, Arizona 85726-6500 / (520) 889-5600
www.swgas.com

NOTICE: This report is required by 49 CFR Part 191. Failure to report can result in a civil penalty not to exceed $100,000 for each violation for each day the violation continues up to a maximum of $1,000,000 for any related series of violations as provided in 49 USC 60122. Form Appro OMB No. 21 -0504

STF-13-20 Sheet 14 of 22

U.S. Department of Transportation
Research and Special Programs Administration

INCIDENT REPORT - GAS DISTRIBUTION SYSTEM

INSTRUCTIONS

Important: *Please read the separate instructions for completing this form before you begin. They clarify the information requested and provide specific examples. If you do not have a copy of the instructions, you can obtain one from the Office Of Pipeline Safety Web Page at* http://ops.dot.gov.

PART A – GENERAL REPORT INFORMATION

Check: ☐ Original Report ☒ Supplemental Report ☒ Final Report

1. Operator Name and Address

a. Operator's 5-digit Identification Number /1 /8 /5 /3 /6 /

b. If Operator does not own the pipeline, enter Owner's 5-digit Identification Number / / / / / /

c. Name of Operator Southwest Gas Corporation

d. Operator street address P. O. Box 98510

e. Operator address Las Vegas , Clark, Nevada 89193-8510
City, County or Parish, State and Zip Code

2. Time and date of the incident

/1 /5 /5/ 2 / hr. /0 /5 / month /2 /7 / day /0 /5 / year

3. Incident Location

a. 1841 South Campbell Avenue, Units 1 & 2
Street or nearest street or road

b. Tucson, Pima
City and County or Parish

c. Arizona, 85713
State and Zip Code

d. Latitude: /3/2/./2/0/0/0/1/3 Longitude:-/1/1/0/./9/4/3/0/9/1
(if not available, see instructions for how to provide specific location)

e. Class location description
○ Class 1 ○ Class 2 ⊙ Class 3 ○ Class 4

f. Incident on Federal Land ○ Yes ⊙ No

4. Type of leak or rupture

⊙ Leak: ○ Pinhole ○ Connection Failure *(complete sec. F5)*

⊙ Puncture, diameter or cross section *(inches)* crack of 1.5

○ Rupture (if applicable):

○ Circumferential – Separation

○ Longitudinal

- Tear/Crack, length *(inches)* ________

- Propagation Length, total, both sides *(feet)* ______

○ N/A

○ Other: ________

5. Consequences *(check and complete all that apply)*

a. ☐ Fatality N/A Total number of people: / / / /

Employees: / / / / *General Public:* / / / /

Non-employee Contractors: / / / /

b. ☒ Injury requiring inpatient hospitalization

Total number of people: / / / 1 /

Employees: / / / / *General Public:* / / / 1 /

Non-employee Contractors: / / / /

c. ☒ Property damage/loss *(estimated)* Total $ 225,000.00

Gas loss $ 0 Operator damage $ 25,000.00

Public/private property damage $ 200,000.00

d. ☒ Gas ignited ⊙ Explosion ○ No Explosion

e. ☐ Gas did not ignite ○ Explosion ○ No Explosion

f. ☒ Evacuation *(general public only)* / / / /4 / people

Evacuation Reason:

○ Unknown

⊙ Emergency worker or public official ordered, precautionary

○ Threat to the public

○ Company policy

6. Elapsed time until area was made safe:

/ /2 / hr. / 3 / 0 / min.

7. Telephone Report

760-206 NRC Report Number /0 /5 / month /2 /7 / day /0 /5 / year

8. a. Estimated pressure at point and time of incident:

60 *PSIG*

b. Max. allowable operating pressure *(MAOP):* 60 *PSIG*

c. MAOP established by:

⊙ Test Pressure 100 psig

○ 49 CFR § 192. 619 (a)(3)

PART B – PREPARER AND AUTHORIZED SIGNATURE

Vernon Sullivan Specialist/Compliance
(type or print) Preparer's Name and Title

(520) 794-6034
Area Code and Telephone Number

vernon.sullivan@swgas.com
Preparer's E-mail Address

(520) 794-6166
Area Code and Facsimile Number

Authorized Signature

Randy Ortlinghaus Director/Gas Operations
(type or print) Name and Title

12/9/05
Date

(520) 794-6053
Area Code and Telephone Number

PART C – ORIGIN OF THE INCIDENT

1. Incident occurred on
   - ⦿ Main ○ Meter Set
   - ○ Service Line ○ Other: ____________
   - ○ Pressure Limiting and Regulating Facility
2. Failure occurred on
   - ⦿ Body of pipe ○ Pipe Seam
   - ○ Joint ○ Component
   - ○ Other: ____________
3. Material involved *(pipe, fitting, or other component)*
   - ○ Steel
   - ○ Cast/Wrought Iron
   - ⦿ Polyethelene Plastic (complete all items that apply in a-c)
   - ○ Other Plastic (complete all items that apply in a-c)
   - Plastic failure was: ☐ a.ductile ☒ b.brittle ☐ c.joint failure
   - ○ Other material: ____________
4. Year the pipe or component which failed was installed: / 1 / 9 / 8 / 1 /

PART D – MATERIAL SPECIFICATION (if applicable)

1. Nominal pipe size *(NPS)* / 2 / . / 0 / 0 / in.
2. Wall thickness / . / 2 / 1 / 6 / in.
3. Specification ASTM D 2513 SMYS / / / / / / /
4. Seam type N/A
5. Valve type N/A
6. Pipe or valve manufactured by DuPont in year / 1 / 9 / 8 / 1 /

PART E – ENVIRONMENT

1. Area of incident
   - ○ Under pavement ○ In open ditch
   - ⦿ Under ground ○ Above ground
   - ○ Inside/under building ○ Under water
   - ○ Other: ____________
2. Depth of cover: 28 inches

PART F – APPARENT CAUSE

***Important:* There are 25 numbered causes in this section. Check the box to the left of the primary cause of the incident. Check one circle in each of the supplemental items to the right of or below the cause you indicate. See the instructions for this form for guidance.**

F1 – CORROSION N/A

1. ☐ External Corrosion
2. ☐ Internal Corrosion

If either F1 (1) External Corrosion, or F1 (2) Internal Corrosion is checked, complete all subparts a – e.

a. Pipe Coating
   - ○ Bare
   - ○ Coated
   - ○ Unknown

b. Visual Examination
   - ○ Localized Pitting
   - ○ General Corrosion
   - ○ Other: ____________

c. Cause of Corrosion
   - ○ Galvanic ○ Stray Current
   - ○ Improper Cathodic Protection
   - ○ Microbiological
   - ○ Other: ____________

d. Was corroded part of pipeline considered to be under cathodic protection prior to discovering incident?
   ○ No ○ Yes ○ Unknown Year Protection Started: / / / / /

e. Was pipe previously damaged in the area of corrosion?
   ○ No ○ Yes ○ Unknown How long prior to incident: / / / / years / / / months

F2 – NATURAL FORCES N/A

3. ☐ Earth Movement ⇒ ○ Earthquake ○ Subsidence ○ Landslide ○ Other: ____________
4. ☐ Lightning
5. ☐ Heavy Rains/Floods ⇒ ○ Washouts ○ Flotation ○ Mudslide ○ Scouring ○ Other: ____________
6. ☐ Temperature ⇒ ○ Thermal stress ○ Frost heave ○ Frozen components ○ Other: ____________
7. ☐ High Winds

F3 – EXCAVATION N/A

8. ☐ Operator Excavation Damage *(including their contractors)* / Not Third Party
9. ☐ Third Party Excavation Damage *(complete a-d)*
   - a. Excavator group
     ○ General Public ○ Government ○ Excavator other than Operator/subcontractor
   - b. Type: ○ Road Work ○ Pipeline ○ Water ○ Electric ○ Sewer ○ Phone/Cable/Fiber ○ Landowner ○ Railroad ○ Building Construction ○ Other: ____________
   - c. Did operator get prior notification of excavation activity?
     ○ No ○ Yes: Date received: / / / mo. / / / day / / / yr.
     Notification received from: ○ One Call System ○ Excavator ○ General Contractor ○ Landowner
   - d. Was pipeline marked?
     ○ No ○ Yes *(If Yes, check applicable items i – iv)*
     - i. Temporary markings: ○ Flags ○ Stakes ○ Paint
     - ii. Permanent markings: ○ Yes ○ No
     - iii. Marks were *(check one)* ○ Accurate ○ Not Accurate
     - iv. Were marks made within required time? ○ Yes ○ No

F4 – OTHER OUTSIDE FORCE DAMAGE N/A

10. ☐ Fire/Explosion as primary cause of failure ⇒ Fire/Explosion cause: ○ Man made ○ Natural *Describe in Part G*
11. ☐ Car, truck or other vehicle not relating to excavation activity damaging pipe
12. ☐ Rupture of Previously Damaged Pipe
13. ☐ Vandalism

F5 – MATERIAL OR WELDS

Material

14. [X] Body of Pipe ⇒ O Dent O Gouge O Wrinkle Bend O Arc Burn ⊙ Other: Crack
15. [ ] Component ⇒ O Valve O Fitting O Vessel O Extruded Outlet O Other: ______
16. [ ] Joint ⇒ O Gasket O O-Ring O Threads O Fusion O Other: ______

Weld

17. [ ] Butt ⇒ O Pipe O Fabrication O Other: ______
18. [ ] Fillet ⇒ O Branch O Hot Tap O Fitting O Repair Sleeve O Other: ______
19. [ ] Pipe Seam ⇒ O LF ERW O DSAW O Seamless O Flash Weld
O HF ERW O SAW O Spiral O Other: ______

Complete a-f if you indicate any cause in part F5.

a. Type of failure:

[X] Construction Defect ⇒ O Poor Workmanship ⊙ Procedure not followed O Poor Construction Procedures

[ ] Material Defect

b. Was failure due to pipe damage sustained in transportation to the construction or fabrication site? O Yes ⊙ No

c. Was part which leaked pressure tested before incident occurred? ⊙ Yes, *complete d-f, if known* O No

d. Date of test: / 0 / 8 / mo. / 1 / 2 / day / 8 / 1 / yr.

e. Time held at test pressure: / 0 / 2 / hr.

f. Estimated test pressure at point of incident: 100 *PSIG*

F6 – EQUIPMENT OR OPERATIONS N/A

20. [ ] Malfunction of Control/Relief Equipment ⇒ O Valve O Instrumentation O Pressure Regulator O Other: ______
21. [ ] Threads Stripped, Broken Pipe Coupling ⇒ O Nipples O Valve Threads O Mechanical Couplings O Other: ______
22. [ ] Leaking Seals

23. [ ] Incorrect Operation

a. Type: O Inadequate Procedures O Inadequate Safety Practices O Failure to Follow Procedures O Other: ______

b. Number of employees involved in incident who failed post-incident drug test: / / / / Alcohol test: / / / /

c. Was person involved in incident qualified per OQ rule? O Yes O No d. Hours on duty for person involved: / / /

F7 – OTHER

24. [ ] Miscellaneous, *describe:* ______
25. [ ] Unknown

⊙ Investigation Complete O Still Under Investigation *(submit a supplemental report when investigation is complete)*

PART G – NARRATIVE DESCRIPTION OF FACTORS CONTRIBUTING TO THE EVENT *(Attach additional sheets as necessary)*

At 1552 hours on May 27, 2005, Southwest Gas was notified of a fire at 1841 South Campbell Avenue. Upon arrival at 1614 hours, two apartment units were found to be damaged by the reported fire. A leak investigation was initiated and the presence of gas was detected below ground. Gas control of the main and services in the vicinity of the fire was achieved at 1822 hours by digging and squeezing, which resulted in an outage of 28 services. One person required inpatient hospitalization. Further investigation determined that the leak was on a 2" polyethylene main. The leak was due to rock impingement. There is a possibility that previous third party excavation in the immediate area was a contributing factor to the incident. An investigation is ongoing.

Results of an analysis conducted on the polyethylene main determined the probable cause of the crack in the pipe was the result of rock impingement. While third party excavation was known to have taken place in the vicinity of the failed pipe section, findings were inconclusive as to whether this work contributed to the incident.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

Form 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2005

Commission File Number 1-7850

SOUTHWEST GAS CORPORATION

(Exact name of registrant as specified in its charter)

California (State or other jurisdiction of incorporation or organization)	88-0085720 (I.R.S. Employer Identification No.)
5241 Spring Mountain Road Post Office Box 98510 Las Vegas, Nevada (Address of principal executive offices)	89193-8510 (Zip Code)

Registrant's telephone number, including area code: (702) 876-7237

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes _X_ No ___

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act).
Yes _X_ No ___

Indicate the number of shares outstanding of each of the issuer's classes of common stock as of the latest practicable date.
Common Stock, $1 Par Value, 38,318,099 shares as of August 1, 2005.

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 June 30, 2005, the combined balances in PGA accounts totaled an under-collection of $58.2 million versus an under-collection of $82.1 million at December 31, 2004. See **PGA Filings** section for more information on recent regulatory filings. Southwest utilizes short-term borrowings to temporarily finance under-collected PGA balances.

In April 2005, the Company replaced its $250 million credit facility, scheduled to expire in May 2007, with a $300 million facility that expires in April 2010. Of the $300 million, $150 million will be available for working capital purposes and $150 million will be designated long-term debt. 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 on the new credit facility is lower than the applicable margin of the previous facility. At June 30, 2005, no borrowings were outstanding on the short-term portion of the credit facility.

The following table sets forth the ratios of earnings to fixed charges for the Company (because of the seasonal nature of the Company's business, these ratios are computed on a twelve-month basis):

	For the Twelve Months Ended	
	June 30, 2005	December 31, 2004
Ratio of earnings to fixed charges	1.86	1.93

Earnings are defined as the sum of pretax income plus fixed charges. Fixed charges consist of all interest expense including capitalized interest, one-third of rent expense (which approximates the interest component of such expense), preferred securities distributions, and amortized debt costs.

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 increased from $1 million per incident to $1 million per incident plus payment of the first $10 million in aggregate claims above $1 million in the policy year. During the second quarter of 2005, a leaking natural gas line was involved in a fire that injured an individual. The cause of the leak is under investigation. Information regarding the extent of the injuries has not been made available to the Company and no claims have been filed against the Company. If the injuries were severe and the Company was deemed fully or partially responsible, the Company could be exposed to the extent noted above and future results of operations would be impacted. However, no range of potential loss has been determined. None of the likely outcomes would materially affect the financial position of the Company.

For the policy year August 2005 to July 2006, the Company entered into insurance contracts that limit the Company's self-insured retention to $1 million per incident plus payment of the first $5 million in aggregate claims above $1 million.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2005

Commission File Number 1-7850

SOUTHWEST GAS CORPORATION

(Exact name of registrant as specified in its charter)

California (State or other jurisdiction of incorporation or organization)	**88-0085720** (I.R.S. Employer Identification No.)
5241 Spring Mountain Road **Post Office Box 98510** **Las Vegas, Nevada** (Address of principal executive offices)	**89193-8510** (Zip Code)

Registrant's telephone number, including area code: (702) 876-7237

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, $1 par value	New York Stock Exchange, Inc.
7.70% Preferred Trust Securities	New York Stock Exchange, Inc.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ✓ No___

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes___ No ✓

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ✓ No___

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ___

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.
Large accelerated filer ✓ Accelerated filer ___ Non-accelerated filer ___

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes___ No ✓

Aggregate market value of the voting and non-voting common stock held by nonaffiliates of the registrant:
$976,113,313 as of June 30, 2005

The number of shares outstanding of common stock:
Common Stock, $1 Par Value, 39,557,464 shares as of March 1, 2006

DOCUMENTS INCORPORATED BY REFERENCE

Description	Part Into Which Incorporated
Annual Report to Shareholders for the Year Ended December 31, 2005	Parts I, II, and IV
2006 Proxy Statement	Part III

Item 3. LEGAL PROCEEDINGS

In May 2005, a leaking natural gas line was involved in a fire in a residence in Tucson, Arizona. An individual was severely injured. 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. A lawsuit was filed against the Company in December 2005 in the Superior Court for the State of Arizona, in and for the County of Pima (Case No. C20057063), in which $3.4 million in medical bills are claimed, $12 million in future medical expenses are claimed, and unspecified claims are made for general damages and punitive damages. Plaintiffs have claimed relief under theories of negligence, negligence per se, strict liability and loss of consortium and punitive damages. The Company has answered the complaint and denied liability. The complaint was amended in February 2006 to identify the parties to the litigation as Arnold Valenzuela, a single man, and Arturo and Julia Valenzuela, husband and wife, plaintiffs, and the Company as the sole defendant. If the Company was deemed fully or partially responsible, the Company estimates its exposure could be as much as $11 million (the maximum self-insured retention amount under its insurance policies). As of December 31, 2005, the Company has recorded an $11 million liability related to this incident.

The Company is named as a defendant in various other legal proceedings. The ultimate dispositions of these proceedings are not presently determinable; however, it is the opinion of management that none of this litigation individually or in the aggregate will have a material adverse impact on the Company's financial position or future results of operations.

Item 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

Item 4A. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The listing of the executive officers of the Company is set forth under **Part III Item 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT**, which by this reference is incorporated herein.

Southwest Gas Corporation.
Annual Report 2005

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 increased from $1 million per incident to $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. The Company recorded a $1 million liability related to this incident during the third quarter of 2005 based on preliminary information available at the time. 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. The Company has answered the complaint and denied liability. If the Company was deemed fully or partially responsible, the Company estimates its exposure could be as much as $11 million (the maximum noted above). In December 2005, the Company increased the reserves related to this incident by $10 million, bringing the total liability to the Company's maximum self-insured retention level of $11 million.

For the policy year August 2005 to July 2006, the Company entered into insurance contracts that limit the Company's 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,	2005	2004	2003
(Thousands of dollars)			
Construction revenues	$259,026	$215,008	$196,651
Cost of construction	237,356	196,792	184,290
Gross profit	21,670	18,216	12,361
General and administrative expenses	6,672	5,742	5,543
Operating income	14,998	12,474	6,818
Other income (expense)	3,009	2,131	1,290
Interest expense	1,009	645	855
Income before income taxes	16,998	13,960	7,253
Income tax expense	6,845	5,539	2,962
Contribution to consolidated net income	$ 10,153	$ 8,421	$ 4,291

2005 vs. 2004

The 2005 contribution to consolidated net income from construction services increased $1.7 million from 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 favorable equipment resale market in the current year.

254-042

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-6-42:

Please identify the total number of Southwest Gas employees who were eligible for MIP in each year, 2003 through 2007, and the total amount of MIP each year.

a. Also indicate the total amount of MIP expense charged to Southwest Gas' Arizona ACC-jurisdictional operations in each year.

Respondent: Revenue Requirements/Human Resources

Response: ***CORRECTED SUPPLEMENTAL ATTACHMENT – MARCH 25 2008***

SUPPLEMENTAL RESPONSE – MARCH 24, 2008

The MIP expense for years 2003 through 2007, along with the portion that would be allocated to Arizona, is attached.

Please note that the prior response for year 2006 was incorrect; it inadvertently included stock option expense. The 2006 amount was corrected to show MIP expense only. Also, the prior response did not show the portion of MIP that should have been allocated to Paiute and SGTC using the MMF allocation factor, prior to applying the 4-Factor to allocate the remainder to Arizona. This response now shows the proper allocation of MIP costs to Arizona.

SOUTHWEST GAS CORPORATION
MANAGEMENT INCENTIVE PLAN (MIP)
2003 THROUGH 2007
IN RESPONSE TO STF-6-42

Line No.	Description (a)	2003 (b)	2004 (c)	2005 (d)	2006 (e)	2007 (f)	Line No.
1	Number of Participants	70	71	72	76	71	1
2	Total MIP Expense [2]	$ 6,256,300	$ 5,699,300	$ 5,681,550	$ 5,241,806 [1]	5,919,502	2
3	Allocation to Paiute Pipeline (PP)/SGTC	5.20%	4.91%	4.91%	4.11%	4.12%	3
4	MIP Allocated to PP/SGTC	$ 325,328	$ 279,836	$ 278,964	$ 215,438	$ 243,883	4
5	MIP Expense Net of PP/SGTC	$ 5,930,972	$ 5,419,464	$ 5,402,586	$ 5,026,368	$ 5,675,619	5
6	AZ Allocation Factor	57.38%	57.66%	57.10%	56.81%	56.78%	6
7	MIP Allocated to AZ [1]	$ 3,403,192	$ 3,124,863	$ 3,084,877	$ 2,855,480	$ 3,222,616	7

[1] Revised to exclude Stock Option Expense
[2] Revised to exclude Exempt Special Incentive. See Updated RUCO-1-10.

UNS Gas
AZ Sales Tax Payment Lag

Revenue Month	Service Period (a) Start	End	Days	Days to End of Month	Tax Payment Date	Lag Days (b)
January	11/29/2004	1/28/2005	61	3	20-Feb	53.50
February	12/29/2004	2/28/2005	62	0	20-Mar	51.00
March	1/28/2005	3/31/2005	63	0	20-Apr	51.50
April	2/26/2005	4/29/2005	62	1	20-May	52.00
May	3/30/2005	5/31/2005	63	0	20-Jun	51.50
June	4/28/2005	6/30/2005	64	0	20-Jul	52.00
July	5/27/2005	7/29/2005	64	2	20-Aug	54.00
August	6/29/2005	8/31/2005	64	0	20-Sep	52.00
September	7/28/2005	9/29/2005	64	1	20-Oct	53.00
October	8/30/2005	10/28/2005	60	3	20-Nov	53.00
November	9/29/2005	11/30/2005	63	0	20-Dec	51.50
December	10/28/2005	12/29/2005	63	2	20-Jan	53.50
						628.5
						12
Average Payment Lag						52.38

(a) Extending from the first day of the first billing cycle to the last day of the last billing cycle

(b) Measured from the midpoint of the service period to the tax payment date

UNS Electric
AZ Sales Tax Payment Lag

Revenue Month	Service Period (a) Start	End	Days	Days to End of Month	Tax Payment Date	Lag Days (b)
January	12/2/2004	1/31/2005	60	0	20-Feb	50.00
February	1/4/2005	2/28/2005	56	0	20-Mar	48.00
March	2/2/2005	3/29/2005	56	2	20-Apr	50.00
April	3/2/2005	4/28/2005	58	2	20-May	51.00
May	4/2/2005	5/27/2005	56	4	20-Jun	52.00
June	5/2/2005	6/28/2005	58	2	20-Jul	51.00
July	6/2/2005	7/29/2005	58	2	20-Aug	51.00
August	7/2/2005	8/29/2005	59	2	20-Sep	51.50
September	8/2/2005	9/29/2005	58	1	20-Oct	50.00
October	9/2/2005	10/28/2005	57	3	20-Nov	51.50
November	10/4/2005	11/29/2005	57	1	20-Dec	49.50
December	11/2/2005	12/28/2005	57	3	20-Jan	51.50
						607
						12
Average Payment Lag						50.58

(a) Extending from the first day of the first billing cycle to the last day of the last billing cycle

(b) Measured from the midpoint of the service period to the tax payment date

TEP
Lead/Lag Study
AZ Sales Tax Payment Lag
July 2005 thru June 2006

Revenue Month	Service Period (a) Start	End	Days	Tax Payment Date	Lag Days (b)
July	5/22/05	7/21/05	60.0	8/20/05	59.0
August	6/23/05	8/19/05	57.0	9/20/05	58.0
September	7/25/05	9/20/05	57.0	10/20/05	57.0
October	8/21/05	10/19/05	59.0	11/20/05	60.0
November	9/22/05	11/17/05	56.0	12/20/05	60.0
December	10/21/05	12/20/05	60.0	1/20/06	60.0
January	11/19/05	1/23/06	65.0	2/20/06	58.0
February	12/22/05	2/21/06	61.0	3/20/06	58.0
March	1/25/06	3/22/06	56.0	4/20/06	59.0
April	2/23/06	4/20/06	56.0	5/20/06	58.0
May	3/24/06	5/19/06	56.0	6/20/06	59.0
June	4/24/06	6/20/06	57.0	7/20/06	57.0
					703.0
					/12
	Average Payment Lag				58.6

Note:
(a) Extending from the first day of first billed cycle in revenue month to last day of billing in revenue month.
(b) Measured from midpoint of the service period to the tax payment date.

CITY OF PHOENIX PRIVILEGE (SALES) TAX RETURN

For office use only

City Treasurer
P.O. Box 29690
Phoenix, AZ 85038-9690

RETURN DUE	CITY LICENSE NO.
1/20/2008	84017643
DELINQUENT IF RECEIVED AFTER 1/31/2008	PERIOD M FROM 1207 THRU 1207

Amended Return

84017643M
Southwest Gas Corporation
P.O. Box 98510 LVC-435
Las Vegas, NV 89193-8510

Please indicate mailing address change here.

☐ To cancel your license, check the box at the left, note reason and date of cancellation and sign the bottom of the form.
Reason ______________
Effective Date ______________

GENERAL NOTICE TO ALL TAXPAYERS

If you had no business activity in this reporting period, check here and sign at the bottom ☐

IF AN "X" APPEARS CALL (602) 262-7339

Business Description	Line	Business Class	Gross Income	Les (-): Deductions from Line A21 on back	Equals (=) Net Taxable	x Tax Rate	Equals (=) Tax Amount
UTILITIES - PSE	1	20	23,107,561.49	$ 613,156.30	22,494,405.19	2.7%	607,348.94
RETAIL	2	22	~~478,918.18~~	0.00	~~478,918.18~~	~~2.2%~~	~~10,536.20~~
	3						
	4						
USE TAX	5	25	XXXXXXXXXXXXXXXX	XXXXXXXXXXXXXXXX	526,810.00 ~~478,918.48~~	2.0% ~~1.0%~~	10,536.20 ~~8,620.53~~

Line	Description		Tax Amount
6	SUBTOTAL (Add lines [illegible] in Column 5)	Equals (=)	~~626,505.67~~
7	TOTAL FROM ADDITIONAL PAGES (if any)	Plus (+)	0.00
8	SUBTOTAL (Add lines 6 and 7)	Equals (=)	~~626,505.67~~
9	ENTER EXCESS CITY TAX COLLECTED (from line B1 on Page 2)	Plus (+)	0.00
10	GRAND TOTAL (Add lines 8 and 9)	Equals (=)	~~626,505.67~~
11	PENALTY & INTEREST (see instructions)	Plus (+)	0.00
12	ENTER TOTAL LIABILITY (Add Lines 10 and 11)	Equals (=)	~~626,505.67~~
13	ENTER CREDIT BALANCE TO BE APPLIED (Total of Lines B2 thru B4 on Page 2)	Minus (-)	0.00
14	ENTER NET AMOUNT DUE (Subtract Line 13 from Line 12)	Equals (=)	~~626,505.67~~
15	ENTER TOTAL AMOUNT PAID (Payable to PHOENIX CITY TREASURER)		~~626,505.67~~ 617,885.14

Under penalties of perjury, I declare that I have examined this return, including accompanying schedules and statements, and to the best of my knowledge and belief is true, correct and complete. Declaration of preparer (other than taxpayer) is based on all information of which preparer has any knowledge.

Do not write in this area

Reporting Period 12/07 - 12/07 M License No. 84017643M

Signature of Taxpayer/Paid Preparer ______ Date 1/9/2008 2/21/08

Laura Hoffman, Sr. Tax Accountant
Print Name of Taxpayer/Paid Preparer

(702) 876-7039
Phone #

A SIGNATURE IS REQUIRED TO MAKE THIS RETURN VALID.
Return form with payment in envelope provided.
Write your license number on your check.
THIS FORM MUST BE RETURNED TO THE CITY EVEN IF THERE IS NO TAX DUE.

MAKE A COPY OF BOTH SIDES OF YOUR COMPLETED TAX RETURN FOR YOUR RECORDS.

TRANSACTION PRIVILEGE AND USE TAX RETURN

City of Scottsdale
Customer Service Division
(480) 312-2400
Mail Payments to: P.O. Box 1949
Scottsdale, AZ 85252-1949

LICENSE NO.	REPORTING PERIOD	DUE BY THE 20th OF
105852	Dec 2007	January-08

PLEASE CHECK ALL THAT MAY APPLY

- [ ] Amended Return
- [ ] Name change only
- [ ] Mailing Address Change Only
- [ ] Cancel License as of ________

Service Address: 10851 N. BLACK CANYON, PHOENIX, AZ 85072

SOUTHWEST GAS CORPORATION
LVC-435
PO BOX 98510
LAS VEGAS NV 89193-8510

SPECIAL NOTICE

Place a check here and sign at the bottom if you have no taxes to file [ ]

[ ] Check here if you have a change in activity, address, a business name, etc. An application will be mailed to you.

Business Description	Line	Bus. Class	Column 1 Gross	Column 2 Deductions	Column 3 = Net Taxable	Column 4 x Tax Rate	Column 5 = Tax Amount
TRANS PRIV TAX	1	237110	214,579.72	51,025.78	163,553.94	1.65%	2,698.64
USE TAX	2	237110	-	0.00	-	1.45%	-
Do Not Use	3	N/A					
Pre 7/2004 Priv	4	237110					
Do Not Use	5	N/A					
	6	SUBTOTAL (Add col. 5 Lines 1 Through 5)					2,698.64
	7	ENTER TOTAL EXCESS CITY TAX COLLECTED (Total from Schedule B on back)				Plus (+)	-
	8	GRAND TOTAL				Equals (=)	2,698.64
	9	PENALTY & INTEREST (see instructions)				Plus (+)	0.00
	10	ENTER TOTAL LIABILITY				Equals (=)	2,698.64
	11	ENTER CREDIT BALANCE TO BE APPLIED (From Schedule B on pg 2)				Minus (-)	0.00
	12	ENTER NET AMOUNT DUE				Equals (=)	2,698.64
	13	ENTER TOTAL AMOUNT PAID					2,698.64
		FOR OFFICE USE ONLY					

Under penalties of perjury, I declare that I have examined this return, including accompanying schedules and statements, and to the best of my knowledge and belief is true, correct and complete. Declaration of preparer (other than taxpayer) is based on all information of which preparer has any knowledge.

Taxpayer's Signature ________ Date: 01/09/08 ________ Paid Preparer's Signature ________

Print Name: Laura Hoffman, Sr. Tax Accountant ________ Phone #: (702) 876-7039 ________ Print Paid Preparer's Name ________

A SIGNATURE IS REQUIRED TO MAKE THIS RETURN VALID
Return original with remittance in envelope provided.
Please make check payable to: **CITY OF SCOTTSDALE** and list your License number on your check.
Or pay in person at: 7447 E. Indian School Rd. Suite 110 or 9379 E. San Salvador Dr. Suite 100

PRIVILEGE (SALES) AND USE TAX RETURN

Tempe

City of Tempe
Tax and License Office
P.O. Box 29618
Phoenix, 85038-9618
Phone: (480) 350-2955
Fax: (480) 350-8859
Email: salestax@tempe.gov
www.tempe.gov/salestax

LICENSE NO.
23239
REPORTING PERIOD Dec 2007
DUE DATE Jan 20 2008

SOUTHWEST GAS CORPORATION
C/O SOUTHWEST GAS CORP.
PO BOX 98510
LAS VEGAS NV 89193-8510

Please indicate any changes in your account:

WHEN YOU ARE CLAIMING A DEDUCTION, BE SURE TO ENTER IT ON THE APPROPRIATE LINE AND COLUMN ON THE FORM BACK, TOTAL AND CARRY THAT NUMBER FORWARD TO THE FORM FRONT.

Business Description	Line	Bus. Class	Column 1 Gross	Column 2 Deductions	Column 3 = Net Taxable	Column 4 x Tax Rate	Column 5 = Tax Amount
UTILITIES	1	4	3,909,955.65	31,461.21	3,878,494.44	0.018	69,812.90
RENTAL REAL PRO	2	13				0.018	-
USE TAX PURCHAS	3	20	88,421.11		88,421.11	0.018	1,591.58
	4						
	5						
	6						
	7	SUBTOTAL (Add col. 5 Lines 1 Through 6)					71,404.48
	8	ENTER TOTAL EXCESS CITY TAX COLLECTED (Total from Schedule B on back)				Plus (+)	-
	9	TOTAL TAX DUE (Add column 5, lines 7 and 8)				Equals (=)	71,404.48
	10a	LATE PAYMENT PENALTY (10% of total tax due)				Plus (+)	0.00
	10b	INTEREST (1% per month of total tax due)				Plus (+)	0.00
	10c	LATE FILING PENALTY (5% per month to maximum 15% of total tax due)				Plus (+)	0.00
	11	ENTER TOTAL LIABILITY (Add column 5, lines 9 through 10c)				Equals (=)	71,404.48
	12	ENTER TOTAL CREDIT BALANCE TO BE APPLIED (From Schedule B on back)				Minus (-)	0.00
	13	ENTER NET AMOUNT DUE (Subtract column 5, line 12 from line 11)				Equals (=)	71,404.48
	14	ENTER TOTAL AMOUNT PAID					71,404.48

Under penalties of perjury, I declare that I have examined this return, including accompanying schedules and statements, and to the best of my knowledge and belief is true, correct and complete. Declaration of preparer (other than taxpayer) is based on all information of which preparer has any knowledge.

Taxpayer's Signature

01/09/08
Date

Paid Preparer's Signature

Laura Hoffman, Sr. Tax Accountant
Print Name

(702) 876-7039
Phone #

Print Paid Preparer's Name

A SIGNATURE IS REQUIRED TO MAKE THIS RETURN VALID
Return original with remittance in envelope provided.
Please make check payable to: **CITY OF TEMPE**

CITY OF TUCSON

TAX RETURN

BUSINESS PRIVILEGE
PUBLIC UTILITY ROOM SURTAX
TRANSIENT RENTAL

City of Tucson / Finance Department
Revenue Division / License Section
255 W. Alameda
Tucson, AZ 85701
(520) 791-4566

CITY LICENSE NO.	
0065848	
PERIOD COVERED	
FROM 12/2007	THROUGH 12/2007
CYCLE M	
OFFICE USE	
a	b c

LVC-435 0065848
SOUTHWEST GAS CORP.
PO BOX 98510
LAS VEGAS NV 89193-8510

3401 E GAS

SPECIAL NOTICE

YOU MUST COMPLETE SCHEDULE B ON PAGE 2 IF YOU HAVE MORE THAN ONE ACTIVITY EVEN IF YOU ARE REPORTING ZERO TAX DUE.

THIS RETURN MUST BE FILED WHETHER OR NOT ANY TAX IS DUE.

THIS RETURN IS DUE ON THE 20TH OF THE MONTH FOLLOWING THE PERIOD IN WHICH TAXES ARE DUE.

			Column 1	Column 2	Column 3	Column 4	Column 5
Business Description	Line	Activity #	Gross	Allowable pg 2 - Deductions	= Net Taxable	x Tax Rate	= Tax Amount
UTILITIES	1	04	13,519,669.60	145,083.60	13,374,586.00	2.00%	267,491.72
CONTRACTING	2	15	0.00	0.00	0.00	2.00%	0.00
PUBLIC UTILITY	3	20	0.00	0.00	0.00	2.00%	0.00
*If you have one activity, fill in the amount in Column 5. If you have more than one, fill out Schedule B on Page 2.	4	SUBTOTAL (Add col. 5 Lines 1 Through 7)					267,491.72
	5	ENTER EXCESS CITY TAX COLLECTED *				Plus (+)	0.00
	6	SUBTOTAL (Add lines 4 and 5)				Equals (=)	267,491.72
	7	PENALTY & INTEREST (see Instruction Sheet) *				Plus (+)	0.00
	8	SUBTOTAL (Add lines 6 and 7)				Equals (=)	267,491.72
	9	ENTER CREDIT BALANCE TO BE APPLIED (attach Notice of Credit) *				Minus (-)	0.00
	10	ENTER NET AMOUNT DUE (Subtract line 9 from line 8)				Equals (=)	267,491.72
	11	ENTER TOTAL AMOUNT PAID					267,491.72

Under penalties of perjury, I declare that I have examined this return, including accompanying schedules and statements, and to the best of my knowledge and belief it is true, correct and complete. Declaration of preparer (other than taxpayer) is based on all information of which preparer has any knowledge.

A SIGNATURE IS REQUIRED TO MAKE THIS RETURN VALID

Taxpayer's Signature | 01/09/08 Date | Paid Preparer's Signature

Laura Hoffman, Sr. Tax Accountant Print Name | (702) 876-7039 Phone # | Print Paid Preparer's Name

RETURN IS DUE ON THE 20th OF THE MONTH FOLLOWING THE REPORTING PERIOD AND DELINQUENT IF NOT RECEIVED BY THE LAST BUSINESS DAY OF THE MONTH. POSTMARKS ARE NOT REGARDED AS EVIDENCE OF DATE RECEIVED.

Make check payable to: City of Tucson
Return original with remittance in envelope provided to: CollectionsP.O. Box 27320**Tucson, AZ 85726**
Or pay in person at: Collections**255 W. Alameda, 1st floor (City Hall). Overnight deliveries should also be sent to this address.

CITY OF TUCSON

TAX RETURN
BUSINESS PRIVILEGE
PUBLIC UTILITY ROOM SURTAX
TRANSIENT RENTAL

City of Tucson / Finance Department
Revenue Division / License Section
255 W. Alameda
Tucson, AZ 85701
(520) 791-4566

CITY LICENSE NO.	
0065848	
PERIOD COVERED	
FROM	THROUGH
12/2007	12/2007
CYCLE	
M	
OFFICE USE	
a	b c

LVC-435 0065848
SOUTHWEST GAS CORP.
PO BOX 98510
LAS VEGAS NV 89193-8510

3401 E GAS

SPECIAL NOTICE

YOU MUST COMPLETE SCHEDULE B ON PAGE 2 IF YOU HAVE MORE THAN ONE ACTIVITY EVEN IF YOU ARE REPORTING ZERO TAX DUE.

THIS RETURN MUST BE FILED WHETHER OR NOT ANY TAX IS DUE.

THIS RETURN IS DUE ON THE 20TH OF THE MONTH FOLLOWING THE PERIOD IN WHICH TAXES ARE DUE.

			Column 1	Column 2	Column 3	Column 4	Column 5
Business Description	Line	Activity #	Gross	Allowable pg 2 - Deductions	= Net Taxable	x Tax Rate	= Tax Amount
USE TAX	1	99	542,654.00	0.00	542,654.00	2.00%	10,853.08
	2						
	3						
*If you have one activity, fill in the amount in Column 5. If you have more than one, fill out Schedule B on Page 2.	4	SUBTOTAL (Add col. 5 Lines 1 Through 7)					10,853.08
	5	ENTER EXCESS CITY TAX COLLECTED *				Plus (+)	0.00
	6	SUBTOTAL (Add lines 4 and 5)				Equals (=)	10,853.08
	7	PENALTY & INTEREST (see instruction Sheet) *				Plus (+)	0.00
	8	SUBTOTAL (Add lines 6 and 7)				Equals (=)	10,853.08
	9	ENTER CREDIT BALANCE TO BE APPLIED (attach Notice of Credit) *				Minus (-)	0.00
	10	ENTER NET AMOUNT DUE (Subtract line 9 from line 8)				Equals (=)	10,853.08
	11	ENTER TOTAL AMOUNT PAID					10,853.08

Under penalties of perjury, I declare that I have examined this return, including accompanying schedules and statements, and to the best of my knowledge and belief it is true, correct and complete. Declaration of preparer (other than taxpayer) is based on all information of which preparer has any knowledge.

A SIGNATURE IS REQUIRED TO MAKE THIS RETURN VALID

Taxpayer's Signature — Date: 01/09/08 — Paid Preparer's Signature

Print Name: Laura Hoffman, Sr. Tax Accountant — Phone #: (702) 876-7039 — Print Paid Preparer's Name

RETURN IS DUE ON THE 20th OF THE MONTH FOLLOWING THE REPORTING PERIOD AND DELINQUENT IF NOT RECEIVED BY THE LAST BUSINESS DAY OF THE MONTH. POSTMARKS ARE NOT REGARDED AS EVIDENCE OF DATE RECEIVED.

Make check payable to: City of Tucson
Return original with remittance in envelope provided to: CollectionsP.O. Box 27320**Tucson, AZ 85726**
Or pay in person at: Collections**255 W. Alameda, 1st floor (City Hall). Overnight deliveries should also be sent to this address.

TRANSACTION PRIVILEGE (SALES) AND USE TAX RETURN

City of Chandler
MAIL STOP 701
P.O. BOX 15001
CHANDLER AZ 85244-5001

Chandler • Arizona
Where Values Make The Difference

LICENSE NO.
8023
REPORTING PERIOD
Dec 2007
DUE BY THE 20th OF
Jan 2008

Check here if mailing address has changed. ☐
Please make corrections to the preprinted address.

SOUTHWEST GAS CORPORATION
LVC - 435
PO BOX 98510
LAS VEGAS NV 89193-8510

Location Address:
5241 SPRING MOUNTAIN RD
LAS VEGAS NV 89193-8510

Place a check here and sign at the bottom if you have no activity to report. ☐

THIS RETURN IS DUE ON THE 20TH OF THE MONTH

Line	Complete Both Sides of Form Business Description	Business Class Code	Column 1 Gross Receipts / Use Taxable Purchases	Column 2 From Sch. A, on back - Deductions	Column 3 = Net Taxable	Column 4 x Tax Rate	Column 5 = Tax Amount
1	USE TAX	99	-		-	1.50%	-
2	UTILITIES	4	3,520,822.53	57,934.17	3,462,888.36	2.75%	95,229.43
3							
4							
5	TOTAL FROM ADD'L PAGES						
6	SUBTOTALS						95,229.43
7	ENTER EXCESS CITY TAX COLLECTED (from SCHEDULE C on the back)					Plus (+)	
8	TOTAL TAX DUE (Add line 6 plus 7)					Equals (=)	95,229.43
9	PENALTY & INTEREST (see instructions on back)					Plus (+)	0.00
10	ENTER TOTAL LIABILITY (Add lines 8 plus 9)					Equals (=)	95,229.43
11	ENTER CREDIT BALANCE TO BE APPLIED (From Schedule B, on back)					Minus (-)	0.00
12	ENTER NET AMOUNT DUE (Subtract line 11 from line 10)					Equals (=)	95,229.43
13	ENTER TOTAL AMOUNT PAID						95,229.43

Under penalties of perjury, I declare that I have examined this return, including the accompanying schedules and statements, and to the best of my knowledge and belief it is true, correct and complete. The declaration of the paid preparer is based upon all information of which preparer has any knowledge.

Taxpayer's Signature

01/09/08
Date

Paid Preparer's Signature

Laura Hoffman, Sr. Tax Accountant
Print Name

(702) 876-7039
Phone #

Print Paid Preparer's Name

A SIGNATURE IS REQUIRED TO MAKE THIS RETURN VALID
Return original with remittance in envelope provided.
Please make check payable to: CITY OF CHANDLER and list your license number on your check.

4815125699

PRIVILEGE (SALES) AND USE TAX RETURN

Mail return and remittance (if applicable) to:

City of Glendale
P.O. Box 800
Glendale, AZ 85311-0800
(602) 930-3190

CITY LICENSE NO.	
100015739-4	
PERIOD COVERED	
FROM	THROUGH
12/01/07	12/31/07
DELINQUENT IF NOT RECEIVED BY 1/20/2008	
RECEIVED	

SOUTHWEST GAS CORPORATION
C/O SOUTHWEST GAS CORP.
PO BOX 98510
LAS VEGAS NV 89193-8510

SPECIAL NOTICE

Place a check here and sign at the bottom if you have no taxes to file ☐

THIS RETURN IS DUE ON THE 20TH OF THE MONTH

			Column 1	Column 2	Column 3	Column 4	Column 5
Business Description	Line	Bus. Class	Gross	Deductions	= Net Taxable	x Tax Rate	= Tax Amount
UTILITIES	1	4	2,897,416.00	71,526.00	2,825,890.00	2.20%	62,169.58
	2	28					
	3	65					
	4	75					
USE TAX	5	99	218.64		218.64	2.20%	4.81
	6						-
	7	TOTAL FROM ADDITIONAL PAGES					
	8	SUBTOTAL (Add col 5 lines 1 through 7)					62,174.39
	9	ENTER EXCESS CITY TAX COLLECTED				Plus (+)	0.00
	10	GRAND TOTAL				Equals (=)	62,174.39
	11	PENALTY & INTEREST (see instructions)				Plus (+)	0.00
	12	ENTER TOTAL LIABILITY				Equals (=)	62,174.39
	13	ENTER CREDIT BALANCE TO BE APPLIED				Minus (-)	0.00
	14	ENTER NET AMOUNT DUE				Equals (=)	62,174.39
	15	ENTER TOTAL AMOUNT PAID					62,174.39

Under penalties of perjury, I declare that I have examined this return, including accompanying schedules and statements, and to the best of my knowledge and belief it is true, correct and complete. Declaration of preparer (other than taxpayer) is based on all information of which preparer has any knowledge.

Taxpayer's Signature — Date: 01/09/08 — Paid Preparer's Signature

Print Name: Laura Hoffman, Sr. Tax Accountant — Phone #: (702) 876-7039 — Print Paid Preparer's Name

A SIGNATURE IS REQUIRED TO MAKE THIS RETURN VALID

Return original with remittance in envelope provided.
Please make check payable to: CITY OF GLENDALE

TRANSACTION PRIVILEGE AND USE TAX RETURN

000245470706122006

CITY OF MESA
Great People, Quality Service!

Tax and Licensing Office
55 North Center Street
Mesa, Arizona 85201
(480)644-2316 Fax (480)644-3999

LICENSE NO. 00024547
REPORTING PERIOD JAN - DEC 2007
DUE DATE 1/20/2008

LVC-435 TAX DEPT
SOUTHWEST GAS CORPORATION
C/O SOUTHWEST GAS CORP.
PO BOX 98510
LAS VEGAS NV 89193-8510

Check here and sign at the bottom to cancel your license

Reason:

SPECIAL NOTICE

Place a check here and sign at the bottom if you have no taxes to file

THIS RETURN IS DUE ON THE 20TH OF THE MONTH

			Column 1	Column 2	Column 3	Column 4	Column 5
Business Description	Line	Bus. Class	Gross	Deductions	Net Taxable	x Tax Rate	= Tax Amount
UTILITIES	1	13	1,258,015.61	1,244,292.75	13,722.86	1.75%	240.15
	2						
	3						
	4						
	5						
	6						
USE TAX	7	20	-	0.00	-	1.75%	-
Total from Addl Pages	8						
	9	SUBTOTAL	1,258,015.61	1,244,292.75	13,722.86	1.75%	240.15
	10	(Total from Schedule B) ENTER EXCESS CITY TAX COLLECTED/JET FUEL				Plus (+)	0.00
	11	TOTAL TAX DUE				Equals (=)	240.15
	12	(see instructions) PENALTY & INTEREST				Plus (+)	0.00
	13	ENTER TOTAL LIABILITY				Equals (=)	240.15
	14	(Total from Schedule B) CREDIT BALANCE TO BE APPLIED				Minus (-)	0.00
	15	ENTER NET AMOUNT DUE				Equals (=)	240.15
	16	ENTER TOTAL AMOUNT PAID					240.15

Under penalties of perjury, I declare that I have examined this return, including accompanying schedules and statements, and to the best of my knowledge and belief it is true, correct and complete. Declaration of preparer (other than taxpayer) is based on all information of which preparer has any knowledge.

Taxpayer's Signature — Date: 01/09/08 — Paid Preparer's Signature

Print Name: Laura Hoffman, Sr. Tax Accountant — Phone #: (702) 876-7039 — Print Paid Preparer's Name

A SIGNATURE IS REQUIRED TO MAKE THIS RETURN VALID
Return original with remittance in envelope provided.
Please make check payable to: CITY OF MESA
Complete both sides of form.

Mailing Address
PO Box 16350
Mesa Arizona 85211-6350

(TPT-1) (Rev. 12-00)

Docket No. G-01551A-07-0504
Attachment RCS-8
Page 78 of 83

LICENSE NO.
2573
REPORTING PERIOD
Dec 2007
DUE BY THE 20th OF
Jan 2008

PRIVILEGE (SALES) and USE TAX RETURN

City of Peoria
Tax and License Section
8401 W. Monroe Street
Peoria, AZ 85345
Phone: (623) 773-7160
Fax: (623) 773-7159

EmailL salestax@peoriaaz.com
http://www.peoriaaz.com/salestax

SOUTHWEST GAS CORPORATION
PO BOX 98510
LVC-435 TAX DEPT
LAS VEGAS NV 89193-8510

Please indicate any change in your account

If you have no taxes to file check this box & sign at bottom ☐

Business Description	Line	Bus. Class	Column 1 Gross	Column 2 Deductions	Column 3 = Net Taxable	Column 4 x Tax Rate	Column 5 = Tax Amount
UTILITIES	1	4	2,181,927.80	8,307.80	2,173,620.00	0.033	71,729.46
	2						
	3						
	4						
	5						
	6						
	7						
	8	ENTER TOTAL EXCESS CITY TAX COLLECTED (Total from Schedule B on back)				Plus (+)	
	9	TOTAL TAX DUE (Add column 5, line 7 and 8)				Equals (=)	71,729.46
	10a	LATE PAYMENT PENALTY (10% of total tax due)				Plus (+)	0.00
	10b	INTEREST (1% per month of the total tax due)				Plus (+)	0.00
	10c	LATE FILING PENALTY (5% per month to maximum 15% of total tax due)				Plus (+)	0.00
	11	ENTER TOTAL LIABILITY (Add column 5, line 9 through 10c)				Equals (=)	71,729.46
	12	ENTER CREDIT BALANCE TO BE APPLIED (From Schedule B on back)				Minus (-)	0.00
	13	ENTER NET AMOUNT DUE (Subtract column 5, line 12 from line 11)				Equals (=)	71,729.46
	14	ENTER TOTAL AMOUNT PAID					71,729.46

Under penalties of perjury, I declare that I have examined this return, including accompanying schedules and statements, and to the best of my knowledge and belief it is true, correct and complete. Declaration of preparer (other than taxpayer) is based on all information of which preparer has any knowledge.

Taxpayer's Signature — Date: 01/09/08 — Paid Preparer's Signature

Laura Hoffman, Sr. Tax Accountant
Print Name — Phone #: (702) 876-7039 — Print Paid Preparer's Name

A SIGNATURE IS REQUIRED TO MAKE THIS RETURN VALID

Please send the original tax return with remittance in the envelope provided to the address shown above.
Please make check payable to: CITY OF PEORIA

LIC09T01V01

Avondale

Sales Tax Department
11465 W Civic Center Drive, Ste. 270
Avondale, Arizona 85323-6808

City License #	Period Covered
6012	December 2007

DELINQUENT IF NOT PAID BY THE LAST BUSINESS DAY OF THE MONTH.

***AUTO-MIXED AADC 852 1048
SOUTHWEST GAS CORPORATION
PO BOX 98510 LVC-435
LAS VEGAS NV 89193-8510

RETURN THIS FORM WITH YOUR REMITTANCE TO:

CITY OF AVONDALE
Sales Tax Department
11465 W Civic Center Drive, Ste. 270
Avondale, Arizona 85323-6808

SPECIAL NOTICE

RETURNS DUE 01/20/08 MUST BE RECEIVED BY 01/31/08 TO AVOID PENALTY AND INTEREST. POSTMARKS ARE NOT CONSIDERED.

Place a check here and sign at the bottom if you have no taxes to file ☐

THIS RETURN IS DUE ON THE 20TH OF THE MONTH

			Column 1	Column 2	Column 3	Column 4	Column 5
Business Description	Line	Bus. Class	Gross	- Deductions	= Net Taxable	x Tax Rate	= Tax Amount
CONTRACTING	1	C					
TRANS/COMM/UTIL	2	T	873,562.40	4,474.00	869,088.40	2.50%	21,727.21
	3						
	4						
	5						
	6						
	7	PRIOR BALANCE					0.00
	8	SUBTOTAL Total Col. 5 Lines 1 Through 7					21,727.21
	9	ENTER EXCESS CITY TAX COLLECTED				Plus (+)	0.00
	10	GRAND TOTAL				Equals (=)	21,727.21
	11	PENALTY				Plus (+)	0.00
	12	INTEREST				Plus (+)	0.00
	13	NET AMOUNT DUE				Equals (=)	21,727.21
	14	ENTER TOTAL AMOUNT PAID					21,727.21

Under penalties of perjury, I declare that I have examined this return, including accompanying schedules and statements, and to the best of my knowledge and belief it is true, correct and complete. Declaration of preparer (other than taxpayer) is based on all information of which preparer has any knowledge.

Taxpayer's Signature — Date: 01/09/08 — Paid Preparer's Signature

Print Name: Laura Hoffman, Sr. Tax Accountant — Phone #: (702) 876-7039 — Print Paid Preparer's Name

( ) Check here if any changes in account status and complete the back of this form.

A SIGNATURE IS REQUIRED TO MAKE THIS RETURN VALID
Return original with remittance in envelope provided.
Please make check payable to: CITY OF AVONDALE

(TPT-1) (Rev. 7-00)

EFT FILER

TRANSACTION PRIVILEGE, USE AND SEVERANCE TAX RETURN (TPT-1)

Arizona Department of Revenue
PO BOX 29010 PHOENIX, AZ 85038-9010

NOTE: TPT-1 RETURNS ARE DUE THE 20TH DAY OF THE FOLLOWING MONTH. FOR ASSISTANCE CALL 602-255-2060 IN THE PHOENIX AREA, OR STATEWIDE TOLL FREE 800 842-7196

STATE LICENSE NUMBER:	11 009297-C
TAXPAYER IDENTIFICATION NUMBER: ☒ EIN ☐ SSN	880085720
PERIOD BEGINNING: 04012007	PERIOD ENDING: 04302007
DOR USE ONLY	☒ LABELED RETURN
POSTMARK DATE	
RECEIVED DATE	

TAXPAYER INFORMATION

☐ Amended Return ☒ Multipage Return ☐ One-Time On ☐ Final

SOUTHWEST GAS CORP
C/O TAX DEPT
PO BOX 98510
LAS VEGAS, NV 89193-8510

21-2233

10011009297C04061050

☐ Address Changed

TRANSACTION DETAIL *(If more reporting lines are necessary, please attach continuation pages.)*

Line	(A) BUSINESS DESCRIPTION	(B) REGION CODE	(C) BUSINESS CLASS	(D) GROSS AMOUNT	(E) DEDUCTION AMOUNT	(F) NET TAXABLE AMOUNT	(G) TAX RATE	(H) TOTAL TAX AMOUNT	(I) ACCOUNTING CREDIT RATE	(J) ACCOUNTING CREDIT
1	UTILITIES	COC	004	162,877.77		162,877.77	.06725	10,953.53	0.000560	-
2	RETAIL	COC	017	38.51		38.51	.06725	2.59	0.000560	-
2	USE TAX	COC	029	586.07		586.07	.05600	32.82	N/A	N/A
3	UTILITIES	COH	004	2,579,581.31		2,579,581.31	.06100	157,354.46	0.000560	-
4	RETAIL	COH	017	-		-	.06100	-	0.000560	-
5	USE TAX	COH	029	573,698.39		573,698.39	.05600	32,127.11	N/A	N/A
6	UTILITIES	GLA	004	423,571.21		423,571.21	.06600	27,955.70	0.000560	-
7	RETAIL	GLA	017	-		-	.06600	-	0.000560	-
	Total			3,576,850.91	-	3,576,850.91		228,426.21		-

TAX COMPUTATION

1 Total deductions from Schedule A		1	-
2 Total Tax Amount (from column H)		2	4,910,032.36
3 State excess tax collected	+	3	-
4 Other excess tax collected	+	4	-
5 Total Tax Liability: Add lines 2, 3, and 4	=	5	4,910,032.36
6 Accounting Credit (from column J)		6	-
7 State excess tax accounting credit: Multiply line 3 by .01	+	7	-
8 Total Accounting Credit: Add lines 6 and 7	=	8	-
9 Net tax due line: Subtract line 8 from line 5		9	4,910,032.36
10 Penalty and interest	+	10	-
11 TPT estimate payments to be use	-	11	-
12 Total amount due this period	=	12	4,910,032.36
13 Additional payment to be applied (for other periods)	+	13	-
14 TOTAL AMOUNT REMITTED WITH THIS RETURN	=	14	**4,910,032.36**

AMENDED RETURN ONLY
ORIGINAL REMITTED AMOUNT

DOR USE
$

Under penalties of perjury, I declare that I have examined this return, including accompanying schedules and statements, and to the best of my knowledge and belief, it is true, correct and complete. Declaration of preparer (other than taxpayer) is based on all information of which preparer has any knowledge.

5/18/07

TAXPAYER'S SIGNATURE DATE
Laura Hoffman, Sr. Tax Accountant

PAID PREPARER'S SIGNATURE (OTHER THAN TAXPAYER)

PAID PREPARER'S EIN OR SSN

ADOR 20-1046 (11/03)

Please make check payable to Arizona Department of Revenue

ansaction Privilege, Use, and Severance Tax Return (TPT-1)

LICENSE NO: 11 009297-C

ACTION DETAIL (ADDITIONAL TRANSACTIONS)

	(A) BUSINESS DESCRIPTION	(B) REGION CODE	(C) BUSINESS CLASS	(D) GROSS AMOUNT	(E) DEDUCTION AMOUNT	(F) NET TAXABLE AMOUNT	(G) TAX RATE	(H) TOTAL TAX AMOUNT	(I) ACCOUNTING CREDIT RATE	(J) ACCOUNTING CREDIT
1	USE TAX	GLA	029	9,043.75		9,043.75	.05600	506.45	N/A	N/A
2	UTILITIES	GLP	004	32,349.55		32,349.55	.06600	2,135.07	0.000560	-
3	UTILITIES	GRA	004	1,322,460.49		1,322,460.49	.06100	80,670.09	0.000560	-
4	UTILITIES	GRN	004	136,288.20		136,288.20	.06100	8,313.58	0.000560	-
5	RETAIL	GRN	017	-		-	.06100	-	0.000560	-
6	USE TAX	GRN	029	22.14		22.14	.05600	1.24	N/A	N/A
7	UTILITIES	LAC	004	29,142.88		29,142.88	.06600	1,923.43	0.000560	-
8	RETAIL	LAC	017	-		-	.06600	-	0.000560	-
9	USE TAX	LAC	029	-		-	.05600	-	N/A	N/A
10	UTILITIES	LAP	004	91,372.88		91,372.88	.06600	6,030.61	0.000560	-
11	RETAIL	LAP	017	-		-	.06600	-	0.000560	-
12	UTILITIES	MAH	004	90,365.08		90,365.08	.06300	5,693.00	0.000560	-
13	RETAIL	MAH	017	-		-	.06300	-	0.000560	-
14	USE TAX	MAH	029	-		-	.05600	-	N/A	N/A
15	UTILITIES	MAO	004	59,414.76		59,414.76	.06300	3,743.13	0.000560	-
16	RETAIL	MAO	017	-		-	.06300	-	0.000560	-
17	USE TAX	MAO	029	-		-	.05600	-	N/A	N/A
18	UTILITIES	MAR	004	41,829,621.27		41,829,621.27	.06300	2,635,266.14	0.000560	-
19	RENTAL-REAL	MAR	013	-		-	.00500	-	N/A	N/A
20	RETAIL	MAR	017	28.89		28.89	.06300	1.82	0.000560	-
21	USE TAX	MAR	029	2,971,567.86		2,971,567.86	.05600	166,407.80	N/A	N/A
22	UTILITIES	MAT	004	3,737.94		3,737.94	.06300	235.49	0.000560	-
23	RETAIL	MAT	017	-		-	.06300	-	0.000560	-
24	USE TAX	MAT	029	-		-	.05600	-	N/A	N/A
25	UTILITIES	MOF	004	8,378.80		8,378.80	.05850	490.16	0.000560	-
26	RETAIL	MOF	017	-		-	.05850	-	N/A	N/A
27	UTILITIES	MOH	004	826,741.37		826,741.37	.05850	48,364.37	0.000560	-
28	RETAIL	MOH	017	-		-	.05850	-	0.000560	-
29	USE TAX	MOH	029	97,973.21		97,973.21	.05600	5,486.50	N/A	N/A
30	UTILITIES	PAD	004	223,172.46		223,172.46	.06100	13,613.52	0.000560	-
31	UTILITIES	PMA	004	17,400,128.69		17,400,128.69	.06100	1,061,407.85	0.000560	-
32	USE TAX	PMA	029	398,010.71		398,010.71	.05600	22,288.60	N/A	N/A
33	UTILITIES	PMN	004	18,745.41		18,745.41	.06100	1,143.47	0.000560	-
34	RETAIL	PMN	017	-		-	.06100	-	0.000560	-
35	USE TAX	PMN	029	-		-	.05600	-	N/A	N/A
	Subtotal....................................			65,548,566.34	-	65,548,566.34		4,063,722.32		-

'SACTION DETAIL (ADDITIONAL TRANSACTIONS)

	(A) BUSINESS DESCRIPTION	(B) REGION CODE	(C) BUSINESS CLASS	(D) GROSS AMOUNT	(E) DEDUCTION AMOUNT	(F) NET TAXABLE AMOUNT	(G) TAX RATE	(H) TOTAL TAX AMOUNT	(I) ACCOUNTING CREDIT RATE	(J) ACCOUNTING CREDIT
1	UTILITIES	PMT	004	13,650.00		13,650.00	.06100	832.65	0.000560	-
2	USE TAX	PMT	029	-		-	.05600	-	N/A	N/A
3	UTILITIES	PNA	004	27,459.09		27,459.09	.06600	1,812.30	0.000560	-
4	RETAIL	PNA	017	-		-	.06600	-	0.000560	-
5	USE TAX	PNA	029	-		-	.05600	-	N/A	N/A
6	UTILITIES	PNH	004	41,289.24		41,289.24	.06600	2,725.09	0.000560	-
7	RETAIL	PNH	017	-		-	.06600	-	0.000560	-
8	USE TAX	PNH	029	-		-	.05600	-	N/A	N/A
9	UTILITIES	PNL	004	2,714,491.67		2,714,491.67	.06600	179,156.45	0.000560	-
0	RETAIL	PNL	017	-		-	.06600	-	0.000560	-
1	USE TAX	PNL	029	641,111.61		641,111.61	.05600	35,902.25	N/A	N/A
2	UTILITIES	YMA	004	1,607,264.63		1,607,264.63	.06700	107,686.73	0.000560	-
3	RETAIL	YMA	017	99.85		99.85	.06700	6.69	0.000560	-
4	USE TAX	YMA	029	667,497.86		667,497.86	.05600	37,379.88	N/A	N/A
5	APACHE JUNCT	AJ	000	-		-	.02200	-	N/A	N/A
6	APACHE JUNCT	AJ	001	246,026.56		246,026.56	.03200	7,872.85	N/A	N/A
7	BISBEE	BB	000	196,990.00		196,990.00	.02500	4,924.75	N/A	N/A
8	BUCKEYE	BE	000	10,798.00		10,798.00	.02000	215.96	N/A	N/A
9	BULLHEAD CIT	BH	000	14,357.50		14,357.50	.02000	287.15	N/A	N/A
20	BULLHEAD CIT	BH	002	97,973.50		97,973.50	.02000	1,959.47	N/A	N/A
21	BENSON	BS	000	10,536.80		10,536.80	.02500	263.42	N/A	N/A
22	CAREFREE	CA	000	158,241.00		158,241.00	.03000	4,747.23	N/A	N/A
	IFTON	CF	000	65,475.67		65,475.67	.03000	1,964.27	N/A	N/A
	CASA GRANDE	CG	000	-		-	.01800	-	N/A	N/A
25	CASA GRANDE	CG	001	8,104.50		8,104.50	.02000	162.09	N/A	N/A
26	CASA GRANDE	CG	002	-		-	.02000	-	N/A	N/A
27	CAVE CREEK	CK	001	94,572.67		94,572.67	.03000	2,837.18	N/A	N/A
28	CAVE CREEK	CK	002	(11,442.80)		(11,442.80)	.02500	(286.07)	N/A	N/A
29	COOLIDGE	CL	000	106,179.67		106,179.67	.03000	3,185.39	N/A	N/A
30	COOLIDGE	CL	002	-		-	.03000	-	N/A	N/A
31	DOUGLAS	DL	000	325,690.80		325,690.80	.02500	8,142.27	N/A	N/A
32	DOUGLAS	DL	002	2,429.60		2,429.60	.02500	60.74	N/A	N/A
33	ELOY	EL	000	130,272.33		130,272.33	.03000	3,908.17	N/A	N/A
34	EL MIRAGE	EM	000	166,551.67		166,551.67	.03000	4,996.55	N/A	N/A
35	FOUNTAIN HILLS	FH	000	245,141.15		245,141.15	.02600	6,373.67	N/A	N/A
	ubtotal..................................			7,580,762.57	-	7,580,762.57		417,117.13		-

ransaction Privilege, Use, and Severance Tax Return (TPT-1)

LICENSE NO 11 009297-C

...SACTION DETAIL (ADDITIONAL TRANSACTIONS)

...	(A) BUSINESS DESCRIPTION	(B) REGION CODE	(C) BUSINESS CLASS	(D) GROSS AMOUNT	(E) DEDUCTION AMOUNT	(F) NET TAXABLE AMOUNT	(G) TAX RATE	(H) TOTAL TAX AMOUNT	(I) ACCOUNTING CREDIT RATE	(J) ACCOUNTING CREDIT
1	FLORENCE	FL	000	234,825.00		234,825.00	.02000	4,696.50	N/A	N/A
2	GILBERT	GB	000	1,858,192.67		1,858,192.67	.01500	27,872.89	N/A	N/A
3	GILA BEND	GI	000	27,064.33		27,064.33	.03000	811.93	N/A	N/A
4	GLOBE	GL	000	209,009.50		209,009.50	.02000	4,180.19	N/A	N/A
5	GUADALUPE	GU	000	50,990.00		50,990.00	.03000	1,529.70	N/A	N/A
6	GOODYEAR	GY	000	1,024,309.00		1,024,309.00	.02000	20,486.18	N/A	N/A
7	HUACHUCA CIT	HC	000	600.00		600.00	.01500	9.00	N/A	N/A
8	KEARNY	KN	000	721.20		721.20	.02500	18.03	N/A	N/A
9	LITCHFIELD P	LP	000	4,555.00		4,555.00	.02000	91.10	N/A	N/A
0	MARANA	MA	000	-		-	.02000	-	N/A	N/A
1	MARANA	MA	004	504,840.50		504,840.50	.04000	20,193.62	N/A	N/A
2	MAMMOTH	MH	000	-		-	.02000	-	N/A	N/A
3	MIAMI	MM	000	-		-	.02500	-	N/A	N/A
4	MARICOPA	MP	000	463,396.00		463,396.00	.02000	9,267.92	N/A	N/A
5	ORO VALLEY	OR	000	828,380.50		828,380.50	.02000	16,567.61	N/A	N/A
6	PAGE	PG	000	154,840.33		154,840.33	.03000	4,645.21	N/A	N/A
7	PAGE	PG	002	586.00		586.00	.03000	17.58	N/A	N/A
8	PARKER	PK	000	68,617.50		68,617.50	.02000	1,372.35	N/A	N/A
9	PARKER	PK	003	-		-	.03000	-	N/A	N/A
20	PARADISE VAL	PV	000	9,705.45		9,705.45	.01650	160.14	N/A	N/A
21	QUEEN CREEK	QC	000	177,276.00		177,276.00	.02000	3,545.52	N/A	N/A
22	SAHUARITA	SA	000	262,066.50		262,066.50	.02000	5,241.33	N/A	N/A
	...PERIOR	SI	000	58,696.00		58,696.00	.02000	1,173.92	N/A	N/A
	...OMERTON	SO	000	7,727.20		7,727.20	.02500	193.18	N/A	N/A
25	SURPRISE	SP	000	1,213,058.18		1,213,058.18	.02200	26,687.28	N/A	N/A
26	SIERRA VISTA	SR	000	-		-	.01750	-	N/A	N/A
27	SIERRA VISTA	SR	002	571,268.57		571,268.57	.01750	9,997.20	N/A	N/A
28	SIERRA VISTA	SR	008	896,846.00		896,846.00	.02000	17,936.92	N/A	N/A
29	SOUTH TUCSON	ST	000	89,399.20		89,399.20	.02500	2,234.98	N/A	N/A
30	SAN LUIS	SU	000	12,305.71		12,305.71	.03500	430.70	N/A	N/A
31	TOLLESON	TN	000	64,032.50		64,032.50	.02000	1,280.65	N/A	N/A
32	TOMBSTONE	TS	000	-		-	.02500	-	N/A	N/A
33	WICKENBURG	WB	000	128,685.88		128,685.88	.01700	2,187.66	N/A	N/A
34	WINKELMAN	WM	000	-		-	.03500	-	N/A	N/A
35	WELLTON	WT	000	6,708.80		6,708.80	.02500	167.72	N/A	N/A
36	YUMA	YM	000	987,284.12		987,284.12	.01700	16,783.83	N/A	N/A
37	YOUNGTOWN	YT	000	49,293.00		49,293.00	.02000	985.86	N/A	N/A
	ubtotal..................................			9,965,280.64	-	9,965,280.64		200,766.70		-

EXHIBIT S-15

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR 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-07-0504

DIRECT

TESTIMONY

OF

ROBERT G. GRAY

EXECUTIVE CONSULTANT III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

MARCH 28, 2008

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EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-07-0504

My Testimony in this proceeding addresses a number of issues related to Southwest Gas Corporation's ("Southwest") purchased gas adjustor ("PGA") mechanism. Southwest has proposed to change the size of the band on the monthly PGA rate and my testimony provides Staff's analysis and recommendations regarding this and other PGA mechanism issues.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Robert G. Gray. I am an Executive Consultant III employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as an Executive Consultant III.

A. In my capacity as an Executive Consultant III, I conduct analysis and provide recommendations to the Commission on natural gas and other utility matters. A copy of my resume is attached as Schedule RGG-1.

Q. What is the scope of this testimony?

A. This testimony will address Southwest Gas Corporation's ("Southwest") purchased gas adjustor ("PGA") mechanism.

Q. Have you reviewed the testimony of Southwest Witness Frank Maglietti in regard to the PGA mechanism?

A. Yes. I have reviewed his testimony and will discuss his proposed change to the PGA mechanism as part of my testimony.

PURCHASED GAS ADJUSTOR

Q. Please discuss the functioning of the PGA mechanism in recent years.

A. At the time the currently effective PGA mechanism was initially implemented in June 1999, natural gas prices had been relatively low and stable for a number of years. Shortly following implementation, significant changes took place in natural gas markets, leading to higher and more volatile natural gas prices which have made the last five years difficult for regulators, local distribution companies, and consumers of natural gas. Recent years have also provided a stern test of various aspects of the PGA mechanism. Staff believes that in general the PGA mechanism as currently designed and operated has worked well, given the difficult circumstances of recent years. A PGA mechanism by nature determines the manner in which costs are passed through to customers, including such issues as timing and structure of such pass throughs. In a market where the underlying commodity cost has risen from around $2.50 per mmbtu to $6.00 or so in recent years, any PGA mechanism is going to reflect those higher costs, which will be passed through to customers in some fashion, the only variance being the manner in which the rising costs are passed along to customers. No PGA structure can change the underlying fact that natural gas prices and price volatility have increased dramatically in recent years. In general, Staff believes that the current PGA mechanism reasonably balances the interest in shielding customers from price volatility with the competing desire to at least to some extent send a price signal to customers regarding the changing level of the underlying commodity costs. Nonetheless, it is a worthwhile exercise to evaluate the on-going operation of the PGA mechanism and whether adjustments are warranted. Southwest has recommended a change to the PGA mechanism, and my testimony below discusses this proposed change and other PGA issues Staff has reviewed.

Q. How does the PGA bandwidth aspect of the PGA mechanism work?

A. As currently configured, the PGA bandwidth limits the movement of the monthly PGA rate over a 12-month period. The current PGA bandwidth of $0.13 per therm means that each month when a new PGA rate is calculated, the new monthly PGA rate cannot be more than $0.13 per therm different than the monthly PGA rate in any of the previous 12 months.

Q. Please discuss the history of the PGA bandwidth.

A. When the general PGA mechanism framework now in place was implemented in 1999, the PGA bandwidth was set at $0.07 per therm for Arizona natural gas local distribution companies ("LDCs"). Given the predominantly low and stable natural gas prices through the 1990s, it was generally expected that a $0.07 per therm bandwidth would not come into play very often. However, shortly thereafter the price of natural gas rose significantly and became much more volatile, resulting in the PGA bandwidth often limiting the movement of the monthly PGA rate for periods of time. In Decision Number 62994 (November 3, 2000), the Commission expanded the PGA bandwidth for Arizona LDCs, including Citizens Utilities Arizona Gas Division (UNS' predecessor) to $0.10 per therm.

Since that Decision the Commission has changed the PGA bandwidth in individual LDC rate cases several times. In Southwest Gas' rate case that concluded in February 2006, the Commission expanded Southwest's PGA bandwidth to $0.13 per therm. In Duncan Rural Services' rate case that was concluded in March 2006, the Commission expanded Duncan's PGA bandwidth such that the monthly PGA rate can change up to $0.10 per therm per month, providing the opportunity for the PGA rate to change up to $1.20 per therm per year. In approving the significant expansion of the PGA bandwidth for Duncan, the Commission cited Duncan's small size and considerable financial constraints. Most recently the Commission expanded the PGA bandwidth for UNS Gas to $0.15 per therm in Decision Number 70011 (November 27, 2007).

Q. Has Southwest proposed a change to the current PGA bandwidth of $0.13 per therm?

A. Yes. Southwest has proposed that the PGA bandwidth be expanded to $0.24 per therm.

Q. Please discuss Southwest's proposal regarding the PGA bandwidth.

A. Southwest's proposal to expand the PGA bandwidth to $0.24 per therm would allow the monthly PGA rate to automatically track Southwest's changing cost of natural gas more fully than currently is the case, but would also potentially subject customers to a $0.24 per therm rate increase without any formal Commission review or approval. For comparison purposes, the $0.24 per therm swing is approximately one sixth the size of the total currently effective per therm residential rate as of December 2007.

When the PGA bandwidth was initially implemented in 1999, the purpose was to provide a reasonable range for movement of the monthly PGA rate that would capture the changing cost of gas in most instances and also limit the exposure of customers to an automatically changing PGA rate within a one-year period. In the end, to some extent even a PGA bandwidth is limited in its protection of customers, as if gas costs reach a high enough level, Southwest can apply for a temporary PGA surcharge to capture the higher costs that did not fall within the existing bandwidth. In such cases, the nature of the PGA surcharge would be subject to Commission review and approval, providing additional oversight before large gas cost increases are passed along to customers. The previous expansion of the bandwidth from $0.07 to $0.10 and then to $0.13 per therm was a recognition that additional flexibility in movement of the monthly PGA rate was needed, while balancing the need to still provide protection for customers from large automatic changes in rates.

By nature perspectives on the size of the PGA bandwidth are influenced by the volatility of the natural gas market in recent years. When natural gas markets are seeing a high level of volatility, as was seen in the price runups in 1999-2000 and as a result of Hurricanes Rita and Katrina in 2005, an argument can be made that the bandwidth needs to be expanded significantly. By contrast, since natural gas prices moderated after the 2005 hurricane impacts ran their course, natural gas prices, while hardly a model of stability, have fluctuated in a more moderate fashion than during prior recent periods. Looking at Southwest's monthly PGA rate, it has not been constrained by the existing $0.13 per therm bandwidth since February 2007, when the 12 month average cost was still reflecting hurricane-related events of late 2005. The February 2008 monthly PGA rate is approximately six cents different than the monthly PGA rate in February 2007, indicating that at the present moment, there is still some unused flexibility within the existing $0.13 per therm bandwidth. However, a significant run-up in natural gas prices could quickly change this circumstance.

Q. What is Staff's recommendation for Southwest's PGA bandwidth?

A. Staff is cognizant of Southwest's desire for greater flexibility in the PGA bandwidth as well as the need for some amount of checks and balances in how gas costs are passed on to customers, particularly in times when gas prices are high and volatile. In the most recent case involving the PGA bandwidth, the recent UNS Gas rate case, the Commission set the bandwidth level to $0.15 per therm. Staff believes that expanding Southwest's PGA bandwidth to $0.15 per therm would be a reasonable balancing of company and consumer interests and is consistent with the Commission's recent action on this issue for Arizona's other large LDC.

Q. Did the Company file testimony regarding the PGA bank balance threshold?

A. No.

Q. Why is Staff addressing the PGA bank balance threshold issues in its testimony?

A. Both the Commission and the Company have gained additional experience with the PGA mechanism, including the thresholds in recent years, leading to a better understanding of what changes might be made to improve the mechanism. Additionally, a rate case is the proper place to address changes to the fundamental mechanics of the PGA mechanism, and this issue was addressed, and changes made, to the PGA bank balance threshold in the recently concluded UNS Gas rate case. Staff believes the circumstances in this case for Southwest are similar to the circumstances in the recent UNS Gas case in regard to the PGA mechanism, and thus Staff believes this is an opportune time to further refine the threshold levels in the PGA mechanism.

Q. Please describe the function of the PGA bank balance threshold within Southwest's PGA mechanism.

A. The PGA bank balance threshold identifies the bank balance level, whether over-collected or under-collected, where Southwest is required to take action at the Commission to either address the over- or under-collection, or explain why they should not do so at that given point in time. For Southwest's PGA mechanism, the bank balance threshold was initially set at $22.4 million by the Commission in Decision Number 61225 (October 30, 1998). Subsequently, the Commission expanded the PGA bank balance threshold to $29.2 million in Decision Number 68487 (February 23, 2006).

Q. Please discuss why the bank balance thresholds were initially created in 1998 and 1999.

A. At the time the thresholds were initially created, they were created to ensure that PGA bank balance levels did not reach very high levels without any action being taken by the utility. In essence they were a trigger to ensure that the utility and the Commission were aware of and would take action as needed to address the balance. At the time, the initial threshold levels were set at points where it was expected that they would only rarely be breeched. This assumption was based upon the history of natural gas prices through the 1990s, when prices were relatively low and stable. Since the initial implementation of these thresholds, the PGA bank balance level has shown much greater volatility than was seen historically, with changes from month to month at times approaching the size of the threshold. The result is that utilities have exceeded the thresholds relatively often in the last 6-7 years. In light of these circumstances, Staff believes that reconsideration of the PGA bank balance threshold levels is warranted at this time.

Q. How do you believe the threshold on undercollected PGA bank balances should now be approached?

A. In recent years, LDCs that have filed for PGA surcharges have often made such filings before actually reaching the threshold, in anticipation of breeching the threshold in the near future. LDCs have always had the flexibility to file for a PGA surcharge (or credit) at any time as they see fit. With much higher and more volatile natural gas prices in recent years, both the Commission and LDCs are keenly aware of changes in the PGA bank balance and natural gas market conditions. For a larger LDC like Southwest, the Company regularly projects a variety of PGA numbers, including bank balances. Staff believes that these circumstances argue for a change in how the threshold on undercollected PGA bank balances is viewed.

A review of the month to month change in the PGA bank balance is also helpful in assessing the amount of change that has taken place in the PGA bank balance in recent years. Schedule RGG-2 contains a graph of Southwest's PGA bank balance since January 2002 and a graph of the raw size of the change in the PGA bank balance each month.

Since January 2002, the largest one month change in the PGA bank balance was approximately $27.4 million, from the end of January 2006 to the end of February 2006. A total of six months showed a change of over $20 million from the previous month between January 2002 and December 2007, with an additional four months with swings of between $10 million and $20 million. A review of the cumulative change over a seasonal timeframe shows the largest change over a three month period was from January 2002 to April 2002, when the PGA bank balance changed by a total of almost $69 million. Given this history of large PGA bank balance swings, retention of the current, relatively small threshold levels indicates the Commission is likely to continue to see filings from Southwest to address PGA bank balance levels on a regular basis if there is substantive market volatility.

Given these circumstances, Staff believes that for Southwest, the Commission should consider eliminating the bank balance threshold in relation to under-collected PGA bank balances. Given high and volatile natural gas prices that appear likely to continue in the near term future, both the Commission and Southwest carefully monitor the functioning of Southwest's PGA, including the changing size of the PGA bank balance. Further, Southwest and other LDCs have shown a strong interest in addressing undercollected PGA bank balances on a timely basis, so it is unlikely that Southwest's undercollected PGA bank balance would grow to very large proportions without action by the Company. Elimination of the threshold on undercollections would, in essence, provide the utility with the discretion to apply for a PGA surcharge when it believes such an action is warranted, while also providing the flexibility for Southwest to avoid such an action if the Company believes changing market conditions do not require such a filing. Staff believes that elimination of the threshold on undercollected PGA bank balances would result in a more smooth operation of the PGA, given the relatively common sizable monthly movements of the PGA bank balance, that at times exceed the size of the threshold itself. Staff therefore recommends elimination of the currently effective threshold on undercollected PGA bank balances.

Q. Has the Commission addressed the issue of the threshold on undercollected PGA bank balances recently?

A. Yes. In the recent UNS Gas rate case, the Commission approved elimination of the threshold on undercollected PGA bank balances, an action that was supported by both Staff and UNS Gas.

Q. How does Staff believe that the threshold on overcollected PGA bank balances should be treated?

A. While Staff believes that much of the previous discussion of the threshold on undercollected PGA bank balances also applies to overcollections, there is an additional public interest aspect to avoiding the growth of an overcollected PGA bank balance to exorbitant levels. On the other hand, provision for Southwest to carry an overcollection of some size can help provide a cushion to customers when natural gas market prices rise significantly, as has happened a number of times in recent years. Under the current threshold level, a sizable increase in natural gas market prices will likely result in Southwest swinging to a sizable undercollected PGA bank balance, even if they had a bank balance close to the current threshold requiring Southwest to take action. The current threshold level for overcollections of $22.4 million is sufficiently small that Southwest could conceivably exceed the threshold, appear before the Commission to implement a credit, and see their balance swing to a sizable undercollection in a short period of time, with Southwest still paying out the credit. Additionally, given volatile market conditions and the size of changes Southwest customers have seen over the past years, a refund over a one year period of $22.4 million over Southwest's customer base is a relatively small amount per therm, approximately $0.04 per therm, given recent sales levels.

Staff believes that the cushioning benefit of having a higher threshold level on overcollections, in addition to the administrative efficiency of not having a threshold level that can be easily exceeded in a month, argues for increasing the threshold level on overcollections substantially. The proper size of such an increase is not entirely clear. In the recent UNS Gas rate case, the Commission increased the overcollection threshold from $4.45 million to $10 million. Staff believes that such an increase reflects the increased bank balance volatility, the administrative efficiency of refunding relatively small per therm amounts and the growth in customers and sales experienced by UNS Gas.

The $10 million threshold adopted for UNS Gas represented a level of approximately $0.09 per therm of total gas sales in 2006 for UNS Gas. Staff believes the approach applied to UNS Gas in setting its overcollected threshold would also be reasonable to apply to Southwest. Application of the same approximately $0.09 per therm of annual sales for Southwest would result in an overcollected threshold of $55.78 million. Staff believes that increasing the overcollected threshold for Southwest to $55.78 million is reasonable given Southwest's size and on-going market conditions and recommends adoption of such a level by the Commission. At such a level, Southwest could have a sizable cushion for customers against a run up in market prices, while still providing substantial relief to customers when the higher threshold level is breeched. Staff believes that such a higher threshold is both administratively more efficient given significant market volatility, and provides the possibility of a substantive cushion for movement in the PGA bank balance toward an undercollection before customers would be likely to face a PGA surcharge. Therefore Staff recommends that the PGA bank balance threshold for overcollections for Southwest be set at $55.78 million dollars.

Q. What does Staff believe the net effect of these proposed changes to the PGA bank balance threshold will be?

A. Staff believes that over time these changes would result in fewer filings with the Commission to implement temporary PGA surcharges and credits and would provide Southwest with additional flexibility to manage its PGA bank balance, including the opportunity to time PGA surcharge filings with the Commission to the specific circumstances at a given time. For example, currently Southwest is required to come to the Commission to address an undercollected bank balance within specific times frames, even if addressing the PGA bank balance at that time could lead to a surcharge during the coldest months of the winter heating season. Under Staff's proposal, Southwest would have the opportunity to wait until the spring to file for a surcharge, or could, in its own judgment, determine that market conditions are such that it believes a surcharge isn't necessary to pursue at all. While natural gas prices have shown some amount of stability in the last couple years, underlying market conditions make it likely that in the near term future natural gas prices will again experience episodes of significant upward price volatility. Staff's proposals will better position Southwest to weather such episodes, while maintaining necessary protections for Southwest's customers.

Q. Southwest has proposed a number of revenue decoupling mechanisms in this case. Would those mechanisms have any impact on the PGA mechanism of they were adopted?

A. Staff's opposes the introduction of Southwest's proposed revenue decoupling mechanisms, as discussed in Staff Witness Frank Radigan's testimony. Southwest's revenue decoupling proposals could potentially impact the design of Southwest's rates. Because customers would pay a different gas cost per therm for different portions of their consumption under Southwest's rate design-related decoupling proposal, the existing PGA mechanism where a single per therm monthly PGA rate is calculated based on a 12-month rolling average would have to be changed. Given the different gas cost numbers for different usage levels, it is likely that a new PGA mechanism reflecting different tiers of gas cost would be more complicated and less understandable to customers. Introduction of revenue decoupling would also impact at least some of the numbers that are reported in the monthly PGA reports the Commission receives. Staff recommends that if any form of revenue decoupling is adopted in this case, that Southwest review the monthly PGA report and work with Staff to implement any needed changes to the report. Staff further recommends that prior to any introduction of the rate design decoupling mechanism, that Southwest address issues regarding how the decoupling rate design would change the functioning of the PGA mechanism and receive Commission approval of a proposal to change the PGA mechanism to reflect these new circumstances.

SUMMARY OF RECOMMENDATIONS

Q. Please summarize your recommendations.

A. My testimony includes the following recommendations:

1. The bandwidth on the monthly PGA rate should be expanded to $.015 per therm.

2. The threshold on the PGA bank balance for undercollected balances should be eliminated.

3. The threshold on the PGA bank balance for overcollected balances should be set at $55.78 million.

4. If a revenue decoupling mechanism is adopted in this case, Southwest should review its monthly PGA report and work with Staff to adjust the report as necessary to reflect changes resulting from revenue decoupling.

5. Prior to any introduction of the rate design decoupling mechanism, Southwest must address issues regarding how the decoupling rate design would change the functioning of the PGA mechanism and must receive Commission approval of a proposal to change the PGA mechanism to reflect these new circumstances.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

RESUME

ROBERT G. GRAY

Education

B.A. Geography, University of Minnesota-Duluth (1988)
M.A. Geography, Arizona State University (1990) Thesis: *A Model for Optimizing the Federal Express Overnight Delivery Aircraft Network.*

Employment History

Arizona Corporation Commission, Utilities Division, Phoenix, Arizona: Executive Consultant III (November 2007 – present), Public Utility Analyst V (October 2001 – November 2007), Senior Economist (August 1997 – October 2001), Economist II (June 1991 - July 1997), Economist I (June 1990 - June 1991). Conduct economic and policy analyses on a variety of natural gas and other utility issues in Arizona, including gas procurement, rate design, interstate pipeline issues, revenue decoupling, energy conservation, low income issues, natural gas research and development funding, customer services issues, special contracts, various tariff matters, and other natural gas issues. Prepare recommendations and present written and oral testimony before the Commission on various utility industry issues. Represent the ACC in natural gas proceedings at the Federal Energy Regulatory Commission and on the National Association of Regulatory Utility Commissioners' Staff Subcommittee on Gas, including serving as Chair of the NARUC Staff Subcommittee on Gas.

Testimony

Resource Planning for Electric Utilities, (Docket No. 0000-90-088), Arizona Corporation Commission, 1990.

Citizens Utilities Company, Electric Rate Case (Docket No. E-1032-92-073), Arizona Corporation Commission, 1993.

Resource Planning for Electric Utilities, (Docket No. 0000-93-052), Arizona Corporation Commission, 1993.

Arizona Public Service Company, Rate Settlement (Docket No. E-1345-94-120), Arizona Corporation Commission, 1994.

U S West Communications, Rate Case (Docket No. E-1051-93-183), Arizona Corporation Commission, 1995.

Citizens Utilities Company, Electric Rate Case (Docket No. E-1032-95-433), Arizona Corporation Commission, 1996.

Southwest Gas Corporation, Natural Gas Rate Case (Docket No. U-1551-96-596), Arizona Corporation Commission, 1997.

Black Mountain Gas Company - Northern States Power Company, Merger (Docket Nos. G-03493A-98-0017, G-01970A-98-0017), Arizona Corporation Commission, 1998.

Black Mountain Gas Company – Page Division Rate Case (Docket Nos. G-03493A-98-0695, G-03493A-98-0705), Arizona Corporation Commission, 1999.

Graham County Utilities Company Rate Case (Docket No. G-02527A-00-0378), Arizona Corporation Commission, 2000.

Black Mountain Gas Company – Cave Creek Division Rate Case (Docket No. G-03703A-00-0283), Arizona Corporation Commission, 2000.

Southwest Gas Corporation, Natural Gas Rate Case (Docket No. G-01551A-00-0309), Arizona Corporation Commission, 2000.

Black Mountain Gas Company – Page Division Rate Case (Docket Nos. G-03493A-01-0263), Arizona Corporation Commission, 2001.

Duncan Rural Services – Natural Gas Rate Case (Docket No. G-02528A-01-0561), Arizona Corporation Commission, 2001.

Toltec Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000Y-01-0112), September 2001.

Lap Paz Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000AA-01-0116), December 2001.

Bowie Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000BB-01-0118), December 2001.

Southwest Gas Corporation, Acquisition of Black Mountain Gas Company (Docket No. G-01551A-02-0425), Arizona Corporation Commission, 2002.

Wellton-Mohawk Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000Z-01-0114), February 2003.

Arizona Public Service Company, Rate Proceeding (Docket No. E-01345A-03-0437), Arizona Corporation Commission, 2004.

Graham County Utilities Company Rate Case (Docket No. G-02527A-04-0301), Arizona Corporation Commission, 2004.

Southwest Gas Corporation, Rate Proceeding (Docket No. G-01551A-04-0876), Arizona Corporation Commission, 2004.

Southern California Edison, Devers – Palo Verde 2 Transmission Line Application before the Arizona Power Plant and Line Siting Committee, (L-00000A-06-0295-00130), 2006.

Semstream Arizona Propane Acquisition of Energy West (Docket G-02696A-06-0515), Arizona Corporation Commission, 2006.

UNS Gas Inc., Rate Proceeding (Docket No. G-04204A-06-0463), Arizona Corporation Commission, 2007.

Semstream Arizona Propane Acquisition of Black Mountain Gas Company – Page Division (Docket G-03703A-06-0694), Arizona Corporation Commission, 2007.

Northern Arizona Energy, LLC, Northern Arizona Energy Project Application before the Arizona Power Plant and Line Siting Committee, (L-00000FF-07-0134-00133), 2007.

Arizona Public Service, Palo Verde Hub to North Gila 500 kV Transmission Lint Project Application before the Arizona Power Plant and Line Siting Committee, (L-00000D-07-0566-00135), 2007.

Publications

(with David Berry, Kim Clark, Lewis Gale, Barbara Keene, and Harry Sauthoff) Staff Report on Resource Planning. (Docket No. U-0000-90-088) Arizona Corporation Commission, 1990.

(with Prem Bahl) "Transmission Access Issues: Present and Future," October, 1991.

(with David Berry) Substitution of Photovoltaics for Line Extensions: Creating Consumer Choices. Arizona Corporation Commission, 1992.

(with Barbara Keene and Kim Clark) Report of the Task Force on the Feasibility of Implementing Sliding Scale Hookup Fees, December, 1992.

(with Mike Kuby) "The Hub and Network Design Problem With Stopovers and Feeders: The Case of Federal Express," Transportation Research A., Vol. 27A, 1993, pp. 1-12.

(with David Berry) Staff Guidelines on Photovoltaics Versus Line Extensions. Arizona Corporation Commission, January 28, 1993.

(with Ray Williamson, Robert Hammond, Frank Mancini, and James Arwood) The Solar Electric Option (Instead of Power Line Extension). A joint publication of the Arizona Corporation Commission and the Arizona Department of Commerce Energy Office, August, 1993.

(with David Berry, Kim Clark, Barbara Keene, Jesse Tsao, Ray Williamson, Randall Sable, Roni Washington, Wilfred Shand, and Prem Bahl) Staff Report on Resource Planning. (Docket No. U-0000-93-052) Arizona Corporation Commission, 1993.

Staff Report On Rural Local Calling Areas. (Docket No. E-1051-93-183) Arizona Corporation Commission, March, 1994.

(with David Berry, Kim Clark, Barbara Keene, Glenn Shippee, Julia Tsao, and Ray Williamson) Staff Report on Resource Planning. (Docket No. U-000-95-506) Arizona Corporation Commission, 1996.

(with Barbara Keene) "Customer Selection Issues," NRRI Quarterly Bulletin, Vol. 19, No. 1, Spring 1998, National Regulatory Research Institute.

Staff Report on Purchased Gas Adjustor Mechanisms, (Docket No. G-00000C-98-0568) Arizona Corporation Commission, October 19, 1998.

Staff Report on the Rolling Average PGA Mechanism, (Docket No. G-00000C-98-0568),Arizona Corporation Commission, September 6, 2000.

Staff Report on the Use of a Circuit-Breaker in Adjustor Mechanisms, Arizona Corporation Commission, September 3, 2003.

Staff Report on Southwest Gas Filing for Pre-Approval of Cost Recovery for Participation in the Kinder Morgan Silver Canyon Pipeline Project, (Docket No. G-01551A-04-0192), Arizona Corporation Commission, June 2, 2004.

Staff Report on Arizona Public Service Company Filing for Pre-Approval of Cost Recovery for Participation in the Kinder Morgan Silver Canyon Pipeline Project, (Docket No. E-01345A-04-0273), Arizona Corporation Commission, August 16, 2004.

Staff Report on Arizona Public Service Company Filing for Pre-Approval of Cost Recovery for Participation in the Transwestern Pipeline Phoenix Project, (Docket No. E-01345A-05-0895), Arizona Corporation Commission, March 2, 2006.

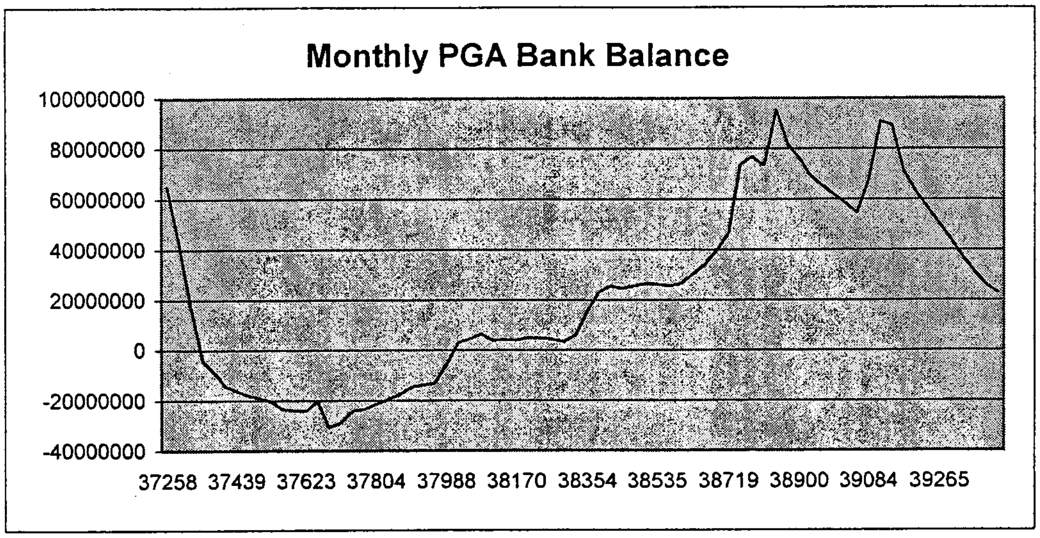
Staff Report on Southwest Gas Filing for Pre-Approval of Cost Recovery for Participation in the Transwestern Pipeline Phoenix Project, (Docket No. G-01551A-060107), Arizona Corporation Commission, May 16, 2006.

Additional Training

1990	Seminars on Regulatory Economics
1993	PURTI course on Public Utilities and the Environment
1996	Center for Public Utilities Workshop on Gas Unbundling and Retail Competition
1997	NARUC 6th Annual Natural Gas Conference
1998	Local Distribution Company Restructuring and Retail Access and Competition Conference
1998	NARUC 7th Annual Natural Gas Conference
1999 – 2007	NARUC Summer Committee Meetings
2001	Center for Public Utilities Workshop on Risk Management in Gas Purchasing
2003-2008	NARUC Winter Committee Meetings
2004-2007	NARUC Annual Convention

Memberships

NARUC - Staff Subcommittee on Gas – Vice-Chair (2002 - 2004)
NARUC - Staff Subcommittee on Gas – Chair (2005 - 2007)
Michigan State Institute for Public Utilities – NARUC Advisory Committee
NARUC Advisory Council for the North American Energy Standards Board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40000000
20000000
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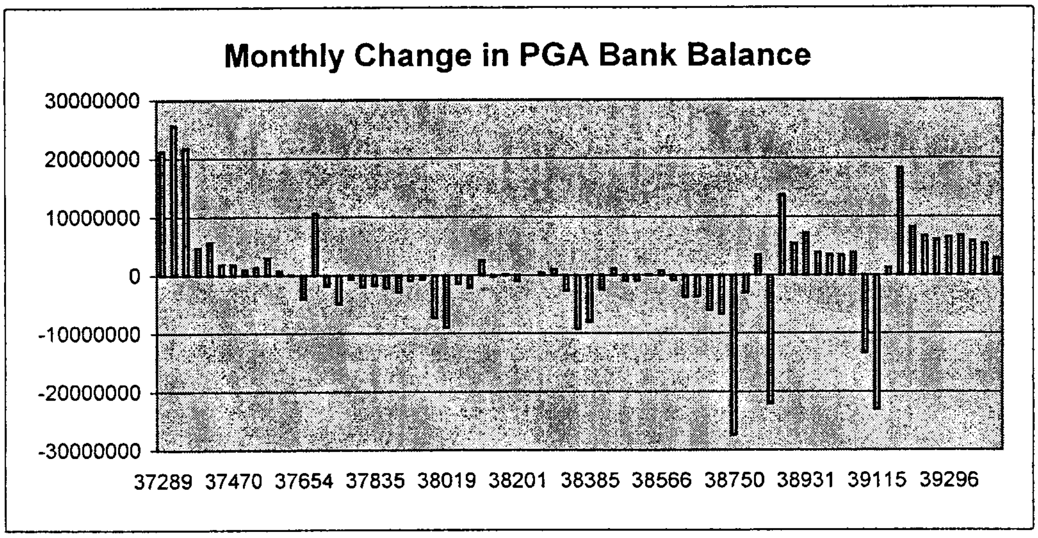
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20000000
10000000
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EXHIBIT
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S-16

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR JUST AND REASONABLE RATES AND CHARGES.	DOCKET NO. G-01551A-07-0504

SURREBUTTAL

TESTIMONY

OF

ROBERT G. GRAY

EXECUTIVE CONSULTANT III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

MAY 27, 2008

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EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-07-0504

My Surrebuttal Testimony addresses a number of issues related to Southwest Gas Corporation's ("Southwest") purchased gas adjustor ("PGA") mechanism and responds to the Rebuttal Testimony of Frank Maglietti and Brooks Congdon on these issues.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Robert G. Gray. I am an Executive Consultant III employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Are you the same Robert Gray that filed Direct Testimony in this proceeding?

A. Yes.

Q. What is the scope of this Surrebuttal Testimony?

A. My testimony responds to outstanding issues related to the purchased gas adjustor ("PGA") mechanism raised in the testimony of Southwest Gas ("Southwest" or "Company") Witnesses Frank Maglietti and Brooks Congdon.

PURCHASED GAS ADJUSTOR

Q. Mr. Maglietti's Rebuttal Testimony continues to recommend adoption of a $0.24 per therm bandwidth for the PGA mechanism. Please comment.

A. The current PGA bandwidth is $0.13 per therm. Staff has proposed increasing the bandwidth to $0.15 per therm, while the Company has proposed an expansion to $0.24 per therm. Staff continues to believe that a $0.15 per therm bandwidth is appropriate in this case. As discussed in detail in Staff's Direct Testimony, setting the PGA bandwidth represents the balancing of a number of competing goals regarding how Southwest's commodity costs are passed through to customers. While Staff understands the Company's interest in a broader bandwidth, providing more room for the monthly PGA rate to adjust automatically, this interest 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. The $0.15 per therm level is approximately 10 percent of Southwest's overall residential per therm rate. Thus, Southwest's rates can change approximately 10 percent in a 12 month period without specific Commission action. Staff believes it is reasonable for the Commission to play a more active role in situations where rates would increase by more than 10 percent within a calendar year and therefore Staff continues to recommend a PGA bandwidth of $0.15 per therm.

Q. Mr. Congdon's Rebuttal Testimony discusses how the PGA mechanism would interact with Southwest's revenue decoupling rate design proposal. Please discuss.

A. Mr. Congdon indicates that the PGA mechanism would not be impacted by the revenue decoupling rate design proposal. While Staff opposes SWG's revenue decoupling proposal for the reasons discussed in Staff witness Radigan's testimony, Staff continues to believe that in some fashion the PGA mechanism would need to be adjusted if a revenue decoupling mechanism is adopted. Under the current PGA mechanism, a single monthly PGA rate is calculated each month. This single monthly PGA rate is then applied to all therms consumed by Southwest customers, with several isolated exceptions such as irrigation customers and special contracts.

In a circumstance where Southwest's revenue decoupling rate design is implemented, there would be a different, quite low, monthly PGA rate applied to the first block of usage, and a second, much higher, monthly PGA rate applied to the second block of usage. Mr. Congdon's testimony discusses how the change in the monthly PGA rates from month to month can be accommodated by the existing PGA mechanism. But the main purpose of the existing PGA mechanism is not to calculate a change in rates per month. Rather, it calculates a new total per therm monthly PGA rate to be applied to all bills in a given month. And under Southwest's revenue decoupling rate design proposal, there would now be two monthly PGA rates (one for the first block and one for the second block), rather than one. While the differential between these two rates would likely be fixed as part of Southwest's proposed revenue decoupling rate design, it still is not clear how Southwest would expect to calculate the actual levels of the two new monthly PGA rates each month. This is yet one of the many concerns Staff has with the Company's proposed revenue decoupling mechanism and another reason why Staff does not support its adoption at this time.

Q. Do you agree with Mr. Congdon's statement on page 22, lines 3-5, of his testimony that "the total amount of residential customers' bills is unaffected by the proposed Volumetric Rate Design."

A. No. Without straying into a full-blown discussion of revenue decoupling, which is an issue being addressed by Staff Witness Frank Radigan, it is important to understand that in an overall sense, the protection Southwest indicates it is seeking from revenue deterioration by recovering most or all of the margin through the first block of rates, will inevitably cause that revenue shortfall to gradually bleed over to the gas cost recovery function of the PGA mechanism. Simply put, under Southwest's rate design proposal, the risk of recovery is shifted significantly from the current circumstance where usage on the margin recovers both gas cost and margin, to a situation where the gas cost component bears the brunt of the risk of any reduction in customer consumption.

For example, let's say in a hypothetical month Southwest experienced a $5 million revenue shortfall under its current rate design, but recovered that $5 million through the first block under its proposed rate design. Under the proposed rate design, because customers would pay the same total amount per therm, the extra $5 million of margin Southwest recovers through the first block would result in Southwest recovering $5 million less in commodity costs through the gas cost component than under current circumstances. Given the large volumes of gas costs passing through the PGA, the likelihood of such shifts resulting in massive changes in the PGA bank balance level over a short time period may be relatively low. However, it is very possible that over a longer timeframe this type of shift could push the PGA bank balance into a sizable undercollection that otherwise would not exist. In effect, the PGA bank balance would serve as a surrogate recovery mechanism under Southwest's rate design proposal, as the risk of not recovering dollars in a given month is shifted to the gas cost component from the margin component. But because the PGA is a straight pass through mechanism, those additional unrecovered gas cost amounts will eventually be borne by Southwest's customers either via the monthly PGA rate or through a surcharge. While this could theoretically swing the other direction, with greater customer usage driving a possible overcollection of gas costs, the Company's contention that customer consumption is continuing to decline would seem to indicate that the Company would expect some level of shortfall in gas cost recovery over time that eventually would require a surcharge or other action to address.

Additionally, as a matter of general principal, the PGA mechanism was originally designed to balance gas costs incurred and gas costs recovered, with these numbers naturally balancing out over time via the 12 month rolling average mechanism. Prices spikes, surcharges, and other unexpected changes can at times upset this balance temporarily. But in principal the mechanism is expected to roughly balance gas costs incurred and gas costs recovered. However, Southwest's proposed revenue decoupling rate design would, at least to some extent, create an imbalance in the existing relationship between gas costs incurred and gas costs recovered. Thus, if any form of Southwest's revenue decoupling rate design is adopted, which Staff does not support, provision would have to be made in some fashion to adjust the PGA mechanism accordingly.

SUMMARY OF RECOMMENDATIONS

Q. Are you changing your recommendations from those contained in your Direct Testimony?

A. No. However, I have clarified the recommendation related to the relationship between the rate design revenue decoupling and the PGA in Recommendation 4 below, in response to the Company's Rebuttal Testimony.

Q. Please summarize your recommendations.

A. My testimony in this case includes the following recommendations:

1. The bandwidth on the monthly PGA rate should be expanded to $.015 per therm.
2. The threshold on the PGA bank balance for undercollected balances should be eliminated.
3. The threshold on the PGA bank balance for overcollected balances should be set at $55.78 million.
4. While Staff is opposed to the adoption of the Company's proposed revenue decoupling mechanism, [the Company's proposal is adopted] a revised PGA mechanism that addresses the changes in the calculation of the PGA and related issues would have to be developed and approved. Further, this would also impact the monthly PGA report and adjustments to the report to reflect changes resulting from revenue decoupling would have to be worked out.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes, it does.

EXHIBIT
S-17

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATON 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-07-0504

DIRECT

TESTIMONY

OF

DAVID C. PARCELL

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

MARCH 28, 2008

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ATTACHMENT

Resume 1

I. INTRODUCTION

Q. Please State your name, occupation, and business address.

A. My name is David C. Parcell. I am President and Senior Economist of Technical Associates, Inc. My business address is Suite 601, 1051 East Cary Street, Richmond, Virginia 23219.

Q. Please summarize your educational background and professional experience.

A. I hold B.A. (1969) and M.A. (1970) degrees in economics from Virginia Polytechnic Institute and State University (Virginia Tech) and a M.B.A. (1985) from Virginia Commonwealth University. I have been a consulting economist with Technical Associates since 1970. I have provided cost of capital testimony in public utility ratemaking proceedings dating back to 1972. In connection with this, I have previously filed testimony and/or testified in approximately 400 utility proceedings before 40 regulatory agencies in the United States and Canada. Attachment 1 provides a more complete description of my education and relevant work experience.

Q. Have you previously testified before the Arizona Corporation Commission?

A. Yes, I have testified in a number of prior Arizona Corporation Commission ("Commission") proceedings, including the recent electric rate cases involving Arizona Public Service Company (Docket No. E-01345A-05-0816), UNS Gas, Inc. (Docket No. G-01345A-05-0463), UNS Electric, Inc. (Docket No. E-0404A-06-0783) and Tucson Electric Power Co. (Docket No. E-01933A-07-0402). Those testimonies were provided on behalf of the Utilities Division Staff.

Q. Do any of your previous testimonies involve rate proceedings of Southwest Gas?

A. Yes. I have previously testified in several rate proceedings involving Southwest Gas Corporation ("Southwest Gas" or "Company"). These cases were before both this Commission and the Nevada Public Service Commission.

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

A. I have been retained by the Utilities Division Staff to evaluate the cost of capital aspects of the most recent filing of Southwest Gas. I have performed independent studies and am making recommendations on the current cost of capital for Southwest Gas. My testimony also responds to the Company's cost of capital proposals sponsored by Southwest Gas witness Frank J. Hanley.

Q. Have you prepared an exhibit in support of your testimony?

A. Yes, I have prepared one exhibit, identified as Schedule 1 through Schedule 12. This exhibit was prepared either by me or under my direction. The information contained in this exhibit is correct to the best of my knowledge and belief.

II. RECOMMENDATIONS AND SUMMARY

Q. What are your recommendations in this proceeding?

A. My overall cost of capital recommendations for Southwest Gas are:

	Percent	Cost	Return
Short-Term Debt	0.00%	N/A	N/A
Long-Term Debt	52.08%	7.96%	4.15%
Preferred Stock	4.48%	8.20%	0.37%
Common Equity	43.44%	9.3-10.5%	4.13-4.56%
Total	100.00%		8.55-9.07%
			8.86% with 10.0% ROE

Southwest Gas' application requests a return on common equity of 11.25 percent and a total cost of capital of 9.45 percent. This cost of capital is based on a hypothetical capital structure comprised of 51 percent long-term debt, 4 percent preferred stock, and 45 percent common equity.

Q. Please summarize your cost of capital analyses and related conclusions for Southwest Gas.

A. This proceeding is concerned with Southwest Gas' regulated natural gas utility operations in Arizona. My analyses are concerned with the Company's total cost of capital. The first step in performing these analyses is the development of the appropriate capital structure. Southwest Gas' proposed capital structure is the "target" capital structure ratios of the Company, which is actually a hypothetical capital structure. I do not use this hypothetical capital structure in my cost of capital analyses, but rather use the Company's actual test period capital structure ratios.

The second step in a cost of capital calculation is a determination of the embedded cost rates of long-term debt and preferred stock. I have used the 7.96 percent cost rate for long-term debt and the 8.20 percent cost rate for preferred stock, both of which are contained in Southwest Gas' application.

The third step in the cost of capital calculation is the estimation of the cost of common equity. I have employed three recognized methodologies to estimate the cost of equity for Southwest Gas. Each of these methodologies is applied to two groups of proxy utilities. These three methodologies and my findings are:

Methodology	Range
Discounted Cash Flow	9.3-10.4%
Capital Asset Pricing Model	9.5-9.8%
Comparable Earnings	10.0-10.5%

Based upon these findings, I conclude that the cost of common equity for the proxy utilities is within a range of 9.3 percent to 10.5 percent (9.9 percent mid-point). This range is determined by the results of all three of my cost of equity methodology results, since all three sets of results fall within this range. I recommend that Southwest Gas' cost of equity be slightly above the mid-point of my 9.3 percent to 10.5 percent range or 10.0 percent. I recommend a slightly higher cost of equity in order to recognize the impact of Southwest Gas' lower equity ratio and debt ratings, relative to those of the proxy groups.

Combining the capital structure and individual cost rates, results in a weighted cost of capital for Southwest Gas. My recommendation overall cost of capital range is 8.55 percent to 9.07 percent (8.86 percent with 10.0 percent cost of equity). I recommend an 8.86 percent cost of capital for Southwest Gas.

III. ECONOMIC PRINCIPLES AND METHODOLOGIES

Q. What are the primary economic principles that establish the standards for determining a fair rate of return for a regulated utility?

A. Public utility rates are normally established in a manner designed to allow the recovery of their costs, including capital costs. This is frequently referred to as "cost of service" ratemaking. Rates for regulated public utilities traditionally have been primarily established using the "rate base - rate of return" concept. Under this method, utilities are allowed to recover a level of operating expenses, taxes, and depreciation deemed reasonable for rate-setting purposes, and are granted an opportunity to earn a fair rate of return on the assets utilized (i.e., rate base) in providing service to their customers.

The rate base is derived from the asset side of the utility's balance sheet as a dollar amount and the rate of return is developed from the liabilities/owners' equity side of the balance

sheet as a percentage. Thus, revenue impact of the cost of capital is derived by multiplying the rate base by the rate of return, including income taxes.
The rate of return is developed from the cost of capital, which is estimated by weighting the capital structure components (i.e., debt, preferred stock, and common equity) by their percentages in the capital structure and multiplying these values by their cost rates. This is also known as the weighted cost of capital.

Technically, "fair rate of return" is a legal and accounting concept that refers to an ex post (after the fact) earned return on an asset base, while the cost of capital is an economic and financial concept which refers to an ex ante (before the fact) expected or required return on a liability base. In regulatory proceedings, however, the two terms are often used interchangeably. I have equated the two concepts in my testimony.

From an economic standpoint, a fair rate of return is normally interpreted to mean that an efficient and economically managed utility will be able to maintain its financial integrity, attract capital, and establish comparable returns for similar risk investments. These concepts are derived from economic and financial theory and are generally implemented using financial models and economic concepts.

From a legal perspective, while I am not a lawyer, it is my understanding that two United States Supreme Court decisions provide the controlling standards for a fair rate of return. The first decision is Bluefield Water Works and Improvement Co. v. Public Serv. Comm'n of West Virginia, 262 U.S. 679 (1923). In this decision, the Court stated:

> *What annual rate will constitute **just compensation** depends upon many circumstances and must be **determined by** the **exercise of fair and enlightened judgment**, having regard to all relevant facts. A **public utility** is entitled to such rates as will permit it to **earn a return** on the value of the property which it employs for the convenience of the public equal to that **generally being made** at the same time and in the same general part of the*

> *country on* ***investments in other business undertakings*** *which are* ***attended by corresponding risks and uncertainties****; but it has no* ***constitutional right to profits*** *such as are realized or anticipated in* ***highly profitable enterprises or speculative ventures****. The* ***return*** *should be reasonably sufficient to assure confidence in the* ***financial soundness*** *of the utility, and should be adequate,* ***under efficient and economical management****, to maintain and* ***support its credit*** *and* ***enable it to raise the money*** *necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally.* **[Emphasis added.]**

Thus, the Bluefield decision, in my opinion as a non-lawyer, established the following standards for a fair rate of return: comparable earnings, financial integrity, and capital attraction. It also noted the changing level of required returns over time as well as an underlying assumption that the utility be operated in an efficient manner.

The second decision is Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1942). In that decision, the Court stated:

> *The rate-making process under the [Natural Gas] Act, i.e., the fixing of 'just and reasonable' rates, involves a* ***balancing*** *of the* ***investor*** *and* ***consumer interests*** *. . . . From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the* ***return*** *to the equity* ***owner*** *should be* ***commensurate*** *with* ***returns*** *on* ***investments*** *in* ***other enterprises having corresponding risks****. That return, moreover, should be sufficient to assure confidence in the* ***financial integrity*** *of the enterprise, so as to* ***maintain its credit*** *and to* ***attract capital****.* **[Emphasis added.]**

The three economic and financial parameters in the Bluefield and Hope decisions - comparable earnings, financial integrity, and capital attraction - reflect the economic criteria encompassed in the "opportunity cost" principle of economics. The opportunity cost principle provides that a utility and its investors should be afforded an opportunity (not a guarantee) to earn a return commensurate with returns they could expect to achieve on investments of similar risk. The opportunity cost principle is consistent with the fundamental premise, on which regulation rests, namely, that it is intended to act as a surrogate for competition.

I understand that because Arizona is a "Fair Value" state, Hope and Bluefield do not set forth the legal requirements applicable to determining fair rate of return in Arizona. In Simms v. Round Valley Light & Power Company,[1] the Arizona Supreme Court took exception to application of the following principle in Arizona since the Constitution mandates consideration of fair value:

> *"In the Hope case the court, in testing the reasonableness of rates fixed by the Federal Power Commission under the Natural Gas Act, 15 U.S.C.A. Section 717 et seq., after holding that congress had provided no formula by which just and reasonable rates were to be determined, ruled that it was the final result reached and not the method used in reaching the result that was controlling and that it was unimportant to 'determine the various permissible ways in which any rate base on which the return is computed might be arrived at."*

My testimony does not advocate that the Commission ignore the *Simms* holding in this regard, or the fair value of Southwest Gas' property, which it is required to consider under Article 15, Section of the Arizona Constitution. Rather, I find the Hope and Bluefield decisions to be helpful in their discussion of comparable earnings, financial integrity and capital attraction. I note that Southwest Gas Electric Witness Hanley also cites the Hope and Bluefield cases as "guidelines" for evaluating the cost of capital for the Company.

Q. How can these parameters be employed to estimate the cost of capital for a utility?

A. Neither the courts nor economic/financial theory have developed exact and mechanical procedures for precisely determining the cost of capital. This is the case because the cost of capital is an opportunity cost and is prospective-looking, which dictates that it must be estimated.

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1 294 P.2d 378 (1956).

There are several useful models that can be employed to assist in estimating the cost of equity capital, which is the capital structure item that is the most difficult to determine. These include the discounted cash flow ("DCF"), capital asset pricing model ("CAPM"), comparable earnings ("CE") and risk premium ("RP") methods. Each of these methods (or models) differs from the others and each, if properly employed, can be a useful tool in estimating the cost of common equity for a regulated utility. Many state regulatory commissions reply upon the DCF and CAPM models to develop the cost of common equity for utilities.

Q. Which methods have you employed in your analyses of the cost of common equity in this proceeding?

A. I have utilized three methodologies to determine Southwest Gas' cost of common equity: the DCF, CAPM, and CE methods. I have not employed a RP model in my analyses although, as discussed later, my CAPM analysis is a form of the RP methodology. Each of these methodologies will be described in more detail in my testimony that follows.

IV. GENERAL ECONOMIC CONDITIONS

Q. Why are economic and financial conditions important in determining the costs of capital?

A. The costs of capital, for both fixed-cost (debt and preferred stock) components and common equity, are determined in part by current and prospective economic and financial conditions. At any given time, each of the following factors has an influence on the costs of capital: the level of economic activity (i.e., growth rate of the economy), the stage of the business cycle (i.e., recession, expansion, or transition), and the level of inflation. The Supreme Court, in its Bluefield decision, which noted that "[a] rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally."

Q. What indicators of economic and financial activity have you evaluated in your analyses?

A. I have examined several sets of economic statistics from 1975 to the present. I chose this time period because it permits the evaluation of economic conditions over three full business cycles plus the current cycle to date, allowing for an assessment of changes in long-term trends. This period also approximates the beginning and continuation of active rate case activities by public utilities.

A business cycle is commonly defined as a complete period of expansion (recovery and growth) and contraction (recession). A full business cycle is a useful and convenient period over which to measure levels and trends in long-term capital costs because it incorporates the cyclical (i.e., stage of business cycle) influences, and thus, permits a comparison of structural (or long-term) trends.

Q. Please describe the timeframe of the three prior business cycles and the most current cycle.

A. The three prior complete cycles and current cycle cover the following periods:

Business Cycle	Expansion Cycle	Contraction Period
1975-1982	Mar. 1975-July 1981	Aug. 1981-Oct. 1982
1982-1991	Nov. 1982-July 1990	Aug. 1990-Mar. 1991
1991-2001	Apr. 1991-Mar. 2001	Apr. 2001-Nov. 2001
Current	Dec. 2001-Present	

Q. Do you have any general observations concerning the changing trends in economic conditions and their impact on costs over this broad period?

A. Yes, I do. As I will describe below, the U.S. economy has enjoyed general prosperity and stability over the period since the early 1980s. This period has been characterized by longer economic expansions, relatively tame contractions, relatively low and declining inflation, and declining interest rates and other capital costs. The current business cycle began in late 2001, following a somewhat modest recession earlier in the year. Over the past several months, the economy has slowed, largely as a result of the collapse of the "sub-prime" mortgage market. There is some concern that the economy may slide into a recession, but this is unclear at this time. Should the economy incur a recession, the impacts on cost of capital would likely be characterized by lower utility growth and declining capital costs.

Q. Please describe recent and current economic and financial conditions and their impact on the costs of capital.

A. Schedule 2 shows several sets of economic data. Pages 1 and 2 contain general macroeconomic statistics while Pages 4 through 6 contain financial market statistics. Pages 1 and 2 of Schedule 2 show that the U.S. economy is currently beginning the seventh year of an economic expansion although, as indicated previously, the economy is currently slowing. This is indicated by the growth in real (i.e., adjusted for inflation) Gross Domestic Product, industrial production, and the unemployment rate. This current expansion has generally been characterized as slower growth, in comparison to prior expansions. This has resulted in lower inflationary pressures and interest rates. In addition, the current slowing of the economy has resulted in a lowering of interest rates.

The rate of inflation is also shown on Pages 1 and 2 of Schedule 2. As is reflected in the Consumer Price Index ("CPI"), for example, inflation rose significantly during the 1975-1982 business cycle and reached double-digit levels in 1979-1980. The rate of inflation declined substantially in 1981 and remained at or below 6.1 percent during the 1983-1991 business cycle. Since 1991, the CPI has been 4.1 percent or lower. The 4.1 percent rate of inflation in 2007 was slightly above the levels since 2000, but is well below the levels of the past thirty years.

Q. What have been the trends in interest rates?

A. Pages 3 and 4 of Schedule 2 show the levels and trends in interest rates. Rates rose sharply to record levels in 1975-1981 when the inflation rate was high and generally rising. Interest rates declined substantially in conjunction with inflation rates throughout the remainder of the 1980s throughout the 1990s. Interest rates declined even further from 2000-2005 and generally recorded their lowest levels since the 1960s.

During the past several years, long-term interest rates have remained low by historic standards. During the 2001 recession and early in the succeeding expansion, the Federal Reserve lowered interest rates (i.e., Federal Funds rate) 11 times in 2001 and twice in 2003 in an effort to stimulate the economy. Following this the Federal Reserve increased short-term interest rates on 17 occasions between 2004 and 2006, although each time by only 0.25 percent, in an attempt to ensure that any perceived inflationary expectations will not stifle continued economic growth. Nevertheless, the economic recovery to date has not resulted in a pronounced increase in long-term rates. Most recently, however, the Federal Reserve has lowered the Federal Funds rate (i.e., short-term rate) on five occasions.

Q. What have been the trends in common share prices?

A. Pages 5 and 6 of Schedule 2 show the levels and trends in common stock prices and ratios. These indicate that share prices were essentially stagnant during the high inflation/interest rate environment of the late 1970s and early 1980s. On the other hand, the 1983-1991 business cycle and the most recent cycle have witnessed a significant upward trend in stock prices. During the initial years of the current expansion, however, stock prices were volatile and declined substantially from their highs reached in 1999 and early 2000. Share prices have increased somewhat since 2003 but have been volatile.

Q. What conclusions do you draw from this discussion of economic and financial conditions?

A. It is apparent that capital costs are currently low in comparison to the levels that have prevailed over the past three decades. In addition, the current weakness in the economy has resulted in a decline in capital costs. Therefore, it can reasonably be expected that cost of equity models currently produce returns that are lower than returns experienced in prior years.

V. SOUTHWEST GAS' OPERATIONS AND RISKS

Q. Please summarize Southwest Gas and its operations.

A. Southwest Gas is an operating gas distribution company. The Company is engaged in the business of purchasing, transporting and distributing natural gas to residential, commercial, and industrial customers in geographically diverse portions of Arizona, Nevada and California. Southwest Gas also owns Paiute Pipeline Co., as well as Northern Pipeline Construction Company. Until 1996, Southwest Gas owned PriMerit Bank (formerly Nevada Savings and Loan).

Q. What are the current security ratings of Southwest Gas?

A. As is shown on Schedule 3, the current bond ratings of Southwest Gas are:

Moody's	Baa3
Standard & Poor's	BBB-
Fitch	BBB

As this indicates, Southwest Gas' bonds presently carry triple B ratings by the three rating agencies who rate the Company's debt.

Q. What has been the trend in Southwest Gas' debt ratings?

A. This is also depicted on Schedule 3. As this Schedule indicates, the Company's debt ratings have been triple B since at least 1995.

Q. How have the rating agencies recently described Southwest Gas?

A. An example of this is provided in an October 11, 2007 RatingsDirect report on Southwest Gas by Standard & Poor's. In this report, Standard & Poor's stated:

> *The ratings on Southwest Gas Corp. are based on its strong business position rating of '4' (Standard & Poor's Rating Services rates a company's business position on a scale of '1' (excellent to '10' (vulnerable)) as a regulated local gas distribution company serving the high-growth service territories in Arizona, Nevada, and, to a lesser extent, California. The ratings also reflect improving operating efficiency and an intermediate financial risk profile. These factors are partially offset by low customer usage due to its warm weather, geographic location, challenges associated with improving regulatory treatment in certain jurisdictions, and a moderately sized unregulated utility construction and maintenance business.*
>
> *The company provides natural gas to more than 1.8 million customers in Arizona (54% of customers), Nevada (36%), and California (10%). Residential and small commercial customers account for nearly all of retail consumption and around 86% of the company's total operating margin. Retail sales are sensitive to weather, which has been a particular challenge for Southwest Gas, given the gradual warming trend observed in its region. . . .*
>
> *Strong customer growth, averaging 5% annually from 2001 to 2006, has helped to offset the effects of declining per capita consumption, allowing for about a 3% annual increase in residential throughput total volumes during the period. Nevada and Arizona have been the two fastest-growing states in the U.S. Customer growth has also driven capital requirements, which increased by about 5.4% annually for the same period. The company projects capital spending will total about $880 million over the 2007-2009 period, with about $337 million ($306 million in 2006) to be spent in 2007. Customer growth is expected to moderate in 2007 to about 3%, partially based on the recent weakness in the housing markets of Phoenix and Las Vegas. This may ease capital spending requirements a bit in the near term.*

> *Southwest Gas depends on regulatory approval of retail rates to cover the cost requirements associated with rapid growth, high natural gas price volatility, and exposure to weather variation. All three of the state regulatory commissions that oversee Southwest's retail rates have allowed the company to recover its actual purchased-gas costs through a purchased-gas adjustment mechanism (PGA). In 2006, the Nevada commission approved the company's gas cost adjustment on a quarterly basis.*
>
> *Arizona regulation uses a historical test year, which creates a regulatory lag, especially when considering the state's high growth rate. Some of this is mitigated by the company's policy of receiving advances from home builders to prefund construction expenditures to new home developments, which are later refunded once the new homeowners are hooked up and receiving gas. . . .*
>
> *Financial performance measurably improved since mid-2006 as a result of regulatory relief and customer growth. Capital outlays remain high, although the company funded about 66% of capital outlays with internal cash flow after dividends in fiscal 2006. The company expects this ratio to improve to about 90% in 2008.*
>
> *Credit measures are strong for the rating, with adjusted funds from operations (FFO) to total debt of about 19% and adjusted FFO interest coverage of about 3.6x for the 12-month period ended June 30, 2007. Meanwhile, debt leverage has decreased, with adjusted debt to capital at 58% on June 20, 2007, down substantially from 69% in 2005.*
>
> *The outlook on Southwest Gas is positive. The positive outlook reflects our expectation of consistently strong cash flow measures and declining debt leverage, primarily as a result of anticipated high levels of internal funding of capital expenditures, minimal new debt financing, and regulator annual equity infusions under the company's common equity shelf and dividend reinvestment programs. Significant rate design improvements could further yield ratings improvement.*

Q. Are you aware that Southwest Gas is requesting certain regulatory cost-recovery mechanisms in this proceeding?

A. Yes, I am. It is my understanding that the Company is requesting approval to implement two new rate design proposals that, if approved, will be risk-reducing. These two proposals involve a Weather Normalization Adjustment Provision ("WNAP") and a

Revenue Decoupling Adjustment Provision ("RDAP"). On a combined basis, these provide for "Full Revenue Decoupling" for Southwest Gas' residential customers and all but its largest general service customers.

Q. How are these proposals risk-reducing to the Company?

A. These rate design proposals, if approved, are risk-reducing to Southwest Gas since the Company's revenues, and income, will be essentially insulated from variations due to weather and usage. The net effect of these proposals is to transfer a significant portion of the Company's risks from its shareholders to its ratepayers. Yet, it does not appear that the Company acknowledges this risk transfer in terms of its requested rate of return.

Q. Is the Staff recommending approval of these new proposals which would transfer significantly more risk to ratepayers?

A. Other Staff witnesses are addressing the Company's new risk-reducing rate design proposals. It is my understanding that the Staff is opposed to them. However, I want to point out that if the Commission should adopt either of them, I would recommend a further downward adjustment to my recommended rate of return in consideration of the reduced risk. The Company should have recognized a reduction to its rate of return in recognition of its risk reducing proposals.

VI. CAPITAL STRUCTURE AND COST OF DEBT

Q. What is the importance of determining a proper capital structure in a regulatory framework?

A. A utility's capital structure is important because the concept of rate base – rate of return regulation requires that a utility's capital structure be determined and utilized in estimating the total cost of capital. Within this framework, it is proper to ascertain whether the utility's capital structure is appropriate relative to its level of business risk and relative to other utilities.

As discussed in Section III of my testimony, the purpose of determining the proper capital structure for a utility is to help ascertain its capital costs. The rate base – rate of return concept recognizes the assets employed in providing utility services and provides for a return on these assets by identifying the liabilities and common equity (and their cost rates) used to finance the assets. In this process, the rate base is derived from the asset side of the balance sheet and the cost of capital is derived from the liabilities/owners' equity side of the balance sheet. The inherent assumption in this procedure is that the dollar values of the capital structure and the rate base are approximately equal and the former is utilized to finance the latter.

The common equity ratio (i.e., the percentage of common equity in the capital structure) is the capital structure item which normally receives the most attention. This is the case because common equity: (1) usually commands the highest cost rate; (2) generates associated income tax liabilities; and, (3) causes the most controversy since its cost cannot be precisely determined.

Q. How have you evaluated the capital structure of Southwest Gas?

A. I have first examined the five year historic (2003-2007) capital structure ratios of Southwest Gas. Schedule 4 shows the historic capital structure ratios of the Company. The respective common equity ratios are as follows:

	Inc'l S-T Debt	Exc'l S-T Debt
2003	33.0%	34.0%
2004	35.8%	35.8%
2005	34.4%	36.8%
2006	38.9%	39.4%
2007	41.0%	41.9%

This indicates a rising common equity ratio over this period. In fact, the most current common equity ratios significantly exceed the levels of five years ago.

Q. How do these capital structure ratios compare to the gas distribution utility industry?

A. I have prepared Schedule 5 to make this comparison. Page 1 of this schedule shows the 2002-2006 capital structure ratios of the Value Line group of LDC's, excluding short-term debt. Page 2 of Schedule 5 indicates the 2002-2006 capital structure ratios for this group, including short-term debt. The average ratios are:

	Inc'l S-T Debt	Exc'l S-T Debt
2002	41%	47.4%
2003	43%	50.4%
2004	43%	51.4%
2005	44%	51.9%
2006	48%	53.1%

These common equity ratios are slightly higher than those of the most recent Southwest Gas ratios.

Q. What capital structure ratios has Southwest Gas requested in this proceeding?

A. The Company requests use of the following "target" capital structure:

Capital Item	Percent
Long-Term Debt	51.0%
Preferred Stock	4.0%
Common Equity	45.0%

This capital structure contains slightly more common equity than the most recent actual capital structures for 2007 which contained a common equity ratio of 41.0 percent including short-term debt, and 41.9 percent exclusive of short-term debt.

Q. What is basis of the Company's capital structure request?

A. In the last rate proceeding of Southwest Gas (Docket No. G-01551A-04-0876), this Commission approved use of a hypothetical capital structure for the Company that contained 55 percent long-term debt, 5 percent preferred stock, and 40 percent common equity. This 40 percent common equity ratio exceeded the actual test period equity ratio (34.1 percent, according to Mr. Wood's testimony, page 5) and was apparently intended to be an "incentive" for the Company to raise its actual equity ratio. As stated by Mr. Wood, in its Decision in this proceeding, the Commission directed the Company to submit a "recapitalization plan" explaining how it intends to achieve an actual 40 percent common equity ratio.

In the present case, the Company is again requesting a hypothetical capital structure, with an even higher common equity ratio, at 45 percent. Southwest Gas witness Wood describes this as a "target" common equity ratio and he indicates (page 9) "it is reasonable to assume that the Company will achieve 45 percent common equity ratio…."

Q. Has the Company raised its equity ratio since the last case?

A. Yes, it has. The actual test period capital structure of the Company contains some 43.4 percent common equity.

Q. Is it necessary to again utilize a hypothetical capital structure for Southwest Gas?

A. No, it is not. The Commission provided the Company with a capital structure incentive in the last case. The Company responded and achieved an equity ratio that satisfied the Commission's directive. In this regard, it is noteworthy that Southwest Gas has historically maintained a common equity ratio that was considerably below that of natural gas distribution utilities in general. At the present time, the Company's capital structure is more in line with that of other gas utilities.

Q. What other reasons support the use of the Company's actual capital structure.

A. I believe that, in general, utilities should use their actual capital structure for ratemaking purposes unless there is a showing that the actual capital structures are significantly out of line with other utilities. In the case of Southwest Gas, this is not a factor. Should the Company want to have its rates set based upon 45 percent common equity ratio, it has the option of raising new common equity in order to actually achieve this level of equity. In any event, the circumstances have changed since the last case and no "incentive" is required at this time.

Q. What capital structure have you used in your analyses?

A. I have utilized the actual test period capital structure of the Company in my analyses. These are shown on my Schedule 1. I note that I normally include short-term debt in my cost of capital calculations and I understand that this Commission also uses short-term debt. However, in this case, it appears that Southwest Gas did not have any short-term debt at the end of the test period, so I did not include any in the capital structure.

Q. What cost rates of long-term debt and preferred stock have you used in your analysis?

A. I have utilized the 7.96 percent cost of long-term debt and 8.20 percent cost of preferred stock shown in the Company's filing.

Q. Can the cost of common equity be determined with the same degree of precision as the costs of debt and preferred stock?

A. No. The cost rates of debt and preferred stock are largely determined by interest payments, issue prices, and related expenses. The cost of common equity, on the other hand, cannot be precisely quantified, primarily because this cost is an opportunity cost. As discussed earlier, there are, however, several models which can be employed to estimate the cost of common equity. Three of the primary methods - DCF, CAPM, and CE - are developed in the following sections of my testimony.

VII. SELECTION OF PROXY GROUPS

Q. How have you estimated the cost of common equity for Southwest Gas?

A. Southwest Gas is a publicly-traded company. Consequently, it is possible to directly apply cost of equity models to this entity. It is customary to analyze groups of comparison or "proxy" companies as a substitute for Southwest Gas to determine its cost of common equity.

I have examined two such groups for comparison to Southwest Gas. The first group of proxy companies is the group of gas distribution companies followed by Value Line, except for those companies that have not paid cash dividends. This group, which reflects a representative sample of LDC's, is a proper proxy for Southwest Gas.

The second proxy group is the group of eight natural gas utilities Mr. Hanley utilized in his testimony.

I note that, by developing my own group of proxy companies, used in conjunction with the groups of proxy companies utilized by Southwest Gas witness Hanley, I have given consideration to the Company's view as to the appropriate composition of the proxy companies for Southwest Gas.

VIII. DISCOUNTED CASH FLOW ANALYSIS

Q. What is the theory and methodological basis of the discounted cash flow model?

A. The DCF model is one of the oldest, as well as the most commonly-used, models for estimating the cost of common equity for public utilities. The DCF model is based on the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows.

The most common variant of the DCF model assumes that dividends are expected to grow at a constant rate. This variant of the dividend discount model is known as the constant growth or Gordon DCF model. In this framework cost of capital is derived by the following formula:

$$K = \frac{D}{P} + g$$

where: K = discount rate (cost of capital)

P = current price

D = current dividend rate

g = constant rate of expected growth

This formula essentially recognizes that the return expected or required by investors is comprised of two factors: the dividend yield (current income) and expected growth in dividends (future income).

Q. Please explain how you have employed the DCF model.

A. I have utilized the constant growth DCF model. In doing so, I have combined the current dividend yield for each group of proxy utility stocks described in the previous section with several indicators of expected dividend growth.

Q. How did you derive the dividend yield component of the DCF equation?

A. There are several methods that can be used for calculating the dividend yield component. These methods generally differ in the manner in which the dividend rate is employed; i.e., current versus future dividends or annual versus quarterly compounding of dividends. I believe the most appropriate dividend yield component is the version listed below:

$$Yield = \frac{D_0(1+0.5g)}{P}$$

This dividend yield component recognizes the timing of dividend payments and dividend increases.

The P_0 in my yield calculation is the average (of high and low) stock price for each proxy company for the most recent three month period (December 2007 - February 2008). The D_0 is the current annualized dividend rate for each proxy company.

Q. How have you estimated the dividend growth component of the DCF equation?

A. The dividend growth rate component of the DCF model is usually the most crucial and controversial element involved in this methodology. The objective of estimating the dividend growth component is to reflect the growth expected by investors that is embodied in the price (and yield) of a company's stock. As such, it is important to recognize that individual investors have different expectations and consider alternative indicators in deriving their expectations. This is evidenced by the fact that every investment decision resulting in the purchase of a particular stock is matched by another investment decision to sell that stock. Obviously, since two investors reach different decisions at the same market price, their expectations differ.

A wide array of indicators exist for estimating the growth expectations of investors. As a result, it is evident that no single indicator of growth is always used by all investors. It therefore is necessary to consider alternative indicators of dividend growth in deriving the growth component of the DCF model.

I have considered five indicators of growth in my DCF analyses. These are:

1. 2002-2006 (5-year average) earnings retention, or fundamental growth (per Value Line);

2. 5-year average of historic growth in earnings per share (EPS), dividends per share (DPS), and book value per share (BVPS) (per Value Line);

3. 2007, 2008, and 2010-2012 projections of earnings retention growth (per Value Line);

4. 2004-2006 to 2010-2012 projections of EPS, DPS, and BVPS (per Value Line); and,

5. 5-year projections of EPS growth as reported in First Call (per Yahoo! Finance).

I believe this combination of growth indicators is a representative and appropriate set with which to begin the process of estimating investor expectations of dividend growth for the groups of proxy companies. I also believe that these growth indicators reflect the types of information that investors consider in making their investment decisions. As I indicated previously, investors have an array of information available to them, all of which should be expected to have some impact on their decision-making process.

Q. Please describe your initial DCF calculations.

A. Schedule 6 presents my DCF analysis. Page 1 shows the calculation of the "raw" (i.e., prior to adjustment for growth) dividend yield for each proxy company. Pages 2 and 3 show the growth rate for the groups of proxy companies. Page 4 shows the "raw" DCF calculations, which are presented on several bases: mean, median, and high values. These results can be summarized as follows:

	Mean	Median	Mean High[2]	Median High[2]
Proxy Group	9.3%	8.7%	10.4%	9.8%
Hanley Group	8.6%	8.1%	9.3%	9.3%

I note that the individual DCF calculations shown on Schedule 6 should not be interpreted to reflect the expected cost of capital for the proxy groups; rather, the individual values shown should be interpreted as alternative information considered by investors.

[2] Using only the highest growth rate.

The DCF results in Schedule 6 indicate average (mean and median) DCF cost rates of 8.1 percent to 9.3 percent. The highest DCF rates (i.e., using the highest growth rates only) are 9.3 percent to 10.4 percent.

Q. What do you conclude from your DCF analyses?

A. These analyses reflect a broad DCF range of 9.3 percent to 10.4 percent for the proxy groups. This is approximated by the upper portion of the average/mean values, as well as the top DCF calculations for the proxy groups examined in the previous analysis. I give less weight to the lower end of the mean/median results. I believe that 9.3 percent to 10.4 percent (9.9 percent mid-point) reflects the proper DCF cost for the proxy groups.

IX. CAPITAL ASSET PRICING MODEL ANALYSIS

Q. Please describe the theory and methodological basis of the capital asset pricing model.

A. The CAPM is a version of the risk premium method. The CAPM describes and measures the relationship between a security's investment risk and its market rate of return. The CAPM was developed in the 1960s and 1970s as an extension of modern portfolio theory ("MPT"), which studies the relationships among risk, diversification, and expected returns.

Q. How is the CAPM derived?

A. The general form of the CAPM is:

$$K = R_f + \beta(R_m - R_f)$$

where: K = cost of equity

R_f = risk free rate

R_m = return on market

β = beta

R_m-R_f = market risk premium

As noted previously, the CAPM is a variant of the risk premium method. I believe the CAPM is generally superior to the simple risk premium method because the CAPM specifically recognizes the risk of a particular company or industry (i.e., beta), whereas the simple risk premium method assumes the same risk premium for all companies exhibiting similar bond ratings.

Q. What groups of companies have you utilized to perform your CAPM analyses?

A. I have performed CAPM analyses for the same groups of proxy utilities evaluated in my DCF analyses.

Q. What rate did you use for the risk-free rate?

A. The first term of the CAPM is the risk-free rate (R_f). The risk-free rate reflects the level of return that can be achieved without accepting any market risk.

In CAPM applications, the risk-free rate is generally recognized by use of U.S. Treasury securities. Two general types of U.S. Treasury securities are often utilized as the R_f component - short-term U.S. Treasury bills and long-term U.S. Treasury bonds.

I have performed CAPM calculations using the three month average yield (December 2007 - February 2008) for 20-year U.S. Treasury bonds. Over this three month period, these bonds had an average yield of 4.49 percent.

Q. What is beta and what betas did you employ in your CAPM?

A. Beta is a measure of the relative volatility (and thus risk) of a particular stock in relation to the overall market. Betas of less than 1.0 are considered less risky than the market, whereas betas greater than 1.0 are more risky. Utility stocks traditionally have had betas below 1.0. I utilized the most recent Value Line betas for each company in the groups of proxy utilities.

Q. How did you estimate the market risk premium component?

A. The market risk premium component (R_m-R_f) represents the investor-expected premium of common stocks over the risk-free rate, or government bonds. For the purpose of estimating the market risk premium, I considered alternative measures of returns of the S&P 500 (a broad-based group of large U.S. companies) and 20-year U.S. Treasury bonds.

First, I have compared the actual annual returns on equity of the S&P 500 with the actual annual yields of U.S. Treasury bonds. Schedule 7 shows the return on equity for the S&P 500 group for the period 1978-2006 (all available years reported by S&P). This schedule also indicates the annual yields on 20-year U.S. Treasury bonds, as well as the annual differentials (i.e., risk premiums) between the S&P 500 and U.S. Treasury 20-year bonds. Based upon these returns, I conclude that this version of the risk premium is about 6.4 percent.

I have also considered the total returns (i.e., dividends/interest plus capital gains/losses) for the S&P 500 group as well as for the long-term government bonds, as tabulated by Ibbotson Associates, using both arithmetic and geometric means. I have considered the total returns for the entire 1926-2007 period, which are as follows:

	S&P 500	L-T Gov't Bonds	Risk Premium
Arithmetic	12.3%	5.8%	6.5%
Geometric	10.4%	5.5%	4.9%

I conclude from this that the expected risk premium is about 5.9 percent (i.e., average of all three risk premiums). I believe that a combination of arithmetic and geometric means is appropriate because investors have access to both types of means and, presumably, both types are reflected in investment decisions and thus stock prices and cost of capital.

Schedule 8 shows my CAPM calculations using the risk premium. The results are:

	Mean	Median
Proxy Group	9.7%	9.5%
Hanley Group	9.8%	9.7%

Q. What is your conclusion concerning the CAPM cost of equity?

A. The CAPM results collectively indicate a cost of about 9.5 percent to 9.8 percent for the two groups of comparison utilities.

X. COMPARABLE EARNINGS ANALYSIS

Q. Please describe the basis of the CE methodology.

A. The CE method is derived from the "corresponding risk" standard of the Bluefield and Hope cases. This method is thus based upon the economic concept of opportunity cost. As previously noted, the cost of capital is an opportunity cost: the prospective return available to investors from alternative investments of similar risk.

The CE method is designed to measure the returns expected to be earned on the original cost book value of similar risk enterprises. Thus, this method provides a direct measure of the fair return, because the CE method translates into practice the competitive principle underlying regulation.

The CE method normally examines the experienced and/or projected returns on book common equity. The logic for examining returns on book equity follows from the use of original cost rate base regulation for public utilities, which uses a utility's book common equity to determine the cost of capital. This cost of capital is, in turn, used as the fair rate of return which is then applied (multiplied) to the book value of rate base to establish the dollar level of capital costs to be recovered by the utility. This technique is consistent with the rate base methodology generally used to set utility rates.

Q. How have you employed the CE methodology in your analysis of Southwest Gas' common equity cost?

A. I conducted the CE methodology by examining realized returns on equity for several groups of companies and evaluating the investor acceptance of these returns by reference to the resulting market-to-book ratios. In this manner, it is possible to assess the degree to which a given level of return equates to the cost of capital. It is generally recognized for utilities that market-to-book ratios of greater than one (i.e., 100 percent) reflect a situation where a company is able to attract new equity capital without dilution (i.e., above book value). As a result, one objective of a fair cost of equity is the maintenance of stock prices above book value.

I would further note that the CE analysis, as I have employed it, is based upon market data (through the use of market-to-book ratios) and, is thus, essentially a market test. As a result, my analysis is not subject to the criticisms occasionally made by some who maintain that past earned returns do not represent the cost of capital. In addition, my analysis uses prospective returns and thus is not confined to historical data.

Q. What time periods have you examined in your CE analysis?

A. My CE analysis considers the experienced equity returns of the proxy groups of utilities for the period 1992-2006 (i.e., past fifteen years). The CE analysis requires that I examine a relatively long period of time in order to determine trends in earnings over at least a full business cycle. Further, in estimating a fair level of return for a future period, it is important to examine earnings over a diverse period of time in order to avoid any undue influence from unusual or abnormal conditions that may occur in a single year or shorter period. Therefore, in forming my judgment of the current cost of equity I have focused on two periods: 2002-2006 (the past five years - the average length of a business cycle) and 1992-2001 (the most recent complete business cycle).

Q. Please describe your CE analysis.

A. Schedules 9 and 10 contain summaries of experienced returns on equity for several groups of companies, while Schedule 11 presents a risk comparison of utilities versus unregulated firms.

Schedule 9 shows the earned returns on average common equity and market-to-book ratios for the two groups of proxy utilities. These can be summarized as follows:

	Historic		Prospective
Group	ROE	M/B	ROE
Proxy Group	11.9-13.1%	180-195%	12.0-12.4%
Hanley Group	12.0-12.3%	180-184%	11.6-11.9%

These results indicate that historic returns of 11.9-13.1 percent have been adequate to provide market-to-book ratios of 180-195 percent for the groups of proxy utilities. Furthermore, projected returns on equity for 2007, 2008, and 2010-2012 are within a range of 11.6 percent to 12.4 percent for the utility groups. These relate to 2006 market-to-book ratios of 191 percent or higher.

Q. Have you also reviewed earnings of unregulated firms?

A. Yes. As an alternative, I also examined a group of largely unregulated firms. I have examined the Standard & Poor's 500 Composite group, because this is a well recognized group of firms that is widely utilized in the investment community and is indicative of the competitive sector of the economy. Schedule 10 presents the earned returns on equity and market-to-book ratios for the S&P 500 group over the past fifteen years. As this Schedule indicates, over the two periods this group's average earned returns ranged from 14.1-14.7 percent with market-to-book ratios ranging between 284 percent and 341 percent.

Q. How can the above information be used to estimate the cost of equity for Southwest Gas?

A. The recent earnings of the proxy utility and S&P 500 groups can be utilized as an indication of the level of return realized and expected in the regulated and competitive sectors of the economy. In order to apply these returns to the cost of equity for proxy utilities, however, it is necessary to compare the risk levels of the utility industry with those of the competitive sector. I have done this in Schedule 11, which compares several risk indicators for the S&P 500 group and the utility groups. The information in this schedule indicates that the S&P 500 group is more risky than the utility proxy groups.

Q. What return on equity is indicated by the CE analysis?

A. Based on the recent earnings and market-to-book ratios, I believe the CE analysis indicates that the cost of equity for the proxy utilities is no more than 10.0 percent to 10.5 percent (10.25 percent mid-point). Recent returns of 11.8-13.1 percent have resulted in market-to-book ratios of 180 and greater. Prospective returns of 11.6 percent to 12.4 percent result in anticipated market-to-book ratios of 190 percent or over. As a result, it is apparent that returns below this level would result in market-to-book ratios of well above 100 percent. Accordingly, an earned return of 10.0 percent to 10.5 percent should result in a market-to-book ratio of over 100 percent. As I indicated earlier, the fact that market-to-book ratios substantially exceed 100 percent indicates that historic and prospective returns of 10 percent to 11 percent reflect earnings levels that exceed the cost of equity for those regulated companies.

In applying the CE analysis, it also is important to recognize recent trends. My recommended range of 10.0 percent to 10.5 percent is further supported by the actual newly authorized returns on common equity from 2002 through June 2007, which are as follows for U.S. natural gas utilities as authorized by state regulatory agencies:

Year	ROE	No. of Decisions
2002	11.03%	21
2003	10.99%	25
2004	10.59%	20
2005	10.46%	26
2006	10.43%	16
2007 (6 months)	10.34%	15

Source: Regulatory Research Associates, "Regulatory Focus" July 3, 2007.

Please also note that my CE analysis is not based on a mathematic formula approach, as are the DCF and CAPM methodologies. Rather, it is based on recent trends and current conditions in equity markets. Further, it is based on the direct relationship between returns on common stock and market-to-book ratios of common stock. In utility rate setting, a fair rate of return is generally based on the utility's assets (i.e., rate base) and the book value of the utility's capital structure. As stated earlier, maintenance of a financially stable utility's market-to-book ratio at 100 percent, or a bit higher, is fully adequate to maintain the utility's financial stability. On the other hand, a market price of a utility's common stock that is 150 percent or more above the stock's book value is indicative of earnings that exceed the utility's reasonable cost of capital. Thus, actual or projected earnings do not directly translate into a utility's reasonable cost of equity. Rather, they must be viewed in relation to the market-to-book ratios of the utility's common stock.

My 10.0 percent to 10.5 percent CE recommendation reflects the fact that historic equity returns of 11.9 percent to 13.1 percent have resulted in market-to-book ratios of 180 percent to 195 percent, which demonstrates that the equity returns exceed the cost of capital. Likewise, projected returns of about 11.6 percent to 12.6 percent relate to 2006 market-to-book ratios of 190 percent and over. My 10.0 percent to 10.5 percent CE recommendation is not designed to result in market-to-book ratios as low as 1.0 for Southwest Gas. Rather, it is based on current market conditions and the proposition that ratepayers should not be required to pay rates based on earnings levels that result in excessive market-to-book ratios.

XI. RETURN ON EQUITY RECOMMENDATION

Q. Please summarize the results of your three cost of equity analyses.

A. My three methodologies produce the following:

Discounted Cash Flow	9.3-10.4%
Capital Asset Pricing Model	9.5-9.8%
Comparable Earnings	10.0-10.5%

My overall conclusion from these results is a reasonable range of 9.3 percent to 10.5 percent, which focuses on the respective individual model findings. The mid-point of this range is 9.9 percent.

Q. What cost of equity do you recommend for Southwest Gas?

A. I recommend a cost of equity of 10.0 percent, which is slightly above the 9.9 percent mid-point of my cost of equity range. I recommend a slightly higher cost of equity to reflect the lower equity ratio and lower debt ratings of Southwest Gas versus the proxy groups.

XII. TOTAL COST OF CAPITAL

Q. What is the total cost of capital for Southwest Gas?

A. Schedule 1 reflects the total cost of capital for the Company using the actual capital structure and costs of short-term debt, long-term debt and preferred stock, and my common equity cost recommendations. The resulting total cost of capital is a range of 8.55 percent to 9.07 percent (8.86 percent with 10.0 percent cost of equity). I recommend that this 8.86 percent total cost of capital be established for Southwest Gas.

Q. Does your cost of capital recommendation provide the company with a sufficient level of earnings to maintain its financial integrity?

A. Yes, it does. Schedule 12 shows the pre-tax coverage that would result if Southwest Gas earned my cost of capital recommendation. As the results indicate, my recommended range would produce a coverage level within the benchmark range for a Triple B rated utility. In addition, the debt ratio (which reflects the Company's proposed capital structure) is within the benchmark for a Triple B rated utility.

XIII. COMMENTS ON COMPANY TESTIMONY

Q. Have you reviewed the cost of capital testimony of Southwest Gas witness Frank J. Hanley?

A. Yes, I have.

Q. What is your understating of his cost of capital recommendation for Southwest Gas?

A. Mr. Hanley is recommending a total cost of capital for Southwest Gas of 9.45 percent, as follows:

	Ratios */	Cost	Weighted Cost
Long-Term Debt	51.0%	7.96%	4.06%
Preferred Stock	4.0%	8.20%	0.33%
Common Equity	45.0%	11.25%	5.06%
			9.45%

*/ April 30, 2007 cost rates applied to a hypothetical capital structure.

Q. How does he derive his cost of equity recommendation?

A. Mr. Hanley performs the following cost of equity analyses and derives the indicated results:

	Southwest Gas	Proxy Group of 8 Value Line LDCs
Discounted Cash Flow	NMF	9.92%
Risk Premium	10.86%	10.96%
Capital Asset Pricing Model	10.28%	10.50%
Comparable Earnings	13.42%	13.88%
Indicated Cost of Equity	11.00%	11.00%
Investment Risk Adjustment	--	0.31%
Recommended Cost of Equity	11.00%	11.31%

His recommendation for Southwest Gas is 11.25 percent.

Q. Do you have any disagreements with any or all of Mr. Hanley's methodologies and recommendations?

A. Yes, I have disagreements with each of his cost of equity methodologies and conclusions, as well as his proposed 0.31 percent "investment risk adjustment" for Southwest Gas. I note that, even though Mr. Hanley claims (page 7, lines 4-5) his methodologies and conclusions are predicated on the Efficient Market Hypothesis ("EMH"), many of the "adjustments" he makes to the models are in violation of the EMH.

Q. Please begin with his DCF model and conclusions.

A. Mr. Hanley's 9.92 percent DCF conclusion is shown on Exhibit ___ (FJH-6). It is apparent from his exhibit that Mr. Hanley only considers the DCF results of two of the eight companies in his proxy group due to his exclusion of all DCF rates of 9.6 percent or less, which he rationalizes as "the lowest rate awarded to a gas distribution utility during the twelve months ended March 2007." I do not believe it is appropriate to exclude virtually all of his DCF results for this reason. I also note that the currently authorized return on equity for Southwest Gas is less than 9.6 percent.

Q. Mr. Hanley maintains in his testimony on pages 8 and 24-28, that the DCF model cannot be used as an estimate of the cost of equity for a utility when the market price of utility stocks exceeds the book value. Do you agree with this position?

A. No, I do not. Knowledgeable and/or informed investors are aware of the fact that most utilities have their rates set based on the book value of their assets (i.e., rate base and capital structure). This knowledge is reflected in the prices that investors are willing to pay for stocks and thus is reflected in DCF cost rates. To make a modification of the DCF cost rates, as Mr. Hanley proposes, amounts to an attempt to "reprice" stock values in order to develop a DCF cost rate more in line with what he thinks the results should be. This is clearly a violation of the principle of "the EMH", which Mr. Hanley cites extensively in his testimony. If one believes that markets are efficient, there is no reason to modify either stock prices or market models based on stock prices.

Q. On page 26, Mr. Hanley states his view that when market prices exceed the book value, the DCF results understate the cost of equity. He also postulates that when the reverse occurs, the DCF results would overstate the cost of capital. Do you have any comments on this?

A. Yes, I do. I was testifying in utility rate cases in the 1970s and early 1980s, a period during which utility stock prices were frequently well below book value. Based on my personal recollections, I cannot remember a single instance in which a utility-sponsored cost of capital witness advocated that the DCF model overstated the cost of equity. I also never have taken this position.

I also note that I testified in a large number of rate proceedings in which Mr. Hanley and members of his firm testified. I can recall of no instances in which any AUS witness testified that the DCF result overstated the cost of equity.

Q. Please describe Mr. Hanley's risk premium methodology and conclusions.

A. Mr. Hanley's risk premium methodology combines his estimate (6.6 percent) of the prospective yield on A rated public utility bonds, adjusted by 0.40 percent (for Southwest Gas) and 0.09 percent (for proxy group) to reflect lower debt ratings with "equity risk premiums" of 3.86 percent and 4.27 percent to arrive at a risk premium cost of equity of 10.86 percent to 10.96 percent.

Q. Do you agree with his methodology and conclusions?

A. No, I do not. I note, first, that recent yields on A rated utility bonds are below the 6.60 percent used by Mr. Hanley. This indicates that his "prospective" yields were overstated. I also disagree with the equity risk premium level of 3.86 percent to 4.27 percent he employs. Mr. Hanley uses two studies to derive this risk premium and averages the two results. First, he compares total returns for the S&P over the 1926-2006 period with yields on corporate bonds over the same period, as well as forecasted total returns on stocks versus prospective yields on corporate bonds to derive an equity risk premium of 6.20 percent. He then multiplies the average by the betas of his LDC proxy groups (in a CAPM context) to develop his 4.14 percent to 4.29 percent equity risk premium. Use of total returns over the 1926-2006 period, in connection with bond yields over the same long period, does not imply that any such relationships are expected by investors in 2008. First, his methodology is a mis-match since its compares holding period returns (i.e., capital gains/losses plus income) with yields on bonds (i.e., only income). In addition, the 1926-2006 period was heavily influenced by the Great Depression, World War II, the high inflation/interest rate environment of the 1970s/1980s, etc. Such factors are not prevalent currently and have the effect of inflating risk premiums over those expected by investors. I believe Mr. Hanley's analyses over-state the required risk premiums at the present time. The fact that Mr. Hanley's forecasted equity risk premium is some two hundred and sixty basis points less than the historic risk premium is further indication of this concern.

In addition, I find it inconsistent on his part to defend use of historic data going back to 1926 in his risk premium and CAPM analyses, and to then ignore historic data in his DCF analyses. I do not see how an investor would place equal weight between returns in 1926 and 2006 in one type of analysis (i.e., risk premium and CAPM) and then give no weight whatsoever to recent (i.e., 5 years) experience in DCF analysis.

Q. Please describe Mr. Hanley's CAPM analyses.

A. Mr. Hanley performs two CAPM analyses. His first CAPM is a "traditional" CAPM, where he concludes that 10.17 percent to 10.49 percent is the CAPM cost. This uses a risk free rate of 5.33 percent (projected yield on 30-year U.S. Treasury bonds). Actual 30-year Treasury bonds have recently yielded below 4.5 percent, which indicates that his prospective yield was excessive.

Mr. Hanley also performs an "empirical" CAPM analysis, wherein he assigns 75 percent weight to actual betas for the proxy groups of gas utilities and a 25 percent weight to an assumed beta of 1.0 (i.e., the market beta). I disagree with this empirical CAPM.

The use of an empirical CAPM overstates the cost of equity for companies with betas below that of the market. What the empirical CAPM actually does is inflate the CAPM cost for the selected company or industry on one-fourth of its equity and assumes that one-fourth of the company has the risk of the overall market. This is not appropriate for Southwest Gas or for other utilities because it essentially creates a hypothetical beta that is used in the place of the actual beta. Investors are provided actual betas by organizations such as Value Line and it is reasonable to believe that investors rely upon these betas to some extent in making investment decisions. Mr. Hanley has provided no rationale or reasons to believe that investors would ignore these published betas and instead rely on hypothetical betas that are neither published nor readily available.

Q. **Mr. Hanley also maintains that the traditional CAPM understates the cost of equity for companies with betas below 1.0. Do you agree with his position?**

A. No, I do not. Again, Mr. Hanley fails to accept the fact that betas are determined using actual stock price movements and reflect actual decisions by investors. If one accepts the Efficient Market Hypothesis, as he does, there is no reason to modify the actual stock price movements and substitute alternative movements, as the empirical CAPM does.

Q. **Please summarize Mr. Hanley's comparable earnings method.**

A. Mr. Hanley's comparable earnings analysis examines the forecasted returns on equity for two groups of 23 and 34 non-utility companies which he perceives as being of similar risk to Southwest Gas and his LDC proxy group. For the 23 companies, he calculated a 5-year forecasted return of 13.42 percent. The corresponding number for the group of 34 companies is 13.88 percent.

I believe this analysis is an improper mechanism for estimating the cost of common equity for Southwest Gas. The equivalence of beta values (i.e., the basis for his selection of comparison companies) does not indicate that the expected earnings and cost of common equity for these non-utilities and utilities are the same. The projected 3-5 year returns for the non-utilities is 13.42 and 13.88 percent in Mr. Hanley's Exhibit___(FTH-13) whereas the respective returns for Mr. Hanley's proxy group of LDC utility companies is only 11.6-11.9 percent (my Schedule 9). This difference in returns demonstrates that utilities are able to maintain similar Value Line betas to non-utilities even though their expected earnings are substantially lower than those of the non-utilities. This result indicates that the expected earnings for the non-utilities are greater than for utilities such as Southwest Gas.

Q. Mr. Hanley concludes that the "indicated cost of equity" for his proxy group is 11.0 percent, which he increases by some 0.31 percent to reflect his perception of a required "investment risk adjustment" for Southwest Gas. What is your response to this proposed adjustment?

A. I disagree with Mr. Hanley's proposed investment risk adjustment for Southwest Gas. Mr. Hanley's 0.31 percent investment risk adjustment (which forms the basis for his 11.25 percent recommendation, which actually incorporates a 0.25 percent adjustment for Southwest Gas) is based on the yield differentials between A rated utility bonds and BBB rated utility bonds (see page 54, lines 6-8 and Sheet 3 of Mr. Hanley's FJH-1). Mr. Hanley is maintaining that, since Southwest Gas has lower debt ratings than his proxy group, the Company's cost of equity should be higher than that for the proxy group by the same differential as the yield differential between A rated and BBB rated utility bonds.

I do not believe that Mr. Hanley's proposed financial risk adjustment is warranted. As I noted in an earlier section of my testimony, Southwest Gas has historically maintained a lower equity ratio than most gas distribution utilities, which clearly has been a significant factor its lower bond ratings. In addition, during much of the late 1980s and 1990s, Southwest Gas owned a savings bank, which was a negative influence on the Company's financial performance and security ratings. Neither of these factors presently exist for Southwest Gas. The Company's common equity ratio is now similar to other gas distribution utilities and the savings bank has been sold. It does appear, however, that the lingering effects of these factors still influence the Company's ratings, especially the historically lower equity ratios.

As a result, I do not believe it is appropriate to add the full 0.31 percent (or 0.25 percent) differential to establish the cost of equity for Southwest Gas. I note, further, that Mr. Hanley's own analyses show the same "indicated common equity cost rate before investment risk adjustments" as shown on his FJH-1, page 2, which indicates the same cost rate for Southwest Gas and his proxy group.

XIV. FAIR VALUE RATE BASE COST OF CAPITAL

Q. What is your understanding of Southwest Gas' position on the issue of fair value rate base and related cost of capital implications?

A. It is my understanding that Southwest Gas is requesting that the fair value of its rate base be used in developing its rates. The Company does not appear to be requesting that its weighted cost of capital be applied to the level of its fair value rate base.

Q. What is your understanding of the Commission's procedure for utilizing the fair value of rate base in setting utility rates?

A. My "non-legal understanding" is that the Commission must consider the fair value of a utility's assets in setting rates. However, I do not agree that this implies that the Company's cost of capital must be applied to the fair value of the rate base.

Q. Are you aware that the Commission has recently conducted a "remand" hearing on the issue of regulatory treatment of fair value rate base for Chaparral City Water Company?

A. Yes, I am. In January of this year, the Commission conducted a public hearing in response to a remand by the Arizona Appeals Court (Appeals No. CA-CC 05-002) decision[3] in Chaparral City Water Company (Docket No. W-02113A-04-0616). The purpose of this hearing was to determine the appropriate cost of capital to be applied to an Arizona utility's fair value rate base.

Q. What is your understanding of the use of fair value rate base in Arizona?

A. My "non-legal understanding" is based in part on the 2006 Arizona Court of Appeals decision[4] in the Chaparral City case (Docket No. 02113A-04-0616), that indicates that the Court agreed with the Commission that "the cost of capital analysis 'is geared to concepts of original cost measures of rate base, not fair value measures of rate base . . . ." The decision goes on to make the following statement: "If the Commission determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology." It is correspondingly the purpose of this section of my testimony to recommend an "appropriate methodology" for use in conjunction with a FVRB.

Q. Do you have any observations based upon your own experience in cost of capital determination, as to whether a cost of capital developed for application to an original cost rate base is consistent with a fair value rate base?

A. Yes, I do. It is my personal experience, based upon over 35 years of providing cost of capital testimony, that the concept of cost of capital is designed to apply to an original cost rate base. This is the case since the cost of capital is derived from the liabilities/owners'

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[3] CA-CC 05-0002, Memorandum Decision dated February 13, 2007.
[4] [4] CA-CC 05-0002, Memorandum Decision dated February 13, 2007.

equity side of a utility's balance sheet using the book values of the capital structure components. The cost of capital, once determined, is then applied to (i.e., multiplied by) the rate base, which is derived from the asset side of the balance sheet (i.e.,OCRB). From a financial perspective, the rationale for this relationship is that the rate base is financed by the capitalization. Under this relationship, a provision is provided for investors (both lenders and owners) to receive a return on their invested capital. Such a relationship is meaningful as long as the cost of capital is applied to the original cost (i.e., book value) rate base, because there is a matching of rate base and capitalization.

When the concept of fair value rate base is incorporated, however, this link between rate base and capital structure is broken. The amount of fair value rate base that exceeds original cost rate base is not financed with investor-supplied funds and, indeed, is not financed at all. As a result, a customary cost of capital analysis cannot be automatically applied to the fair value rate base since there is no financial link between the two concepts. In my "non-legal" opinion, both the Commission and Appeals Court have also recognized this lack of compatibility between a customary weighted cost of capital ("WCOC") analysis and FVRB.

Q. Why is it important that there be a link between the concepts of rate base and cost of capital?

A. This link is important since financial theory indicates that investors should be provided an opportunity to earn a return on the capital they provided to the utility. Since the capital finances the rate base (in an original cost world), the link between cost of capital and rate base satisfies this financial objective.

Q. Based on your experience as a cost of capital witness over the past 35 years, do you have a suggestion as to how to account for the use of a FVRB in setting rates for Southwest Gas?

A. Yes, I do. Since the increment between fair value rate base and original cost rate base is not financed with investor-supplied funds, it is logical and appropriate, from a financial standpoint, to assume that this increment has no financing cost. As a result, the cost of capital, through the capital structure, can be modified to account for a level of cost-free capital in an equal dollar amount to the increment of FVRB over the OCRB. Such a procedure would still provide for a return being earned on all investor-supplied funds and would thus be consistent with financial standards.

Q. Have you made such a proposal in this proceeding?

A. Yes, I have. As is shown below, I have developed a capital structure and FVROR that applies to Southwest Gas' FVRB.

Item	Amount	Percent	Cost	Fair Value Return
Short-term Debt[5]	$0	0.00%		
Long-term Debt	557,641,284	40.01%	7.96%	3.18%
Preferred Stock	47,969,143	3.44%	8.20%	0.28%
Common Equity	465,129,366	33.37%	10.0%	3.34%
FVRB Increment[6]	323,152,085	23.18%	0.00%	0.00%
Total FVRB Capital	$1,393,891,878	100.00%		6.80%

Applying this 6.80 percent to the FVRB provides for a return on all investor-supplied capital and is therefore an appropriate rate to apply to the FVRB from a financial and economic standpoint. As such, it provides for an appropriate fair value rate of return to be applied to a FVRB.

[5] As is the case for my cost of capital calculations, no short-term debt is included since the Company had none at the end of the test period.
[6] FVRB minus OCRB.

Q. Have you developed an alternative method with which to apply a FVROR to a FVRB?

A. Yes, I have. Should the Commission determine that there should be a specific return (greater than zero) applied to the FVRB Increment, I have provided such a procedure.

Q. Why is it necessary to add a return on only the portion of FVRB that exceeds the OCRB?

A. The WCOC authorized by the Commission has already provided for a full cost of equity return and cost of debt on the portions of equity and debt capital that are supporting the OCRB portion of the FVRB. As a result, there is no need to provide any additional return on the portions of FVRB supported by common equity and debt.

Stated differently, both the cost of debt and the return on common equity (i.e., capital stock, paid-in capital, and retained earnings - the investment of common shareholders) are already provided for in a traditional WCOC. Only the portion of the FVRB that exceeds OCRB ("Fair Value Increment") needs to have a specific return identified in order to reflect a return component on that Fair Value Increment.

Q. What is the proper cost rate to apply to the Fair Value Increment?

A. As I indicated previously, from a financial perspective, it should not be necessary to provide for <u>any</u> return on the Fair Value Increment since this is not investor-supplied capital. However, the Commission may choose to evaluate this issue from both a financial and a public policy perspective. I am aware that Southwest Gas may claim that the concept of fair value carries with it the notion that investors should receive some benefit when fair value is greater than original cost and should suffer some detriment when fair value is less than original cost. It is possible that the Commission may determine that Arizona's fair value provision, which is somewhat unique, is not inconsistent with these concepts. Nonetheless, the idea that the Company should receive some benefit from the Fair Value Increment does not mean that one should automatically apply to the FVRB a WCOC developed by reference to original cost rate base. If it is determined that it is desirable to provide an additional (non-zero) return on the Fair Value Increment, the proper return should be no larger than the real (i.e., after inflation is removed) risk-free rate of return.

Q. What is the risk-free return?

A. The risk-free return is, in financial terms, the return on an investment that carries little or no risk. Risk-free investments are universally defined as U.S. Treasury Securities, with short-term maturities usually being used as the risk-free rate. Over the past several months, various maturities of U.S. Treasury securities have yielded from about 2.0 percent (short-term) to 4.5 percent (long-term) in nominal terms. Rates have declined recently. I also note that 2008-2009 forecasts of U.S. Treasury securities are about 4.0 percent to 4.5 percent. As a result, I use 4.5 percent as the nominal risk-free rate.

Q. What is the "real" risk-free rate?

A. The concept of real rates involves the removal of the rate of inflation from the nominal risk-free rate. In 2007, the rate of inflation, as measured by the Consumer Price Index ("CPI"), was 4.1 percent. Forecasts of the CPI for 2008-2009 are about 2 percent. As a result, I propose to use a 2 percent inflation rate for computing the real risk-free rate, which is computed as follows:

Nominal Risk-Free Rate	4.5%
Less: Inflation Rate	2.0%
Equals: Real Risk-Free Rate	2.5%

Q. Please explain why Southwest Gas' FVROR should consider the real risk-free rate, as opposed to the nominal risk-free rate.

A. The investors of Southwest Gas are already receiving an inflation factor due to the inclusion of inflation in the FVRB Increment. Specifically, the Fair Value Increment incorporates inflation by considering the current value of assets, which reflect, in part, past inflation. It would be double-counting to also include the inflation components in the return to be applied to the FVRB Increment.

Q. What return on the Fair Value Increment do you recommend in your alternative FVROR proposal?

A. My alternative FVROR proposal incorporates a return on the Fair Value Increment with a maximum value of 2.5 percent, as developed above. However, I wish to emphasize that this 2.5 percent value is the maximum value that could be applied to the FVRB Increment. In reality, any value between zero percent and 2.5 percent could be used as the cost rate on the FVRB Increment. As I stated above, this Fair Value Increment return is in addition to the return that the Company's investors already earn on their investment in the Company. In this sense, an above-zero cost rate for the fair value increment represents a bonus to the Company that would have to find its justification in policy considerations instead of in pure economic or financial principles; for that reason, the selection of an appropriate cost rate within this range should fall to the Commission's discretion. I would propose the mid-point of this range, or 1.25 percent.

Q. What is the resulting impact of your alternative proposal in this proceeding?

A. I am proposing the following modified FVROR for Southwest Gas:

Capital Item	Percent	Cost	Return
Short-term Debt	0.00%		
Long-term Debt	40.07%	7.96%	3.18%
Preferred Stock	3.44%	8.20%	0.28%
Common Equity	33.37%	10.00%	3.34%
FVRB Increment	23.18%	1.25%	0.29%
Total	100.00%		7.09%

As shown in the above table, this alternative proposal provides for a non-zero return on the Fair Value Increment of Southwest Gas, and provides for an overall fair value rate of return of 7.09 percent on the FVRB.

Q. Of the two alternative proposals for determining the fair value rate of return that should be applied to the FVRB, which one do you believe is more appropriate and why?

A. From a financial perspective, I believe the first proposal (i.e., zero-cost for FVRB Increment) is most appropriate. This proposal is consistent with financial principles and would fully compensate the Company's investors for their investment. In addition, this proposal utilizes the FVRB of the Company. If the Commission were to determine that a non-zero return on the Fair Value Increment is desirable, the alternative (i.e., a 1.25% cost-rate for the FVRB increment) is not inappropriate.

Q. Do these proposals provide for a return on the FVRB of Southwest Gas?

A. Yes, they do.

Q. Will Staff continue to evaluate appropriate methods for determining the fair value rate of return on fair value rate base?

A. It is my understanding that the Commission Staff will continue to consider these issues in the context of future rate cases. Individual rate cases present different issues and varying sets of circumstances. For example, if one were to assign a non-zero cost rate to the fair value increment, it may be appropriate to determine the cost of equity to reflect a reduction in risk. I have not proposed such an adjustment in this case, but these issues may appear as Staff continues to consider appropriate methods for determining and evaluating the concept of fair value rate of return on fair value rate base.

Q. Does this conclude your Direct Testimony?

A. Yes.

BACKGROUND AND EXPERIENCE PROFILE
DAVID C. PARCELL, MBA, CRRA
PRESIDENT/SENIOR ECONOMIST

EDUCATION

1985	M.B.A., Virginia Commonwealth University
1970	M.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)
1969	B.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)

POSITIONS

2007-Present	President, Technical Associates, Inc.
1995-2007	Executive Vice President and Senior Economist, Technical Associates, Inc.
1993-1995	Vice President and Senior Economist, C. W. Amos of Virginia
1972-1993	Vice President and Senior Economist, Technical Associates, Inc.
1969-1972	Research Economist, Technical Associates, Inc.
1968-1969	Research Associate, Department of Economics, Virginia Polytechnic Institute and State University

ACADEMIC HONORS

Omicron Delta Epsilon - Honor Society in Economics
Beta Gamma Sigma - National Scholastic Honor Society of Business Administration
Alpha Iota Delta - National Decision Sciences Honorary Society
Phi Kappa Phi - Scholastic Honor Society

PROFESSIONAL DESIGNATIONS

Certified Rate of Return Analyst - Founding Member
Member of Association for Investment Management and Research (AIMR)

RELEVANT EXPERIENCE

<u>Financial Economics</u> -- Advised and assisted many Virginia banks and savings and loan associations on organizational and regulatory matters. Testified approximately 25 times before the Virginia State Corporation Commission and the Regional Administrator of National Banks on matters related to branching and organization for banks, savings and loan associations, and consumer finance companies. Advised financial institutions on interest rate structure and loan maturity. Testified before Virginia State Corporation Commission on maximum rates for consumer finance companies.

Testified before several committees and subcommittees of Virginia General Assembly on numerous banking matters.

Clients have included First National Bank of Rocky Mount, Patrick Henry National Bank, Peoples Bank of Danville, Blue Ridge Bank, Bank of Essex, and Signet Bank.

Published articles in law reviews and other periodicals on structure and regulation of banking/financial services industry.

<u>Utility Economics</u> -- Performed numerous financial studies of regulated public utilities. Testified in over 300 cases before some thirty state and federal regulatory agencies.

Prepared numerous rate of return studies incorporating cost of equity determination based on DCF, CAPM, comparable earnings and other models. Developed procedures for identifying differential risk characteristics by nuclear construction and other factors.

Conducted studies with respect to cost of service and indexing for determining utility rates, the development of annual review procedures for regulatory control of utilities, fuel and power plant cost recovery adjustment clauses, power supply agreements among affiliates, utility franchise fees, and use of short-term debt in capital structure.

Presented expert testimony before federal regulatory agencies Federal Energy Regulatory Commission, Federal Power Commission, and National Energy Board (Canada), state regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Missouri, Nebraska, Nevada, New Hampshire, New Jersey, New Mexico, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, West Virginia, Washington, Wisconsin, and Yukon Territory (Canada).

Published articles in law reviews and other periodicals on the theory and purpose of regulation and other regulatory subjects.

Clients served include state regulatory agencies in Alaska, Arizona, Delaware, Missouri, North Carolina, Ontario (Canada), and Virginia; consumer advocates and attorneys general in Alabama, Arizona, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maryland, Nevada, New Mexico, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, and West Virginia; federal agencies including Defense Communications Agency, the Department of Energy, Department of the Navy, and General Services Administration; and various organizations such as Bath Iron Works, Illinois Citizens' Utility Board, Illinois Governor's Office of Consumer Services, Illinois Small Business Utility Advocate, Wisconsin's Environmental Decade, Wisconsin's Citizens Utility Board, and Old Dominion Electric Cooperative.

Insurance Economics -- Conducted analyses of the relationship between the investment income earned by insurance companies on their portfolios and the premiums charged for insurance. Analyzed impact of diversification on financial strength of Blue Cross/Blue Shield Plans in Virginia.

Conducted studies of profitability and cost of capital for property/casualty insurance industry. Evaluated risk of and required return on surplus for various lines of insurance business.

Presented expert testimony before Virginia State Corporation Commission concerning cost of capital and expected gains from investment portfolio. Testified before insurance bureaus of Maine, New Jersey, North Carolina, Rhode Island, South Carolina and Vermont concerning cost of equity for insurance companies.

Prepared cost of capital and investment income return analyses for numerous insurance companies concerning several lines of insurance business. Analyses used by Virginia Bureau of Insurance for purposes of setting rates.

Special Studies -- Conducted analyses which evaluated the financial and economic implications of legislative and administrative changes. Subject matter of analyses include returnable bottles, retail beer sales, wine sales regulations, taxi-cab taxation, and bank regulation. Testified before several Virginia General Assembly subcommittees.

Testified before Virginia ABC Commission concerning economic impact of mixed beverage license.

Clients include Virginia Beer Wholesalers, Wine Institute, Virginia Retail Merchants Association, and Virginia Taxicab Association.

Franchise, Merger & Anti-Trust Economics -- Conducted studies on competitive impact on market structures due to joint ventures, mergers, franchising and other business restructuring. Analyzed the costs and benefits to parties involved in mergers. Testified in federal courts and before banking and other regulatory bodies concerning the structure and performance of markets, as well as on the impact of restrictive practices.

Clients served include Dominion Bankshares, asphalt contractors, and law firms.

Transportation Economics -- Conducted cost of capital studies to assess profitability of oil pipelines, trucks, taxicabs and railroads. Analyses have been presented before the Federal Energy Regulatory Commission and Alaska Pipeline Commission in rate proceedings. Served as a consultant to the Rail Services Planning Office on the reorganization of rail services in the U.S.

Economic Loss Analyses -- Testified in federal courts, state courts, and other adjudicative forums regarding the economic loss sustained through personal and business injury whether due to bodily harm, discrimination, non-performance, or anticompetitive practices. Testified on economic loss to a commercial bank resulting from publication of adverse information concerning solvency. Testimony has been presented on behalf of private individuals and business firms.

MEMBERSHIPS

American Economic Association
Virginia Association of Economists
Richmond Society of Financial Analysts
Financial Analysts Federation
Society of Utility and Regulatory Financial Analysts

Board of Directors	1992-2000
Secretary/Treasurer	1994-1998
President	1998-2000

RESEARCH ACTIVITY

Books and Major Research Reports

"Stock Price As An Indicator of Performance," Master of Arts Thesis, Virginia Tech, 1970

"Revision of the Property and Casualty Insurance Ratemaking Process Under Prior Approval in the Commonwealth of Virginia," prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Charles Schotta and Michael J. Ileo, 1971

"An analysis of the Virginia Consumer Finance Industry to Determine the Need for Restructuring the Rate and Size Ceilings on Small Loans in Virginia and the Process by which They are Governed," prepared for the Virginia Consumer Finance Association, with Michael J. Ileo, 1973

State Banks and the State Corporation Commission: A Historical Review, Technical Associates, Inc., 1974

"A Study of the Implications of the Sale of Wine by the Virginia Department of Alcoholic Beverage Control", prepared for the Virginia Wine Wholesalers Association, Virginia Retail Merchants Association, Virginia Food Dealers Association, Virginia Association of Chain Drugstores, Southland Corporation, and the Wine Institute, 1983.

"Performance and Diversification of the Blue Cross/Blue Shield Plans in Virginia: An Operational Review", prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Michael J. Ileo and Alexander F. Skirpan, 1988.

The Cost of Capital - A Practitioners' Guide, Society of Utility and Regulatory Financial

Analysts, 1997 (previous editions in 1991, 1992, 1993, 1994, and 1995).

Papers Presented and Articles Published

"The Differential Effect of Bank Structure on the Transmission of Open Market Operations," Western Economic Association Meeting, with Charles Schotta, 1971

"The Economic Objectives of Regulation: The Trend in Virginia," (with Michael J. Ileo), William and Mary Law Review, Vol. 14, No. 2, 1973

"Evolution of the Virginia Banking Structure, 1962-1974: The Effects of the Buck-Holland Bill", (with Michael J. Ileo), William and Mary Law Review, Vol. 16, No. 3, 1975

"Banking Structure and Statewide Branching: The Potential for Virginia", William and Mary Law Review, Vol. 18, No. 1, 1976

"Bank Expansion and Electronic Banking: Virginia Banking Structure Changes Past, Present, and Future," William and Mary Business Review," Vol. 1, No. 2, 1976

"Electronic Banking - Wave of the Future?" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 1, 1976

"The Pricing of Electricity" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 2, 1976

"The Public Interest - Bank and Savings and Loan Expansion in Virginia" (with Richard D. Rogers), University of Richmond Law Review, Vol. 11, No. 3, 1977

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Exhibit DCP-1

SOUTHWEST GAS CORP.
TOTAL COST OF CAPITAL

Item	Amount	Percent		Cost			Weighted Cost	
Short-Term Debt	$0	0.00%					0.00%	
Long-Term Debt	$1,163,505,877	52.08%		7.96%			4.15%	
Preferred Stock	$100,000,000	4.48%		8.20%			0.37%	
Common Equity	$970,385,472	43.44%	9.30%		10.50%	4.04%		4.56%
Total	$2,233,891,349	100.00%				8.55%		9.07%
							8.86%	With 10.0% ROE

ECONOMIC INDICATORS

Year	Real GDP Growth*	Industrial Production Growth	Unemploy-ment Rate	Consumer Price Index	Producer Price Index
		1975 - 1982 Cycle			
1975	-1.1%	-8.9%	8.5%	7.0%	6.6%
1976	5.4%	10.8%	7.7%	4.8%	3.7%
1977	5.5%	5.9%	7.0%	6.8%	6.9%
1978	5.0%	5.7%	6.0%	9.0%	9.2%
1979	2.8%	4.4%	5.8%	13.3%	12.8%
1980	-0.2%	-1.9%	7.0%	12.4%	11.8%
1981	1.8%	1.9%	7.5%	8.9%	7.1%
1982	-2.1%	-4.4%	9.5%	3.8%	3.6%
		1983 - 1991 Cycle			
1983	4.0%	3.7%	9.5%	3.8%	0.6%
1984	6.8%	9.3%	7.5%	3.9%	1.7%
1985	3.7%	1.7%	7.2%	3.8%	1.8%
1986	3.1%	0.9%	7.0%	1.1%	-2.3%
1987	2.9%	4.9%	6.2%	4.4%	2.2%
1988	3.8%	4.5%	5.5%	4.4%	4.0%
1989	3.5%	1.8%	5.3%	4.6%	4.9%
1990	1.8%	-0.2%	5.6%	6.1%	5.7%
1991	-0.5%	-2.0%	6.8%	3.1%	-0.1%
		1992 - 2001 Cycle			
1992	3.0%	3.1%	7.5%	2.9%	1.6%
1993	2.7%	3.3%	6.9%	2.7%	0.2%
1994	4.0%	5.4%	6.1%	2.7%	1.7%
1995	2.5%	4.8%	5.6%	2.5%	2.3%
1996	3.7%	4.3%	5.4%	3.3%	2.8%
1997	4.5%	7.2%	4.9%	1.7%	-1.2%
1998	4.2%	6.1%	4.5%	1.6%	0.0%
1999	4.5%	4.7%	4.2%	2.7%	2.9%
2000	3.7%	4.5%	4.0%	3.4%	3.6%
2001	0.8%	-3.5%	4.7%	1.6%	-1.6%
		Current Cycle			
2002	1.6%	0.0%	5.8%	2.4%	1.2%
2003	2.5%	1.1%	6.0%	1.9%	4.0%
2004	3.6%	2.5%	5.5%	3.3%	4.2%
2005	3.1%	3.2%	5.1%	3.4%	5.4%
2006	2.9%	3.9%	4.6%	2.5%	1.1%
2007	2.2%	2.1%	4.6%	4.1%	6.3%

*GDP=Gross Domestic Product

Source: Council of Economic Advisors, Economic Indicators, various issues.

ECONOMIC INDICATORS

Year	Real GDP Growth*	Industrial Production Growth	Unemploy-ment Rate	Consumer Price Index	Producer Price Index
2002					
1st Qtr.	2.7%	-3.8%	5.6%	2.8%	4.4%
2nd Qtr.	2.2%	-1.2%	5.9%	0.9%	-2.0%
3rd Qtr.	2.4%	0.8%	5.8%	2.4%	1.2%
4th Qtr.	0.2%	1.4%	5.9%	1.6%	0.4%
2003					
1st Qtr.	1.2%	1.1%	5.8%	4.8%	5.6%
2nd Qtr.	3.5%	-0.9%	6.2%	0.0%	-0.5%
3rd Qtr.	7.5%	-0.9%	6.1%	3.2%	3.2%
4th Qtr.	2.7%	1.5%	5.9%	-0.3%	2.8%
2004					
1st Qtr.	3.0%	2.8%	5.6%	5.2%	5.2%
2nd Qtr.	3.5%	4.9%	5.6%	4.4%	4.4%
3rd Qtr.	3.6%	4.6%	5.4%	0.8%	0.8%
4th Qtr.	2.5%	4.3%	5.4%	3.6%	7.2%
2005					
1st Qtr.	3.1%	3.8%	5.3%	4.4%	5.6%
2nd Qtr.	2.8%	3.0%	5.1%	1.6%	-0.4%
3rd Qtr.	4.5%	2.7%	5.0%	8.8%	14.0%
4th Qtr.	1.2%	2.9%	4.9%	-2.0%	4.0%
2006					
1st Qtr.	4.8%	3.4%	4.7%	4.8%	-0.2%
2nd Qtr.	2.4%	4.5%	4.6%	4.8%	5.6%
3rd Qtr.	1.1%	5.2%	4.7%	0.4%	-4.4%
4th Qtr.	2.1%	3.5%	4.5%	0.0%	3.6%
2007					
1st Qtr.	0.6%	2.5%	4.5%	4.8%	6.4%
2nd Qtr.	3.8%	1.6%	4.5%	5.2%	6.8%
3rd Qtr.	4.9%	1.8%	4.6%	1.2%	1.2%
4th Qtr.	0.6%	1.7%	4.8%	5.6%	12.8%

Source: Council of Economic Advisors, Economic Indicators, various issues.

INTEREST RATES

Year	Prime Rate	US Treas T Bills 3 Month	US Treas T Bonds 10 Year	Utility Bonds Aaa	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
			1975 - 1982 Cycle				
1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.96%
1976	6.84%	4.99%	7.61%	8.63%	8.92%	9.29%	9.82%
1977	6.83%	5.27%	7.42%	8.19%	8.43%	8.61%	9.06%
1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9.62%
1979	12.67%	10.04%	9.44%	9.86%	10.22%	10.49%	10.96%
1980	15.27%	11.51%	11.46%	12.30%	13.00%	13.34%	13.95%
1981	18.89%	14.03%	13.93%	14.64%	15.30%	15.95%	16.60%
1982	14.86%	10.69%	13.00%	14.22%	14.79%	15.86%	16.45%
			1983 - 1991 Cycle				
1983	10.79%	8.63%	11.10%	12.52%	12.83%	13.66%	14.20%
1984	12.04%	9.58%	12.44%	12.72%	13.66%	14.03%	14.53%
1985	9.93%	7.48%	10.62%	11.68%	12.06%	12.47%	12.96%
1986	8.33%	5.98%	7.68%	8.92%	9.30%	9.58%	10.00%
1987	8.21%	5.82%	8.39%	9.52%	9.77%	10.10%	10.53%
1988	9.32%	6.69%	8.85%	10.05%	10.26%	10.49%	11.00%
1989	10.87%	8.12%	8.49%	9.32%	9.56%	9.77%	9.97%
1990	10.01%	7.51%	8.55%	9.45%	9.65%	9.86%	10.06%
1991	8.46%	5.42%	7.86%	8.85%	9.09%	9.36%	9.55%
			1992 - 2001 Cycle				
1992	6.25%	3.45%	7.01%	8.19%	8.55%	8.69%	8.86%
1993	6.00%	3.02%	5.87%	7.29%	7.44%	7.59%	7.91%
1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	8.63%
1995	8.83%	5.51%	6.57%	7.68%	7.77%	7.89%	8.29%
1996	8.27%	5.02%	6.44%	7.48%	7.57%	7.75%	8.16%
1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.60%	7.95%
1998	8.35%	4.81%	5.26%	6.77%	6.91%	7.04%	7.26%
1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.62%	7.88%
2000	9.23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
2001	6.91%	3.45%	5.02%	7.47%	7.59%	7.78%	8.02%
			Current Cycle				
2002	4.67%	1.62%	4.61%	[1]	7.19%	7.37%	8.02%
2003	4.12%	1.02%	4.01%		6.40%	6.58%	6.84%
2004	4.34%	1.38%	4.27%		6.04%	6.16%	6.40%
2005	6.19%	3.16%	4.29%		5.44%	5.65%	5.93%
2006	7.96%	4.73%	4.80%		5.84%	6.07%	6.32%
2007	8.05%	4.41%	4.63%		5.94%	6.07%	6.33%

[1] Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

INTEREST RATES

Year	Prime Rate	US Treas T Bills 3 Month	US Treas T Bonds 10 Year	Utility Bonds Aaa [1]	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
2003							
Jan	4.25%	1.17%	4.05%	[1]	6.87%	7.06%	7.47%
Feb	4.25%	1.16%	3.90%		6.66%	6.93%	7.17%
Mar	4.25%	1.13%	3.81%		6.56%	6.79%	7.05%
Apr	4.25%	1.14%	3.96%		6.47%	6.64%	6.94%
May	4.25%	1.08%	3.57%		6.20%	6.36%	6.47%
June	4.00%	0.95%	3.33%		6.12%	6.21%	6.30%
July	4.00%	0.90%	3.98%		6.37%	6.57%	6.67%
Aug	4.00%	0.96%	4.45%		6.48%	6.78%	7.08%
Sept	4.00%	0.95%	4.27%		6.30%	6.56%	6.87%
Oct	4.00%	0.93%	4.29%		6.28%	6.43%	6.79%
Nov	4.00%	0.94%	4.30%		6.26%	6.37%	6.69%
Dec	4.00%	0.90%	4.27%		6.18%	6.27%	6.61%
2004							
Jan	4.00%	0.89%	4.15%		6.06%	6.15%	6.47%
Feb	4.00%	0.92%	4.08%		6.10%	6.15%	6.28%
Mar	4.00%	0.94%	3.83%		5.93%	5.97%	6.12%
Apr	4.00%	0.94%	4.35%		6.33%	6.35%	6.46%
May	4.00%	1.04%	4.72%		6.66%	6.62%	6.75%
June	4.00%	1.27%	4.73%		6.30%	6.46%	6.84%
July	4.25%	1.35%	4.50%		6.09%	6.27%	6.67%
Aug	4.50%	1.48%	4.28%		5.95%	6.14%	6.45%
Sept	4.75%	1.65%	4.13%		5.79%	5.98%	6.27%
Oct	4.75%	1.75%	4.10%		5.74%	5.94%	6.17%
Nov	5.00%	2.06%	4.19%		5.79%	5.97%	6.16%
Dec	5.25%	2.20%	4.23%		5.78%	5.92%	6.10%
2005							
Jan	5.25%	2.32%	4.22%		5.68%	5.78%	5.95%
Feb	5.50%	2.53%	4.17%		5.55%	5.61%	5.76%
Mar	5.75%	2.75%	4.50%		5.76%	5.83%	6.01%
Apr	5.75%	2.79%	4.34%		5.56%	5.64%	5.95%
May	6.00%	2.86%	4.14%		5.39%	5.53%	5.88%
June	6.25%	2.99%	4.00%		5.05%	5.40%	5.70%
July	6.25%	3.22%	4.18%		5.18%	5.51%	5.81%
Aug	6.50%	3.45%	4.26%		5.23%	5.50%	5.80%
Sept	6.75%	3.47%	4.20%		5.27%	5.52%	5.83%
Oct	6.75%	3.70%	4.46%		5.50%	5.79%	6.08%
Nov	7.00%	3.90%	4.54%		5.59%	5.88%	6.19%
Dec	7.25%	3.89%	4.47%		5.55%	5.80%	6.14%
2006							
Jan	7.50%	4.20%	4.42%		5.50%	5.75%	6.06%
Feb	7.50%	4.41%	4.57%		5.55%	5.82%	6.11%
Mar	7.75%	4.51%	4.72%		5.71%	5.98%	6.26%
Apr	7.75%	4.59%	4.99%		6.02%	6.29%	6.54%
May	8.00%	4.72%	5.11%		6.16%	6.42%	6.59%
June	8.25%	4.79%	5.11%		6.16%	6.40%	6.61%
July	8.25%	4.96%	5.09%		6.13%	6.37%	6.61%
Aug	8.25%	4.98%	4.88%		5.97%	6.20%	6.43%
Sept	8.25%	4.82%	4.72%		5.81%	6.00%	6.26%
Oct	8.25%	4.89%	4.73%		5.80%	5.98%	6.24%
Nov	8.25%	4.95%	4.60%		5.61%	5.80%	6.04%
Dec	8.25%	4.85%	4.56%		5.62%	5.81%	6.05%
2007							
Jan	8.25%	4.96%	4.76%		5.78%	5.96%	6.16%
Feb	8.25%	5.02%	4.72%		5.73%	5.90%	6.10%
Mar	8.25%	4.97%	4.56%		5.66%	5.85%	6.10%
Apr	8.25%	4.88%	4.69%		5.83%	5.97%	6.24%
May	8.25%	4.77%	4.75%		5.86%	5.99%	6.23%
June	8.25%	4.63%	5.10%		6.18%	6.30%	6.54%
July	8.25%	4.84%	5.00%		6.11%	6.25%	6.49%
Aug	8.25%	4.34%	4.67%		6.11%	6.24%	6.51%
Sept	7.75%	4.01%	4.52%		6.10%	6.18%	6.45%
Oct	7.50%	3.97%	4.53%		6.04%	6.11%	6.36%
Nov	7.50%	3.49%	4.15%		5.87%	5.97%	6.27%
Dec	7.25%	3.08%	4.10%		6.03%	6.16%	6.51%
2008							
Jan	6.00%	2.86%	3.74%		5.87%	6.02%	6.35%

[1] Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

STOCK PRICE INDICATORS

Year	S&P Composite [1]	NASDAQ Composite [1]	DJIA	S&P D/P	S&P E/P
		1975 - 1982 Cycle			
1975			802.49	4.31%	9.15%
1976			974.92	3.77%	8.90%
1977			894.63	4.62%	10.79%
1978			820.23	5.28%	12.03%
1979			844.40	5.47%	13.46%
1980			891.41	5.26%	12.66%
1981			932.92	5.20%	11.96%
1982			884.36	5.81%	11.60%
		1983 - 1991 Cycle			
1983			1,190.34	4.40%	8.03%
1984			1,178.48	4.64%	10.02%
1985			1,328.23	4.25%	8.12%
1986			1,792.76	3.49%	6.09%
1987			2,275.99	3.08%	5.48%
1988	[1]	[1]	2,060.82	3.64%	8.01%
1989	322.84		2,508.91	3.45%	7.41%
1990	334.59		2,678.94	3.61%	6.47%
1991	376.18	491.69	2,929.33	3.24%	4.79%
		1992 - 2001 Cycle			
1992	415.74	599.26	3,284.29	2.99%	4.22%
1993	451.21	715.16	3,522.06	2.78%	4.46%
1994	460.42	751.65	3,793.77	2.82%	5.83%
1995	541.72	925.19	4,493.76	2.56%	6.09%
1996	670.50	1,164.96	5,742.89	2.19%	5.24%
1997	873.43	1,469.49	7,441.15	1.77%	4.57%
1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
2000	1,427.22	3,783.67	10,734.90	1.15%	3.63%
2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
		Current Cycle			
2002	993.94	1,539.73	9,226.43	1.61%	2.92%
2003	965.23	1,647.17	8,993.59	1.77%	3.84%
2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
2005	1,207.23	2,099.32	10,547.67	1.83%	5.36%
2006	1,310.46	2,263.41	11,408.67	1.87%	5.78%
2007	1,477.19	2,578.47	13,169.98	1.86%	

[1] Note: this source did not publish the S&P Composite prior to 1988 and the NASDAQ Composite prior to 1991.

Source: Council of Economic Advisors, Economic Indicators, various issues.

STOCK PRICE INDICATORS

YEAR	S&P Composite	NASDAQ Composite	DJIA	S&P D/P	S&P E/P
2002					
1st Qtr.	1,131.56	1,879.85	10,105.27	1.39%	2.15%
2nd Qtr.	1,068.45	1,641.53	9,912.70	1.49%	2.70%
3rd Qtr.	894.65	1,308.17	8,487.59	1.76%	3.68%
4th Qtr.	887.91	1,346.07	8,400.17	1.79%	3.14%
2003					
1st Qtr.	860.03	1,350.44	8,122.83	1.89%	3.57%
2nd Qtr.	938.00	1,521.92	8,684.52	1.75%	3.55%
3rd Qtr.	1,000.50	1,765.96	9,310.57	1.74%	3.87%
4th Qtr.	1,056.42	1,934.71	9,856.44	1.69%	4.38%
2004					
1st Qtr.	1,133.29	2,041.95	10,488.43	1.64%	4.62%
2nd Qtr.	1,122.87	1,984.13	10,289.04	1.71%	4.92%
3rd Qtr.	1,104.15	1,872.90	10,129.85	1.79%	5.18%
4th Qtr.	1,162.07	2,050.22	10,362.25	1.75%	4.83%
2005					
1st Qtr.	1,191.98	2,056.01	10,648.48	1.77%	5.11%
2nd Qtr.	1,181.65	2,012.24	10,382.35	1.85%	5.32%
3rd Qtr.	1,225.91	2,144.61	10,532.24	1.83%	5.42%
4th Qtr.	1,262.07	2,246.09	10,827.79	1.86%	5.60%
2006					
1st Qtr.	1,283.04	2,287.97	10,996.04	1.85%	5.61%
2nd Qtr.	1,281.77	2,240.46	11,188.84	1.90%	5.86%
3rd Qtr.	1,288.40	2,141.97	11,274.49	1.91%	5.88%
4th Qtr.	1,389.48	2,390.26	12,175.30	1.81%	5.75%
2007					
1st Qtr.	1,425.30	2,444.85	12,470.97	1.84%	5.85%
2nd Qtr.	1,496.43	2,552.37	13,214.26	1.82%	5.65%
3rd Qtr.	1,490.81	2,609.68	13,488.43	1.86%	5.15%
4th Qtr.	1,494.09	2,701.59	13,502.95	1.91%	

[1] Note: this source did not publish the S&P Composite prior to 1988 and the NASDA(Composite prior to 1991.

Source: Council of Economic Advisors, Economic Indicators, various issues.

SOUTHWEST GAS CORP
BOND RATINGS

Date	Moody's	Standard & Poor's	Fitch
1995	Baa3	BBB-	
1996	Baa2	BBB-	
1997	Baa2	BBB-	
1998	Baa2	BBB-	
1999	Baa2	BBB-	
2000	Baa2	BBB-	BBB
2001	Baa2	BBB-	BBB
2002	Baa2	BBB-	BBB
2003	Baa2	BBB-	BBB
2004	Baa2	BBB-	BBB
2005	Baa2	BBB-	BBB
2006	Baa3	BBB-	BBB
2007	Baa3	BBB-	BBB

Source: Response to Request No. STF-2-6.

SOUTHWEST GAS CORP.
CAPITAL STRUCTURE RATIOS
2002 - 2007
($000)

YEAR	COMMON EQUITY	LONG-TERM DEBT	SHORT-TERM DEBT
2003	$630,467	$1,221,164	$58,435
	33.0%	63.9%	3.1%
	34.0%	66.0%	
2004	$705,676	$1,262,936	
	35.8%	64.2%	0.0%
	35.8%	64.2%	
2005	$751,135	$1,324,898	$107,215
	34.4%	60.7%	4.9%
	36.2%	63.8%	
2006	$901,425	$1,386,354	$27,545
	38.9%	59.9%	1.2%
	39.4%	60.6%	
2007	$983,673	$1,366,067	$47,079
	41.0%	57.0%	2.0%
	41.9%	58.1%	

Note: Percentages may not total 100.0% due to rounding.

Source: Southwest Gas Corp., Annual Reports to Stockholders.

VALUE LINE GAS DISTRIBUTION COMPANIES
COMMON EQUITY RATIOS

COMPANY	2000	2001	2002	2003	2004	2005	2006	Average	2009-2011
AGL Resources	48.3%	38.7%	41.7%	49.7%	46.0%	48.1%	49.8%	46.0%	51.5%
Atmos Energy	51.9%	45.7%	46.1%	49.8%	56.8%	42.3%	43.0%	47.9%	49.0%
Energen	53.1%	46.9%	53.2%	55.8%	56.7%	56.6%	67.4%	55.7%	60.0%
Laclede Group	54.5%	50.2%	52.3%	49.4%	48.3%	51.8%	50.4%	51.0%	51.0%
New Jersey Resources	52.9%	49.9%	49.4%	61.9%	59.7%	58.0%	65.2%	56.7%	72.8%
NICOR	66.7%	61.7%	64.5%	60.3%	60.1%	62.5%	63.7%	62.8%	74.0%
Northwest Natural Gas	50.9%	53.2%	51.5%	50.3%	54.0%	53.0%	53.7%	52.4%	52.0%
Piedmont Natural Gas	53.9%	52.4%	56.1%	57.8%	56.4%	58.6%	51.7%	55.3%	50.8%
South Jersey Industries	37.6%	35.9%	46.1%	49.0%	51.0%	55.1%	55.3%	47.1%	59.0%
Southwest Gas	35.8%	39.6%	34.1%	34.0%	35.8%	36.2%	39.4%	36.4%	47.0%
UGI	19.1%	17.4%	21.7%	33.0%	35.0%	41.7%	35.9%	29.1%	67.0%
WGL Holdings	54.8%	56.3%	52.4%	54.3%	57.2%	58.6%	61.5%	56.4%	65.8%
Average	48.3%	45.7%	47.4%	50.4%	51.4%	51.9%	53.1%	49.7%	58.3%
Composite			41.4%	43.7%	45.7%	48.3%		44.8%	46.0%

Source: Value Line Investment Survey.

COMPARISON COMPANIES
CAPITAL STRUCTURE RATIOS
INCLUDING SHORT-TERM DEBT

Company	2001	2002	2003	2004	2005	2006
AGL Resources	32%	33%	41%	41%	41%	42%
Atmos Energy	40%	39%	45%	41%	38%	45%
Energen	45%	47%	55%	51%	56%	64%
Laclede Group	41%	37%	37%	40%	38%	58%
New Jersey Resources	43%	44%	44%	45%	43%	51%
NICOR	50%	51%	41%	43%	42%	51%
Northwest Natural Gas	46%	48%	50%	49%	47%	48%
Piedmont Natural Gas	51%	54%	53%	53%	48%	46%
South Jersey Industries	32%	34%	41%	31%	45%	44%
Southwest Gas	31%	33%	33%	34%	36%	41%
UGI	14%	24%	29%	31%	33%	32%
WGL Holdings	48%	48%	49%	52%	58%	51%
Average	**39%**	**41%**	**43%**	**43%**	**44%**	**48%**

Source: AUS Utility Reports.

COMPARISON COMPANIES
DIVIDEND YIELD

COMPANY	DPS	November, 2007 - January, 2008 HIGH	LOW	AVERAGE	YIELD
Value Line Natural Gas Distribution Companies					
AGL Resources	$1.64	$39.21	$35.42	$37.32	4.4%
Atmos Energy	$1.30	$28.85	$26.00	$27.43	4.7%
Energen	$0.46	$70.41	$57.61	$64.01	0.7%
Laclede Group	$1.50	$35.72	$31.86	$33.79	4.4%
New Jersey Resources	$1.60	$52.07	$43.83	$47.95	3.3%
NICOR	$1.86	$45.16	$37.40	$41.28	4.5%
Northwest Natural Gas	$1.50	$50.89	$44.62	$47.76	3.1%
Piedmont Natural Gas	$1.00	$27.98	$24.01	$26.00	3.8%
South Jersey Industries	$1.08	$38.50	$33.82	$36.16	3.0%
Southwest Gas	$0.86	$30.97	$26.30	$28.64	3.0%
UGI	$0.74	$28.18	$23.99	$26.09	2.8%
WGL Holdings	$1.37	$34.62	$31.31	$32.97	4.2%
Average					**3.5%**
Hanley Proxy Companies					
AGL Resources	$1.64	$39.21	$35.42	$37.32	4.4%
Atmos Energy	$1.30	$28.85	$26.00	$27.43	4.7%
Laclede Group	$1.50	$35.72	$31.86	$33.79	4.4%
NICOR	$1.86	$45.16	$37.40	$41.28	4.5%
Northwest Natural Gas	$1.50	$50.89	$44.62	$47.76	3.1%
Piedmont Natural Gas	$1.00	$27.98	$24.01	$26.00	3.8%
South Jersey Industries	$1.08	$38.50	$33.82	$36.16	3.0%
WGL Holdings	$1.37	$34.62	$31.31	$32.97	4.2%
Average					**4.0%**

Source: Yahoo! Finance.

COMPARISON COMPANIES
RETENTION GROWTH RATES

COMPANY	2002	2003	2004	2005	2006	Average	2007	2008	'10-'12	Average
Value Line Natural Gas										
AGL Resources	7.0%	6.6%	5.6%	6.2%	6.3%	6.3%	5.0%	6.0%	6.0%	5.7%
Atmos Energy	1.9%	2.8%	1.7%	2.3%	3.6%	2.5%	3.0%	3.0%	4.0%	3.3%
Energen	7.0%	12.1%	12.4%	16.1%	16.7%	12.9%	19.0%	16.5%	12.5%	16.0%
Laclede Group	0.0%	3.1%	2.7%	3.1%	5.1%	2.8%	4.0%	3.5%	4.0%	3.8%
New Jersey Resources	6.9%	7.7%	7.8%	8.5%	6.3%	7.4%	6.5%	6.0%	5.0%	5.8%
NICOR	6.5%	1.5%	2.1%	2.3%	5.2%	3.5%	4.5%	5.0%	4.0%	4.5%
Northwest Natural Gas	1.9%	2.6%	2.7%	3.7%	4.2%	3.0%	5.0%	5.0%	4.5%	4.8%
Piedmont Natural Gas	1.7%	3.1%	3.7%	3.6%	2.8%	3.0%	3.5%	3.5%	3.5%	3.5%
South Jersey Industries	4.7%	5.0%	5.9%	6.2%	10.2%	6.4%	6.0%	6.5%	10.0%	7.5%
Southwest Gas	1.9%	1.7%	4.3%	2.2%	5.3%	3.1%	5.5%	6.5%	7.0%	6.3%
UGI	9.7%	9.2%	7.3%	11.5%	9.4%	9.4%	8.8%	9.0%	8.5%	8.8%
WGL Holdings	0.0%	6.2%	4.1%	4.6%	3.1%	3.6%	3.6%	4.0%	3.0%	3.5%
Average						**5.3%**				**6.1%**
Hanley Proxy Companies										
AGL Resources	7.0%	6.6%	5.6%	6.2%	6.3%	6.3%	5.0%	6.0%	6.0%	5.7%
Atmos Energy	1.9%	2.8%	1.7%	2.3%	3.6%	2.5%	3.0%	3.0%	4.0%	3.3%
Laclede Group	0.0%	3.1%	2.7%	3.1%	5.1%	2.8%	4.0%	3.5%	4.0%	3.8%
NICOR	6.5%	1.5%	2.1%	2.3%	5.2%	3.5%	4.5%	5.0%	4.0%	4.5%
Northwest Natural Gas	1.9%	2.6%	2.7%	3.7%	4.2%	3.0%	5.0%	5.0%	4.5%	4.8%
Piedmont Natural Gas	1.7%	3.1%	3.7%	3.6%	2.8%	3.0%	3.5%	3.5%	3.5%	3.5%
South Jersey Industries	4.7%	5.0%	5.9%	6.2%	10.2%	6.4%	6.0%	6.5%	10.0%	7.5%
WGL Holdings	0.0%	6.2%	4.1%	4.6%	3.1%	3.6%	3.6%	4.0%	3.0%	3.5%
Average						**3.9%**				**4.6%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
PER SHARE GROWTH RATES

	5-Year Historic Growth Rates				Est'd '04-'06 to '10-'12 Growth Rates			
COMPANY	EPS	DPS	BVPS	Average	EPS	DPS	BVPS	Average
Value Line Natural Gas								
AGL Resources	15.0%	4.0%	10.5%	9.8%	3.5%	5.5%	2.5%	3.8%
Atmos Energy	10.0%	2.0%	8.5%	6.8%	5.0%	1.5%	5.5%	4.0%
Energen	22.0%	4.0%	14.0%	13.3%	5.5%	7.0%	9.0%	7.2%
Laclede Group	6.5%	0.5%	3.5%	3.5%	4.0%	2.5%	5.0%	3.8%
New Jersey Resources	8.0%	3.5%	8.5%	6.7%	4.0%	5.0%	10.5%	6.5%
NICOR	-3.0%	2.5%	2.5%	0.7%	3.0%	0.0%	6.0%	3.0%
Northwest Natural Gas	3.0%	1.5%	3.5%	2.7%	7.0%	5.5%	3.5%	5.3%
Piedmont Natural Gas	5.0%	5.0%	6.5%	5.5%	4.0%	4.5%	2.5%	3.7%
South Jersey Industries	9.5%	3.5%	13.5%	8.8%		5.5%	4.5%	5.0%
Southwest Gas	6.0%	0.0%	3.5%	3.2%	8.0%	1.5%	4.0%	4.5%
UGI	22.5%	5.0%	25.0%	17.5%	7.0%	2.5%	11.5%	7.0%
WGL Holdings	6.0%	1.5%	3.0%	3.5%	2.0%	2.5%	4.5%	3.0%
Average	9.2%	2.8%	8.5%	**6.8%**	4.8%	3.6%	5.8%	**4.7%**
Hanley Proxy Companies								
AGL Resources	15.0%	4.0%	10.5%	9.8%	3.5%	5.5%	2.5%	3.8%
Atmos Energy	10.0%	2.0%	8.5%	6.8%	5.0%	1.5%	5.5%	4.0%
Laclede Group	6.5%	0.5%	3.5%	3.5%	4.0%	2.5%	5.0%	3.8%
NICOR	-3.0%	2.5%	2.5%	0.7%	3.0%	0.0%	6.0%	3.0%
Northwest Natural Gas	3.0%	1.5%	3.5%	2.7%	7.0%	5.5%	3.5%	5.3%
Piedmont Natural Gas	5.0%	5.0%	6.5%	5.5%	4.0%	4.5%	2.5%	3.7%
South Jersey Industries	9.5%	3.5%	13.5%	8.8%		5.5%	4.5%	5.0%
WGL Holdings	6.0%	1.5%	3.0%	3.5%	2.0%	2.5%	4.5%	3.0%
Average	6.5%	2.6%	6.4%	**5.2%**	4.1%	3.4%	4.3%	**4.0%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
DCF COST RATES

COMPANY	ADJUSTED YIELD	HISTORIC RETENTION GROWTH	PROSPECTIVE RETENTION GROWTH	HISTORIC PER SHARE GROWTH	PROSPECTIVE PER SHARE GROWTH	FIRST CALL EPS GROWTH	AVERAGE GROWTH	DCF RATES
Value Line Natural Gas								
AGL Resources	4.5%	6.3%	5.7%	9.8%	3.8%	5.0%	6.1%	10.7%
Atmos Energy	4.8%	2.5%	3.3%	6.8%	4.0%	5.3%	4.4%	9.2%
Energen	0.8%	12.9%	16.0%	13.3%	7.2%	7.2%	11.3%	12.1%
Laclede Group	4.5%	2.8%	3.8%	3.5%	3.8%	3.5%	3.5%	8.0%
New Jersey Resources	3.4%	7.4%	5.8%	6.7%	6.5%	5.1%	6.3%	9.8%
NICOR	4.6%	3.5%	4.5%	0.7%	3.0%	3.7%	3.1%	7.6%
Northwest Natural Gas	3.2%	3.0%	4.8%	2.7%	5.3%	4.9%	4.2%	7.4%
Piedmont Natural Gas	3.9%	3.0%	3.5%	5.5%	3.7%	5.2%	4.2%	8.1%
South Jersey Industries	3.1%	6.4%	7.5%	8.8%	5.0%	6.6%	6.9%	10.0%
Southwest Gas	3.1%	3.1%	6.3%	3.2%	4.5%	4.7%	4.4%	7.4%
UGI	3.0%	9.4%	8.8%	17.5%	7.0%	8.0%	10.1%	13.1%
WGL Holdings	4.2%	3.6%	3.5%	3.5%	3.0%	4.0%	3.5%	7.8%
Mean	3.6%	5.3%	6.1%	6.8%	4.7%	5.3%	5.7%	**9.3%**
Median	3.7%	3.6%	5.3%	6.1%	4.3%	5.1%	4.4%	**8.7%**
Mean Composite		8.9%	9.7%	**10.4%**	8.3%	8.9%	9.3%	
Median Composite		7.2%	8.9%	**9.8%**	7.9%	8.7%	8.1%	
Hanley Proxy Companies								
AGL Resources	4.5%	6.3%	5.7%	9.8%	3.8%	5.0%	6.1%	10.7%
Atmos Energy	4.8%	2.5%	3.3%	6.8%	4.0%	5.3%	4.4%	9.2%
Laclede Group	4.5%	2.8%	3.8%	3.5%	3.8%	3.5%	3.5%	8.0%
NICOR	4.6%	3.5%	4.5%	0.7%	3.0%	3.7%	3.1%	7.6%
Northwest Natural Gas	3.2%	3.0%	4.8%	2.7%	5.3%	4.9%	4.2%	7.4%
Piedmont Natural Gas	3.9%	3.0%	3.5%	5.5%	3.7%	5.2%	4.2%	8.1%
South Jersey Industries	3.1%	6.4%	7.5%	8.8%	5.0%	6.6%	6.9%	10.0%
WGL Holdings	4.2%	3.6%	3.5%	3.5%	3.0%	4.0%	3.5%	7.8%
Mean	4.1%	3.9%	4.6%	5.2%	4.0%	4.8%	4.5%	**8.6%**
Median	4.4%	3.3%	4.2%	4.5%	3.8%	4.9%	4.2%	**8.1%**
Mean Composite		8.0%	8.7%	**9.3%**	8.1%	8.9%	8.6%	
Median Composite		7.6%	8.5%	8.9%	8.2%	**9.3%**	8.5%	

Sources: Prior pages of this schedule.

STANDARD & POOR'S 500 COMPOSITE
20-YEAR U.S. TREASURY BOND YIELDS
RISK PREMIUMS

Year	EPS	BVPS	ROE	20-YEAR T-BOND YIELD	RISK PREMIUM
1977		$79.07			
1978	$12.33	$85.35	15.00%	7.90%	7.10%
1979	$14.86	$94.27	16.55%	8.86%	7.69%
1980	$14.82	$102.48	15.06%	9.97%	5.09%
1981	$15.36	$109.43	14.50%	11.55%	2.95%
1982	$12.64	$112.46	11.39%	13.50%	-2.11%
1983	$14.03	$116.93	12.23%	10.38%	1.85%
1984	$16.64	$122.47	13.90%	11.74%	2.16%
1985	$14.61	$125.20	11.80%	11.25%	0.55%
1986	$14.48	$126.82	11.49%	8.98%	2.51%
1987	$17.50	$134.04	13.42%	7.92%	5.50%
1988	$23.75	$141.32	17.25%	8.97%	8.28%
1989	$22.87	$147.26	15.85%	8.81%	7.04%
1990	$21.73	$153.01	14.47%	8.19%	6.28%
1991	$16.29	$158.85	10.45%	8.22%	2.23%
1992	$19.09	$149.74	12.37%	7.29%	5.08%
1993	$21.89	$180.88	13.24%	7.17%	6.07%
1994	$30.60	$193.06	16.37%	6.59%	9.78%
1995	$33.96	$215.51	16.62%	7.60%	9.02%
1996	$38.73	$237.08	17.11%	6.18%	10.93%
1997	$39.72	$249.52	16.33%	6.64%	9.69%
1998	$37.71	$266.40	14.62%	5.83%	8.79%
1999	$48.17	$290.68	17.29%	5.57%	11.72%
2000	$50.00	$325.80	16.22%	6.50%	9.72%
2001	$24.69	$338.37	7.43%	5.53%	1.90%
2002	$27.59	$321.72	8.36%	5.59%	2.77%
2003	$48.73	$367.17	14.15%	4.80%	9.35%
2004	$58.55	$414.75	14.98%	5.02%	9.96%
2005	$69.93	$453.06	16.12%	4.69%	11.43%
2006	$81.51	$504.39	17.03%	4.68%	12.35%
Average					**6.40%**

Source: Standard & Poor's Analysts' Handbook, Ibbotson Associates Handbook.

COMPARISON COMPANIES
CAPM COST RATES

COMPANY	RISK-FREE RATE	BETA	RISK PREMIUM	CAPM RATES
Value Line Natural Gas				
AGL Resources	4.49%	0.85	5.90%	9.5%
Atmos Energy	4.49%	0.85	5.90%	9.5%
Energen	4.49%	0.90	5.90%	9.8%
Laclede Group	4.49%	0.95	5.90%	10.1%
New Jersey Resources	4.49%	0.85	5.90%	9.5%
NICOR	4.49%	1.00	5.90%	10.4%
Northwest Natural Gas	4.49%	0.90	5.90%	9.8%
Piedmont Natural Gas	4.49%	0.85	5.90%	9.5%
South Jersey Industries	4.49%	0.85	5.90%	9.5%
Southwest Gas	4.49%	0.90	5.90%	9.8%
UGI	4.49%	0.85	5.90%	9.5%
WGL Holdings	4.49%	0.85	5.90%	9.5%
Mean				**9.7%**
Median				**9.5%**
Hanley Proxy Companies				
AGL Resources	4.49%	0.85	5.90%	9.5%
Atmos Energy	4.49%	0.85	5.90%	9.5%
Laclede Group	4.49%	0.95	5.90%	10.1%
NICOR	4.49%	1.00	5.90%	10.4%
Northwest Natural Gas	4.49%	0.90	5.90%	9.8%
Piedmont Natural Gas	4.49%	0.85	5.90%	9.5%
South Jersey Industries	4.49%	0.85	5.90%	9.5%
WGL Holdings	4.49%	0.85	5.90%	9.5%
Mean				**9.7%**
Median				**9.5%**

Sources: Value Line Investment Survey, Standard & Poor's Analysts' Handbook, Federal Reserve.

COMPARISON COMPANIES
RATES OF RETURN ON AVERAGE COMMON EQUITY

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	1992-2001 Average	2002-2006 Average	2007	2008	2010-2012
Value Line Natural Gas																				
AGL Resources	11.8%	11.0%	11.6%	13.1%	13.2%	12.7%	12.6%	7.9%	11.2%	12.7%	14.7%	15.3%	13.9%	13.3%	13.6%	11.8%	14.2%	12.5%	13.5%	14.0%
Atmos Energy	10.7%	12.7%	10.0%	12.2%	14.4%	12.3%	15.8%	6.7%	8.5%	11.1%	10.3%	11.2%	9.1%	9.1%	10.0%	11.4%	9.9%	8.5%	8.5%	9.0%
Energen	12.6%	13.4%	13.9%	11.3%	11.9%	12.3%	11.4%	11.3%	14.3%	15.6%	12.4%	17.2%	17.0%	20.3%	22.2%	12.8%	17.8%	21.5%	19.0%	15.0%
Laclede Group	9.9%	13.4%	11.5%	10.0%	14.0%	13.2%	11.0%	10.0%	9.1%	10.6%	7.8%	11.8%	11.2%	11.1%	13.1%	11.3%	11.0%	11.0%	10.5%	10.5%
New Jersey Resources	12.1%	11.9%	13.0%	13.3%	13.8%	14.5%	14.6%	14.9%	15.1%	15.2%	15.9%	16.7%	15.8%	16.2%	14.6%	13.8%	15.8%	13.0%	12.0%	10.5%
NICOR	15.3%	15.3%	15.7%	14.6%	17.0%	16.9%	14.7%	15.7%	18.2%	18.8%	17.3%	12.4%	13.0%	13.0%	16.0%	16.2%	14.3%	14.0%	13.5%	11.5%
Northwest Natural Gas	6.0%	13.7%	12.2%	11.4%	13.2%	11.2%	6.3%	10.1%	10.2%	10.3%	8.7%	9.2%	9.3%	10.1%	10.9%	10.5%	9.6%	11.0%	11.5%	11.5%
Piedmont Natural Gas	14.1%	13.8%	12.2%	12.3%	13.2%	13.8%	13.6%	12.1%	12.5%	12.0%	10.8%	12.2%	12.4%	11.6%	10.9%	13.0%	11.6%	12.0%	12.0%	12.0%
South Jersey Industries	11.8%	11.0%	8.5%	11.4%	11.1%	11.9%	10.1%	15.6%	15.4%	15.3%	14.0%	13.1%	13.4%	13.2%	17.2%	12.2%	14.2%	12.5%	13.0%	16.5%
Southwest Gas	5.1%	3.9%	7.5%	0.6%	1.7%	5.4%	10.4%	7.5%	7.3%	6.7%	6.6%	6.2%	8.8%	6.5%	9.7%	5.6%	7.6%	9.5%	10.0%	10.5%
UGI	9.1%	3.2%	9.0%	4.9%	9.2%	12.9%	10.9%	13.4%	17.4%	22.7%	25.9%	21.9%	16.5%	19.5%	16.1%	11.3%	20.0%	9.6%	14.0%	13.0%
WGL Holdings	12.5%	12.1%	12.6%	12.4%	15.0%	14.1%	11.3%	10.3%	11.9%	11.9%	7.1%	14.4%	11.9%	12.1%	10.8%	12.4%	11.3%	11.1%	11.0%	10.5%
Average	10.9%	11.3%	11.5%	10.6%	12.3%	12.6%	11.9%	11.3%	12.6%	13.6%	12.6%	13.5%	12.7%	13.0%	13.8%	**11.9%**	**13.1%**	**12.2%**	**12.4%**	**12.0%**
Composite																**11.9%**	**13.1%**			
Hanley Proxy Companies																				
AGL Resources	11.8%	11.0%	11.6%	13.1%	13.2%	12.7%	12.6%	7.9%	11.2%	12.7%	14.7%	15.3%	13.9%	13.3%	13.6%	11.8%	14.2%	12.5%	13.5%	14.0%
Atmos Energy	10.7%	12.7%	10.0%	12.2%	14.4%	12.3%	15.8%	6.7%	8.5%	11.1%	10.3%	11.2%	9.1%	9.1%	10.0%	11.4%	9.9%	8.5%	8.5%	9.0%
Laclede Group	9.9%	13.4%	11.5%	10.0%	14.0%	13.2%	11.0%	10.0%	9.1%	10.6%	7.8%	11.8%	11.2%	11.1%	13.1%	11.3%	11.0%	11.0%	10.5%	10.5%
NICOR	15.3%	15.3%	15.7%	14.6%	17.0%	16.9%	14.7%	15.7%	18.2%	18.8%	17.3%	12.4%	13.0%	13.0%	16.0%	16.2%	14.3%	14.0%	13.5%	11.5%
Northwest Natural Gas	6.0%	13.7%	12.2%	11.4%	13.2%	11.2%	6.3%	10.1%	10.2%	10.3%	8.7%	9.2%	9.3%	10.1%	10.9%	10.5%	9.6%	11.0%	11.5%	11.5%
Piedmont Natural Gas	14.1%	13.8%	12.2%	12.3%	13.2%	13.8%	13.6%	12.1%	12.5%	12.0%	10.8%	12.2%	12.4%	11.6%	10.9%	13.0%	11.6%	12.0%	12.0%	12.0%
South Jersey Industries	11.8%	11.0%	8.5%	11.4%	11.1%	11.9%	10.1%	15.6%	15.4%	15.3%	14.0%	13.1%	13.4%	13.2%	17.2%	12.2%	14.2%	12.5%	13.0%	16.5%
WGL Holdings	12.5%	12.1%	12.6%	12.4%	15.0%	14.1%	11.3%	10.3%	11.9%	11.9%	7.1%	14.4%	11.9%	12.1%	10.8%	12.4%	11.3%	11.1%	11.0%	10.5%
Mean	11.5%	12.9%	11.8%	12.2%	13.9%	13.3%	11.9%	11.1%	12.1%	12.8%	11.3%	12.5%	11.8%	11.7%	12.8%	**12.3%**	**12.0%**	**11.6%**	**11.7%**	**11.9%**
Composite																**12.3%**	**12.0%**			

Source: Calculations made from data contained in Value Line Investment Survey.

COMPARISON COMPANIES
MARKET TO BOOK RATIOS

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	1992-2001 Average	2002-2006 Average
Value Line Natural Gas																	
AGL Resources	181%	195%	169%	172%	189%	183%	183%	169%	168%	184%	171%	188%	184%	191%	186%	179%	184%
Atmos Energy	158%	194%	186%	196%	248%	241%	246%	216%	167%	170%	150%	152%	147%	145%	146%	202%	148%
Energen	138%	171%	150%	145%	161%	186%	174%	147%	189%	215%	160%	194%	242%	309%	280%	168%	237%
Laclede Group	158%	187%	178%	163%	168%	175%	174%	159%	141%	155%	145%	169%	179%	179%	184%	166%	171%
New Jersey Resources	161%	185%	162%	179%	190%	229%	225%	224%	227%	224%	220%	244%	251%	275%	247%	201%	247%
NICOR	179%	216%	195%	187%	220%	242%	260%	226%	227%	239%	199%	185%	210%	222%	234%	219%	210%
Northwest Natural Gas	162%	176%	161%	146%	156%	173%	169%	141%	129%	133%	145%	144%	153%	172%	177%	155%	158%
Piedmont Natural Gas	180%	214%	186%	182%	183%	217%	222%	213%	195%	199%	186%	211%	212%	208%	221%	199%	208%
South Jersey Industries	154%	175%	141%	142%	146%	178%	209%	202%	196%	205%	185%	170%	195%	221%	209%	175%	196%
Southwest Gas	81%	100%	103%	103%	121%	129%	139%	147%	120%	127%	123%	118%	127%	135%	161%	117%	133%
UGI	187%	162%	161%	166%	196%	226%	222%	196%	244%	292%	318%	286%	240%	279%	247%	205%	274%
WGL Holdings	173%	189%	165%	164%	178%	199%	197%	176%	177%	177%	152%	162%	175%	183%	168%	180%	168%
Average	159%	180%	163%	162%	180%	198%	202%	185%	182%	193%	180%	185%	193%	210%	205%	180%	195%
Composite																180%	192%
Hanley Proxy Companies																	
AGL Resources	181%	195%	169%	172%	189%	183%	183%	169%	168%	184%	171%	188%	184%	191%	186%	179%	184%
Atmos Energy	158%	194%	186%	196%	248%	241%	246%	216%	167%	170%	150%	152%	147%	145%	146%	202%	148%
Laclede Group	158%	187%	178%	163%	168%	175%	174%	159%	141%	155%	145%	169%	179%	179%	184%	166%	171%
NICOR	179%	216%	195%	187%	220%	242%	260%	226%	227%	239%	199%	185%	210%	222%	234%	219%	210%
Northwest Natural Gas	162%	176%	161%	146%	156%	173%	169%	141%	129%	133%	145%	144%	153%	172%	177%	155%	158%
Piedmont Natural Gas	180%	214%	186%	182%	183%	217%	222%	213%	195%	199%	186%	211%	212%	208%	221%	199%	208%
South Jersey Industries	154%	175%	141%	142%	146%	178%	209%	202%	196%	205%	185%	170%	195%	221%	209%	175%	196%
WGL Holdings	173%	189%	165%	164%	178%	199%	197%	176%	177%	177%	152%	162%	175%	183%	168%	180%	168%
Mean	168%	193%	173%	169%	186%	201%	208%	188%	175%	183%	167%	173%	182%	190%	191%	184%	180%
Composite																184%	179%

Source: Calculations made from data contained in Value Line Investment Survey.

STANDARD & POOR'S 500 COMPOSITE RETURNS AND MARKET-TO-BOOK RATIOS 1992 - 2006

YEAR	RETURN ON AVERAGE EQUITY	MARKET-TO BOOK RATIO
1992	12.2%	271%
1993	13.2%	272%
1994	16.4%	246%
1995	16.6%	264%
1996	17.1%	299%
1997	16.3%	354%
1998	14.6%	421%
1999	17.3%	481%
2000	16.2%	453%
2001	7.5%	353%
2002	8.4%	296%
2003	14.2%	278%
2004	15.0%	291%
2005	16.1%	278%
2006	17.0%	277%
Averages:		
1992-2001	14.7%	341%
2002-2006	14.1%	284%

Source: Standard & Poor's Analyst's Handbook, 2007 edition, page 1.

RISK INDICATORS

GROUP	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FIN STR	S & P STK RANK
S & P's 500 Composite	2.7	1.05	B++	B+
Value Line Natural Gas	1.9	0.88	B++	B+
Hanley Proxy Companies	1.9	0.89	B++	B+
Southwest Gas	3.0	0.90	B	B+

Sources: Value Line Investment Survey, Standard & Poor's Stock Guide.

Definitions:

Safety rankings are in a range of 1 to 5, with 1 representing the highest safety or lowest risk.

Beta reflects the variability of a particular stock, relative to the market as a whole. A stock with a beta of 1.0 moves in concert with the market, a stock with a beta below 1.0 is less variable than the market, and a stock with a beta above 1.0 is more variable than the market.

Financial strengths range from C to A++, with the latter representing the highest level.

Common stock rankings range from D to A+, with the later representing the highest level.

Exhibit DCP-12
Page 1 of 1

SOUTHWEST GAS CORP.
PRE-TAX COVERAGE

Item	Percent	Cost	Weighted Cost	Pre-Tax Cost	
Short-Term Debt	0.00%		0.00%	0.00%	
Long-Term Debt	52.08%	7.96%	4.15%	4.15%	
Preferred Stock	4.48%	8.20%	0.37%	0.61%	
Common Equity	43.44%	10.00%	4.34%	7.24%	
Total	100.00%		8.86%	12.00%	1/

1/ Post-tax weighted cost divided by .60 (composite tax factor)

Pre-Tax coverage =	12.00%/ 4.15% **2.89**	
Standard & Poor[s Utility Benchmark Ratios: Business Profile of "3"	A	BBB
Pre-tax coverage	2.8x - 3.4x	1.8x - 2.8x
Total debt to total capital	50%-55%	55%-65%

EXHIBIT
S-18

BEFORE THE ARIZONA CORPORATION COMMISSION

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

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 THE SOUTHWEST GAS CORPORATION DEVOTED TO ITS OPERATIONS THROUGHOUT ARIZONA	DOCKET NO. G-01551A-07-0504

SURREBUTTAL

TESTIMONY

OF

DAVID C. PARCELL

ON BEHALF OF

THE ARIZONA CORPORATION COMMISSION,

UTILITIES DIVISION STAFF

MAY 27, 2008

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INTRODUCTION

Q. Please state your name and address.

A. My name is David C. Parcell. I am President and Senior Economist of Technical Associates, Inc. My business address is Suite 601, 1051 East Cary Street, Richmond, Virginia 23219.

Q. Are you the same David C. Parcell who filed Direct Testimony on behalf of the Commission Staff in this proceeding?

A. Yes, I am.

Q. What is the purpose of your current testimony?

A. My current testimony is Surrebuttal Testimony in response to the Rebuttal Testimonies of Southwest Gas Corporation ("SWG" or "Company") witnesses Frank J. Hanley and Theodore K. Wood.

Q. How is your Surrebuttal Testimony organized?

A. My Surrebuttal Testimony first responds to the Rebuttal Testimony of Mr. Hanley. Next, I respond to the Rebuttal Testimony of Mr. Wood. Finally, I updated my Exhibits contained in my Direct Testimony and updated my DCF, CAPM, and CE analyses.

RESPONSE TO REBUTTAL TESTIMONY OF FRANK J. HANLEY

Q. Please describe the issues raised in Mr. Hanley's Rebuttal Testimony that you are responding to in this Surrebuttal Testimony.

A. My response to Mr. Hanley's Rebuttal Testimony generally follows the format he utilizes and is organized into the following topics:

- General comments
- Capital structure issues
- Discounted Cash Flow Issues
- Capital Asset Pricing Model Issues
- Comparable Earnings Method Issues
- Fair Value Rate Base Cost of Capital

General Comments

Q. On page 1 and pages 34-35 of his Rebuttal Testimony, Mr. Hanley continues to maintain, as he did in his Direct Testimony, that the cost of equity for SWG is 11.25 percent. Do you have any responses to this assertion?

A. Yes, I do. First, I note that, in SWG's most recent Arizona rate proceeding (i.e., Docket No. G-01551A-04-0876, decided by the Commission in Decision No. 68487 dated February 23, 2006), the Company was awarded a cost of common equity of 9.50 percent, applicable to a hypothetical capital structure with a common equity ratio of 40.0 percent. Mr. Hanley was the Company's cost of capital witness in this proceeding and he recommended an 11.42 percent cost of equity in that proceeding. Clearly, the Commission did not adopt Mr. Hanley's recommendation in the most recent SWG rate proceeding. The Commission should also not adopt Mr. Hanley's cost of equity recommendation in this current proceeding.

Second, Mr. Hanley's 11.25 percent cost of equity recommendation for SWG is not within the mainstream of recent cost of equity awards for natural gas distribution utilities in the U.S. Mr. Hanley cites, on pages 35-37 of his Rebuttal Testimony, the reporting of authorized returns on equity ("ROE") for natural gas local distribution companies ("LDCs"), by Regulatory Research Associates ("RRA"). However, Mr. Hanley does not acknowledge the level and trends of ROE awards for natural gas distribution utilities. It is noteworthy that the recent average ROE awards for the past several years have been as follows:

Year	Avg. ROE
2003	10.99%
2004	10.59%
2005	10.46%
2006	10.43%
2007	10.24%

In no year since 2004 has the average ROE approached 11.0 percent, which is well below Mr. Hanley's 11.25 percent recommendation for SWG. It is also apparent that the average ROE awards have declined each year since 2003 and stood at 10.24 percent in 2007. Mr. Hanley's current recommendation recognizes neither the Commission's 9.5 percent ROE authorization for SWG in 2006 nor the decline in ROE since that time.

Q. Does Mr. Hanley's testimony provide any indication of the relationship between current equity costs and equity costs at the time of SWG' last rate proceeding?

A. Yes. Mr. Hanley's conclusions reflect a decline in equity costs. In the Company's last rate proceeding, (Docket No. G-01551A-04-0876, filed in 2004) Mr. Hanley recommended an 11.42 percent cost of equity for the Company. In the current proceeding he is recommending an 11.25 percent cost of equity, a decline of 17 basis points.

Capital Structure Issues

Q. On page 4, lines 12-16, Mr. Hanley claims that your 0.1 percent allowance to recognize SWG' lower common equity ratio is "grossly inadequate." Do you have any response to this assertion?

A. Yes, I do. Mr. Hanley's is contradictory to the Commission's findings in the prior rate case. In SWG' last rate proceeding in 2005, the Commission utilized a hypothetical capital structure for the Company that contained a common equity percentage of 40.0 percent. In utilizing this hypothetical capital structure, the Commission noted:

> *We agree with Staff that use of a 40 percent equity ratio is appropriate in this proceeding.* ***The 40 percent ratio is more than 5 points higher than the ratio in existence at the end of the test year and 3 points higher than the Company's equity at the end of June 2005.*** *This hypothetical capital structure is consistent with our Order in the Company's last rate case (Decision No. 64172, at 17). Although Southwest Gas has made some progress over the past decade to improve its equity position relative to debt,* ***our continuing need to employ an inflated equity ratio for setting rates in case after case highlights the need to encourage even greater efforts to increase the equity ratio. Ultimately, however, the level of equity lies within the control of the Company's management and not with ratepayers who have been asked to shoulder the burden of rates set based on a hypothetical structure that does not actually exist.***
>
> *As Staff witness Hill pointed out,* ***ratepayers have for many years been burdened with an authorized return set using a hypothetical capital structure far greater than the Company's actual equity ratio. At some point, we must send Southwest Gas a signal that it must improve its capital structure up to the hypothetical level that has been employed for many years or it must live with the results of its actual capital structure.*** *Therefore, we believe it is also appropriate to adopt Staff's recommendation to require Southwest to submit a re-capitalization plan explaining how it intends to achieve a 40 percent equity prior to the Company's next rate case. We do not believe it is necessary, at this time, to determine whether failure to reach the 40 percent goal would result in use of the Company's actual capital structure in its next rate case. However, the possibility of such a determination in the next rate case will depend on the Company's efforts to make progress on this issue based on the plan it develops and implements pursuant to this Order.* **[Emphasis added]**

This quote from the Decision clearly indicates the history and intent of the Commission's prior use of a hypothetical capital structure for SWG.

Q. **Do you believe that the Commission should continue to provide an incentive to SWG through a larger increment to its cost of equity due to a slightly lower equity ratio that the Company continues to maintain relative to other LDCs?**

A. No, I do not. The Commission has already provided SWG with incentive over a long period of time, most of which the Company failed to live up to the expectations that it would actually achieve the level of hypothetical equity used for ratemaking purposes. It is unreasonable for the Company to now maintain that it is continually entitled to some continued incentive from the Commission.

Q. **Has SWG historically maintained a lower common equity ratio than other LDCs?**

A. Yes, it has. I noted this on pages 16-17 of my Direct Testimony, as well as on my Schedules 4 and 5. As indicated, SWG' historic equity ratios have been several percentage points less than other LDCs. In particular, prior to 2006 (i.e., at the time of last Commission decision), the Company's equity ratios were below 35 percent.

Q. **Do you believe it was the Commission's intention in the last SWG proceeding to offer the Company an incentive to raise its equity ratio?**

A. Yes. It is apparent from the previously-cited decision that the Commission intended to encourage the Company to raise its equity ratio. As noted above, the Commission specifically stated (page 25) its intention to "encourage" the Company to increase its equity ratio.

Q. Has the Company actually increased its equity ratio since the last proceeding?

A. Yes, it has. As I noted in my Direct Testimony, the Company's equity ratio (including short-term debt) increased from 34.4 percent in 2005 to 41.0 percent in 2007.

Q. Does the Company's capitalization changes since the last proceeding imply that the Commission is obligated to again use a hypothetical capital structure with an ever higher equity ratio?

A. No. The Commission provided an incentive to SWG in 2006 in order to encourage the Company to bring its common equity ratio more in line with other LDCs. SWG has generally responded positively to this incentive. As noted elsewhere, its test period equity ratio is 43.44 percent.

However, it does not follow that the Commission's incentive in the last case represents an invitation for the Company to continually request an even higher common equity ratio.

Q. Mr. Hanley maintains, on pages 5-6, that SWG' requested rate design proposals should not be construed as risk-reducing to the Company in terms of the impact on its cost of equity. Do you agree with his assertion?

A. No, I do not. Mr. Hanley's perception of the impacts of the Company's rate design proposals (i.e., rate decoupling, performance-based rates, or weather normalization adjustments protection) focuses on the existence of some of these mechanisms in the rate structures of other LDCs. However, it is not appropriate to consider the reduction to risks from this perspective. To put risk reduction in proper perspective for SWG, we need to consider the extent to which any <u>new</u> rate design mechanisms are risk-reducing to SWG in relation to its previous position. Clearly, these rate design proposals are new to SWG and, should they be approved by the Commission, they would be risk-reducing to the Company relative to its historic and present situation.

Q. Mr. Hanley claims, on page 6, lines 19-22, that the risk of SWG has "increased dramatically" over the past 11 months. Do you agree with this assertion?

A. No, I do not. Mr. Hanley's perception of SWG' "risk rate differential" is based entirely on the bond yield differential between A-rated and BBB-rated bonds.

This so-called differential is a temporary phenomenon related to the "flight to safety" associated with the sub-prime mortgage crisis that has permeated the U.S. economy over the past several months. This sub-prime mortgage crisis represents a major challenge to many individuals, corporations and industries in the U.S. It is not proper to try to insulate SWG from macro-economic circumstances impacting its customers. In addition, the table below shows that independent appraisals of SWG' risk have not increased over the past year:

	2007	2008
Value Line Safety	3	3
Value Line Beta	.85	.90
Value Line Financial Strength	B	B
Moody's Bond Rating	Baa3	Baa3
S&P Bond Rating	BBB-	BBB-

Q. Mr. Hanley maintains (page 4, lines 19-21; page 5, lines 2 and 3) that SWG has lower bond ratings than his proxy group of LDCs. He also recognizes (page 16, lines 9-14 of his Direct Testimony) that SWG has a lower common equity ratio than his LDCs group. Do you have any comments on these comparisons?

A. Yes, I do. As I indicated in my Direct Testimony, SWG has historically maintained a more leveraged capital structure (i.e., less common equity) than the typical LDC. I believe the Company's lower security ratings have been directly linked to the lower equity ratios. As a result, it is apparent that the Company's past financial strategy has impacted its ratings.

In addition, it appears that only in the past few years has SWG moved its equity ratio more in line with other LDCs. Not coincidentally, this improvement in the equity ratio only occurred after continuing actions on the part of the Commission, as discussed above. Bond rating upgrades do not occur instantaneously with improved financial parameters. However, maintaining consistently better financial metrics should lead to upgraded ratings for SWG.

DCF Issues

Q. On page 7, lines 11-19, Mr. Hanley maintains that the DCF model "mathematically mis-specify investors' required return rate when the market value of common stock differs significantly from its book value." Do you agree with this?

A. No, I do not. If stock markets are efficient, as Mr. Hanley recognized in his Direct Testimony, all relevant information is reflected in stock prices, including the differential between book value and market price for regulated utilities. As a result, there is no justification for "adjusting" stock-priced based models, such as DCF.

CAPM Issues

Q. On page 9, lines 6-22, Mr. Hanley disagrees with your position that the CAPM is generally superior to the simple risk premium method. What is your response to this?

A. Mr. Hanley disagrees with my position that CAPM specifically recognizes the risk of a particular company or industry, whereas the simple risk premium does not. Mr. Hanley states his opinion that I am "incorrect" in my position. I disagree with him on this point.

Mr. Hanley's position apparently focuses on the use of public utility bond yields in his risk premium analysis which he believes properly recognizes the risk of the subject company. This is misleading in terms of its ability to measure risk comparability. It should be noted that Mr. Hanley's risk premium model starts with the prospective yield on Aaa rated corporate bonds. Since SWG does not have Aaa rated debt, he then computes the historic differential between Aaa rated corporate bonds and A-rated public utility bonds for the period March – April, 2007 (as shown in his Exhibit ___(FJH-29, sheet 16 of 32).

This procedure makes no allowance for the differences among various types of utilities that are included in the A rated public utility bonds. His procedure assumes that all A-rated public utilities have the same cost of capital. However, he has not offered any evidence that this is the case.

In addition, his procedure implicitly assumes that the yield differential of this two-month period reflects the on-going differential in the eyes of investors. Again, he has not offered any evidence that supports this proposition.

My CAPM analysis, in contrast, uses a specific measure of risk (i.e., beta) that reflects the relative stock price variability of specific stocks, or groups of similar-risk stocks. As such, the beta component in a CAPM analysis does specifically recognize the risk of the subject company, unlike the risk premium that essentially assigns the same cost of equity for all utilities with the same bond rating.

Q. But doesn't Mr. Hanley state that beta "generally reflects on average only about 32 percent of company-specific risk?

A. Yes, he does. Nevertheless, this does not prohibit use of beta as a risk measure. Mr. Hanley does not offer an opinion as to how much of company-specific risk is captured by the two-month differential between Aaa rated corporate bonds and A-rated public utility bonds.

Q. On page 11, Mr. Hanley claims that 30-year bonds should reflect the risk free rate in a CAPM analysis. Do you agree with this?

A. No, I do not. The risk premium developed in Morningstar (Mr. Hanley's data source for this claim) uses 20-year Treasury bonds as the long-term government bond rate, not 30-year Treasury bonds. As a result, Mr. Hanley is proposing a "mis-match" in his CAPM comments.

Q. On page 10, lines 15-20, Mr. Hanley claims that you have performed "two CAPM analyses". Is this true?

A. No, it is not true. As is apparent from pages 25-28 and Exhibit DCP-8 of my Direct Testimony, I have only performed one CAPM analysis.

Q. Mr. Hanley states, on pages 12-14, that it is improper to consider geometric mean returns in the determination of a risk premium and that only arithmetic returns are appropriate. Do you agree with this position?

A. No, I do not. What is important is what investors rely upon in making investment decisions. It is apparent that investors have access to both types of returns when they make investment decisions.

In fact, it is noteworthy that mutual fund investors regularly receive reports on their own funds, as well as prospective funds they are considering investing in, that show only geometric returns (see for example, Exhibit DCP-13 which shows historic performance information for one of the nation's largest mutual funds). Based on this, I find it difficult to accept Mr. Hanley's position that only arithmetic returns are appropriate.

Q. Does Mr. Hanley use Value Line information in his cost of capital analyses?

A. Yes, he does. He has in fact submitted several Value Line reports on various natural gas utilities on his Exhibit___(FJH-29).

Q. Do the Value Line reports in his exhibit show historic growth rates for the natural gas utilities?

A. Yes, they do.

Q. Do these Value Line reports show historic returns on an arithmetic basis?

A. No, they do not.

Q. Do the Value Line reports show historic returns on a geometric (i.e., compound) growth rate basis?

A. Yes, they do. See Exhibit DCP-14, which describes Value Line's method of calculating growth rates. As a result, any investor reviewing Value Line, as Mr. Hanley does, would be using geometric growth rates.

Q. Is it your position that only geometric growth rates be used?

A. No. I believe that both arithmetic and geometric growth rates should be used. This is the case since investors have access to both and presumably use both. This is also consistent with the efficient market hypothesis, which Mr. Hanley cites.

Q. Does Mr. Hanley cite (pages 12-13) his perception of "financial literature" requires that arithmetic returns being used for this purpose?

A. He does state this in his testimony. However, the cost of capital determination is not an academic exercise made is some laboratory or university classroom. The true cost of equity is made in the "laboratory" of the financial markets, based on the ongoing inter-play of countless investors, each with their own agendas and beliefs. This is verified by the fact that each time a share of stock is purchased by one investor, it is simultaneously being sold by another investor, indicating that their respective views at that time differ.

Again, investors have access to both arithmetic and geometric growth rates. In all likelihood, there is more geometric growth data readily available to investors (e.g., mutual fund reports and Value Line) than arithmetic growth data.

Q. Has this Commission recently made a finding as to whether it is appropriate to use geometric as well as arithmetic returns in this context?

A. Yes, it has. In the Decision in the recent UNS Electric case (Docket No. E-04204A-06-0783) the Commission specifically stated (page 43) that it agreed with the use of geometric returns in this manner: "We agree with the Staff that it is appropriate to consider the geometric returns in calculating a comparable company CAPM because to do otherwise would fail to give recognition to the fact that many investors have access to such information for purposes of making investment decisions."

Q. On page 17, line 21, Mr. Hanley claims that the S&P 500 Composite Index does not include public utilities. Is he correct?

A. No, he is not. The S&P 500 Composite Index includes a number of public utilities, both electric and natural gas distribution. The current "Sector Breakdown" of the S&P 500 includes about 3.44 percent "utilities" (see Exhibit DCP-15).

Q. On page 14, lines 15-24, Mr. Hanley claims to have "recalculated" your CAPM results. Is this a proper exercise?

A. No, it is not. Mr. Hanley's "recalculations" are simply his attempt to interject his CAPM components, which this Commission has recently rejected, into my CAPM analyses. Such a recalculation is incorrect and improper.

Comparable Earnings Method ("CEM")

Q. On page 22, Mr. Hanley indicates his belief that your association of market-to-book ratios and returns on equity are "not supported by either the academic literature nor by a historical analysis of the experience of unregulated companies." What is your response to this?

A. I disagree totally with Mr. Hanley on this point. Clearly, most public utilities have their rates regulated (i.e., set) based upon the book value of their rate base and capital structure. In fact, the cost of capital is reflected in the fair return on book value of common equity. Investors are aware of this relationship (i.e., efficient market hypothesis, to again quote Mr. Hanley). Any reference to the experience of unregulated companies, as is evident in Mr. Hanley's Rebuttal Testimony, simply misses the point of public utility regulation.

Fair Value Rate Base Cost of Capital

Q. What is Mr. Hanley's response to your proposal for establishing a Fair Value Rate Base Cost of Capital?

A. I note first of all that, unlike other recent utility positions (i.e., UNS Gas, UNS Electric, and Chaparral City Water), SWG witness Hanley is not requesting that its weighted cost of capital ("WCOC") be applied to the Company's Fair Value Rate Base ("FVRB"). I also note that Mr. Hanley, unlike the above-cited utilities, recognizes that there is a link between the concepts of rate base and cost of capital. Finally, I observe that Mr. Hanley recognizes that the application of the WCOC to an original cost rate base ("OCRB") provides for a fair and reasonable opportunity to earn a return.

Q. Mr. Hanley maintains, on page 39, lines 24-25, that your proposed methodology has been "rejected" by the Arizona Appeals Court in the Chaparral City Water Co. case. Is this correct?

A. No, it is not true. My proposal has not been rejected or accepted by the Appeals Court because it has not been examined by the Court. The Staff's recommended rate of return in this case fell at the low end of the range for FVROR that I computed.

Q. Were you a Commission Staff Witness in the Chaparral City Water remand case?

A. Yes, I was. In the Chaparral City remand case, I made a similar proposal.

Q. Have you testified in any other Arizona cases on this issue?

A. Yes, I have. I testified in the UNS Gas case (Docket No. G-04204A-06-0463) and UNS Electric case (Docket No. E-04204A-06-0783). In both of those proceedings, the Commission adopted my recommendation on the FVROR.

Q. Did SWG recommend a FVROR in its direct filing?

A. No, it did not.

Q. What is Mr. Hanley recommending in his Rebuttal Testimony?

A. In his Rebuttal Testimony (page 40), Mr. Hanley is recommending a 2.05 percent cost rate for the FVRB Increment. In doing so, he is proposing a similar procedure to that I am proposing as my Option 2, as we both apply the rate of "expected inflation" to the yield on long-term Treasury bonds. Our results differ as follows:

	T-Bond Rate	Inflation	Differential
Parcell	4.5%	2.0%	2.5%
Hanley	4.5%	2.45%	2.05%

I note that Mr. Hanley's 2.45 percent inflation estimate appears to present a more current estimate than the 2.0 percent rate I used.

My "risk free" rate is thus 2.5 percent, which forms the upper bound of my secondary recommendation of 0 percent to 2.5 percent (1.25 percent mid-point), whereas Mr. Hanley recommends the 2.05 percent figure. I note that, had I used Mr. Hanley's procedure, my recommendation would have been 0 percent to 2.05 percent (1.025 percent mid-point). As a result, our differences are not methodological but rather are more policy orientated in terms of what is the appropriate FVROR.

Q. Do you believe Mr. Hanley's 2.05 percent FVROR recommendation is proper?

A. No, I do not. As I indicate in my Direct Testimony, a zero percent FVROR is the proper figure to use. Should the Commission wish to use some positive value for the FVROR, any figure between 0 percent and 2.5 percent would fall within the range I computed. Staff's recommendation is at the low end of this range. Should the Commission desire to exceed Staff's recommendation to use the low end of the range, I recommend no higher than the mid-point of the range.

RESPONSE TO REBUTTAL TESTIMONY OF THEODORE K. WOOD

Q. How is your response to Mr. Wood's Rebuttal organized?

A. Mr. Wood's Rebuttal Testimony essentially focuses on two issues: (1) Capital Structure; and, (2) SWG' risk.

My Surrebuttal Testimony to Mr. Wood accordingly focuses on these two general areas.

Capital Structure

Q. What is Mr. Wood's position on the proper capital structure for SWG?

A. Mr. Wood maintains, as he did in his Direct Testimony, that the proper capital structure for the Company is its "target" capital structure comprised of 45 percent common equity, 4 percent preferred equity, and 51 percent long-term debt.

Q. Mr. Wood maintains, on pages 4-5, that the Commission has previously authorized use of a "target" capital structure for ratemaking purposes in the UNS Gas rate case (Docket No. G-042041-06-0463). Do you have any response to this?

A. Yes, I do. Due to my participation on Staff's behalf in the UNS Gas case, I am aware that this company was formed in 2003 when UniSource Energy purchased the gas and electric operations in Arizona from Citizens Utilities. Prior to the purchase, there was no "company" in Arizona that represented these entities, as these were operated under the Citizens' corporate umbrella. At the time of the purchase, UNS Gas and UNS Electric were created as separate companies and were initially capitalized with 35 percent common equity. Since then, neither company has paid dividends to the parent and each has grown its common equity through retained earnings and equity infusions from UniSource Energy.

This contrasts with SWG, which has existed for many years and has maintained its own publicly-traded capital. As noted previously in my Surrebuttal Testimony, this Commission has, in the past, used a hypothetical or target capital structure for SWG in an apparent effort to encourage the company to actually increase its equity ratio. The target common equity ratio used for SWG has been 40.0 percent, which exceeded the actual common equity ratio of the company. But SWG has reached the 40.0 percent target set by the Commission. Thus, ratepayers should no longer have to bear the burden associated with a hypothetical capital structure.

Q. Does the use of a hypothetical capital structure for UNS Gas imply that a hypothetical capital structure is again proper for SWG?

A. No, it does not. As noted earlier, the Commission has in earlier cases provided incentives to SWG to increase its equity ratio. The Commission's actions to encourage the Company to obtain a 40% equity ratio target has been reached. This should not be regarded as an open-ended invitation to continually ask for a higher equity ratio than the Company maintains.

Risk of SWG

Q. What is Mr. Wood's assessment of SWG' risks?

A. Mr. Wood maintains, as he did in his Direct Testimony, that the Company has above-average risk and should be awarded an above-average cost of capital.

Q. Has Mr. Wood provided any evidence that the Company's risk has increased since it last rate case in 2005?

A. No, he has not. As I indicated in my Surrebuttal Testimony in response to Mr. Hanley, the Company was awarded a 9.5 percent cost of equity applicable to a 40.0 percent common equity ratio in its most recent rate case.

Q. How does your recommendation relate to the 2005 Commission findings?

A. I am recommending a higher cost of common equity for the Company (i.e., 10.0 percent vs. 9.5 percent) that is to be applied to a higher common equity percentage (i.e., 43.44 percent vs. 40.0 percent).

Q. **Does Mr. Wood acknowledge these higher recommendations in his Rebuttal Testimony?**

A. No, he does not.

Q. **On page 14, Mr. Wood states that credit ratings are not based on historical common equity ratios. Do you agree with this assertion?**

A. No, I do not. The credit rating agencies do not often change a Company's ratings and usually only do so when they believe that the Company has made some improvements or experiences some decline in their financial metrics, which include capital structure ratios. One distinguishing characteristic of SWG is its historic use of a more leveraged capital structure than other LDCs. I believe that this continues to play a role in the Company's ratings.

Q. **On pages 15-16 Mr. Wood maintains that a comparison of capital structures among companies should be done ignoring short-term debt. Do you agree with this?**

A. No, I do not. I note, in this regard, that Standard & Poor's financial metrics used in assigning ratings include all debt, including short-term debt.

Q. **Does Mr. Wood cite the rating agencies and their criteria in his Rebuttal Testimony?**

A. Yes, he does. On pages 18-20, he discusses the rating agencies and the criteria they employ in assigning ratings.

Q. **Does he acknowledge the use of short-term debt by the rating agencies?**

A. No, he does not.

Q. Mr. Wood also addresses, on pages 20-22, the authorized returns on equity for natural gas utilities throughout the U.S. Do you have any response to this?

A. Yes, I do. As I indicated in my Surrebuttal Testimony in response to Mr. Hanley, the average authorized return on equity for LDCs has declined in recent years.

Q. Have the authorized returns approached the 11.25 percent return on equity that SWG has requested in the proceeding?

A. No. Not since at least 2003 have average authorized returns been anywhere near 11.0 percent, not to mention 11.25 percent as requested by SWG.

Q. Throughout his Rebuttal Testimony, Mr. Wood repeatedly makes reference to SWG' "Higher Relative Investment Risk." Do you have any comments concerning these claims?

A. Yes, I do. Mr. Wood cites, as a major factor in his relative risk assessment, the lower bond ratings of SWG versus other LDCs.

It is noteworthy that Standard & Poor's recently published a report on SWG on April 24, 2008. In this report, attached as Exhibit DCP-16, S&P noted that the Company's outlook is "positive" and "reflects Standard & Poor's Rating Services' expectation that the Company's improved financial performance could lead to a higher rating over the near term."

S&P also noted the "strong business risk profile" of SWG as a positive factor in the rating process. In this regard, S&P noted the Company's "large, stable, residential, and commercial customer base", the "absence of competition", and "relatively lower operating risks".

S&P also noted the Company's "aggressive financial risk profile" as a negative component. As I have indicated previously, this stems from SWG' historic management policy of maintaining a lower equity ratio in comparison to other LDCs. Also as I noted, the Commission has historically used a hypothetical capital structure with a higher equity ratio than that maintained by the Company in order to provide an incentive to the company to increase its equity ratio.

UPDATE OF COST OF CAPITAL ANALYSES

Q. Please explain the updates to your cost of capital analyses.

A. I have updated several of the exhibits to my Direct Testimony to incorporate more recent data than that available at the time my Direct Testimony was prepared. My Direct Testimony was generally prepared during the month of January 2008 and was filed on March 28, 2008. My DCF analyses used stock prices for the months of November 2007 – January 2008 and Value Line data as of December 14, 2007. My CAPM analyses used risk-free rates as the same three-month period and betas from the same Value Line report. My CE analysis used historic data through 2006 and projected data from the December 14, 2007 Value Line.

I now have more recent data available as follows:

- Value Line report of March 14, 2008
- Stock price data for period February – April of 2008
- Historic data updated to include 2007
- Risk-free rate data for period February – April of 2008
- Historic return on equity data for 2007
- Projected return on equity data from more recent Value Line

I have accordingly updated my cost of equity analyses to reflect these more current data sources. In addition, I have updated several other exhibits that contain economic/financial data and certain capital structure data. I have attached to this Surrebuttal Testimony a complete copy of my exhibits with any updated exhibits labeled as "Updated" in order to provide a single and complete copy of my exhibits.

Q. Please describe the updates to your respective cost of equity analyses.

A. My Exhibit DCP-6 Updated contains the update to my DCF analyses, using dividend yields for the three-month period February – April of 2008, the inclusion of 2007 in historic data, use of the March 14, 2008 Value Line, and the most current First Call EPS forecasts. The updated results compare to the results in my Direct Testimony as follows:

Direct Testimony

	Mean	Median	Mean High	Median High
Proxy Group	9.3%	8.7%	10.4%	9.8%
Hanley Group	8.6%	8.1%	9.3%	9.3%

Updated Testimony

	Mean	Median	Mean High	Median High
Proxy Group	9.5%	8.6%	10.6%	9.6%
Hanley Group	8.9%	8.5%	9.7%	9.9%

In general, these updates indicate DCF results of about 0.2 percent above the levels of my Direct Testimony.

My Exhibit DCP-8 Updated contains the update to my CAPM analyses, using a risk-free rate (yield on 20-year U.S. Treasury bonds) for the three-month period February – April of 2008 and the most recent betas from the March 14, 2008 Value Line. The updated results compare to the results of my Direct Testimony as follows:

Direct Testimony

	Mean	Median
Proxy Group	9.7%	9.5%
Hanley Group	9.8%	9.7%

Updated Testimony

	Mean	Median
Proxy Group	9.6%	9.4%
Hanley Group	9.5%	9.4%

In general, these updates indicate CAPM results of about 0.2 percent less than those levels in my Direct Testimony.

Exhibit DCP-9 Updated shows the results of my updated CE analysis for the proxy gas utilities, using 2007 figures in the historic data and the prospective returns from the March 14, 2008 Value Line. The updated results compare to the results of my Direct Testimony as follows:

Direct Testimony

	Historic ROE	Historic M/B	Prospective ROE
Proxy Group	11.9-13.1%	180-195%	12.0-12.4%
Hanley Group	12.0-12.3%	180-184%	11.6-11.9%

Updated Testimony

	Historic ROE	Historic M/B	Prospective ROE
Proxy Group	11.9-13.2%	180-200%	12.2-12.6%
Hanley Group	12.1-12.3%	184-186%	11.4-12.1%

These updated results indicate no change in the CE results.

In summary, the updated analyses indicate a slight upward change in the DCF results, a slight downward change in the CAPM results, and no change in the CE results. As a result, I conclude that the cost of equity I recommended in my Direct Testimony – 9.9 percent prior to capital structure/bond ratings adjustment and 10.0 percent after adjustment – remains my recommendation. I note that this is similar to Mr. Hanley's updated conclusions (page 35, lines 5-19) that the cost of equity has not changed in recent months.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes, it does.

SOUTHWEST GAS CORP.
TOTAL COST OF CAPITAL

Item	Amount	Percent		Cost			Weighted Cost	
Short-Term Debt	$0	0.00%					0.00%	
Long-Term Debt	$1,163,505,877	52.08%		7.96%			4.15%	
Preferred Stock	$100,000,000	4.48%		8.20%			0.37%	
Common Equity	$970,385,472	43.44%	9.30%		10.50%	4.04%		4.56%
Total	$2,233,891,349	100.00%				8.55%		9.07%
							8.86%	With 10.0% ROE

ECONOMIC INDICATORS

Year	Real GDP Growth*	Industrial Production Growth	Unemployment Rate	Consumer Price Index	Producer Price Index
			1975 - 1982 Cycle		
1975	-1.1%	-8.9%	8.5%	7.0%	6.6%
1976	5.4%	10.8%	7.7%	4.8%	3.7%
1977	5.5%	5.9%	7.0%	6.8%	6.9%
1978	5.0%	5.7%	6.0%	9.0%	9.2%
1979	2.8%	4.4%	5.8%	13.3%	12.8%
1980	-0.2%	-1.9%	7.0%	12.4%	11.8%
1981	1.8%	1.9%	7.5%	8.9%	7.1%
1982	-2.1%	-4.4%	9.5%	3.8%	3.6%
			1983 - 1991 Cycle		
1983	4.0%	3.7%	9.5%	3.8%	0.6%
1984	6.8%	9.3%	7.5%	3.9%	1.7%
1985	3.7%	1.7%	7.2%	3.8%	1.8%
1986	3.1%	0.9%	7.0%	1.1%	-2.3%
1987	2.9%	4.9%	6.2%	4.4%	2.2%
1988	3.8%	4.5%	5.5%	4.4%	4.0%
1989	3.5%	1.8%	5.3%	4.6%	4.9%
1990	1.8%	-0.2%	5.6%	6.1%	5.7%
1991	-0.5%	-2.0%	6.8%	3.1%	-0.1%
			1992 - 2001 Cycle		
1992	3.0%	3.1%	7.5%	2.9%	1.6%
1993	2.7%	3.3%	6.9%	2.7%	0.2%
1994	4.0%	5.4%	6.1%	2.7%	1.7%
1995	2.5%	4.8%	5.6%	2.5%	2.3%
1996	3.7%	4.3%	5.4%	3.3%	2.8%
1997	4.5%	7.2%	4.9%	1.7%	-1.2%
1998	4.2%	5.9%	4.5%	1.6%	0.0%
1999	4.5%	4.3%	4.2%	2.7%	2.9%
2000	3.7%	4.2%	4.0%	3.4%	3.6%
2001	0.8%	-3.4%	4.7%	1.6%	-1.6%
			Current Cycle		
2002	1.6%	-0.1%	5.8%	2.4%	1.2%
2003	2.5%	1.2%	6.0%	1.9%	4.0%
2004	3.6%	2.5%	5.5%	3.3%	4.2%
2005	3.1%	3.3%	5.1%	3.4%	5.4%
2006	2.9%	2.2%	4.6%	2.5%	1.1%
2007	2.2%	1.7%	4.6%	4.1%	6.3%

*GDP=Gross Domestic Product

Source: Council of Economic Advisors, Economic Indicators, various issues.

ECONOMIC INDICATORS

Year	Real GDP Growth*	Industrial Production Growth	Unemploy-ment Rate	Consumer Price Index	Producer Price Index
2002					
1st Qtr.	2.7%	-3.8%	5.6%	2.8%	4.4%
2nd Qtr.	2.2%	-1.2%	5.9%	0.9%	-2.0%
3rd Qtr.	2.4%	0.8%	5.8%	2.4%	1.2%
4th Qtr.	0.2%	1.4%	5.9%	1.6%	0.4%
2003					
1st Qtr.	1.2%	1.1%	5.8%	4.8%	5.6%
2nd Qtr.	3.5%	-0.9%	6.2%	0.0%	-0.5%
3rd Qtr.	7.5%	-0.9%	6.1%	3.2%	3.2%
4th Qtr.	2.7%	1.5%	5.9%	-0.3%	2.8%
2004					
1st Qtr.	3.0%	2.8%	5.6%	5.2%	5.2%
2nd Qtr.	3.5%	4.9%	5.6%	4.4%	4.4%
3rd Qtr.	3.6%	4.6%	5.4%	0.8%	0.8%
4th Qtr.	2.5%	4.3%	5.4%	3.6%	7.2%
2005					
1st Qtr.	3.1%	3.8%	5.3%	4.4%	5.6%
2nd Qtr.	2.8%	3.0%	5.1%	1.6%	-0.4%
3rd Qtr.	4.5%	2.7%	5.0%	8.8%	14.0%
4th Qtr.	1.2%	2.9%	4.9%	-2.0%	4.0%
2006					
1st Qtr.	4.8%	3.4%	4.7%	4.8%	-0.2%
2nd Qtr.	2.4%	4.5%	4.6%	4.8%	5.6%
3rd Qtr.	1.1%	5.2%	4.7%	0.4%	-4.4%
4th Qtr.	2.1%	3.5%	4.5%	0.0%	3.6%
2007					
1st Qtr.	0.6%	2.5%	4.5%	4.8%	6.4%
2nd Qtr.	3.8%	1.6%	4.5%	5.2%	6.8%
3rd Qtr.	4.9%	1.8%	4.6%	1.2%	1.2%
4th Qtr.	0.6%	3.3%	4.6%	5.6%	12.8%
2008					
1st Qtr.			4.9%		

Source: Council of Economic Advisors, Economic Indicators, various issues.

INTEREST RATES

Year	Prime Rate	US Treas T Bills 3 Month	US Treas T Bonds 10 Year	Utility Bonds Aaa	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
			1975 - 1982 Cycle				
1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.96%
1976	6.84%	4.99%	7.61%	8.63%	8.92%	9.29%	9.82%
1977	6.83%	5.27%	7.42%	8.19%	8.43%	8.61%	9.06%
1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9.62%
1979	12.67%	10.04%	9.44%	9.86%	10.22%	10.49%	10.96%
1980	15.27%	11.51%	11.46%	12.30%	13.00%	13.34%	13.95%
1981	18.89%	14.03%	13.93%	14.64%	15.30%	15.95%	16.60%
1982	14.86%	10.69%	13.00%	14.22%	14.79%	15.86%	16.45%
			1983 - 1991 Cycle				
1983	10.79%	8.63%	11.10%	12.52%	12.83%	13.66%	14.20%
1984	12.04%	9.58%	12.44%	12.72%	13.66%	14.03%	14.53%
1985	9.93%	7.48%	10.62%	11.68%	12.06%	12.47%	12.96%
1986	8.33%	5.98%	7.68%	8.92%	9.30%	9.58%	10.00%
1987	8.21%	5.82%	8.39%	9.52%	9.77%	10.10%	10.53%
1988	9.32%	6.69%	8.85%	10.05%	10.26%	10.49%	11.00%
1989	10.87%	8.12%	8.49%	9.32%	9.56%	9.77%	9.97%
1990	10.01%	7.51%	8.55%	9.45%	9.65%	9.86%	10.06%
1991	8.46%	5.42%	7.86%	8.85%	9.09%	9.36%	9.55%
			1992 - 2001 Cycle				
1992	6.25%	3.45%	7.01%	8.19%	8.55%	8.69%	8.86%
1993	6.00%	3.02%	5.87%	7.29%	7.44%	7.59%	7.91%
1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	8.63%
1995	8.83%	5.51%	6.57%	7.68%	7.77%	7.89%	8.29%
1996	8.27%	5.02%	6.44%	7.48%	7.57%	7.75%	8.16%
1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.60%	7.95%
1998	8.35%	4.81%	5.26%	6.77%	6.91%	7.04%	7.26%
1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.62%	7.88%
2000	9.23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
2001	6.91%	3.45%	5.02%	7.47%	7.59%	7.78%	8.02%
			Current Cycle				
2002	4.67%	1.62%	4.61%	[1]	7.19%	7.37%	8.02%
2003	4.12%	1.02%	4.01%		6.40%	6.58%	6.84%
2004	4.34%	1.38%	4.27%		6.04%	6.16%	6.40%
2005	6.19%	3.16%	4.29%		5.44%	5.65%	5.93%
2006	7.96%	4.73%	4.80%		5.84%	6.07%	6.32%
2007	8.05%	4.41%	4.63%		5.94%	6.07%	6.33%

[1] Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

INTEREST RATES

Year	Prime Rate	US Treas T Bills 3 Month	US Treas T Bonds 10 Year	Utility Bonds Aaa [1]	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
2003							
Jan	4.25%	1.17%	4.05%	[1]	6.87%	7.06%	7.47%
Feb	4.25%	1.16%	3.90%		6.66%	6.93%	7.17%
Mar	4.25%	1.13%	3.81%		6.56%	6.79%	7.05%
Apr	4.25%	1.14%	3.96%		6.47%	6.64%	6.94%
May	4.25%	1.08%	3.57%		6.20%	6.36%	6.47%
June	4.00%	0.95%	3.33%		6.12%	6.21%	6.30%
July	4.00%	0.90%	3.98%		6.37%	6.57%	6.67%
Aug	4.00%	0.96%	4.45%		6.48%	6.78%	7.08%
Sept	4.00%	0.95%	4.27%		6.30%	6.56%	6.87%
Oct	4.00%	0.93%	4.29%		6.28%	6.43%	6.79%
Nov	4.00%	0.94%	4.30%		6.26%	6.37%	6.69%
Dec	4.00%	0.90%	4.27%		6.18%	6.27%	6.61%
2004							
Jan	4.00%	0.89%	4.15%		6.06%	6.15%	6.47%
Feb	4.00%	0.92%	4.08%		6.10%	6.15%	6.28%
Mar	4.00%	0.94%	3.83%		5.93%	5.97%	6.12%
Apr	4.00%	0.94%	4.35%		6.33%	6.35%	6.46%
May	4.00%	1.04%	4.72%		6.66%	6.62%	6.75%
June	4.00%	1.27%	4.73%		6.30%	6.46%	6.84%
July	4.25%	1.35%	4.50%		6.09%	6.27%	6.67%
Aug	4.50%	1.48%	4.28%		5.95%	6.14%	6.45%
Sept	4.75%	1.65%	4.13%		5.79%	5.98%	6.27%
Oct	4.75%	1.75%	4.10%		5.74%	5.94%	6.17%
Nov	5.00%	2.06%	4.19%		5.79%	5.97%	6.16%
Dec	5.25%	2.20%	4.23%		5.78%	5.92%	6.10%
2005							
Jan	5.25%	2.32%	4.22%		5.68%	5.78%	5.95%
Feb	5.50%	2.53%	4.17%		5.55%	5.61%	5.76%
Mar	5.75%	2.75%	4.50%		5.76%	5.83%	6.01%
Apr	5.75%	2.79%	4.34%		5.56%	5.64%	5.95%
May	6.00%	2.86%	4.14%		5.39%	5.53%	5.88%
June	6.25%	2.99%	4.00%		5.05%	5.40%	5.70%
July	6.25%	3.22%	4.18%		5.18%	5.51%	5.81%
Aug	6.50%	3.45%	4.26%		5.23%	5.50%	5.80%
Sept	6.75%	3.47%	4.20%		5.27%	5.52%	5.83%
Oct	6.75%	3.70%	4.46%		5.50%	5.79%	6.08%
Nov	7.00%	3.90%	4.54%		5.59%	5.88%	6.19%
Dec	7.25%	3.89%	4.47%		5.55%	5.80%	6.14%
2006							
Jan	7.50%	4.20%	4.42%		5.50%	5.75%	6.06%
Feb	7.50%	4.41%	4.57%		5.55%	5.82%	6.11%
Mar	7.75%	4.51%	4.72%		5.71%	5.98%	6.26%
Apr	7.75%	4.59%	4.99%		6.02%	6.29%	6.54%
May	8.00%	4.72%	5.11%		6.16%	6.42%	6.59%
June	8.25%	4.79%	5.11%		6.16%	6.40%	6.61%
July	8.25%	4.96%	5.09%		6.13%	6.37%	6.61%
Aug	8.25%	4.98%	4.88%		5.97%	6.20%	6.43%
Sept	8.25%	4.82%	4.72%		5.81%	6.00%	6.26%
Oct	8.25%	4.89%	4.73%		5.80%	5.98%	6.24%
Nov	8.25%	4.95%	4.60%		5.61%	5.80%	6.04%
Dec	8.25%	4.85%	4.56%		5.62%	5.81%	6.05%
2007							
Jan	8.25%	4.96%	4.76%		5.78%	5.96%	6.16%
Feb	8.25%	5.02%	4.72%		5.73%	5.90%	6.10%
Mar	8.25%	4.97%	4.56%		5.66%	5.85%	6.10%
Apr	8.25%	4.88%	4.69%		5.83%	5.97%	6.24%
May	8.25%	4.77%	4.75%		5.86%	5.99%	6.23%
June	8.25%	4.63%	5.10%		6.18%	6.30%	6.54%
July	8.25%	4.84%	5.00%		6.11%	6.25%	6.49%
Aug	8.25%	4.34%	4.67%		6.11%	6.24%	6.51%
Sept	7.75%	4.01%	4.52%		6.10%	6.18%	6.45%
Oct	7.50%	3.97%	4.53%		6.04%	6.11%	6.36%
Nov	7.50%	3.49%	4.15%		5.87%	5.97%	6.27%
Dec	7.25%	3.08%	4.10%		6.03%	6.16%	6.51%
2008							
Jan	6.00%	2.86%	3.74%		5.87%	6.02%	6.35%
Feb	6.00%	2.21%	3.74%		6.04%	6.21%	6.60%
Mar	5.25%	1.38%	3.51%		5.99%	6.21%	6.68%
Apr					5.99%	6.29%	6.82%

[1] Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

STOCK PRICE INDICATORS

Year	S&P Composite [1]	NASDAQ Composite [1]	DJIA	S&P D/P	S&P E/P
		1975 - 1982 Cycle			
1975			802.49	4.31%	9.15%
1976			974.92	3.77%	8.90%
1977			894.63	4.62%	10.79%
1978			820.23	5.28%	12.03%
1979			844.40	5.47%	13.46%
1980			891.41	5.26%	12.66%
1981			932.92	5.20%	11.96%
1982			884.36	5.81%	11.60%
		1983 - 1991 Cycle			
1983			1,190.34	4.40%	8.03%
1984			1,178.48	4.64%	10.02%
1985			1,328.23	4.25%	8.12%
1986			1,792.76	3.49%	6.09%
1987			2,275.99	3.08%	5.48%
1988	[1]	[1]	2,060.82	3.64%	8.01%
1989	322.84		2,508.91	3.45%	7.41%
1990	334.59		2,678.94	3.61%	6.47%
1991	376.18	491.69	2,929.33	3.24%	4.79%
		1992 - 2001 Cycle			
1992	415.74	599.26	3,284.29	2.99%	4.22%
1993	451.21	715.16	3,522.06	2.78%	4.46%
1994	460.42	751.65	3,793.77	2.82%	5.83%
1995	541.72	925.19	4,493.76	2.56%	6.09%
1996	670.50	1,164.96	5,742.89	2.19%	5.24%
1997	873.43	1,469.49	7,441.15	1.77%	4.57%
1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
2000	1,427.22	3,783.67	10,734.90	1.15%	3.63%
2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
		Current Cycle			
2002	993.94	1,539.73	9,226.43	1.61%	2.92%
2003	965.23	1,647.17	8,993.59	1.77%	3.84%
2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
2005	1,207.23	2,099.32	10,547.67	1.83%	5.36%
2006	1,310.46	2,263.41	11,408.67	1.87%	5.78%
2007	1,477.19	2,578.47	13,169.98	1.86%	

[1] Note: this source did not publish the S&P Composite prior to 1988 and the NASDAQ Composite prior to 1991.

Source: Council of Economic Advisors, Economic Indicators, various issues.

STOCK PRICE INDICATORS

YEAR	S&P Composite	NASDAQ Composite	DJIA	S&P D/P	S&P E/P
2002					
1st Qtr.	1,131.56	1,879.85	10,105.27	1.39%	2.15%
2nd Qtr.	1,068.45	1,641.53	9,912.70	1.49%	2.70%
3rd Qtr.	894.65	1,308.17	8,487.59	1.76%	3.68%
4th Qtr.	887.91	1,346.07	8,400.17	1.79%	3.14%
2003					
1st Qtr.	860.03	1,350.44	8,122.83	1.89%	3.57%
2nd Qtr.	938.00	1,521.92	8,684.52	1.75%	3.55%
3rd Qtr.	1,000.50	1,765.96	9,310.57	1.74%	3.87%
4th Qtr.	1,056.42	1,934.71	9,856.44	1.69%	4.38%
2004					
1st Qtr.	1,133.29	2,041.95	10,488.43	1.64%	4.62%
2nd Qtr.	1,122.87	1,984.13	10,289.04	1.71%	4.92%
3rd Qtr.	1,104.15	1,872.90	10,129.85	1.79%	5.18%
4th Qtr.	1,162.07	2,050.22	10,362.25	1.75%	4.83%
2005					
1st Qtr.	1,191.98	2,056.01	10,648.48	1.77%	5.11%
2nd Qtr.	1,181.65	2,012.24	10,382.35	1.85%	5.32%
3rd Qtr.	1,225.91	2,144.61	10,532.24	1.83%	5.42%
4th Qtr.	1,262.07	2,246.09	10,827.79	1.86%	5.60%
2006					
1st Qtr.	1,283.04	2,287.97	10,996.04	1.85%	5.61%
2nd Qtr.	1,281.77	2,240.46	11,188.84	1.90%	5.86%
3rd Qtr.	1,288.40	2,141.97	11,274.49	1.91%	5.88%
4th Qtr.	1,389.48	2,390.26	12,175.30	1.81%	5.75%
2007					
1st Qtr.	1,425.30	2,444.85	12,470.97	1.84%	5.85%
2nd Qtr.	1,496.43	2,552.37	13,214.26	1.82%	5.65%
3rd Qtr.	1,490.81	2,609.68	13,488.43	1.86%	5.15%
4th Qtr.	1,494.09	2,701.59	13,502.95	1.91%	4.51%
2008					
1st Qtr.	1,350.19	2,332.91	12,383.86	2.11%	

[1] Note: this source did not publish the S&P Composite prior to 1988 and the NASDA(Composite prior to 1991.

Source: Council of Economic Advisors, Economic Indicators, various issues.

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SOUTHWEST GAS CORP
BOND RATINGS

Date	Moody's	Standard & Poor's	Fitch
1995	Baa3	BBB-	
1996	Baa2	BBB-	
1997	Baa2	BBB-	
1998	Baa2	BBB-	
1999	Baa2	BBB-	
2000	Baa2	BBB-	BBB
2001	Baa2	BBB-	BBB
2002	Baa2	BBB-	BBB
2003	Baa2	BBB-	BBB
2004	Baa2	BBB-	BBB
2005	Baa2	BBB-	BBB
2006	Baa3	BBB-	BBB
2007	Baa3	BBB-	BBB
2008	Baa3	BBB-	BBB

Source: Response to Request No. STF-2-6.

SOUTHWEST GAS CORP.
CAPITAL STRUCTURE RATIOS
2002 - 2007
($000)

YEAR	COMMON EQUITY	LONG-TERM DEBT	SHORT-TERM DEBT
2003	$630,467	$1,221,164	$58,435
	33.0%	63.9%	3.1%
	34.0%	66.0%	
2004	$705,676	$1,262,936	
	35.8%	64.2%	0.0%
	35.8%	64.2%	
2005	$751,135	$1,324,898	$107,215
	34.4%	60.7%	4.9%
	36.2%	63.8%	
2006	$901,425	$1,386,354	$27,545
	38.9%	59.9%	1.2%
	39.4%	60.6%	
2007	$983,673	$1,366,067	$47,079
	41.0%	57.0%	2.0%
	41.9%	58.1%	

Note: Percentages may not total 100.0% due to rounding.

Source: Southwest Gas Corp., Annual Reports to Stockholders.

VALUE LINE GAS DISTRIBUTION COMPANIES
COMMON EQUITY RATIOS

COMPANY	2000	2001	2002	2003	2004	2005	2006	2007	Average	2010-2012
AGL Resources	48.3%	38.7%	41.7%	49.7%	46.0%	48.1%	49.8%	49.8%	46.5%	51.5%
Atmos Energy	51.9%	45.7%	46.1%	49.8%	56.8%	42.3%	43.0%	48.0%	48.0%	49.0%
Energen	53.1%	46.9%	53.2%	55.8%	56.7%	56.6%	67.4%	71.0%	57.6%	60.0%
Laclede Group	54.5%	50.2%	52.3%	49.4%	48.3%	51.8%	50.4%	54.7%	51.5%	51.0%
New Jersey Resources	52.9%	49.9%	49.4%	61.9%	59.7%	58.0%	65.2%	62.7%	57.5%	72.8%
NICOR	66.7%	61.7%	64.5%	60.3%	60.1%	62.5%	63.7%	70.0%	63.7%	74.0%
Northwest Natural Gas	50.9%	53.2%	51.5%	50.3%	54.0%	53.0%	53.7%	53.7%	52.5%	52.0%
Piedmont Natural Gas	53.9%	52.4%	56.1%	57.8%	56.4%	58.6%	51.7%	51.6%	54.8%	50.8%
South Jersey Industries	37.6%	35.9%	46.1%	49.0%	51.0%	55.1%	55.3%	57.3%	48.4%	59.0%
Southwest Gas	35.8%	39.6%	34.1%	34.0%	35.8%	36.2%	39.4%	41.9%	37.1%	47.0%
UGI	19.1%	17.4%	21.7%	33.0%	35.0%	41.7%	35.9%	39.3%	30.4%	67.0%
WGL Holdings	54.8%	56.3%	52.4%	54.3%	57.2%	58.6%	61.5%	60.3%	56.9%	65.8%
Average	48.3%	45.7%	47.4%	50.4%	51.4%	51.9%	53.1%	55.0%	50.4%	58.3%
Composite			41.4%	43.7%	45.7%	48.3%	47.0%	48.0%	45.7%	46.0%

Source: Value Line Investment Survey.

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COMPARISON COMPANIES
CAPITAL STRUCTURE RATIOS
INCLUDING SHORT-TERM DEBT

Company	2001	2002	2003	2004	2005	2006	2007
AGL Resources	32%	33%	41%	41%	41%	42%	42%
Atmos Energy	40%	39%	45%	41%	38%	45%	47%
Energen	45%	47%	55%	51%	56%	64%	67%
Laclede Group	41%	37%	37%	40%	38%	58%	40%
New Jersey Resources	43%	44%	44%	45%	43%	51%	49%
NICOR	50%	51%	41%	43%	42%	51%	58%
Northwest Natural Gas	46%	48%	50%	49%	47%	48%	48%
Piedmont Natural Gas	51%	54%	53%	53%	48%	46%	46%
South Jersey Industries	32%	34%	41%	31%	45%	44%	48%
Southwest Gas	31%	33%	33%	34%	36%	41%	43%
UGI	14%	24%	29%	31%	33%	32%	35%
WGL Holdings	48%	48%	49%	52%	58%	51%	51%
Average	**39%**	**41%**	**43%**	**43%**	**44%**	**48%**	**48%**

Source: AUS Utility Reports.

COMPARISON COMPANIES
DIVIDEND YIELD

COMPANY	DPS	HIGH	LOW	AVERAGE	YIELD
		February - April, 2008			
Value Line Natural Gas Distribution Companies					
AGL Resources	$1.68	$39.13	$33.75	$36.44	4.6%
Atmos Energy	$1.30	$29.29	$25.00	$27.15	4.8%
Energen	$0.48	$72.39	$57.97	$65.18	0.7%
Laclede Group	$1.50	$38.28	$32.76	$35.52	4.2%
New Jersey Resources	$0.75	$33.47	$30.95	$32.21	2.3%
NICOR	$1.86	$42.62	$32.35	$37.49	5.0%
Northwest Natural Gas	$1.50	$48.81	$41.07	$44.94	3.3%
Piedmont Natural Gas	$1.04	$27.68	$24.05	$25.87	4.0%
South Jersey Industries	$1.08	$36.88	$31.90	$34.39	3.1%
Southwest Gas	$0.86	$30.05	$25.14	$27.60	3.1%
UGI	$0.74	$27.22	$24.41	$25.82	2.9%
WGL Holdings	$1.42	$33.94	$30.26	$32.10	4.4%
Average					**3.5%**
Hanley Proxy Companies					
AGL Resources	$1.68	$39.13	$33.75	$36.44	4.6%
Atmos Energy	$1.30	$29.29	$25.00	$27.15	4.8%
Laclede Group	$1.50	$38.28	$32.76	$35.52	4.2%
NICOR	$1.86	$42.62	$32.35	$37.49	5.0%
Northwest Natural Gas	$1.50	$48.81	$41.07	$44.94	3.3%
Piedmont Natural Gas	$1.04	$27.68	$24.05	$25.87	4.0%
South Jersey Industries	$1.08	$36.88	$31.90	$34.39	3.1%
WGL Holdings	$1.42	$33.94	$30.26	$32.10	4.4%
Average					**4.2%**

Source: Yahoo! Finance.

COMPARISON COMPANIES
RETENTION GROWTH RATES

COMPANY	2003	2004	2005	2006	2007	Average	2008	2009	'11-'13	Average
Value Line Natural Gas										
AGL Resources	6.6%	5.6%	6.2%	6.3%	5.3%	6.0%	5.0%	5.5%	6.5%	5.7%
Atmos Energy	2.8%	1.7%	2.3%	3.6%	3.0%	2.7%	3.0%	3.5%	4.0%	3.5%
Energen	12.1%	12.4%	16.1%	16.7%	20.0%	15.5%	18.5%	19.0%	14.0%	17.2%
Laclede Group	3.1%	2.7%	3.1%	5.1%	4.3%	3.7%	4.0%	4.0%	4.5%	4.2%
New Jersey Resources	7.7%	7.8%	8.5%	6.3%	3.6%	6.8%	6.0%	6.0%	5.0%	5.7%
NICOR	1.5%	2.1%	2.3%	5.2%	4.5%	3.1%	2.0%	3.5%	5.5%	3.7%
Northwest Natural Gas	2.6%	2.7%	3.7%	4.5%	6.0%	3.9%	5.0%	5.0%	5.0%	5.0%
Piedmont Natural Gas	3.1%	3.7%	3.6%	2.8%	3.5%	3.3%	3.5%	3.5%	4.0%	3.7%
South Jersey Industries	5.0%	5.9%	6.2%	10.2%	6.7%	6.8%	6.5%	7.0%	8.5%	7.3%
Southwest Gas	1.7%	4.3%	2.2%	5.3%	4.8%	3.7%	5.0%	5.5%	6.0%	5.5%
UGI	9.2%	7.3%	11.5%	9.4%	8.7%	9.2%	9.0%	9.5%	8.5%	9.0%
WGL Holdings	6.2%	4.1%	4.6%	3.1%	3.5%	4.3%	4.0%	4.0%	4.0%	4.0%
Average						**5.7%**				**6.2%**
Hanley Proxy Companies										
AGL Resources	6.6%	5.6%	6.2%	6.3%	5.3%	6.0%	5.0%	5.5%	6.5%	5.7%
Atmos Energy	2.8%	1.7%	2.3%	3.6%	3.0%	2.7%	3.0%	3.5%	4.0%	3.5%
Laclede Group	3.1%	2.7%	3.1%	5.1%	4.3%	3.7%	4.0%	4.0%	4.5%	4.2%
NICOR	1.5%	2.1%	2.3%	5.2%	4.5%	3.1%	2.0%	3.5%	5.5%	3.7%
Northwest Natural Gas	2.6%	2.7%	3.7%	4.5%	6.0%	3.9%	5.0%	5.0%	5.0%	5.0%
Piedmont Natural Gas	3.1%	3.7%	3.6%	2.8%	3.5%	3.3%	3.5%	3.5%	4.0%	3.7%
South Jersey Industries	5.0%	5.9%	6.2%	10.2%	6.7%	6.8%	6.5%	7.0%	8.5%	7.3%
WGL Holdings	6.2%	4.1%	4.6%	3.1%	3.5%	4.3%	4.0%	4.0%	4.0%	4.0%
Average						**4.2%**				**4.6%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
PER SHARE GROWTH RATES

COMPANY	5-Year Historic Growth Rates EPS	DPS	BVPS	Average	Est'd '05-'07 to '11-'13 Growth Rates EPS	DPS	BVPS	Average
Value Line Natural Gas								
AGL Resources	15.0%	4.0%	10.5%	9.8%	3.5%	4.0%	1.5%	3.0%
Atmos Energy	7.5%	1.5%	9.0%	6.0%	4.5%	2.0%	3.5%	3.3%
Energen	22.0%	4.0%	14.0%	13.3%	7.5%	7.5%	9.0%	8.0%
Laclede Group	9.5%	1.0%	4.5%	5.0%	3.5%	2.5%	5.0%	3.7%
New Jersey Resources	6.0%	4.0%	10.0%	6.7%	6.0%	6.0%	9.0%	7.0%
NICOR	-3.0%	2.5%	2.5%	0.7%	4.0%	0.5%	4.0%	2.8%
Northwest Natural Gas	3.5%	1.5%	3.5%	2.8%	7.0%	5.5%	3.5%	5.3%
Piedmont Natural Gas	6.0%	4.5%	6.5%	5.7%	5.0%	4.0%	3.5%	4.2%
South Jersey Industries	12.0%	3.5%	13.5%	9.7%		5.5%	5.0%	5.3%
Southwest Gas	6.0%	0.0%	3.5%	3.2%	7.5%	4.0%	3.5%	5.0%
UGI	19.5%	5.5%	26.5%	17.2%	7.0%	8.0%	11.0%	8.7%
WGL Holdings	5.0%	1.5%	3.5%	3.3%	3.5%	2.5%	5.0%	3.7%
Average	9.1%	2.8%	9.0%	**6.9%**	5.4%	4.3%	5.3%	**5.0%**
Hanley Proxy Companies								
AGL Resources	15.0%	4.0%	10.5%	9.8%	3.5%	4.0%	1.5%	3.0%
Atmos Energy	7.5%	1.5%	9.0%	6.0%	4.5%	2.0%	3.5%	3.3%
Laclede Group	9.5%	1.0%	4.5%	5.0%	3.5%	2.5%	5.0%	3.7%
NICOR	-3.0%	2.5%	2.5%	0.7%	4.0%	0.5%	4.0%	2.8%
Northwest Natural Gas	3.5%	1.5%	3.5%	2.8%	7.0%	5.5%	3.5%	5.3%
Piedmont Natural Gas	6.0%	4.5%	6.5%	5.7%	5.0%	4.0%	3.5%	4.2%
South Jersey Industries	12.0%	3.5%	13.5%	9.7%		5.5%	5.0%	5.3%
WGL Holdings	5.0%	1.5%	3.5%	3.3%	3.5%	2.5%	5.0%	3.7%
Average	6.9%	2.5%	6.7%	**5.4%**	4.4%	3.3%	3.9%	**3.9%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
DCF COST RATES

COMPANY	ADJUSTED YIELD	HISTORIC RETENTION GROWTH	PROSPECTIVE RETENTION GROWTH	HISTORIC PER SHARE GROWTH	PROSPECTIVE PER SHARE GROWTH	FIRST CALL EPS GROWTH	AVERAGE GROWTH	DCF RATES
Value Line Natural Gas								
AGL Resources	4.7%	6.0%	5.7%	9.8%	3.0%	5.3%	6.0%	10.7%
Atmos Energy	4.9%	2.7%	3.5%	6.0%	3.3%	4.7%	4.0%	8.9%
Energen	0.8%	15.5%	17.2%	13.3%	8.0%	8.5%	12.5%	13.3%
Laclede Group	4.3%	3.7%	4.2%	5.0%	3.7%	3.5%	4.0%	8.3%
New Jersey Resources	2.4%	6.8%	5.7%	6.7%	7.0%	5.5%	6.3%	8.7%
NICOR	5.0%	3.1%	3.7%	0.7%	2.8%	3.8%	2.8%	7.8%
Northwest Natural Gas	3.4%	3.9%	5.0%	2.8%	5.3%	4.9%	4.4%	7.8%
Piedmont Natural Gas	4.1%	3.3%	3.7%	5.7%	4.2%	5.2%	4.4%	8.5%
South Jersey Industries	3.3%	6.8%	7.3%	9.7%	5.3%	6.6%	7.1%	10.4%
Southwest Gas	3.2%	3.7%	5.5%	3.2%	5.0%	5.7%	4.6%	7.8%
UGI	3.0%	9.2%	9.0%	17.2%	8.7%	8.0%	10.4%	13.4%
WGL Holdings	4.5%	4.3%	4.0%	3.3%	3.7%	5.0%	4.1%	8.6%
Mean	3.6%	5.7%	6.2%	6.9%	5.0%	5.5%	5.9%	**9.5%**
Median	3.8%	4.1%	5.3%	5.8%	4.6%	5.2%	4.5%	**8.6%**
Mean Composite		9.4%	9.8%	**10.6%**	8.6%	9.2%	9.5%	
Median Composite		7.9%	9.0%	**9.6%**	8.3%	9.0%	8.3%	
Hanley Proxy Companies								
AGL Resources	4.7%	6.0%	5.7%	9.8%	3.0%	5.3%	6.0%	10.7%
Atmos Energy	4.9%	2.7%	3.5%	6.0%	3.3%	4.7%	4.0%	8.9%
Laclede Group	4.3%	3.7%	4.2%	5.0%	3.7%	3.5%	4.0%	8.3%
NICOR	5.0%	3.1%	3.7%	0.7%	2.8%	3.8%	2.8%	7.8%
Northwest Natural Gas	3.4%	3.9%	5.0%	2.8%	5.3%	4.9%	4.4%	7.8%
Piedmont Natural Gas	4.1%	3.3%	3.7%	5.7%	4.2%	5.2%	4.4%	8.5%
South Jersey Industries	3.3%	6.8%	7.3%	9.7%	5.3%	6.6%	7.1%	10.4%
WGL Holdings	4.5%	4.3%	4.0%	3.3%	3.7%	5.0%	4.1%	8.6%
Mean	4.3%	4.2%	4.6%	5.4%	3.9%	4.9%	4.6%	**8.9%**
Median	4.4%	3.8%	4.1%	5.3%	3.7%	5.0%	4.2%	**8.5%**
Mean Composite		8.5%	8.9%	**9.7%**	8.2%	9.1%	8.9%	
Median Composite		8.2%	8.5%	**9.7%**	8.1%	9.4%	8.6%	

Sources: Prior pages of this schedule.

STANDARD & POOR'S 500 COMPOSITE
20-YEAR U.S. TREASURY BOND YIELDS
RISK PREMIUMS

Year	EPS	BVPS	ROE	20-YEAR T-BOND YIELD	RISK PREMIUM
1977		$79.07			
1978	$12.33	$85.35	15.00%	7.90%	7.10%
1979	$14.86	$94.27	16.55%	8.86%	7.69%
1980	$14.82	$102.48	15.06%	9.97%	5.09%
1981	$15.36	$109.43	14.50%	11.55%	2.95%
1982	$12.64	$112.46	11.39%	13.50%	-2.11%
1983	$14.03	$116.93	12.23%	10.38%	1.85%
1984	$16.64	$122.47	13.90%	11.74%	2.16%
1985	$14.61	$125.20	11.80%	11.25%	0.55%
1986	$14.48	$126.82	11.49%	8.98%	2.51%
1987	$17.50	$134.04	13.42%	7.92%	5.50%
1988	$23.75	$141.32	17.25%	8.97%	8.28%
1989	$22.87	$147.26	15.85%	8.81%	7.04%
1990	$21.73	$153.01	14.47%	8.19%	6.28%
1991	$16.29	$158.85	10.45%	8.22%	2.23%
1992	$19.09	$149.74	12.37%	7.29%	5.08%
1993	$21.89	$180.88	13.24%	7.17%	6.07%
1994	$30.60	$193.06	16.37%	6.59%	9.78%
1995	$33.96	$215.51	16.62%	7.60%	9.02%
1996	$38.73	$237.08	17.11%	6.18%	10.93%
1997	$39.72	$249.52	16.33%	6.64%	9.69%
1998	$37.71	$266.40	14.62%	5.83%	8.79%
1999	$48.17	$290.68	17.29%	5.57%	11.72%
2000	$50.00	$325.80	16.22%	6.50%	9.72%
2001	$24.69	$338.37	7.43%	5.53%	1.90%
2002	$27.59	$321.72	8.36%	5.59%	2.77%
2003	$48.73	$367.17	14.15%	4.80%	9.35%
2004	$58.55	$414.75	14.98%	5.02%	9.96%
2005	$69.93	$453.06	16.12%	4.69%	11.43%
2006	$81.51	$504.39	17.03%	4.68%	12.35%
Average					**6.40%**

Source: Standard & Poor's Analysts' Handbook, Ibbotson Associates Handbook.

COMPARISON COMPANIES
CAPM COST RATES

COMPANY	RISK-FREE RATE	BETA	RISK PREMIUM	CAPM RATES
Value Line Natural Gas				
AGL Resources	4.43%	0.85	5.90%	9.4%
Atmos Energy	4.43%	0.85	5.90%	9.4%
Energen	4.43%	0.95	5.90%	10.0%
Laclede Group	4.43%	0.90	5.90%	9.7%
New Jersey Resources	4.43%	0.85	5.90%	9.4%
NICOR	4.43%	1.00	5.90%	10.3%
Northwest Natural Gas	4.43%	0.80	5.90%	9.2%
Piedmont Natural Gas	4.43%	0.85	5.90%	9.4%
South Jersey Industries	4.43%	0.80	5.90%	9.2%
Southwest Gas	4.43%	0.90	5.90%	9.7%
UGI	4.43%	0.90	5.90%	9.7%
WGL Holdings	4.43%	0.85	5.90%	9.4%
Mean				**9.6%**
Median				**9.4%**
Hanley Proxy Companies				
AGL Resources	4.43%	0.85	5.90%	9.4%
Atmos Energy	4.43%	0.85	5.90%	9.4%
Laclede Group	4.43%	0.90	5.90%	9.7%
NICOR	4.43%	1.00	5.90%	10.3%
Northwest Natural Gas	4.43%	0.80	5.90%	9.2%
Piedmont Natural Gas	4.43%	0.85	5.90%	9.4%
South Jersey Industries	4.43%	0.80	5.90%	9.2%
WGL Holdings	4.43%	0.85	5.90%	9.4%
Mean				**9.5%**
Median				**9.4%**

Sources: Value Line Investment Survey, Standard & Poor's Analysts' Handbook, Federal Reserve.

COMPARISON COMPANIES
RATES OF RETURN ON AVERAGE COMMON EQUITY

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	1992-2001 Average	2003-2007 Average	2008	2009	2011-2013
Value Line Natural Gas																					
AGL Resources	11.8%	11.0%	11.6%	13.1%	13.2%	12.7%	12.6%	7.9%	11.2%	12.7%	14.7%	15.3%	13.9%	13.3%	13.6%	13.2%	11.8%	13.9%	12.5%	13.0%	14.5%
Atmos Energy	10.7%	12.7%	10.0%	12.2%	14.4%	12.3%	15.8%	6.7%	8.5%	11.1%	10.3%	11.2%	9.1%	9.1%	10.0%	9.2%	11.4%	9.7%	9.0%	9.5%	9.5%
Energen	12.6%	13.4%	13.9%	11.3%	11.9%	12.3%	11.4%	11.3%	14.3%	15.6%	12.4%	17.2%	17.0%	20.3%	22.2%	24.5%	12.8%	20.2%	21.0%	21.5%	16.5%
Laclede Group	9.9%	13.4%	11.5%	10.0%	14.0%	13.2%	11.0%	10.0%	9.1%	10.6%	7.8%	11.8%	11.2%	11.1%	13.1%	12.0%	11.3%	11.8%	11.5%	11.0%	11.0%
New Jersey Resources	12.1%	11.9%	13.0%	13.3%	13.8%	14.5%	14.6%	14.9%	15.1%	15.2%	15.9%	16.7%	15.8%	16.2%	14.6%	10.2%	13.8%	14.7%	13.0%	12.5%	10.5%
NICOR	15.3%	15.3%	15.7%	14.6%	17.0%	16.9%	14.7%	15.7%	18.2%	18.8%	17.3%	12.4%	13.0%	12.8%	15.2%	13.8%	16.2%	13.4%	11.0%	12.0%	13.5%
Northwest Natural Gas	6.0%	13.7%	12.2%	11.4%	13.2%	11.2%	6.3%	10.1%	10.2%	10.3%	8.7%	9.2%	9.3%	10.1%	10.9%	12.4%	10.5%	10.4%	11.0%	11.0%	11.0%
Piedmont Natural Gas	14.1%	13.8%	12.2%	12.3%	13.2%	13.8%	13.6%	12.1%	12.5%	12.0%	10.8%	12.2%	12.4%	11.6%	11.0%	11.8%	13.0%	11.8%	12.0%	12.0%	12.5%
South Jersey Industries	11.8%	11.0%	8.5%	11.4%	11.1%	11.9%	10.1%	15.6%	15.4%	15.3%	14.0%	13.1%	13.4%	13.2%	17.2%	13.3%	12.2%	14.0%	13.0%	13.5%	14.5%
Southwest Gas	5.1%	3.9%	7.5%	0.6%	1.7%	5.4%	10.4%	7.5%	7.3%	6.7%	6.6%	6.2%	8.8%	6.5%	9.7%	8.8%	5.6%	8.0%	9.0%	9.5%	10.0%
UGI	9.1%	3.2%	9.0%	4.9%	9.2%	12.9%	10.9%	13.4%	17.4%	22.7%	25.9%	21.9%	16.5%	19.5%	16.1%	15.7%	11.3%	17.9%	14.5%	14.5%	12.5%
WGL Holdings	12.5%	12.1%	12.6%	12.4%	15.0%	14.1%	11.3%	10.3%	11.9%	11.9%	7.1%	14.4%	11.9%	12.1%	10.8%	11.0%	12.4%	12.0%	11.5%	11.0%	10.5%
Average	10.9%	11.3%	11.5%	10.6%	12.3%	12.6%	11.9%	11.3%	12.6%	13.6%	12.6%	13.5%	12.7%	13.0%	13.7%	13.0%	11.9%	13.2%	12.4%	12.6%	12.2%
Composite																	11.9%	13.2%			
Hanley Proxy Companies																					
AGL Resources	11.8%	11.0%	11.6%	13.1%	13.2%	12.7%	12.6%	7.9%	11.2%	12.7%	14.7%	15.3%	13.9%	13.3%	13.6%	13.2%	11.8%	13.9%	12.5%	13.0%	14.5%
Atmos Energy	10.7%	12.7%	10.0%	12.2%	14.4%	12.3%	15.8%	6.7%	8.5%	11.1%	10.3%	11.2%	9.1%	9.1%	10.0%	9.2%	11.4%	9.7%	9.0%	9.5%	9.5%
Laclede Group	9.9%	13.4%	11.5%	10.0%	14.0%	13.2%	11.0%	10.0%	9.1%	10.6%	7.8%	11.8%	11.2%	11.1%	13.1%	12.0%	11.3%	11.8%	11.5%	11.0%	11.0%
NICOR	15.3%	15.3%	15.7%	14.6%	17.0%	16.9%	14.7%	15.7%	18.2%	18.8%	17.3%	12.4%	13.0%	12.8%	15.2%	13.8%	16.2%	13.4%	11.0%	12.0%	13.5%
Northwest Natural Gas	6.0%	13.7%	12.2%	11.4%	13.2%	11.2%	6.3%	10.1%	10.2%	10.3%	8.7%	9.2%	9.3%	10.1%	10.9%	12.4%	10.5%	10.4%	11.0%	11.0%	11.0%
Piedmont Natural Gas	14.1%	13.8%	12.2%	12.3%	13.2%	13.8%	13.6%	12.1%	12.5%	12.0%	10.8%	12.2%	12.4%	11.6%	11.0%	11.8%	13.0%	11.8%	12.0%	12.0%	12.5%
South Jersey Industries	11.8%	11.0%	8.5%	11.4%	11.1%	11.9%	10.1%	15.6%	15.4%	15.3%	14.0%	13.1%	13.4%	13.2%	17.2%	13.3%	12.2%	14.0%	13.0%	13.5%	14.5%
WGL Holdings	12.5%	12.1%	12.6%	12.4%	15.0%	14.1%	11.3%	10.3%	11.9%	11.9%	7.1%	14.4%	11.9%	12.1%	10.8%	11.0%	12.4%	12.0%	11.5%	11.0%	10.5%
Mean	11.5%	12.9%	11.8%	12.2%	13.9%	13.3%	11.9%	11.1%	12.1%	12.8%	11.3%	12.5%	11.8%	11.7%	12.7%	12.1%	12.3%	12.1%	11.4%	11.6%	12.1%
Composite																	12.3%	12.1%			

Source: Calculations made from data contained in Value Line Investment Survey.

COMPARISON COMPANIES
MARKET TO BOOK RATIOS

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	1992-2001 Average	2003-2007 Average
Value Line Natural Gas																		
AGL Resources	181%	195%	169%	172%	189%	183%	183%	169%	168%	184%	171%	188%	184%	191%	186%	188%	179%	187%
Atmos Energy	158%	194%	186%	196%	248%	241%	246%	216%	167%	170%	150%	152%	147%	145%	146%	136%	202%	145%
Energen	138%	171%	150%	145%	161%	186%	174%	147%	189%	215%	160%	194%	242%	309%	280%	327%	168%	270%
Laclede Group	158%	187%	178%	163%	168%	175%	174%	159%	141%	155%	145%	169%	179%	179%	184%	168%	166%	176%
New Jersey Resources	161%	185%	162%	179%	190%	229%	225%	224%	227%	224%	220%	244%	251%	275%	246%	223%	201%	248%
NICOR	179%	216%	195%	187%	220%	242%	260%	226%	227%	239%	199%	185%	210%	222%	234%	230%	219%	216%
Northwest Natural Gas	162%	176%	161%	146%	156%	173%	169%	141%	129%	133%	145%	144%	153%	172%	177%	208%	155%	171%
Piedmont Natural Gas	180%	214%	186%	182%	183%	217%	222%	213%	195%	199%	186%	211%	212%	208%	221%	210%	199%	212%
South Jersey Industries	154%	175%	141%	142%	146%	178%	209%	202%	196%	205%	185%	170%	195%	221%	209%	231%	175%	205%
Southwest Gas	81%	100%	103%	103%	121%	129%	139%	147%	120%	127%	123%	118%	127%	135%	161%	149%	117%	138%
UGI	187%	162%	161%	166%	196%	226%	222%	196%	244%	292%	318%	286%	240%	279%	247%	230%	205%	256%
WGL Holdings	173%	189%	165%	164%	178%	199%	197%	176%	177%	177%	152%	162%	175%	183%	168%	172%	180%	172%
Average	159%	180%	163%	162%	180%	198%	202%	185%	182%	193%	180%	185%	193%	210%	205%	206%	180%	200%
Composite																	180%	200%
Hanley Proxy Companies																		
AGL Resources	181%	195%	169%	172%	189%	183%	183%	169%	168%	184%	171%	188%	184%	191%	186%	188%	179%	187%
Atmos Energy	158%	194%	186%	196%	248%	241%	246%	216%	167%	170%	150%	152%	147%	145%	146%	136%	202%	145%
Laclede Group	158%	187%	178%	163%	168%	175%	174%	159%	141%	155%	145%	169%	179%	179%	184%	168%	166%	176%
NICOR	179%	216%	195%	187%	220%	242%	260%	226%	227%	239%	199%	185%	210%	222%	234%	230%	219%	216%
Northwest Natural Gas	162%	176%	161%	146%	156%	173%	169%	141%	129%	133%	145%	144%	153%	172%	177%	208%	155%	171%
Piedmont Natural Gas	180%	214%	186%	182%	183%	217%	222%	213%	195%	199%	186%	211%	212%	208%	221%	210%	199%	212%
South Jersey Industries	154%	175%	141%	142%	146%	178%	209%	202%	196%	205%	185%	170%	195%	221%	209%	231%	175%	205%
WGL Holdings	173%	189%	165%	164%	178%	199%	197%	176%	177%	177%	152%	162%	175%	183%	168%	172%	180%	172%
Mean	168%	193%	173%	169%	186%	201%	208%	188%	175%	183%	167%	173%	182%	190%	191%	193%	184%	186%
Composite																	184%	186%

Source: Calculations made from data contained in Value Line Investment Survey.

STANDARD & POOR'S 500 COMPOSITE
RETURNS AND MARKET-TO-BOOK RATIOS
1992 - 2006

YEAR	RETURN ON AVERAGE EQUITY	MARKET-TO BOOK RATIO
1992	12.2%	271%
1993	13.2%	272%
1994	16.4%	246%
1995	16.6%	264%
1996	17.1%	299%
1997	16.3%	354%
1998	14.6%	421%
1999	17.3%	481%
2000	16.2%	453%
2001	7.5%	353%
2002	8.4%	296%
2003	14.2%	278%
2004	15.0%	291%
2005	16.1%	278%
2006	17.0%	277%
Averages:		
1992-2001	14.7%	341%
2002-2006	14.1%	284%

Source: Standard & Poor's Analyst's Handbook, 2007 edition, page 1.

COMPANY	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FINANCIAL STRENGTH		S& P STOCK RANKING	
Value Line Natural Gas						
AGL Resources	2	0.85	B++	3.67	A-	3.67
Atmos Energy	2	0.85	B+	3.33	B+	3.33
Energen	2	0.95	A	4.00	A	4.00
Laclede Group	2	0.90	B+	3.33	B+	3.33
New Jersey Resources	1	0.85	A	4.00	A	4.00
NICOR	3	1.00	A	4.00	B	3.00
Northwest Natural Gas	1	0.80	A	4.00	B+	3.33
Piedmont Natural Gas	2	0.85	B++	3.67	A-	3.67
South Jersey Industries	2	0.80	B++	3.67	B+	3.33
Southwest Gas	3	0.90	B	3.00	B+	3.33
UGI	2	0.90	B+	3.33	A	4.00
WGL Holdings	1	0.85	A	4.00	B+	3.33
Average	1.9	0.88	B++	3.67	B+	3.53
[illegible]anley Proxy Companies						
AGL Resources	2	0.85	B++	3.67	A-	3.67
Atmos Energy	2	0.85	B+	3.33	B+	3.33
Laclede Group	2	0.90	B+	3.33	B+	3.33
NICOR	3	1.00	A	4.00	B	3.00
Northwest Natural Gas	1	0.80	A	4.00	B+	3.33
Piedmont Natural Gas	2	0.85	B++	3.67	A-	3.67
South Jersey Industries	2	0.80	B++	3.67	B+	3.33
WGL Holdings	1	0.85	A	4.00	B+	3.33
Average	1.9	0.86	B++	3.71	B+	3.37

RISK INDICATORS

GROUP	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FIN STR	S & P STK RANK
S & P's 500 Composite	2.7	1.05	B++	B+
Value Line Natural Gas	1.9	0.88	B++	B+
Hanley Proxy Companies	1.9	0.86	B++	B+
Southwest Gas	3.0	0.90	B	B+

Sources: Value Line Investment Survey, Standard & Poor's Stock Guide.

Definitions:

Safety rankings are in a range of 1 to 5, with 1 representing the highest safety or lowest risk.

Beta reflects the variability of a particular stock, relative to the market as a whole. A stock with a beta of 1.0 moves in concert with the market, a stock with a beta below 1.0 is less variable than the market, and a stock with a beta above 1.0 is more variable than the market.

Financial strengths range from C to A++, with the latter representing the highest level.

Common stock rankings range from D to A+, with the later representing the highest level.

SOUTHWEST GAS CORP.
PRE-TAX COVERAGE

Item	Percent	Cost	Weighted Cost	Pre-Tax Cost	
Short-Term Debt	0.00%		0.00%	0.00%	
Long-Term Debt	52.08%	7.96%	4.15%	4.15%	
Preferred Stock	4.48%	8.20%	0.37%	0.61%	
Common Equity	43.44%	10.00%	4.34%	7.24%	
Total	100.00%		8.86%	12.00%	1/

1/ Post-tax weighted cost divided by .60 (composite tax factor)

Pre-Tax coverage =	12.00%x (11.64% / 4.15%) **2.89**	
Standard & Poor[s Utility Benchmark Ratios: Business Profile of "3"	A	BBB
Pre-tax coverage	2.8x - 3.4x	1.8x - 2.8x
Total debt to total capital	50%-55%	55%-65%

VANGUARD 500 INDEX FUND
DEMONSTRATION OF MUTUAL FUND HISTORIC PERFORMANCE USING GEOMETRIC GROWTH RATES

Vanguard®

Vanguard 500 Index Fund Admiral Shares (VFIAX)

The performance data shown represent past performance, which is not a guarantee of future results. Investment returns and principal value will fluctuate, so that investors' shares, when sold, may be worth more or less than their original cost. Current performance may be lower or higher than the performance data cited. See performance data current to the most recent month-end. Expense ratio information can be found on the Overview page.

Cumulative Total Returns

(as of 04/30/2008)

	1 Year	3 Year	5 Year	10 Year	Since Inception 11/13/2000
500 Index Fund Adm	–4.68%	26.64%	65.27%	—	16.31%
S&P 500 Index*	–4.68%	26.78%	65.66%	46.51%	—

Annual Investment Returns

(as of 12/31/2007)

	500 Index Fund Adm			S&P 500 Index*
Year Ended	Capital Return	Income Return	Total Return	Total Return
2007	3.49%	1.98%	5.47%	5.49%
2006	13.64%	2.11%	15.75%	15.79%
2005	2.94%	1.93%	4.87%	4.91%
2004	8.73%	2.10%	10.82%	10.88%
2003	26.53%	2.06%	28.59%	28.68%
2002	–23.36%	1.27%	–22.10%	–22.10%
2001	–13.11%	1.14%	–11.98%	–11.89%
2000**	–2.41%	0.31%	–2.10%	—

Quarterly Investment Returns

(as of 03/31/2008)

	500 Index Fund Adm					S&P 500 Index*
Year	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Year-End Return	Year-End Average
2008	–9.45%	—	—	—	—	—
2007	0.63%	6.26%	2.05%	–3.34%	5.47%	5.49%
2006	4.21%	–1.45%	5.65%	6.68%	15.75%	15.79%
2005	–2.14%	1.35%	3.59%	2.07%	4.87%	4.91%
2004	1.67%	1.71%	–1.88%	9.22%	10.82%	10.88%
2003	–3.17%	15.40%	2.62%	12.15%	28.59%	28.68%

2002	0.25%	−13.42%	−17.20%	8.40%	−22.10%	−22.10%
2001	−11.88%	5.82%	−14.70%	10.67%	−11.98%	−11.89%

*A widely used barometer of U.S. stock market performance; as a market-weighted index of leading companies in leading industries, it is dominated by large-capitalization companies.

** Since inception on 11/13/2000

Glossary

Important fund performance information

cumulative total return

The total return on a fund from a certain period of time up to the present.

For example, if a fund's net asset value (NAV) started at $10, and 3 years later, the NAV equals $15, the cumulative return would be 50% (as opposed to an average annual return of 14.47%). Cumulative returns are always calculated as of the end of each month.

Print

OK

DEMONSTRATION OF VALUE LINE INVESTMENT SURVEY CALCULATING GROWTH RATES USING COMPOUND (GEOMETRIC) GROWTH RATES

Value Line Investment Survey *for Windows*® Version 3.0

Value Line Investment Survey *for Windows*® Version 3.0

About Value Line

The Value Line Investment Survey

The Value Line Investment Survey *for Windows*®

What's New in Version 3.0

Value Line Technical Support

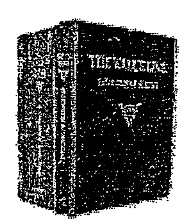
About Value Line

Value Line was founded in New York in 1931 by Arnold Bernhard, then a young analyst, amidst the crisis of confidence wrought by the Great Depression. His goal was to help investors in their quest to achieve superior returns from stocks by providing access to the same information that professionals had at their fingertips. His vision grew into one of the most enduring and trusted institutions in the financial world. Backed by disciplined, objective analytic methodologies that have been proven over six decades, and by one of the world's largest independent research staffs, including over 100 professional securities analysts, statisticians and economists, Value Line has become an indispensable source for investors around the globe. Value Line's businesses are broad-based, including financial publications and electronic data services, a family of no-load mutual funds, and asset management for retirement and endowment accounts. Its research services include domestic stocks, Canadian stocks, mutual funds, convertibles, and options, which are available in both print and electronic form.

Value Line's headquarters are located at 220 East 42nd Street, New York, NY 10017. Telephone 212-907-1500. For technical support, call 800-654-0508.

The Value Line Investment Survey

The Value Line Investment Survey printed version was created in 1931 for one purpose and one purpose only to guide you in your quest to realize superior returns on your invested capital. Based on disciplined, objective, quantitative, analytical methodologies that have proven themselves over the last 60 years, plus a staff of more than 70 professional securities analysts, Value Line can serve as an invaluable tool in making your investment decisions.



Appendix B

General Rules for Managing Your Portfolio 127

Glossary

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index, and the risk-free rate of return of a three-month Treasury Bill. For example, if a stock has a beta of 1.5, it would be expected to gain 15% when the index gains 10%. If however, the stock actually gains 20%, this excess return represents the stock's alpha. Value Line expresses alpha as an annualized figure.

American Depository Receipts (ADRs) - Since most other nations do not allow stock certificates to leave the country, a foreign company will arrange for a trustee (typically a large bank) to issue ADRs (sometimes called American Depository Shares, or ADSs) representing the actual, or underlying, shares. Each ADR is equivalent to a specified number of shares (the ratio is shown in a footnote on the Value Line page).

American Stock Exchange Composite - A market-capitalization weighted index of the prices of the stocks traded on the American Stock Exchange.

Annual Change D-J Industrials - The annual change from year end to year end in the Dow Jones Industrial Average, expressed as a percentage.

Annual Change in Net Asset Value (Investment Companies) - The change in percentage terms of the net asset value per share at the end of any given year from what it was at the end of the preceding year, adjusted for any capital gains distributions made during the year.

Annual Rates of Change (Per Share) - Compounded annual rates of change of pershare sales, cash flow, earnings, dividends, and book value (or other industry-specific per-share figures) over the past ten years and five years and estimated over the coming three to five years. All forecasted rates of change are computed from the average figure for the past three-year period to an average for a future three-year period. If data for a three-year base period are not available, a two- or one-year base may be used.

Arbitrage - The simultaneous purchase of an asset in one market and sale of the same asset, or assets equivalent to the asset purchased, in another market. Often referred to as "classical arbitrage," this type of transaction should result in a risk-free profit. Risk Arbitrage refers to transactions in stocks involved in takeover activity.

Arbitrageur - A person or organization that engages in arbitrage activity.

DEMONSTRATION OF INCLUSION OF UTILITIES IN STANDARD & POOR'S 500 INDEX

STANDARD
&POOR'S

S&P 500

EXCHANGE-TRADED PRODUCTS:

EXCHANGE-TRADED FUNDS (ETFs)
SPDR®
Select Sector SPDRs
iShares S&P 500
iShares S&P 500 Growth
iShares S&P 500 Value
iUnits S&P 500

FUTURES
S&P 500
E-Mini S&P 500
S&P 500 Growth
S&P 500 Value
S&P 500 Sector Futures

OPTIONS
S&P 500
Select Sector SPDRs

Contact Us:

index_services@standardandpoors.com

New York	+1.212.438.2046
Toronto	+1.416.507.3200
London	+44.20.7176.8888
Paris	+33.1.40.75.77.91
Tokyo	+813.4550.8463
Beijing	+86.10.6569.2919
Sydney	+61.2.9255.9870

For more information, visit our Web site:
www.indices.standardandpoors.com

About the Index

Widely regarded as the best single gauge of the U.S. equities market, this world-renowned index includes 500 leading companies in leading industries of the U.S. economy. Although the S&P 500 focuses on the large cap segment of the market, with approximately 75% coverage of U.S. equities, it is also an ideal proxy for the total market. S&P 500 is part of a series of S&P U.S. indices that can be used as building blocks for portfolio construction.

S&P 500 is maintained by the S&P Index Committee, a team of Standard & Poor's economists and index analysts, who meet on a regular basis. The goal of the Index Committee is to ensure that the S&P 500 remains a leading indicator of U.S. equities, reflecting the risk and return characteristics of the broader large cap universe on an on-going basis. The Index Committee also monitors constituent liquidity to ensure efficient portfolio trading while keeping index turnover to a minimum.

Index Methodology

The S&P Index Committee follows a set of published guidelines for maintaining the index. Complete details of these guidelines, including the criteria for index additions and removals, policy statements, and research papers are available on the Web site at www.indices.standardandpoors.com. These guidelines provide the transparency required and fairness needed to enable investors to replicate the index and achieve the same performance as the S&P 500.

CRITERIA FOR INDEX ADDITIONS

- *U.S. Company.* Determining factors include location of the company's operations, its corporate structure, its accounting standards and its exchange listings.
- *Market Capitalization.* Companies with market cap in excess of US$ 5 billion. This minimum is reviewed from time to time to ensure consistency with market conditions.
- *Public Float.* There must be public float of at least 50%.
- *Financial Viability.* Companies should have four consecutive quarters of positive as-reported earnings, where as-reported earnings are defined as GAAP Net Income excluding discontinued operations and extraordinary items.
- *Adequate Liquidity and Reasonable Price.* The ratio of annual dollar value traded to market capitalization for the company should be 0.30 or greater. Very low stock prices can affect a stock's liquidity.
- *Sector Representation.* Companies' industry classifications contribute to the maintenance of a sector balance that is in line with the sector composition of the universe of eligible companies with market cap in excess of US$ 5 billion.
- *Company Type.* Constituents must be operating companies. Close-end funds, holding companies, partnerships, investment vehicles and royalty trusts are not eligible. Real Estate Investment Trusts (REITs) and business development companies (BDCs) are eligible for inclusion.

Continued index membership is not necessarily subject to these guidelines. The Index Committee strives to minimize unnecessary turnover in index membership and each removal is determined on a case-by-case basis.

CRITERIA FOR INDEX REMOVALS

- Companies that substantially violate one or more of the criteria for index inclusion.
- Companies involved in merger, acquisition, or significant restructuring such that they no longer meet the inclusion criteria.

Leading Measures for U.S. Markets

S&P 500

S&P U.S. Indices

09/30/2007

The large cap segment of the U.S. equities market, covering approximately 75% of the U.S. equities market.

S&P Composite 1500

S&P 500 | S&P MidCap 400 | S&P SmallCap 600

S&P 100

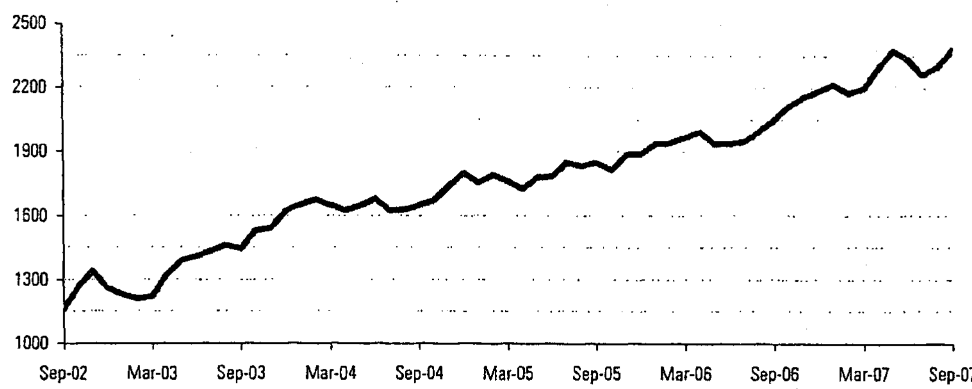
S&P 900

S&P 1000

Index Performance

Returns	1 Month	3.74%
	3 Month	2.03%
	YTD	9.13%
Returns (% pa)	1 Year	16.44%
	3 Years	13.14%
	5 Years	15.45%
	7 Years	2.60%
Risk (% pa)	3 Years Std Dev	7.52%
	5 Years Std Dev	9.70%
Sharpe Ratio	3 Years	0.3293
	5 Years	0.3556

5 Year Historical Performance



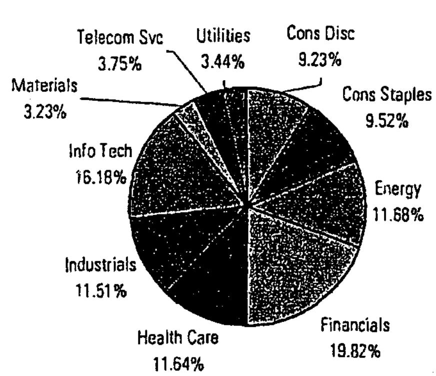
Top 10 Companies

Country	Company	Float Adjusted Market Cap ($ Million)	Index Weight	Sector Weight	Investable Weight Factor	GICS® Sector
USA	Exxon Mobil Corp.	513,362.0	3.81%	32.62%	1.00	Energy
USA	General Electric	424,191.7	3.15%	27.36%	1.00	Industrials
USA	AT&T Inc.	258,047.5	1.92%	51.10%	1.00	Telecommunication Services
USA	Microsoft Corp.	237,533.7	1.76%	10.90%	0.86	Information Technology
USA	Citigroup Inc.	232,162.4	1.72%	8.70%	1.00	Financials
USA	Bank of America Corp.	223,065.7	1.66%	8.36%	1.00	Financials
USA	Procter & Gamble	219,513.6	1.63%	17.13%	1.00	Consumer Staples
USA	Cisco Systems	201,669.1	1.50%	9.25%	1.00	Information Technology
USA	Chevron Corp.	199,485.4	1.48%	12.67%	1.00	Energy
USA	Johnson & Johnson	190,169.2	1.41%	12.13%	1.00	Health Care

Tickers

S&P 500	
Bloomberg	SPX
Reuters	.SPX

Sector Breakdown



Portfolio Characteristics

Number of Companies	500
Adjusted Market Cap ($ Billion)	13,469.72
Company Size (Adjusted $ Billion):	
Average	26.94
Largest	513.36
Smallest	1.33
Median	13.14
% Weight Largest Company	3.81%
Top 10 Holdings (% Market Cap Share)	20.04%

STANDARD & POOR'S RATINGSDIRECT REPORT ON SOUTHWEST GAS COMPANY DATED APRIL 24, 2008

Southwest Gas Corp.

Major Rating Factors

Corporate Credit Rating

BBB-/Positive/--

Strengths:

- A low-risk natural gas distribution business;
- A favorable customer mix and high growth service territories;
- Purchased-gas adjustment (PGA) mechanisms that eliminate a majority of the company's exposure to commodity prices; and
- Strong cash flow measures and declining debt leverage.

Weaknesses:

- Absence of weather normalization and decoupling rate structures, which expose the company's earnings and cash flow to conservation and weather-related sales variations;
- Elevated projected capital expenditures of about $290 million per year;
- Moderate exposure to the effects of natural gas price volatility on PGA receivable balances and potential liquidity requirements; and
- Long-term capital or contracting requirements with regard to natural gas storage capability for the company's Arizona and Southern Nevada service areas.

Rationale

The ratings on Las Vegas, Nev.-based Southwest Gas Corp. reflect its strong business risk profile and aggressive financial risk profile. The ratings are based on the consolidated credit profile of its natural gas operations segment (87% of operating income in 2007) and its construction services business, Northern Pipeline Construction Co. (NPL; 13%).

Southwest Gas' strong business risk profile reflects a large, stable, residential, and commercial customer base of about 1.8 million customers, strong customer growth prospects in Arizona (54% of customers), Nevada (36%), and California (10%), the absence of competition, and relatively low operating risks. Challenges associated with improving its regulatory cost-recovery mechanisms, ownership of a small, unregulated construction and maintenance business, gradual reductions in total gas volumes, and limited geographic service territory temper the company's strong business profile.

The Arizona Corporation Commission (ACC), the Public Utilities Commission of Nevada, and the California Public Utilities Commission each regulate Southwest Gas. Each regulatory commission provides the company with various cost-recovery mechanisms. However, we view the ACC regulatory oversight as less supportive of credit than other jurisdictions due to its limitations on purchased-gas cost recoveries and rate design that is solely based on gas throughput. This type of rate design exposes the company to reduced cash flows as volumes decline related to conservation. Decoupling, an alternate rate design, separates the utility's margins and cash flow from commodity sales and encourages conservation. These mechanisms are currently under consideration as part of the company's most recent rate case.

Slowing customer growth, reduced total throughput, and improved rate design are among the reasons for Southwest

Gas' recent rate filings. While Southwest Gas' annual customer growth averaged more than 4% over the past five years, the company expects future growth to be only 1.5% to 3% due to the depressed real estate market conditions. Despite strong historical customer growth statistics, annual total consumption has nevertheless dropped 1% per year, on average, since 2003, due to conservation efforts, making rate design a key credit driver for the company.

Southwest Gas' nonregulated subsidiary, NPL, is not currently a significant rating factor because most of its contracts shield Southwest Gas from the majority of costs. In addition, about 20% of NPL's revenues are derived from Southwest Gas' gas operations.

Southwest Gas has an aggressive financial risk profile, with bondholder protection measures that are currently strong for the rating, which supports the positive outlook. We expect near-term performance to remain strong for the rating with additional improvements from customer growth and regulatory rate increases. As of Dec. 31, 2007, total debt, including operating leases and tax-affected pensions and post-retirement obligations, was about $1.5 billion with debt to capital of almost 60%. Benefitting from customer growth and regulatory rate increases, cash flow metrics have improved over the past few years, with 2007 adjusted funds from operations (FFO) to total debt of 20% and FFO interest coverage of about 4x, compared with 14% and 3.4x, respectively, in 2005.

Liquidity

Southwest Gas maintains adequate liquidity. As of Dec. 31, 2007, the company had $32 million in cash and $291 million available under its $300 million credit facility, which matures in April 2012. Natural gas purchases and capital outlays related to growth in the service territory are the primary uses of liquidity. Natural gas sales are seasonal, with peak usage in the winter months. Natural gas prices and weather patterns primarily determine liquidity needs.

Given the low-risk nature of Southwest Gas' regulated utility operations and healthy service territory, the company should generate reasonably stable cash flow. The company reported cash from operations of almost $350 million for 2007, which will not fully cover annual dividends (about $36 million), annual capital expenditures (about $300 million forecast for 2008 and about $550 forecast for 2009-2010 combined), and near-term debt maturities ($38 million due in 2008 and $10 million in 2009). To bridge the funding gap, the company expects to raise $70 million to $80 million through stock offerings, borrow under its revolving credit facility, or through other external means.

Outlook

The outlook on Southwest Gas is positive. The positive outlook reflects Standard & Poor's Ratings Services' expectation that the company's improved financial performance could lead to a higher rating over the near term. We could revise the outlook to stable if financial performance deteriorates from current levels as a result of unfavorable regulatory actions, an increase in leverage, or material reductions in customer usage (either due to weather or efficiency) without adequate regulatory protections.

Accounting

Standard & Poor's adjusts Southwest Gas' financial statements for operating leases and pension and post-retirement obligations. The adjustment includes adding a debt equivalent, interest expense, and depreciation to the company's reported financial statements. As a result, debt equivalents of $24 million are added for operating leases and $90 million for pension and post-retirement obligations.

Due to the distortions in leverage and cash flow metrics caused by the substantial seasonal working-capital requirements of gas utilities, Standard & Poor's adjusts inventory and debt balances by netting the value of inventory against the outstanding commercial paper for regulated subsidiaries. This adjustment provides a more accurate view of the company's financial performance by reducing seasonality, where there is a very high likelihood of recovery. As inventories are depleted and accounts receivable are monetized, with support from commodity pass-through mechanisms, these funds reduce the utility's short-term borrowings.

Standard & Poor's views Southwest Gas' $100 million of trust-preferred securities as having "intermediate equity content". Under our hybrid criteria, we calculate the company's financial ratios with 50% of the outstanding balance attributed to debt and 50% to equity. Similarly, we treat 50% of the associated distributions as dividends and 50% as interest.

Southwest Gas prepares its financial statements using SFAS No. 71, "Accounting for Effects of Certain Types of Regulation." Consequently, Southwest Gas recorded certain regulatory assets and liabilities as of Dec. 31, 2007, of $218 million and $226 million, respectively. Net regulatory assets represent less than 1% of total capitalization.

Table 1

Southwest Gas Corp. -- Peer Comparison*

Industry Sector: Gas

	--Average of past three fiscal years--			
	Southwest Gas Corp.	**NiSource Inc.**	**CenterPoint Energy Resources Corp.**	**Atmos Energy Corp.**
Rating as of April 17, 2008	BBB-/Positive/--	BBB-/Stable/--	BBB/Positive/A-2	BBB/Positive/A-2
(Mil. $)				
Revenues	1,963.7	7,776.3	7,791.3	5,670.9
Net income from cont. oper.	70.3	303.0	229.0	150.7
Funds from operations (FFO)	256.0	867.3	524.7	411.6
Capital expenditures	327.2	697.9	564.0	411.1
Cash and investments	26.8	46.2	12.3	97.8
Debt	1,490.6	7,705.8	2,685.9	2,639.1
Preferred stock	50.0	27.0	0.0	0.0
Equity	910.5	4,946.5	2,948.7	1,674.3
Debt and equity	2,401.1	12,652.4	5,634.6	4,313.4
Adjusted ratios				
EBIT interest coverage (x)	2.2	2.1	2.9	2.7
FFO int. cov. (x)	3.7	2.8	3.6	3.5
FFO/debt (%)	17.2	11.3	19.5	15.6
Discretionary cash flow/debt (%)	(4.3)	(0.1)	(14.4)	(3.9)
Net cash flow/capex (%)	66.8	88.2	75.3	74.7
Debt/total capital (%)	62.1	60.9	47.7	61.2
Return on common equity (%)	8.2	5.8	7.9	9.3
Common dividend payout ratio (un-adj.) (%)	47.9	82.9	43.7	69.2
Ratios before adjustments for postretirement obligations				
Oper. income/sales (bef. D&A) (%)	18.8	19.8	9.5	10.4

Table 1

Southwest Gas Corp. -- Peer Comparison*(cont.)				
EBIT interest coverage (x)	2.2	2.1	2.9	2.6
FFO/debt (%)	17.9	11.4	19.9	16.8
Debt/EBITDA (x)	3.8	4.8	3.6	4.3
Debt/total capital (%)	60.0	59.1	47.0	59.2

*Fully adjusted (including postretirement obligations).

Table 2

Southwest Gas Corp. -- Financial Summary*					
Industry Sector: Gas					
	--Fiscal year ended Dec. 31--				
	2007	**2006**	**2005**	**2004**	**2003**
Rating history	BBB-/Positive/--	BBB-/Stable/--	BBB-/Stable/--	BBB-/Stable/--	BBB-/Stable/--
(Mil. $)					
Revenues	2,152.1	2,024.8	1,714.3	1,477.1	1,231.0
Net income from continuing operations	83.2	83.9	43.8	56.8	38.5
Funds from operations (FFO)	290.6	260.0	217.4	252.0	228.5
Capital expenditures	344.7	343.0	294.1	301.9	239.8
Cash and investments	32.0	18.8	29.6	13.6	17.2
Debt	1,476.4	1,488.1	1,507.3	1,453.9	1,325.1
Preferred stock	50.0	50.0	50.0	50.0	50.0
Equity	1,033.7	951.4	746.4	684.6	619.3
Debt and equity	2,510.1	2,439.6	2,253.7	2,138.5	1,944.4
Adjusted ratios					
EBIT interest coverage (x)	2.5	2.4	1.8	2.0	1.7
FFO int. cov. (x)	4.0	3.7	3.4	3.9	3.8
FFO/debt (%)	19.7	17.5	14.4	17.3	17.2
Discretionary cash flow/debt (%)	(1.4)	(5.8)	(5.4)	(11.9)	(4.0)
Net cash flow/capex (%)	72.7	64.9	62.0	72.7	82.1
Debt/debt and equity (%)	58.8	61.0	66.9	68.0	68.2
Return on common equity (%)	8.7	9.8	5.7	8.4	5.9
Common dividend payout ratio (un-adj.) (%)	43.6	39.9	71.3	50.8	71.9
Ratios before adjustments for postretirement obligations					
Oper. income/revenues (bef. D&A) (%)	19.0	18.9	18.2	21.9	22.8
EBIT interest coverage (x)	2.4	2.4	1.8	2.1	1.7
FFO/debt (%)	20.3	18.2	15.2	18.2	17.8
Debt/EBITDA (x)	3.4	3.6	4.5	4.3	4.5
Debt/debt and equity (%)	57.3	59.3	63.7	64.5	65.0

*Fully adjusted (including postretirement obligations).

Table 3

Reconciliation Of Southwest Gas Corp. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. $)*

--Fiscal year ended Dec. 31, 2007--

Southwest Gas Corp. reported amounts

	Debt	Shareholders' equity	Operating income (before D&A)	Operating income (before D&A)	Operating income (after D&A)	Interest expense	Cash flow from operations	Cash flow from operations	Dividends paid	Capital expenditures
Reported	1,413.1	983.7	403.1	403.1	220.6	96.2	347.8	347.8	36.3	340.9
Standard & Poor's adjustments										
Operating leases	24.0	--	6.2	1.6	1.6	1.6	4.5	4.5	--	5.1
Intermediate hybrids reported as debt	(50.0)	50.0	--	--	--	(3.9)	3.9	3.9	3.9	--
Postretirement benefit obligations	89.2	--	5.4	5.4	5.4	--	8.9	8.9	--	--
Capitalized interest	--	--	--	--	--	1.3	(1.3)	(1.3)	--	(1.3)
Reclassification of nonoperating income (expenses)	--	--	--	--	6.6	--	--	--	--	--
Reclassification of working-capital cash flow changes	--	--	--	--	--	--	--	(73.2)	--	--
Total adjustments	63.3	50.0	11.5	7.0	13.6	(0.9)	16.0	(57.2)	3.9	3.8

Standard & Poor's adjusted amounts

	Debt	Equity	Operating income (before D&A)	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations	Dividends paid	Capital expenditures
Adjusted	1,476.4	1,033.7	414.6	410.1	234.2	95.3	363.8	290.6	40.1	344.7

*Southwest Gas Corp. reported amounts shown are taken from the company's financial statements but might include adjustments made by data providers or reclassifications made by Standard & Poor's analysts. Please note that two reported amounts (operating income before D&A and cash flow from operations) are used to derive more than one Standard & Poor's-adjusted amount (operating income before D&A and EBITDA, and cash flow from operations and funds from operations, respectively). Consequently, the first section in some tables may feature duplicate descriptions and amounts.

Ratings Detail (As Of April 24, 2008)*

Southwest Gas Corp.	
Corporate Credit Rating	BBB-/Positive/--
Preferred Stock	
Local Currency	BB
Senior Unsecured	
Local Currency	BBB-
Corporate Credit Ratings History	
13-Mar-2007	BBB-/Positive/--

Ratings Detail (As Of April 24, 2008)*(cont.)	
11-Aug-2003	BBB-/Stable/--
01-Feb-2001	BBB-/Negative/--
Financial Risk Profile	Aggressive

Debt Maturities

As of Dec. 31, 2007:
2008: $38.1 mil.
2009: $10.4 mil.
2010: $5.4 mil.
2011: $202.6 mil.
2012: $350.1 mil.
Thereafter: $697.0 mil.

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

BEFORE THE ARIZONA CORPORATION COMMISSION

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IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR JUST AND REASONABLE RATES AND CHARGES.	)))))	DOCKET NO. G-01551A-07-0504

SURREBUTTAL

TESTIMONY

OF

PHILLIP S. TEUMIM

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

MAY 27, 2008

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DOCKET NO. G-01551A-07-0504

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A. Mr. Mashas took issue with my recommendation that in its next rate case, SWG file "... an explanation, with sample calculations, of how it has been implementing those [line extension] tariff provisions, and explain whether and to what extent it has made changes in the methodology and its application over the 10 years the tariff has been in place." [Teumim PFT, pp. 7-9]

Q. Company Witness Mashas states that his Rebuttal Testimony addresses those issues and therefore there is no need for the Company to file such testimony in its next rate proceeding. [Mashas Rebuttal p. 24 – 25] Do you agree?

A. No, I do not. Based on the information Mr. Mashas provided, I think it is even more important. He stated that while it has been nearly 10 years since the Company filed with the Commission to modify the Rule 6 portion of its tariff, the Incremental Contribution Model ("ICM") utilized by the Company to ensure new customer additions are cost justified has been modified on numerous occasions. [Id, pp. 18 – 19] From his testimony, those changes appear to be quite significant.

He also points out that the Company formalized the policies and procedures for the ICM recently, as shown in his Exhibits RAM-4 and RAM-5. Those exhibits demonstrate clearly that this was a large undertaking by the Company which has not, to my knowledge, been examined in detail by Staff or the Commission.

While it was helpful for witness Mashas to briefly summarize the ICM and its modifications in testimony, his testimony does nothing to allay my concerns. What I am recommending is that the Company explain the modifications and demonstrate that their application produces fair and reasonable results consistent with current Commission policies.

Further, many of the topics and issues considered and the decisions made by the Company are key issues in the Hook-up Fee proceeding. Therefore, I think it emphasizes the importance of my recommendation, and points out the further need for the Company to demonstrate how its policies and procedures ultimately comport with the results of the

Hook-up Fee proceeding. The Hook-up Fee Docket findings should be available at the time of the next rate filing.

Q. Company witness Mashas offered to get together with Staff to explain how the model works with real examples of actual projects. Do you believe this would be useful?

A. Yes, I am informed by Staff that it would be helpful. And the Company's participation and provision of this information in the current Hook-up Fee Docket has been helpful. But this does not change my recommendation with respect to the Company's providing additional information in its next rate case, for reviewing by the Commission, Staff and Interveners. The Hook-up Fee Docket should have concluded before the Company's next rate case so the Company should be able to demonstrate consistency with the results of that Docket as well.

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Q. SWEEP Witness Schlegel proposes that the Company increase its annual DSM available funding level to at least $12 million, to expand existing DSM programs and to develop new programs. Do you agree with Mr. Schlegel's recommendation?

A. No. That number was derived based on the percent of total revenues and expenditures per customer as applied by Questar. Mr. Schlegel than compared that number to the approved funding level of $4.4 million for SWG, which is expected to be reached in 2009. [Shlegel PFT, p. 3] I do not believe that a comparison with Questar is sufficient basis for making changes. Second, as I noted in my Direct Testimony, most of SWG's DSM programs are in the startup phase, with full implementation expected in 2008 and with an evaluation expected to be performed at the end of the 2008 program year. I also noted that the 2008 program year budget was approximately $3 million, and that it would be premature to evaluate the relative success of the programs at this time. Further, I recommended that the

Company track and report estimated and actual hard dollar cost-benefit analyses and payback periods. [Teumim PFT, p. 12]

With respect to future levels, I recommend that the Commission increase the approved funding level for cost-effective programs above $4.4 million for 2010 and beyond, but at a more modest level than that proposed by Mr. Schlegel. Looking out for an additional three years, a reasonable approach would be to allow for increased funding of $1 million per year for the years 2010 through 2012. This would set the approved level for those years at $5.4 million, $6.4 million and $7.4 million respectively. This approach will allow for continuing analysis of the existing programs, modifications if necessary, and reasonable development of new programs.

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EXHIBIT
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S-19

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
*** * ***
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-13
(ACC-STF-13-1 THROUGH ACC-STF-13-25)

DOCKET NO.:	G-01551A-07-0504
COMMISSION:	ARIZONA CORPORATION COMMISSION
DATE OF REQUEST:	MAY 13, 2008

Request No. ACC-STF-13-24:

Stock-based compensation. Refer to Ms. Hobbs' rebuttal testimony at pages 4-5. (a) Please identify the stock-based compensation in the test year separated between (1) MIP and (2) non-MIP. (b) Please explain how the MIP measures affect the payout and cost of the non-MIP stock-based compensation programs. (c) Please document specifically how the MIP targets have affected the expense for non-MIP stock based compensation that SWG included in test year expense.

Respondent: Human Resources

Response:

a. As provided in response to data request no. RUCO-1-10 -- updated March 25, 2008 -- the stock option expense (non-MIP) for the test year was $1,507,520. Total MIP was $5,919,502, of which $2,325,086 was cash-based and $3,587,416 was stock-based.

b. and c. MIP measures do not impact the payouts under the stock option expense program.

EXHIBIT
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S-20
admitted

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 THROUGH ACC-STF-1-99)

DOCKET NO.:	G-01551A-07-0504
COMMISSION:	ARIZONA CORPORATION COMMISSION
DATE OF REQUEST:	NOVEMBER 9, 2007

Request No. STF-1-49:

Employee Benefits.

a List and describe all retirement and incentive programs available to Company officers and employees and to affiliate officers and employees whose cost is charged to SWG.

b Specifically identify the cost of any SERP or similar programs directly charged or allocated.

c State the cost by program, of each retirement program directly charged or allocated.

d Provide the incentive compensation program financial performance goals for 2005, 2006 and 2007.

e For each incentive compensation program goal, for each year, show the actual results and how it compared with the target.

f Provide the incentive compensation program in effect in each year, 2005, 2006 and 2007.

g Show in detail how any special recognition awards recorded in the test year were determined.

Respondent: Human Resources

Response:

a **List and describe all retirement and incentive programs available to Company officers and employees and to affiliate officers and employees whose cost is charged to SWG.**

(Continued on Page 2)

Response to STF-1-49: *(continued)*

Basic Retirement Plan
All employees, including executives, participate in the Company's non-contributory, defined benefit retirement plan (BRP). Benefits are based on an employee's years of service, up to a maximum of 52.5% of the 12-month average of the employee's highest five consecutive years' salaries, excluding bonuses, within the final 10 years of service. The maximum benefit is reached after 30 years of service, the employee must be at least 55 years old to participate in the plan, and some reductions may apply depending on the age and years of service at the time of retirement. In order for contributions to the BRP to be deductible for federal income taxes, for 2007, the maximum annual compensation that can be considered in determining benefits under the basic plan is $225,000. For future years, the maximum annual compensation will be adjusted to reflect changes in the cost of living as established by the Internal Revenue Service.

Supplemental Employee Retirement Plan (SERP)
Executives also participate in the Company's supplemental retirement plan. Benefits from the plan, when added to the benefits received under the BRP, will equal 60% of annual compensation for senior executives and 50% of annual compensation for all others. Annual compensation is defined as the 12-month average of the highest 36 months of salary. Those who were officers prior to 1991, may retire once they reach age 55 with a minimum of 10 years of service, however, some reductions may apply. All other officers must be at least 55 with 20 or more years of service to receive retirement benefits, and some reductions may apply, depending on the age and years of service at the retirement date.

The SERP is an unqualified plan and, as such, payments are not guaranteed (i.e., participants are general creditors of the corporation). SERP benefits are common in the utility industry.

Executive Deferral Plan
Under the Executive Deferral Plan (EDP), executives at the vice president level and above (officers) may defer up to 100% of their annual compensation and 100% of their cash incentive awards. As a part of this plan, the Company provides matching contributions that parallel the contributions made under the Company's 401(k) plan, which is available to all employees, equal to one-half the deferred amount up to 6% of their annual salary. Officers do not receive a Company match under the 401(k) plan. Pre-selected payouts begin six months after the retirement date.

(Continued on Page 3)

Response to STF-1-49: *(continued)*

The EDP is an unqualified plan and, as such, participant balances are not guaranteed. Various types of deferred compensation plans are common in the utility industry.

Management Incentive Plan
The Management Incentive Plan (MIP) provides variable compensation to executives for the achievement of specific goals and benchmarks important to both the short-term and long-term success of the Company. The MIP award is at risk each year based on performance relative to five measures. The five performance measures used to determine the total award under the MIP are as follows:

Three absolute measures include:
- 3-year weighted return on equity
- Customer to employee ratio
- Customer satisfaction survey result

Two relative measures:
- Current return on equity versus peers
- Customer-to-employee ratio versus peers

Each measurement has a threshold, a target and a maximum, and, at target, contributes 20 percent toward the total award for the year. An award under a specific criteria may be given within a range from 70 percent, at threshold, to 140 percent, at maximum. Performance below the threshold results in no award under a specific criteria. There is no incremental value for performance over the maximum for any of the five criteria. In summary, an award can range from 0 percent to 140 percent of the stated MIP opportunity. In any year where the corporate dividend is reduced, there is no MIP award given.

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 60 percent is awarded through the issuance of performance shares, which are issued to the executives and key management employees three years in the future. The longer-term performance shares act as a retention tool while aligning the interests of executives/key management employees, shareholders, and customers.

The MIP award opportunity is measured as a percentage of base salary and varies by title, as follows:

(Continued on Page 4)

Response to STF-1-49: *(continued)*

- CEO	115%
- President	100%
- Executive VP	90%
- Senior VP	75%
- VP	50%
- Director/Senior Manager (non-officers)	30%

Equity Compensation
The Stock Incentive Plan (SIP), in place since 1996, made its final option award distribution in July 2006. In May 2007, the SIP was replaced by the Restricted Stock/Unit Plan (RSP).

The RSP is available to officers and other key management employees. The RSP award opportunity is measured as a percentage of base salary and varies by title, as follows:

Position	% of Year-End Base Salaries	Award Range (%)
CEO	45	22.5 to 67.5
President	30	15.0 to 45.0
Executive VP	25	12.5 to 37.5
Senior VP	20	10.0 to 30.0
VP	15	7.5 to 22.5
Other Participants	10	5.0 to 15.0

As a measurement of long-term sustained performance, the average MIP award over the three-year period ending before the award date will be the criteria that will be used in calculating awards for officers and key management employees under the RSP. Awards granted pursuant to the RSP will range from 50 to 150 percent of the target for each participant. The minimum three-year average MIP payout percentage required to receive an award under the RSP will be 90 percent. The dollar amount of an award received under the RSP will be converted to restricted share units using the market price on the date such awards are approved by the Board of Directors. The awards will vest over a three-year period with 40 percent for the first year and 30 percent for the second and third years.

Officers also participate in all of the general employee benefit programs, including: health care, life insurance, disability insurance, vacation, and other optional programs.

(Continued on Page 5)

Response to STF-1-49: *(continued)*

Employees Investment Plan/401(k) - The Southwest Gas Corporation Employees' Investment Plan (EIP) is a qualified defined contribution plan that provides a retirement savings mechanism by allowing tax-deferred contributions and the tax-deferred growth of earnings. As a part of the plan, the Company provides matching contributions equal to one-half the deferred amount up to 6% of the contributing employee's annual salary. Employees control how savings are invested by investing in any of the investment options the EIP offers. Officers of Southwest Gas may invest in the EIP, but they are not eligible to receive a Company match in the EIP.

Special Incentive Program - The program has been provided in each of the last several years to reward and recognize exempt employees who make outstanding contributions to the Company. The program is designed for exempt (salaried) employees only who do not qualify for the Management Incentive Plan (MIP).

Awards are limited to 15% of the eligible population. To qualify, an employee has to be recommended, in writing, by an officer. The recommendation must be based on a significant work contribution during the prior year. (Length of service or working long hours are not considered.) All nominations are then reviewed by the appropriate senior officer and the CEO for final approval. Awards range from $500 to $2,500.

This program provides management with a tool with which to recognize people who go over and above what is required in their daily job assignments and provide value to the Company and its customers.

b **Specifically identify the cost of any SERP or similar programs directly charged or allocated.**

The cost of SERP is on WP Schedule C-2, Adj. No. 3, Sheet 8, Line 11. Column B has the total cost to Southwest, Columns C and D have the cost directly attributable to Arizona, and Column F has the System Allocable amount, which is allocated to Arizona with the 4-Factor.

c **State the cost by program, of each retirement program directly charged or allocated.**

The cost of the BRP is on WP Schedule C-2, Adj. No. 3, Sheet 8, Line 1, the cost for Deferred Compensation (referred to above as EDP) is on Line 12, and the

(Continued on Page 6)

Response to STF-1-49: *(continued)*

cost of the 401(k) plan (or Employee Investment Plan) is on Line 2. Column B has the total cost to Southwest, Columns C and D have the cost directly attributable to Arizona, and Column F has the System Allocable amount, which is allocated to Arizona with the 4-Factor.

d **Provide the incentive compensation program financial performance goals for 2005, 2006 and 2007.**

Please see the attached spreadsheet.

e **For each incentive compensation program goal, for each year, show the actual results and how it compared with the target.**

Please see the attached spreadsheet.

f **Provide the incentive compensation program in effect in each year, 2005, 2006 and 2007.**

Copies of the Management Incentive Plan booklet are attached.

g **Show in detail how any special recognition awards recorded in the test year were determined.**

Please see the paragraph on Special Incentive Program in item a. above.

MIP Measure Analysis
2002 through 2006

MIP Performance Goals and Actual Results

MEASUREMENT		PY 2006	PY 2005	PY 2004
3-yr. weighted ROE		6.99	5.31	6.46
	target:	8.0	8.0	8.0
	earned:	87.375	66.375	80.8
	x 20% weight	**17.48**	**0.00**	**16.16**
Customer/Employee Ratio:		706	661	633
	target:	591	574	557
	earned:	140.0	140.0	140.0
	x 20% weight	**28.00**	**28.00**	**28.00**
Customer Service Satisfaction: (percent)		94.0	93.0	93.0
	target:	85.0	85.0	85.0
	earned:	136.0	132.0	132.0
	x 20% weight	**27.20**	**26.40**	**26.40**
ROE vs. peers: (percentile)		53	6	43
	target:	50	50	50
	earned:	104.8	0.0	91.6
	x 20% weight	**20.96**	**0.00**	**18.32**
Customer/Employee vs peers: (percentile)		70	87	88
	target:	76	76	76
	earned:	92.8	131.9	134.8
	x 20% weight	**18.56**	**26.38**	**26.96**
TOTAL (percent of target)		**112**	**81**	**116**

Response To Data Request
Acc. STF -1-49 (f)

SOUTHWEST GAS CORPORATION

Management Incentive Plan

SOUTHWEST GAS CORPORATION

®

Information Booklet

Management Incentive Plan

August 2002

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GENERAL REMARKS

This booklet has been created to explain the concepts of the Southwest Gas Corporation Management Incentive Plan, adopted by the Board of Directors in 1993 and revised in 2000. It is intended for use by the participants involved in Southwest Gas Corporation's Management Incentive Plan (Southwest Gas Corporation will be hereafter referred to as "SWG" or the "Company").

Every attempt has been made to ensure that the Management Incentive Plan conforms to the latest rules and regulations of the Securities and Exchange Commission (SEC) and Internal Revenue Service (IRS). This booklet, however, should not be considered an official legal document. The official plan document is available in Corporate Human Resources and may be consulted for further information.

Plan participants should periodically check with their personal tax, accounting, or legal counsel about changes in regulations governing incentive programs, created through legislative actions, new or amended SEC regulations, and IRS and Tax Code interpretations. For information about tax savings, or the ramifications of participation in the plan, you should consult your tax professional.

This document reflects current federal income tax treatment (which may be subject to change in the future) and does not include state or local ramifications.

PURPOSE OF THE PROGRAM

- To focus SWG management on the achievement of specific performance objectives important to the Company's short-term and long-term success.
- To ensure that there is a strong link between Company performance and financial rewards for management.
- To foster a common interest between SWG management, customers and shareholders.
- To encourage management ownership of SWG stock.

ELEMENTS OF THE PROGRAM

Annual Incentive Award: The dollar amount earned by a plan participant on the basis of SWG performance during the annual performance period. A portion of the award is payable in cash as soon as practicable following the end of the performance period. The remaining portion is converted into performance shares and subject to a restriction period.

Performance Shares: A contingent right to receive shares of common stock in SWG which are not to be distributed to the participant until and unless certain restrictions have lapsed and/or certain performance criteria have been satisfied.

Dividend Credits: Additional dollar amounts convertible into Performance Shares (during the restriction period) as determined by the cumulative quarterly dividends declared on Company common stock during the restriction period. The plan allows the Committee the discretion to pay dividends quarterly rather than converting the dividends into additional Performance Shares.

Note: Normally, annual incentive awards will be calculated and paid during the first quarter following the end of the plan year.

ELIGIBILITY AND SELECTION

Positions qualifying for participation in the Management Incentive Plan will be determined by SWG senior management and approved by the Compensation Committee of SWG's Board of Directors, hereafter referred to as the "Committee."

Generally speaking, award potential and/or guidelines will be determined separately for each eligible tier of SWG management. The tiers, their composition, and the guideline awards for each tier are subject to change from time to time.

Selection for participation in one year does not guarantee selection in succeeding years.

INCENTIVE AWARD OPPORTUNITIES

Individuals selected for participation in the Management Incentive Plan will be assigned incentive award opportunities, which are expressed as a percentage of their base salaries.

The incentive award opportunities include a targeted incentive award and a range around the target that corresponds to various levels of performance measured on a number of dimensions. Meeting the individual measurement goal at the expected target pays 100 percent for that measurement. The range for each individual measurement equals 70 percent at threshold and increases to 140 percent at maximum. Performance below threshold results in zero payout for the measure.

Target, threshold, or maximum incentive award opportunities for any tier are subject to change at the discretion of the Committee. The following table depicts the targeted incentive award opportunity effective January 2000, as a percent of base salary, by tier of participant:

INCENTIVE AWARD OPPORTUNITY					
TIER	POSITION	MINIMUM	THRESHOLD	TARGET	MAXIMUM
1	President/CEO	0%	81%	115%	161%
2	Executive Officers	0%	63%	90%	126%
3	Senior Officers	0%	53%	75%	105%
4	Officers	0%	35%	50%	70%
5	Non-Officers	0%	21%	30%	42%

FREQUENCY

Incentive awards will be granted on an annual basis consistent with SWG's compensation philosophy and strategy, and taking into account the Company's overall competitive posture on all aspects of direct compensation.

ANNUAL INCENTIVE AWARD

Annual incentive awards will be provided to eligible participants in the plan each year if Company performance measures are achieved.

ANNUAL PERFORMANCE MEASURES

For the purpose of determining the actual awards earned under the annual incentive portion of the Management Incentive Plan, performance will be evaluated on several dimensions.

The annual performance measures, which are equally weighted, are as follows:

Absolute measures:

- Gas Segment Adjusted ROE—Three-year weighted average gas segment return on equity (ROE), adjusted annually for the Consumer Price Index (CPI). The adjusted ROE will be further modified for above-average customer growth.
- Customer to Employee Ratio—a measure of productivity calculated by dividing total gas segment customers by total gas segment employees.
- Customer Service Satisfaction—determined through ongoing surveys conducted by an independent outside entity.

Relative Measures:

- ROE vs. Peers—gas segment ROE ranking compared to a peer group composed of similarly-sized gas distribution companies.
- Customer to Employee Ratio vs. Peers—gas segment customer to employee ratio compared to a peer group composed of similarly-sized gas distribution companies.

Gas segment adjusted ROE will be calculated using a three-year weighted average with weights applied as follows: current year ROE-50 percent weight; preceding year ROE-30 percent weight; two years preceding ROE-20 percent weight.

Gas segment ROE vs. Peers will be calculated utilizing current year results adjusted for customer growth. The CPI adjustment will not be utilized in this calculation.

Note: Individual performance will be measured annually. If a participant fails to meet established goals or performance expectations, an adjustment may be made to the individual award.

AWARD CALCULATION SCHEDULES

Targets—The measurement targets will be established annually. Current measurements are reflected in the next table.

Limitation on Award Value—Annual award opportunities at all levels are capped at 140 percent of the target award. Each individual measurement has a threshold value of 70 percent of the target for that measurement and a maximum value of 140 percent of target. When threshold is not met for any measurement, the award value for that measurement is -0-.

Actual awards earned will be calculated by using the table below.

PERFORMANCE MEASURES AND WEIGHTS

MEASURE	THRESHOLD	TARGET	MAXIMUM	WEIGHTING	SOURCE FOR MEASUREMENT
Absolute:					
Three-Year Weighted ROE	5.6%	8.0%	10.0%	20%	Gas segment ROE adjusted for CPI and customer growth
Customer to Employee Ratio	70%	100%	140%	20%	Target = prior year C/E target + 3% improved productivity
Customer Service Satisfaction	75%	85%	95%	20%	Quarterly surveys
Relative:					
ROE vs. Peer Group	25th Percentile	50th Percentile	75th Percentile	20%	Financial publications for distribution companies
Customer to Employee vs. Peer Group	51st Percentile	76th Percentile	90th Percentile	20%	Annual surveys
POTENTIAL	**70%**	**100%**	**140%**	**100%**	**TOTAL**

Note: *No annual incentive awards will be payable unless the Company's dividends equal or exceed the prior year's dividends.*

Award Payout—Following the calculation and Committee approval of the annual incentive award, it is divided into short- and long-term components. The short-term component, which is 40 percent of the total award, is paid in cash to the participant. The long-term component, which is the remaining 60 percent of the award, is converted into three-year performance shares.

Award Form—The short-term component of the annual award each year will be paid in cash. The long term component award is paid in Company stock following successful completion of the three-year restriction period.

Withholding Taxes—The Company will deduct all federal, state, and local taxes of any kind required by law to be withheld upon the payment of the annual incentive award.

PERFORMANCE SHARES

The long-term component of the Management Incentive Plan is reflected through the use of performance shares, which are paid in shares of Southwest Gas common stock following successful completion of the restriction period.

Award Term—Awards of performance shares will be made each year (contingent on a payout from the annual incentive plan), and will be subject to a three-year restriction period.

Number of Shares Granted—The number of performance shares granted to an individual is determined by two factors: the amount of the award earned under the long-term component of the annual incentive plan, and the price of SWG common stock at the date of the conversion into performance shares.

The amount of the annual incentive award to be converted into performance shares is divided by the fair market value of SWG stock at the date of the conversion to determine the number of performance shares that a participant receives.

Restriction Period—All performance shares will be restricted for a period of three years, during which time the plan participants will not have ownership of, or be able to sell, the stock, or rights to the stock which underlie the award. During the restriction period, SWG will maintain performance share accounts for each participant, which may increase in size as dividends are declared on SWG common stock and, if applicable, are reinvested. At the end of the restriction period (or earlier if circumstances warrant), each participant's performance share account will be closed by calculating a final number of shares and paying the participant in whole shares of SWG common stock.

DIVIDENDS

The Management Incentive Plan document allows the Committee to determine whether dividends will be paid quarterly or reinvested in performance shares for each participant. The determination will be made annually for the plan year.

For plan years with dividends paid quarterly, the payments will be in cash.

For plan years with dividend reinvestment, the following will apply:

- The dividend rate paid on SWG common stock during the restriction period will be used to determine the amount credited to the participant's performance share account.
- Dividends will be credited to the participant's performance share account in an equivalent number of performance shares on a quarterly basis.

LONG-TERM PERFORMANCE MEASURE

The Committee may modify the number of performance shares that may be earned by a participant based upon Company performance over the three-year restriction period.

The total number of performance shares may be reduced by as much as 20 percent, based on the overall performance of the Company.

The measurement(s) used for analyzing long-term performance will be selected by the Committee for each plan year.

LIMITATION OF AWARD VALUE

Performance shares are not limited to a specified value, but are dependent on the amount of increase/decrease in the fair market value of SWG's common stock from the conversion date to the end of the restriction period.

The number of performance shares actually earned will be a function of the number of performance shares earned at the conversion date (the beginning of the restriction period), additional performance shares resulting from dividend credits during the restriction period, if applicable, and Company performance over the restriction period. In no event, however, can a participant be awarded in excess of 100 percent of the sum of the number of shares earned at the beginning of a restriction period and the number of performance shares resulting from dividend credits during the restriction period.

Award Payout—The final value of the performance share award will be equal to the product of the fair market value of SWG's common stock at the end of the restriction period, multiplied by the number of performance shares ultimately earned (as determined at the end of the restriction period).

Award Form—At the end of the restriction period, performance share awards will be paid in whole shares of SWG common stock. At the discretion of the Committee, and if deemed appropriate, awards may be paid in cash or a combination of cash and stock.

Withholding Taxes—The Company will deduct all federal, state, and local taxes of any kind required by law to be withheld upon the payment of the performance shares. Such payment, at the option of the participant, may be made by directing the Company to withhold shares of SWG common stock to cover the estimated tax liability.

TAX AND INSIDER TRADING TREATMENT

A summary of tax considerations for the Company and the Participant appear in the following table.

AWARD TYPE	INCOME TAX IMPACT ON PARTICIPANT	FEDERAL INSURANCE CONTRIBUTIONS ACT (FICA) TAX IMPACT ON PARTICIPANT	TAXABLE AMOUNT
Annual Incentive	Taxes withheld at statutory withholding rates (federal), plus applicable state taxes.	When paid, taxed at 7.65% FICA tax rate.	Value of award earned (i.e., gross amount of cash award paid).
Performance Shares	Federal and state taxes payable when common stock issued. Taxes may be withheld: 1) from regular wages, or 2) by a reduction in net shares issued.	FICA tax payable at *earlier* of when: 1) Participant is eligible to retire, or 2) stock is issued.	Fair market value of shares.

Note: Specific questions about the tax impact created by the Management Incentive Plan should be discussed with the Participant's personal tax advisor or legal counsel.

The table below outlines the insider trading treatment of the awards:

AWARD TYPE	INSIDER TRADING AGREEMENT
Performance Shares	Shares settled in stock will not be considered a "purchase" or a "sale," although a "sale" will occur when the stock is sold. Shares settled in cash will be considered a "sale" **Consult legal counsel.**

TERMINATIONS, TRANSFERS, PROMOTIONS, AND NEW HIRES

The effect of terminations on awards is outlined in the table below:

TERMINATION EVENT	ANNUAL INCENTIVE	PERFORMANCE SHARES
Retirement	Pro-rata payout at end of the performance period based on length of time elapsed since the annual performance period began.	Immediate payout of all performance shares.
Disability	Pro-rata payout at end of the performance period based on length of time elapsed since the annual performance period began.	Immediate payout of all performance shares.
Death	Pro-rata payout at end of the performance period based on length of time elapsed since the annual performance period began.	Immediate payout of all performance shares.
Resignation or discharge for cause	Forfeit rights to award.	Forfeit rights to award.
Involuntary termination without cause	Pro-rata payout at end of the performance period based on length of time elapsed since the annual performance period began.	Immediate payout of all performance shares.

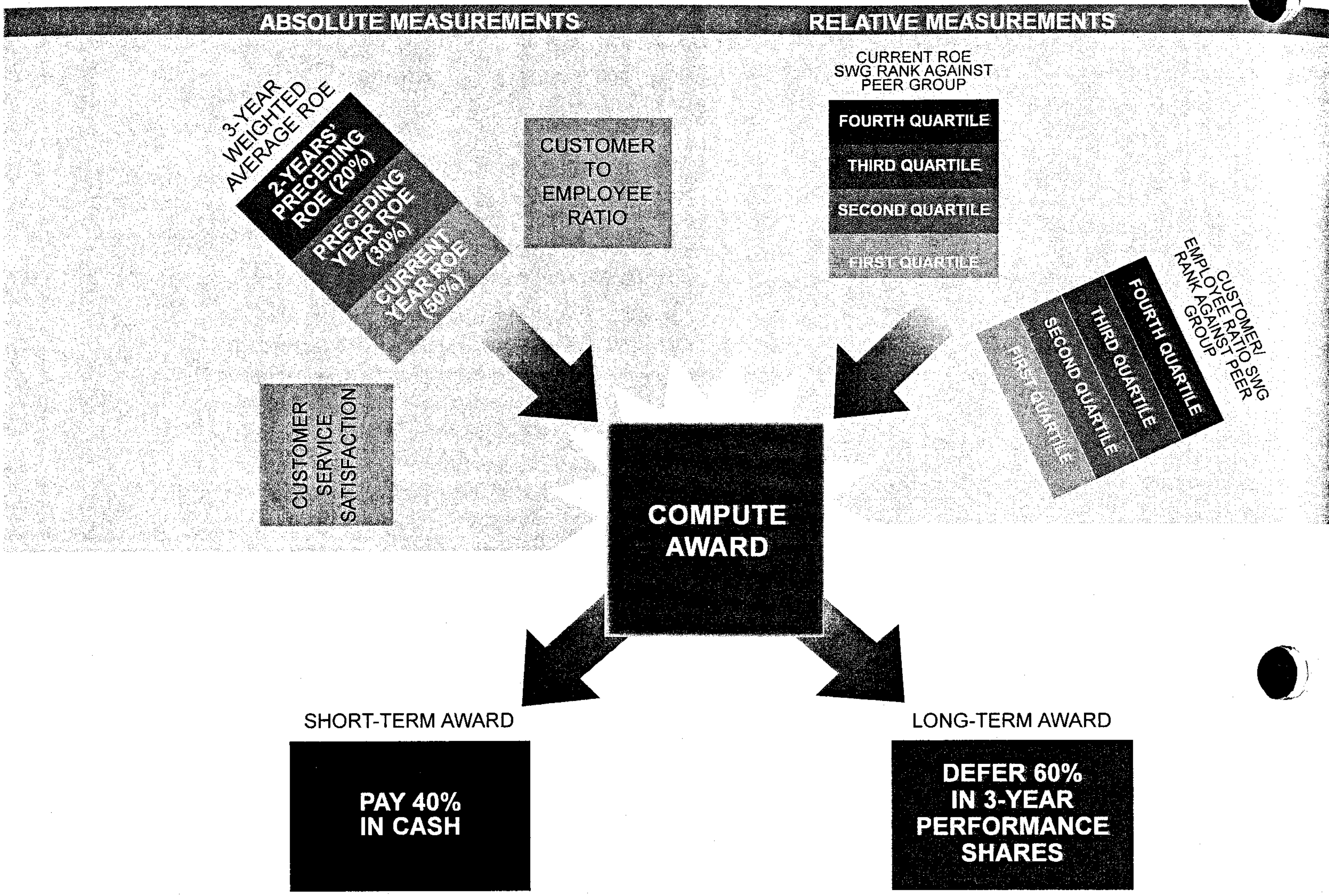
Note: The Committee may, at its discretion, elect to treat individual situations differently than the guidelines above provide.

The following table summarizes the treatment of transfers, promotions, and new hires:

TYPE OF MOVE	EFFECT ON PARTICIPATION
Into eligible position	Eligible for pro-rata participation based on the length of time elapsed since the performance period began.
Into ineligible position	Pro-rata award based on number of months in eligible position and no future grants.
Into another eligible position	If new award level is different, the weighted average of the two award levels for the corresponding positions would be used based on number of months of the year spent in each position.
New Hire	Eligible for pro-rata participation based on the length of time elapsed since the performance period began.

Note: The Committee may, at its discretion, elect to treat individual situations differently than the guidelines above provide.

MANAGEMENT INCENTIVE PLAN CALCULATION FLOW CHART



SAMPLE PAYOUT HISTORY

MEASUREMENT	YEAR 1	YEAR 2	YEAR 3
Three-year weighted ROE w/Growth	<5.6	8.30	7.39
target	8.00	8.00	8.00
% target award earned	-0-	108.0%	92.0%
x 20% weight	0.0	21.6	18.4
Customer/Employee Ratio	542	552	565
target	525	541	557
% target award earned	140.0%	127.1%	119.2%
x 20% weight	28.0	25.4	23.8
Customer/Service Satisfaction	95.0%	94.0%	96.0%
target	85.0%	85.0%	85.0%
% target award earned	140.0%	136.0%	140.0%
x 20% weight	28.0	27.2	28.0
ROE vs. Peers (percentile)	<25	57	29
target	50	50	50
% target award earned	-0-	111.2%	74.8%
x 20% weight	0.0	22.2	15.0
Customer/Employee vs. Peers (percentile)	78	90	82
target	76	76	76
% target award earned	105.8%	140.0%	117.4%
x 20% weight	21.2	28.0	23.5
TOTAL EARNED (as percentage of target)	77.0	124.0	109.0

If you are an officer with a target award opportunity of 50 percent of base salary, your payout, expressed as a percent of your salary, would be as follows:

Total Incentive Award	38.5	62	54.5
Short-term (40%)	15.4	24.8	21.8
Long-term (60%)	23.1	37.2	32.7

ANNUAL INCENTIVE AWARD

EXHIBIT 1

THREE-YEAR WEIGHTED ROE MEASURE
AS A PERCENT OF TARGET AT VARYING LEVELS OF PERFORMANCE

ACTUAL PERFORMANCE AS % TARGET	% TARGET AWARD EARNED	ACTUAL PERFORMANCE AS % TARGET	% TARGET AWARD EARNED
<70%	0%	95%	95%
70%	70%	96%	96%
71%	71%	97%	97%
72%	72%	98%	98%
73%	73%	99%	99%
74%	74%	100%	100%
75%	75%	101%	102%
76%	76%	102%	104%
77%	77%	103%	106%
78%	78%	104%	108%
79%	79%	105%	110%
80%	80%	106%	112%
81%	81%	107%	114%
82%	82%	108%	116%
83%	83%	109%	118%
84%	84%	110%	120%
85%	85%	111%	122%
86%	86%	112%	124%
87%	87%	113%	126%
88%	88%	114%	128%
89%	89%	115%	130%
90%	90%	116%	132%
91%	91%	117%	134%
92%	92%	118%	136%
93%	93%	119%	138%
94%	94%	120%	140%

ANNUAL INCENTIVE PLAN

EXHIBIT 2

CUSTOMER PER EMPLOYEE MEASURE
AS A PERCENT OF TARGET AT VARYING LEVELS OF PERFORMANCE

ACTUAL PERFORMANCE AS % TARGET	% TARGET AWARD EARNED
<97.0%	0.0%
97.0%	70.0%
97.5%	75.0%
98.0%	80.0%
98.5%	85.0%
99.0%	90.0%
99.5%	95.0%

[illegible]	[illegible]
100.0%	100.0%
100.5%	106.7%
101.0%	[illegible]
101.5%	120.0%
102.0%	[illegible]
102.5%	133.3%
103.0%	140.0%

ANNUAL INCENTIVE PLAN

EXHIBIT 3

CUSTOMER SATISFACTION MEASURE
AS PERCENT OF TARGET AT VARYING LEVELS OF PERFORMANCE

PERCENTILE RANKING	% OF TARGET EARNED
<75%	0%
75%	70%
76%	74%
77%	77%
78%	80%
79%	83%
80%	86%
81%	89%
82%	92%
83%	95%
84%	98%

[illegible]	[illegible]
85%	100%
86%	104%
87%	[illegible]
88%	112%
89%	[illegible]
90%	120%
91%	[illegible]
92%	128%
93%	[illegible]
94%	136%
95%>	[illegible]

ANNUAL INCENTIVE AWARD

EXHIBIT 4

ROE VS. PEER GROUP MEASURE
AS A PERCENT OF TARGET AT VARYING LEVELS OF PERFORMANCE

PERCENTILE RANKING	% OF TARGET EARNED
<25%	0.0%
25%	70.0%
26%	71.2%
27%	72.4%
28%	73.6%
29%	74.8%
30%	76.0%
31%	77.2%
32%	78.4%
33%	79.6%
34%	80.8%
35%	82.0%
36%	83.2%
37%	84.4%
38%	85.6%
39%	86.8%
40%	88.0%
41%	89.2%
42%	90.4%
43%	91.6%
44%	92.8%
45%	94.0%
46%	95.2%
47%	96.4%
48%	97.6%
49%	98.8%

PERCENTILE RANKING	% OF TARGET EARNED
50%	100.0%
51%	101.6%
52%	103.2%
53%	104.8%
54%	106.4%
55%	108.0%
56%	109.6%
57%	111.2%
58%	112.8%
59%	114.4%
60%	116.0%
61%	117.6%
62%	119.2%
63%	120.8%
64%	122.4%
65%	124.0%
66%	125.6%
67%	127.2%
68%	128.8%
69%	130.4%
70%	132.0%
71%	133.6%
72%	135.2%
73%	136.8%
74%	138.4%
75%>	140.0%

ANNUAL INCENTIVE AWARD

EXHIBIT 5

CUSTOMER TO EMPLOYEE RATIO VS. PEER GROUP MEASURE AS A PERCENT OF TARGET AT VARYING LEVELS OF PERFORMANCE

PERCENTILE RANKING	% OF TARGET EARNED
<51%	0.0%
51%	70.0%
52%	71.2%
53%	72.4%
54%	73.6%
55%	74.8%
56%	76.0%
57%	77.2%
58%	78.4%
59%	79.6%
60%	80.8%
61%	82.0%
62%	83.2%
63%	84.4%
64%	85.6%
65%	86.8%
66%	88.0%
67%	89.2%
68%	90.4%
69%	91.6%
70%	92.8
71%	94.0%
72%	95.2%
73%	96.4%
74%	97.6%
75%	98.8%
76%	100.0%
77%	102.9%
78%	105.8%
79%	108.7%
80%	111.6%
81%	114.5%
82%	117.4%
83%	120.3%
84%	123.2%
85%	126.1%
86%	129.0%
87%	131.9%
88%	134.8%
89%	137.7%
90%>	140.0%

SOUTHWEST GAS

Right from the Start.®

(RIM Rev. 8/2002)

EXHIBIT
ALL-STATE LEGAL®
S-21

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-12
(ACC-STF-12-1)

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 5, 2008

Request No. ACC-STF-12-1:

AGA dues and benefits.

(a) Please provide the complete report from which Ms. Aldridge's Exhibit No. RLA-2 was excerpted.

(b) Please show the percentage of AGA dues related to each function listed on Exhibit No. RLA-2.

(c) Please provide the complete report and all supporting information for the AGA benefits listed on page 24 of Ms. Aldridge's testimony.

(d) Please show in detail how the AGA estimated each type of savings and avoided cost benefit.

(e) Have the AGA claimed benefits ever been independently reviewed, verified or audited? If so, please identify what independent party or entity conducted the review, verification or audit, the dates of such verification, and provide a copy of the related review, verification and audit reports.

(f) Please identify, quantify and explain each benefit which comprises the total claimed $479 million.

(g) Please relate the claimed AGA benefits to each of the AGA functions listed in the most recent AGA report to NARUC.

(h) Please provide a copy of the AGA Advertisements in 2006 and 2007.

(i) Please identify and provide a copy of all testimony in regulatory and legislative proceedings filed by the AGA in 2004, 2005 2006 and 2007.

(j) Please provide all AGA legislative comments in 2007.

(k) Please provide the materials used by the AGA in 2007 to promote interest in the investment opportunities in the industry.

(Continued on Page 2)

Response to ACC-STF-12-1: *(continued)*

Respondent: Revenue Requirements

Response:

Southwest objects to this Data Request on the grounds that it is overbroad and unduly burdensome. Subject to and without waiving this objection, Southwest responds as follows:

a. Exhibit No. ___(RLA-2) was not an excerpt from any report of which Southwest is aware. It was provided by AGA to explain the functions listed on page III-2 of the latest audit on the expenditures of AGA dated March 2005. The audit report is attached.

b. Please see the Company's response to part a. For the percentages used in this proceeding, please refer to the response to data request no. STF-6-52.

c-k. AGA is an independent organization, of which Southwest is a member. Southwest does not direct nor control the activities of AGA. Southwest does not have the information requested in parts (c) through (k) of this Data Request in its possession nor does Southwest have access to such information.

Attachment
STF-12-1

AUDIT REPORT ON THE EXPENDITURES

OF THE

AMERICAN GAS ASSOCIATION

(For the 12 month period ended December 31, 2002

March 2005

NARUC STAFF SUBCOMMITTEE
ON ACCOUNTING AND FINANCE

**National Association of
Regulatory Utility Commissioners
1101 Vermont Avenue; Suite 200
Washington, D.C. 20005**

N A R U C

National Association of Regulatory Utility Commissioners

March 2005

To: **The State Regulatory Commissions**

From: **The NARUC Staff Subcommittee on Accounting and Finance**

Re: **Transmittal of the 2002 Report on the Expenditures of the American Gas Association**

Dear State Regulatory Commissions:

This is the annual report on the expenditures of the American Gas Association (AGA) provided for your review and consideration. Hopefully you will find the information contained herein to be useful in helping you to decide which, if any, of the costs of the association you should approve for inclusion in utility rates. Often, state commissioners review the costs of the association charged or allocated to the utilities in their jurisdiction in accordance with the policies of their commission for treatment of costs directly incurred by the state's utilities for similar activities.

With the possible exception of expenses directly related to research and development relevant to utility operations, and a proportional amount of associated administrative overhead expense, these expense categories may be viewed by some State commissions as potential vehicles for charging ratepayers with such costs as lobbying, advocacy or promotional activities which may not be to their benefit.

The Staff Subcommittee on Accounting and Finance is pleased to provide you with the AGA report for 2002 to allow you to review the information contained therein and to utilize it in a manner consistent with your commission's regulatory policies and practices.

Sincerely,

Thomas J. Ferris

Thomas J. Ferris
Chair
Staff Subcommittee on Accounting and Finance

1101 Vermont Avenue, NW, Suite 200, Washington D.C. 20005 • 202.898.2200 • 202.898.2213 *fax* • http://www.naruc.org

Calculation of Lobbying Expenses Pursuant to
Internal Revenue Code Section 162(e)

The American Gas Association incurred lobbying expenses, as defined under IRC Section 162, of 2.28% of total member dues during calendar year 2002.

IRC Section 162 Definition of Lobbying

(e) Denial of deduction for certain lobbying and political expenditures
- (1) In general no deduction shall be allowed under subsection (a) for any amount paid or incurred in connection with -
  - (A) influencing legislation,
  - (B) participation in, or intervention in, any political campaign on behalf of (or in opposition to) any candidate for public office,
  - (C) any attempt to influence the general public, or segments thereof, with respect to elections, legislative matters, or referendums, or
  - (D) any direct communication with a covered executive branch official in an attempt to influence the official actions or positions of such official.
- (2) Exception for local legislation - In the case of any legislation of any local council or similar governing body -
  - (A) paragraph (1)(A) shall not apply, and
  - (B) the deduction allowed by subsection (a) shall include all ordinary and necessary expenses (including, but not limited to, traveling expenses described in subsection (a)(2) and the cost of preparing testimony) paid or incurred during the taxable year in carrying on any trade or business -
    - (i) in direct connection with appearances before, submission of statements to, or sending communications to the committees, or individual members, of such council or body with respect to legislation or proposed legislation of direct interest to the taxpayer, or
    - (ii) in direct connection with communication of information between the taxpayer and an organization of which the taxpayer is a member with respect to any such legislation or proposed legislation which is of direct interest to the taxpayer and to such organization, and that portion of the dues so paid or incurred with respect to any organization of which the taxpayer is a member which is attributable to the expenses of the activities described in clauses (i) and (ii) carried on by such organization.
- (3) Application to dues of tax-exempt organizations - No deduction shall be allowed under subsection (a) for the portion of dues or other similar amounts paid by the taxpayer to an organization which is exempt from tax under this subtitle which the organization notifies the taxpayer under section 6033(e)(1)(A)(ii) is allocable to expenditures to which paragraph (1) applies.
- (4) Influencing legislation - For purposes of this subsection -
  - (A) In general The term "influencing legislation" means any attempt to influence any legislation through communication with any member or employee of a legislative body, or with any government official or employee who may participate in the formulation of legislation.
  - (B) Legislation - The term "legislation" has the meaning given such term by section 4911(e)(2).
- (5) Other special rules
  - (A) Exception for certain taxpayers - In the case of any taxpayer engaged in the trade or business of conducting activities described in paragraph (1), paragraph (1) shall not apply to expenditures of the taxpayer in conducting such activities directly on behalf of another person (but shall apply to payments by such other person to the taxpayer for conducting such activities).
  - (B) De minimis exception
    - (i) In general Paragraph (1) shall not apply to any in-house expenditures for any taxable year if such expenditures do not exceed $2,000. In determining whether a taxpayer exceeds the $2,000 limit under this clause, there shall not be taken into account overhead costs otherwise allocable to activities described in paragraphs (1)(A) and (D).
    - (ii) In-house expenditures for purposes of clause (i), the term "in-house expenditures" means expenditures described in paragraphs (1)(A) and (D) other than
      - (I) payments by the taxpayer to a person engaged in the trade or business of conducting activities described in paragraph (1) for the conduct of such activities on behalf of the taxpayer, or
      - (II) dues or other similar amounts paid or incurred by the taxpayer which are allocable to activities described in paragraph (1).
  - (C) Expenses incurred in connection with lobbying and political activities - Any amount paid or incurred for research for, or preparation, planning, or coordination of, any activity described in paragraph (1) shall be treated as paid or incurred in connection with such activity.
- (6) Covered executive branch official - For purposes of this subsection, the term "covered executive branch official" means -
  - (A) the President,
  - (B) the Vice President,
  - (C) any officer or employee of the White House Office of the Executive Office of the President, and the 2 most senior level officers of each of the other agencies in such Executive Office, and
  - (D) (i) any individual serving in a position in level I of the Executive Schedule under section 5312 of title 5, United States Code, (ii) any other individual designated by the President as having Cabinet level status, and (iii) any immediate deputy of an individual described in clause (i) or (ii).
- (7) Special rule for Indian tribal governments - For purposes of this subsection, an Indian tribal government shall be treated in the same manner as a local council or similar governing body.
- (8) Cross reference - For reporting requirements and alternative taxes related to this subsection, see section 6033(e).

Citation: IRC Sec. 6033(e)

AMERICAN GAS ASSOCIATION

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Report of American Gas Association Financial Operations
In accordance with agreement between
American Gas Association and NARUC Oversight Committee

For the Year Ended December 31, 2002

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Internal Revenue Service Form 990

The American Gas Association is a non-profit and tax exempt organization required to file informational returns with the U.S. Internal Revenue Service (IRS). Public inspection of the completed American Gas Association Exempt Organization Return (IRS Form 990) may be made in accordance with IRS regulation by request directly to the Internal Revenue Service, Attention: FOI Reading Room, 1111 Constitution Avenue, N.W., Washington, D.C. 20224. The American Gas Association makes its Exempt Organization Return available for public inspection during normal business hours (9:00 a.m. - 5:00 p.m.) at the Association's principal office, 400 N. Capitol St., N.W., Washington, D.C. 20001, preferably by written request directed to Joseph L. Martin, AGA's Controller, at the same address. State public utility commissions that wish to receive a copy of AGA's Exempt Organization Return should also direct their request to Joseph Martin. Internal Revenue Service Form 4506-A may also be used to request copies of the return from the Internal Revenue Service if public inspection is not desired by the requestor. IRS may make a charge for its photocopying service.

AMERICAN GAS ASSOCIATION

Audited Financial Statements

December 31, 2002 and 2001

AMERICAN GAS ASSOCIATION

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langan
associates, p.c.
Certified Public Accountants and Consultants

Independent Auditor's Report

To Board of Directors and Members
American Gas Association
Washington, D.C., U.S.A.

We have audited the accompanying statements of financial position of the American Gas Association as of December 31, 2002 and 2001, and the related statements of activities and cash flows for the years then ended. These financial statements are the responsibility of the Association's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the American Gas Association as of December 31, 2002 and 2001, and the changes in its net assets and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

Langan Associates, P.C.

Arlington, Virginia, U.S.A.
March 21, 2003

980 N. Michigan Avenue, PMB 1400
Chicago, IL 60611
Tel. 312/988 4872 • Fax 312/214 3510

2900 South Quincy Street, Suite 150
Arlington, VA 22206
Tel. 703/998 5100 • Fax 703/998 5102

100 Park Avenue, 16th Floor
New York, NY 10017
Tel. 212/880 2625 • Fax 212/880 6499

internet www.langancpa.com
e-mail langan@langancpa.com

AMERICAN GAS ASSOCIATION

Statements of Financial Position

December 31, 2002 and 2001

Assets	2002	2001
Cash and cash equivalents (note 2)	$ 3,263,529	$ 3,013,511
Marketable securities (note 2)	20,676,561	23,071,272
Receivables:		
Trade, less allowance for doubtful accounts of $19,754 and $155,434, respectively	474,735	240,356
Dues and subscriptions	62,245	251,419
Accrued interest receivable	90,956	103,046
Prepaid expenses and other assets (note 4)	345,444	198,997
Property, plant, and equipment, net (note 3)	2,608,264	3,215,816
	$ 27,521,734	$ 30,094,417

Liabilities and Net Assets		
Accounts payable	$ 2,010,025	$ 2,831,017
Deferred dues and subscriptions revenue	955,238	1,241,686
Accrued expenses (note 7)	952,140	1,030,944
Appliance standards/certification liabilities (note 8)	3,257,300	3,289,859
Deferred compensation	224,677	237,517
Other liabilities	830,244	870,593
Pension liability (note 4)	1,531,068	1,045,369
Postretirement benefits other than pension (note 4)	850,289	854,771
Total liabilities	10,610,981	11,401,756
Unrestricted net assets (note 4)	16,910,753	18,692,661
Commitments and contingencies (notes 5, 6, 7, and 8)		
	$ 27,521,734	$ 30,094,417

See accompanying notes to financial statements.

AMERICAN GAS ASSOCIATION

Statements of Activities

Years ended December 31, 2002 and 2001

	2002	2001
Revenue:		
Dues	$ 16,561,660	$ 16,635,138
Voluntary advertising/Manufacturers' cooperative advertising	32,500	250,000
Meetings and publications	3,161,467	3,514,861
Dividends and interest, net (note 1)	1,040,984	1,285,534
Miscellaneous	330,280	319,356
Total revenue	21,126,891	22,004,889
Expenses:		
Programs:		
Member services:		
Public affairs	5,939,486	5,703,920
Policy, planning, and regulatory affairs	3,261,692	3,382,900
Market development	349,589	1,196,791
Corporate affairs	2,014,503	2,123,818
Operating and engineering	3,729,829	3,664,863
Industry finance and administrative programs	1,230,238	934,852
General counsel	768,219	641,984
Total program expenses	17,293,556	17,649,128
General administration	3,894,457	4,273,134
Total expenses	21,188,013	21,922,262
Change in unrestricted net assets before net realized and unrealized losses on marketable securities	(61,122)	82,627
Net realized and unrealized losses on marketable securities	(1,351,811)	(926,325)
Change in unrestricted net assets	(1,412,933)	(843,698)
Unrestricted net assets, beginning of year	18,692,661	19,536,359
Unrestricted net assets, end of year, before recognition of pension plan additional minimum liability	17,279,728	18,692,661
Pension plan additional minimum liability (note 4)	(368,975)	-
Unrestricted net assets, end of year	$ 16,910,753	$ 18,692,661

See accompanying notes to financial statements.

AMERICAN GAS ASSOCIATION

Statements of Cash Flows

Years ended December 31, 2002 and 2001

	2002	2001
Cash flows from operating activities:		
Change in unrestricted net assets	$ (1,412,933)	$ (843,698)
Adjustments to reconcile change in unrestricted net assets to net cash (used in) provided by operating activities:		
Depreciation and amortization	929,946	928,206
Unrealized and realized losses on marketable securities	1,351,811	926,325
Gains on disposal of property, plant, and equipment	(5,750)	(425)
Increase in minimum pension liability	(368,975)	-
Decrease (increase) in operating assets:		
Receivables	(45,205)	560,782
Accrued interest receivable	12,090	49,730
Prepaid expenses and other assets	(146,447)	358,972
Increase (decrease) in operating liabilities:		
Accounts payable	(820,992)	(213,519)
Deferred dues and subscriptions revenue	(286,448)	642,780
Accrued expenses	(78,804)	80,054
Appliance standards/certification liabilities	(32,559)	(452,059)
Deferred compensation	(12,840)	87,024
Other liabilities	(40,349)	33,146
Pension liability	485,699	(71,787)
Postretirement benefits other than pension	(4,482)	23,085
Total adjustments	936,695	2,952,314
Net cash (used in) provided by operating activities	(476,238)	2,108,616
Cash flows from investing activities:		
Purchases of marketable securities	(10,463,463)	(12,516,031)
Sales/maturities of marketable securities	11,506,363	10,356,165
Acquisition of property, plant, and equipment	(322,394)	(660,455)
Proceeds from sales of property, plant, and equipment	5,750	425
Net cash provided by (used in) investing activities	726,256	(2,819,896)
Net increase (decrease) in cash and cash equivalents	250,018	(711,280)
Cash and cash equivalents at beginning of year	3,013,511	3,724,791
Cash and cash equivalents at end of year	$ 3,263,529	$ 3,013,511

See accompanying notes to financial statements.

(1) Organization and Summary of Significant Accounting Policies

The American Gas Association (the "Association") is a nonstock and not-for-profit organization incorporated in the State of Delaware. The Association's membership and activities are related to member companies involved in the distribution of natural gas.

The significant accounting policies are as follows:

Basis of Presentation

Net assets and revenues, expenses, gains, and losses are classified based on the existence or absence of donor-imposed restrictions. Accordingly, the net assets of the Association, and changes therein, are all classified as unrestricted net assets since they are not subject to donor-imposed stipulations.

Cash Equivalents

For financial reporting purposes, cash equivalents include commercial paper, money market accounts, overnight repurchase agreements, and government agency obligations purchased with an initial maturity of 90 days or less.

Marketable Securities

Marketable securities consist of securities issued by the United States government, corporate obligations, and equity mutual funds. Marketable securities are stated at fair value. For the years ended December 31, 2002 and 2001, dividends and interest income is presented net of investment fees totaling $83,629 and $67,011, respectively.

Publication Inventories

Publications and items held for resale are charged to expense when acquired.

Property, Plant, and Equipment

Furniture, fixtures, and equipment are stated at cost less accumulated depreciation. Depreciation is calculated on the straight-line method over the estimated useful lives of the assets (3-10 years). Leasehold improvements are stated at cost less accumulated amortization. Amortization is calculated on the straight-line method over the shorter of the estimated life of the related asset or remaining term of the lease.

(Continued)

(1) **Continued**

Revenue Recognition

Membership dues are recognized as revenue in the year to which the membership applies. Dues received in advance are deferred. Publications revenue is recognized upon the sale of the related publication and meetings revenue is recognized when the related meetings are held.

Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America 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.

Functional Allocation of Expenses

The costs of providing the various programs and other activities have been summarized on a functional basis in the statements of activities. Accordingly, certain costs have been allocated among the programs and supporting services benefited. Salaries are charged directly to the programs and supporting services served. Fringe benefits are allocated to the programs and supporting services proportionate to salaries charged, and certain expenses benefiting all programs and supporting services are allocated based on the number of staff supporting each service.

Income Taxes

The Association is recognized as exempt from federal income tax under Section 501(c)(6) of the Internal Revenue Code, except for taxes on unrelated business income. Income tax expense on unrelated business activities totaled approximately $25,000 and $20,500 for the years ended December 31, 2002 and 2001, respectively.

The Association has elected to pay the federal proxy tax on behalf of its members on expenses related to lobbying activities. The proxy tax approximates $125,000 for both years ended December 31, 2002 and 2001.

Reclassifications

Certain reclassifications of prior year balances have been made to conform to the current year presentation.

(Continued)

(2) Cash and Cash Equivalents and Marketable Securities

At December 31, 2002 and 2001, the components of cash and cash equivalents and marketable securities were as follows:

	2002	2001
Cash	$ 482,603	$ 461,013
Cash equivalents:		
Money market accounts	1,432,064	2,204,914
U.S. government agency obligations	599,760	-
Commercial paper	749,102	347,584
Total cash and cash equivalents	$ 3,263,529	$ 3,013,511
U.S. government agency obligations	$ 4,053,550	$ 4,322,497
Mortgage-backed securities	-	255,117
Corporate obligations	1,737,602	1,544,019
Other debt securities	9,128,124	9,968,957
Equity mutual funds and securities	5,757,285	6,980,682
Total marketable securities	$ 20,676,561	$ 23,071,272

(3) Property, Plant, and Equipment

Property, plant, and equipment are composed of the following as of December 31, 2002 and 2001:

	2002	2001
Leasehold improvements	$ 986,148	$ 949,311
Equipment	3,267,192	3,624,270
Furniture and fixtures	1,199,761	1,199,761
	5,453,101	5,773,342
Less accumulated depreciation and amortization	(2,844,837)	(2,557,526)
Property, plant, and equipment, net	$ 2,608,264	$ 3,215,816

(Continued)

(4) Pension and Other Postretirement Benefits

The Association has the following noncontributory defined benefit pension plans:

- a qualified plan which covers substantially all Association employees,
- a non-qualified plan which is for employees who were determined to be eligible by the Association's Compensation Committee when the plan was created in 1985 (plan was frozen to new participants in 1986), and
- a non-qualified "excess" plan for those employees whose compensation exceeds the IRS limits for the qualified plan. This plan was approved by the Compensation Committee and is effective January 1, 2003.

These plans provide retirement benefits based on employees' years of services and compensation prior to retirement. In addition, there is an unfunded, nonqualified supplemental retirement benefit plan for the President and CEO that was approved by the Board of Directors in February 2001.

The funded plan's assets consist primarily of common stocks and U.S. government and corporate bonds.

The following provides a reconciliation of benefit obligations, plan assets, and funded status of the plans at December 31, 2002 and 2001:

	Pension Benefits		Other Postretirement Benefits	
	2002	2001	2002	2001
Benefit obligation	$ 25,592,012	$ 23,168,922	$ 8,489,792	$ 7,554,951
Fair value of plan assets	19,832,983	23,282,900	4,203,939	5,037,630
Funded status	$ (5,759,029)	$ 113,978	$ (4,285,853)	$ (2,517,321)
Accrued benefit cost recognized in the statements of financial position	$ 1,531,068	$ 1,045,369	$ 850,289	$ 854,771
Intangible asset recognized in the statements of financial position	$ 98,428	$ -	$ -	$ -

(Continued)

(4) Continued

Weighted-average assumptions:	Pension Benefits		Other Postretirement Benefits	
	2002	2001	2002	2001
Discount rate	6.75%	7.25%	6.75%	7.25%
Expected return on plan assets	8.50%	8.50%	8.50%	8.50%
Rate of compensation increase	4.50%	4.50%	N/A	N/A

Net periodic pension and other postretirement costs for 2002 and 2001 include the following components:

	Pension Benefits		Other Postretirement Benefits	
	2002	2001	2002	2001
Pension (benefit) cost	$ 461,488	$ 139,626	$ 205,763	$ 23,285
Employer contribution	443,191	211,414	218,476	-
Plan participants' contributions	-	-	47,554	123,910
Benefits paid	1,576,467	1,341,069	545,110	594,492

In accordance with Statement of Financial Accounting Standard (SFAS) No. 87, *"Employers' Accounting for Pensions"*, the Association has recognized the required minimum liability represented by the excess of the accumulated benefit obligation over the plan assets at December 31, 2002 and 2001, which totaled $827,925 and $360,522, respectively. An intangible pension asset of $98,428, representing the unamortized prior service cost of the defined benefit plan, has been recognized within prepaid expenses and other assets in the accompanying statement of financial position as of December 31, 2002. The change in the total minimum liability of $368,975 is being recognized as a reduction to unrestricted net assets.

(4) Continued

Other Postretirement Benefits

The Association provides its retirees with postretirement group medical and life insurance benefits. Eligibility is determined by a combination of hire date, retirement date and tenure. The medical benefits provided by the Association are coordinated with Medicare. The plan is contributory and contains other cost-sharing features such as deductibles and coinsurance. The costs of medical benefits are paid from a Voluntary Employees' Beneficiary Association (VEBA).

The discount rate used to determine the Accumulated Postretirement Benefit Obligation (APBO) was 6.75 and 7.25 percent as of December 31, 2002 and 2001, respectively. A 9 percent health care cost trend rate was assumed for 2002, decreasing 1 percent each year thereafter to an ultimate rate of 4.5 percent. If the assumed health care cost trend rate were increased by 1 percentage point in each year, the net periodic postretirement benefit cost would be higher by $64,457 and the APBO higher by $950,358 as of December 31, 2002. The rate of increase in the compensation level used for life insurance projections at December 31, 2002 and 2001 was 4.5 percent.

(5) 401(k) Plan

The Association maintains a contributory employees' 401(k) Plan (the "Plan"). An eligible employee is defined as any employee of the Association who regularly works more than 20 hours per week and 1,000 hours in a calendar year. The Association matches 50 to 100 percent of the employee's contribution depending on the length of the employee's participation in the Plan, which is vested over a three year period. The Association also maintains a non-qualified "excess plan" for employees whose compensation exceeds IRS limits. Employer contributions to these plans for the years ended 2002 and 2001 were approximately $494,000 and $470,000, respectively.

(6) Leases

On September 23, 1998, the Association signed a 10-year lease for office space at 400 N. Capitol St., N.W., Washington, D.C., which commenced on March 12, 1999. The Association also leases various equipment under operating leases. The minimum future rental payments under these operating leases are as follows:

Year ending December 31,	
2003	$ 1,689,721
2004	1,703,691
2005	1,343,413
2006	1,370,265
2007	1,397,802
2008 and thereafter	1,724,012
	$ 9,228,904

Rental expense related to these leases amounted to approximately $1,383,000 and $1,357,000 for 2002 and 2001, respectively.

(7) Commitments and Contingencies

Self-insurance

The Association is self-insured for certain liabilities that arise in the normal course of business. Net losses incurred in excess of underlying limits ranging from $100,000 to $500,000 on any one occurrence for general, pollution, automobile, and employers' liability up to $35,000,000 are generally covered under excess liability insurance policies.

The Association has recorded a liability for possible losses from product liability claims filed against the Association which, in the event of an unfavorable outcome, would not be covered by the excess liability insurance policy. The amount recorded, which is included in accrued expenses, was approximately $719,000 at December 31, 2002 and 2001.

Commitments

The Association is committed under certain contracts for the purchase of various services, including research and consulting services, for approximately $175,000.

These contracts are expected to be completed on or before December 31, 2003.

(Continued)

(8) Appliance Standards/Certification Liabilities

On June 30, 1997, the Association transferred its subsidiary (IAS US) and joint venture interest in International Approval Services, Inc. (IAS) to the Canadian Standards Association (CSA). As a result of the sale, the Association retained responsibility for certain liability claims that may arise from equipment that was certified and manufactured prior to June 30, 1997. The present value of these liabilities amounted to approximately $3,257,000 and $3,290,000 in 2002 and 2001, respectively.

langan
associates, p.c.
Certified Public Accountants and Consultants

Independent Auditor's Report on Supplementary Information

To the Board of Directors and Members
American Gas Association
Washington, D.C., U.S.A.

We have audited and reported separately herein on the financial statements of the American Gas Association as of and for the year ended December 31, 2002 and have issued our report thereon dated March 21, 2003.

Our audit was made for the purpose of forming an opinion on the basic financial statements of the American Gas Association taken as a whole. The supplementary information included in Schedules III - 2 through III - 19 is presented for purposes of additional analysis and is not a required part of the basic financial statements. Such information has been subjected to the auditing procedures applied in the audit of the basic financial statements and, in our opinion, is fairly stated in all material respects in relation to the financial statements taken as a whole.

Langan Associates, P.C.

Arlington, Virginia, U.S.A.
December 4, 2003

980 N. Michigan Avenue, PMB 1400
Chicago, IL 60611
Tel. 312/988 4872 • Fax 312/214 3510

2900 South Quincy Street, Suite 150
Arlington, VA 22206
Tel. 703/998 5100 • Fax 703/998 5102

100 Park Avenue, 16th Floor
New York, NY 10017
Tel. 212/880 2625 • Fax 212/880 6499

internet www.langancpa.com
e-mail langan@langancpa.com

American Gas Association
Expenditures Funded by Member Dues
For the Year Ended December 31, 2002

Group Number	Group Name	Net Expense		Adjustments	G&A Allocation (3)	Adjusted Net Expense	% of Dues
03	Public Affairs	5,410,775	1, 2	(2,002,356)	585,765	3,994,184	24.13%
03	Communications	-	2	2,123,138	447,031	2,570,169	15.53%
06, 16	Corporate Affairs and International	1,313,293		-	431,616	1,744,909	10.54%
05	General Counsel & Corp. Secretary	680,525	1	(4,718)	184,978	860,785	5.20%
09	Regulatory Affairs	1,322,474	1	812,875	431,616	2,566,965	15.51%
08	Marketing Development	176,417	1	(141)	215,808	392,084	2.37%
14	Operating & Engineering Services	2,352,235	1	(714,677)	986,553	2,624,111	15.85%
07	Policy & Analysis	1,317,647	1	299,769	524,106	2,141,522	12.94%
12	Industry Finance & Admin. Programs	709,822		-	77,074	786,896	4.75%
01,10,11	General & Administrative Expense	3,884,547		-	(3,884,547)	-	0.00%
	Grand Total	17,167,735		$ 513,890	$ -	$ 17,681,625	106.82%

Adjustments as a result of AGA/NARUC Oversight Committee Staff agreement.

1 Allocation of salaries and other expenses to benefiting group.

2 Breakout of communications portion of division expenses

3 G&A allocated on basis of average equivalent full-time employees during 2002.

AMERICAN GAS ASSOCIATION

Definitions of Functional Cost Centers
For the Year Ended December 31, 2002

COST CENTER	DESCRIPTION
03	Communications develops informational materials for member companies and consumers and coordinates all media activity.
	Public Affairs provides members with information on legislative developments; prepares testimony, comments, and filings regarding legislative activities; lobbies on behalf of the industry.
12	Finance & Administration develops and implements programs in such areas as accounting, human resources and risk management for member companies.
05	General Counsel & Corporate Secretary provides legal counsel to the Association.
06	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.
09	Regulatory Affairs provides members with information on FERC and state regulatory developments; prepares testimony, comments, and filings regarding regulatory activities.
08	Market Development assists members in their efforts to encourage the most efficient utilization of gas energy by exchanging information about marketing trends, conducting utilization efficiency programs and exploring market opportunities.
14	Operating & Engineering develops and implements programs and practices to meet the operational, safety and engineering needs of the industry.
07	Policy & Analysis identifies the need for and conducts energy analyses and modeling efforts in the areas of gas supply and demand, economics and the environment.
	General & Administrative includes:
01	Office of the President provides senior management guidance for all A.G.A. activities.
10	Human Resources develops and administers employee programs and provides general office and personnel services.

11 Finance and Administration develops and administers financial accounting and treasury services and maintains computers services capability.

* Reserve: Extraordinary adjustments are recorded as reserve charges. Major adjustments are identified in the audited financial statements.

* Not funded by current year General Fund Dues.

AMERICAN GAS ASSOCIATION

Reconciliation of Expenses to
Audited Financial Statements
For the Year Ended December 31, 2002

Expenses allocated to General Fund	17,681,625
Expenses Funded by Non dues Revenue (For example, advertising income from American Gas Magazine; AGA sponsored meeting and trade show fees; exhibit revenue; sale of AGA publications; sponsorships; etc.)	3,525,296
Accounting Year End Adjustments- Expenses for 2002 recorded in 2003 in accordance with generally accepted accounting principles.	(18,908)
Total Expenses per Audited Financial Statements	21,188,013

AMERICAN GAS ASSOCIATION

Schedule of Allocation Method for
General and Administrative Expenses
For the Year Ended December 31, 2002

General and Administrative Expenses allocated consist of the following cost centers:

Office of the President less lobbying expense of the President, if any, which has been charged to the Market Growth and Industry Structure of Government Relations Group.

Human Resources including expenses associated with personnel and employee benefit administration.

Finance and Administration which includes corporate accounting, information systems, mail room, print shop, space rental, and leasehold improvement, furniture and equipment amortization.

The General and Administrative expenses allocable have been allocated to each of the General Fund operating groups on the basis of the authorized positions in each group as of December 31, 2002.

AMERICAN GAS ASSOCIATION

Schedule of Honoraria and Expense Reimbursement
Appointed and Elected Government Officials
For the Year ended December 31, 2002

GOVERNMENT OFFICIAL / REASON	COST CENTER	HONORARIA	EXPENSE
Barnett, Chuck Legislative Assistant Senator Blanch Lincoln Spoke at the Public Affairs Forum April, 2002	03	0	1,193
Bingel, Thad Counsel for House of Representatives Spoke at the Public Affairs Forum April, 2002	03	0	15
Cooper, William Counsel House Commerce Committee Spoke at the Public Affairs Forum April, 2002	03	0	1,537
Flynt, Lt. Col. Bill Director, Homeland Infrastructure Security Threats Office Spoke at Operations Conference May, 2002	14	0	465
Hadley, David V. Commissioner Indiana Utility Regulatory Commission Spoke at NARUC/Financial Community Visit April, 2002	09	0	37
Hemingway, Roy Commissioner Oregon Public Utility Commission Spoke at NARUC/Financial Community Visit September, 2002	09	0	456
Lane, Charlotte R. Commissioner West Virginia Public Service Commission Spoke at NARUC/Financial Community Visit April, 2002	09	0	997

AMERICAN GAS ASSOCIATION

Schedule of Honoraria and Expense Reimbursement
Appointed and Elected Government Officials
For the Year ended December 31, 2002

GOVERNMENT OFFICIAL / REASON	COST CENTER	HONORARIA	EXPENSE
McCarty, William Chairman September, 2002	09	0	947
McNally, Bob Special Assistant to the President, White House Task Force on Energy Project Spoke at Public Affairs Forum April, 2002	03	0	1,463
Pemberton, John Chief of Staff, U.S. Environmental Protection Agency Spoke at the National Accounts Conference & Exhibition June, 2002	08	0	141
Regula, Ralph U.S. Representative from Ohio Spoke at the Public Affairs Forum April, 2002	03	0	1,697
Reha, Phyllis Commissioner Minnesota Public Utility Commission Spoke at NARUC/Financial Community Visit January, 2002	09	0	596
Rucker, Kelly Legislative Director Senator Blanch Lincoln Spoke at the Public Affairs Forum April, 2002	03	0	1,807
Sanford, Jo Anne Chairman North Carolina Utilities Commission Spoke at NARUC/Financial Community Visit September, 2002	09	0	917

AMERICAN GAS ASSOCIATION

Schedule of Honoraria and Expense Reimbursement
Appointed and Elected Government Officials
For the Year ended December 31, 2002

GOVERNMENT OFFICIAL / REASON	COST CENTER	HONORARIA	EXPENSE
Shlomo, Harary Director Infrastructure Security, Israeli Government Spoke at Operations Conference May, 2002	14	0	604
Simmons, Kelvin L. Commissioner Missouri Public Service Commission Spoke at NARUC/Financial Community Visit April, 2002	09	0	649
Smith, Joan Commissioner Oregon Public Utility Commission Spoke at NARUC/Financial Community Visit April, 2002	09	0	2,023
Svanda, David Commissioner Michigan Public Service Commission Spoke at NARUC/Financial Community Visit September, 2002	09	0	440
Wise, Stan Commissioner Georgia Public Service Commission Spoke at the Public Affairs Forum April, 2002	03	0	187
Wise, Stan Commissioner Georgia Public Service Commission Spoke at NARUC/Financial Community Visit April, 2002	09	0	411
TOTAL HONORARIA AND EXPENSES		**$0**	**$16,582**

AMERICAN GAS ASSOCIATION

Schedule of Contributions, Corporate Memberships and Club Dues
For the Year Ended December 31, 2002

Cost Center	Recipient	Amount
03	Alliance for Energy and Economics	100,000
03	Alliance to Save Energy	10,000
03	American Legislative Exchange Council	7,000
14	American National Standards Institute	5,465
01	ASAE	5,000
03	Blue Dog Non-Federal PAC	5,000
03	Business Council for Sustainable Energy Future	10,000
03	Business Institute for Political Analysis Coalition	10,000
03	Campaign for Home Energy Assistance	20,000
03	Center for the New West	5,000
03	Citizens for Michigan's Future	5,000
07	Colorado School of Mines	10,000
14	Common Ground Alliance	10,000
03	Democratic Congressional	53,000
03	Democratic Governor's Association	7,500
03	Democratic Leadership Council	15,000

AMERICAN GAS ASSOCIATION

Schedule of Contributions, Corporate Memberships and Club Dues
For the Year Ended December 31, 2002

Cost Center	Recipient	Amount
03	**Democratic National Committee**	25,000
03	**Democratic Senatorial Campaign Committee**	50,000
14	**Edison Electric Institute**	22,000
01 & 03	**Ford's Theater Society**	20,000
03	**GASPAC**	29,898
03	**Glacier PAC**	8,000
03	**National Chamber Foundation**	10,000
03	**National Fuel Funds Network**	5,000
03	**National Republican Congressional Committee**	15,000
03	**National Republican Senatorial Committee**	17,500
03	**New Democrat Network**	10,000
03	**NRCC Congressional Forum Membership**	50,000
03	**Rebuilding Together**	5,000
03	**Republican Majority Fund**	10,000
03	**Republican National Committee**	40,000
03	**Ripon Society**	5,000

AMERICAN GAS ASSOCIATION

Schedule of Contributions, Corporate Memberships and Club Dues
For the Year Ended December 31, 2002

Cost Center	Recipient	Amount
03	**The 2002 President's Dinner Committee**	5,000
03	**The United States Conference of Mayors**	10,000
03	**United States Olympic Committee**	10,000
01	**US Capitol Historical Society**	5,000
03	**U.S. Chamber of Commerce**	15,000
03	**USO World Headquarters**	5,000
12	**Utility Business Education Coalition**	25,000

Total $5,000 or Greater	**$675,363**
Total Less Than $5,000	**125,348**
Total Contributions, Corporate Memberships & Club Dues	**$800,711**

American Gas Association
Expenses of AGA Employees for Meals and Related
Activities with any Third Party by Group
For the Year Ended December 31, 2002

Public Affairs/Communications	$ 51,185
General Counsel and Corporate Secretary	3,835
Corporate Affairs and International	8,979
Policy and Analysis	378
Marketing Development	3,563
Regulatory Affairs	22,236
Finance and Administration Services	11,987
Operating and Engineering Services	17,647
General and Administrative Expenses	9,741
General Fund	$ 129,551

AMERICAN GAS ASSOCIATION

Government Relations Division Expenses Including
Allocation of General and Administrative Expense

For the year ended December 31, 2002

Division	Expense
Public Affairs The American Gas Association monitored and represented the activities of Congress and Federal agencies that affected issues of importance to the natural gas industry and its customers. This division also monitored state and local legislative and regulatory trends. In 2002 its major federal, legislative and regulatory efforts were pipeline safety legislation and regulation, Federal funding for Low Income Home Energy Assistance Program (LIHEAP), federal funding for research, and national energy policy legislation.	$3,994,184
Regulatory Affairs Prepares comments in regulatory proceedings before the FERC and participates in public policy discussions with NARUC. During 2002, it was active in a number of FERC proceedings involving regulations of interstate pipelines.	$2,566,965
Total Government Relations Expenses	$6,561,149

American Gas Association
Personnel Assigned to Government Relations
As of December 31, 2002

Office of Vice President

Roger Cooper	Executive Vice President Policy & Plai
Rick Shelby	Executive Vice President Public Affair:
Sue Swann	Senior Staff Associate to Vice Presidents

Public Affairs

Charlie Fritts	Vice President Government Relations
Stephen Crout	Managing Director
Tom Moskitis	Director External Affairs
Darrell Henry	Director Public Affairs
Kyle Rogers	Government Relations Director
Julie Kabous	Government Relations Director
Elaine Rose Couture	Senior Staff Associate
Shirleen Timbers	Senior Staff Associate

Regulatory Affairs

Jane Lewis	Senior Managing Counsel
Cynthia Marple	Director Rates & Regulatory Affairs
Eric Wise	Senior Counsel & Director
Jeff Petrash	Senior Managing Counsel
Laura Ferrazzano	Paralegal

American Gas Association
Member Company Dues
For the Year Ended December 31, 2002

Company	General Fund Dues
AGL Resources, Inc.	$ 422,057
Alabama Gas Corporation	181,358
Allegheny Energy	19,973
Alliant Energy	67,455
Aquila, Inc.	242,796
Arkansas Oklahoma Gas Corp Corporation	19,380
Atmos Energy Corporation	320,746
Avista Corporation	65,425
Baltimore Gas and Electric Company	243,488
Bath Electric, Gas & Water Systems	811
Boonville Natural Gas Corporation	500
Cascade Natural Gas	150,002
Central Hudson Gas & Electric Corporation	43,022
Chesapeake Utilities Corporation	23,386
Cinergy	111,464
Citipower LLC	518
Citizens Gas & Coke Utility	136,532
City Gas Company (Wisconsin)	1,738
City of Charlottesville, Gas Division	1,816
City of Corpus Christi	4,275
City of Holyoke Gas & Electric Dept.	3,262
City of Las Cruces	518
City of Richmond, Dept of Pub Utils.	42,925
City Public Service of San Antonio	82,216
Clearwater Gas System	1,842
CMS Energy Corporation	419,063
Colorado Springs Utilities	10,539
Conectiv	97,323
Consolidated Edison Company of New York, Inc.	484,211
Corning Natural Gas Corporation	8,710
CoServ Gas Ltd.	500
Cut Bank Gas Company	300
Delta Natural Gas Company, Inc.	23,866
Dominion	381,156
DTE Energy	409,697
Easton Utilities	1,318
Energy East Corporation	388,750
ENERGY WEST, INC.	13,402
Entergy	34,740
Equitable Resources, Inc.	194,149
Exelon	286,616
Fairbanks Natural Gas	500
Fort Pierce Utilities Authority	1,104
Gainesville Reg'l Utils., Gas Dept.	6,272
Gila Resources, Inc.	1,588
Illinois Gas Company	825
Indiantown Gas Company, Inc.	500

American Gas Association
Member Company Dues
For the Year Ended December 31, 2002

Company	General Fund Dues
Intermountain Gas Company	101,388
KeySpan	611,703
Knoxville Utilities Board	20,124
Laclede Gas Company	230,795
LeAnn Gas Company	500
Long Beach Energy	30,876
Louisville Gas & Electric Company	47,160
Lumberport-Shinnston Gas Company, Inc.	500
Madison Gas and Electric Company	62,706
MDU Resources	43,700
Memphis Light, Gas & Water Division	70,870
Metropolitan Utilities District of Omaha	13,276
Middle Tenn. Natural Gas Utility Dist.	24,026
Mobile Gas Service Corp. (Energy South)	53,553
Montana Power Company	51,784
Mt. Carmel Public Utility Company	500
National Fuel Gas Distribution Corporation	327,756
New Jersey Resources Corporation	255,501
Niagara Mohawk Power Corporation	225,000
Nicor Gas	423,833
NiSource, Inc.	667,233
North Carolina Natural Gas Corp.oration	130,170
NSTAR Gas	154,805
NUI Corporation	203,390
NW Natural	290,974
Oak Ridge Utility District	1,680
Ohio Valley Gas, Inc.	1,769
Okaloosa County Gas District	500
Oncor Group (TXU Gas)	255,089
ONEOK, Inc.	310,895
Pacific Gas and Electric Company	524,649
Peoples Energy Corporation	388,882
Philadelphia Gas Works	237,081
Piedmont Natural Gas Company, Inc.	313,683
PPL Corp.	49,131
Public service Company of New Mexico	160,690
Public Service Electric and Gas Company	409,068
Questar Gas Company	218,844
Reliant Energy	383,913
RGC Resources, Inc.	20,025
Richmond Utilities Board	500
Rochester Gas & Electric Corporation	147,627
SEMCO Energy, Inc.	181,715
Sierra Pacific Power Company	47,979
South Jersey Gas Company	215,031
Southern Union Company	362,208
Southwest Gas Corporation	336,483

American Gas Association
Member Company Dues
For the Year Ended December 31, 2002

Company	General Fund Dues
Southwestern Energy Company	40,041
Southwestern Virginia Gas Company	2,991
Superior, Water, Light and Power Company	2,862
TECO Peoples Gas System, Inc.	43,284
Terrebonne Parish Consolidated Government	500
UGI Utilities, Inc.	233,042
Union Oil & Gas, Inc.	500
Vectren Corporation	306,330
Vermont Gas Systems, Inc.	18,874
Wakefield Municipal Gas & Light Department	518
Washington Gas	362,241
Wisconsin Electric - Wisconsin Gas	283,582
Westfield Gas & Electric Light Department	2,430
Wisconsin Public Service Corporation	83,532
Wyoming Gas Company	2,848
Xcel Energy	309,397
Yankee Gas Services Company	181,985
Total Distribution Member Company Dues	$ 15,437,156

Category	General Fund Dues
Full Member Company Dues	$ 15,437,156
Limited Member Company Dues	684,188
International Company Dues	155,000
Associate Dues	285,316
Total General Fund Dues	$ 16,561,660

AMERICAN GAS ASSOCIATION
Schedule of Directors and Officers
Salary Expense
2002

Title, Name and Address	Compensation	Contr. to Employee Benefit Plans
Chairman of the Board		
William Michael Warren Jr. Birmingham, Alabama	Not compensated by the Association *	Not compensated by the Association.*
First Vice Chairman		
Richard G. Reiten Portland, Oregon	Not compensated by the Association.	Not compensated by the Association.
Second Vice Chairman**		
Robert W. Best Dallas, Texas	Not compensated by the Association.	Not compensated by the Association.
President		
David N. Parker McLean, Virginia	$1,217,798	$281,047
Chief Financial and Administrative Officer		
Kevin M. Hardardt Great Falls, Virginia	$228,659	$42,593
General Counsel		
Kevin B. Belford Arlington, Virginia	$198,704	$45,622
Executive Vice President		
Roger B. Cooper Washington, D.C.	$258,675	$50,281
Executive Vice President		
Richard D. Shelby McLean, VA	$288,884	$49,976
Senior Vice President and Corporate Secretary		
Jay Copan Fairfax Station, VA	$192,479	$45,075
Senior Vice President		
Lori S. Traweek Centreville, VA	$197,146	$35,673

* The Chairman of the Board and other Board members, with the exception of those listed above, receive no compensation from the Association. The Chairman of the Board is reimbursed for ordinary and necessary expenses associated with Chairman's duties. Compensation shown is IRS 990 amount Part V for the 2002 calendar year.

** There are forty-two other Board members not listed as they receive no compensation.

EXHIBIT
ALL-STATE LEGAL®
S-22

S13-002

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-13
(ACC-STF-13-1 THROUGH ACC-STF-13-25)

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MAY 13, 2008

Request No. ACC-STF-13-2:

AGA dues and benefits. Refer to SWG Rebuttal Exhibits RLA-1 and FLA-2 attached to Randi Aldridge's testimony. (a) Is Kevin Hardardt being presented as a witness in this proceeding? If not, explain fully why not. (b) Has Mr. Hardardt ever presented testimony on AGA activities in any other regulatory proceedings? If so, please list each such proceeding (jurisdiction, docket number, utility, date testimony was filed). (c) Has Mr. Hardardt ever been cross examined on any testimony he filed in any jurisdiction regarding AGA activities? If so, please identify each instance and provide the transcript of such cross. (d) Has Mr. Hardardt ever been deposed concerning any testimony he filed in any jurisdiction regarding AGA activities? If so, please identify each instance and provide the transcript of such deposition(s). (e) Please provide all workpapers, calculations, studies and documents relied upon by Mr. Hardardt. (f) Please tie each AGA benefit claimed by Mr. Hardardt to a category of the AGA 2007 budget as listed on Exhibit RLA-2. (g) Please provide all correspondence between SWG and AGA and between SWG and Mr. Hardardt concerning his rebuttal testimony, including a copy of the agreement and fees for such testimony. (h) Identify each AGA function listed on SWG Rebuttal Exhibit RLA-2, sheet 1 of 1 which supports AGA lobbying. (i) Show exactly by AGA budget function where the 2% of member dues devoted to the narrow definition of lobbying under IRC section 162 resides.

Respondent: Revenue Requirements

Response:

The information provided by AGA to Southwest to be used in the response to Staff data request no. STF-12-1 was presented as rebuttal exhibits, not rebuttal testimony. Southwest is not presenting an additional witness for AGA dues. Southwest did not pay AGA to provide information to respond to Staff's data

(Continued on Page 2)

Response to ACC-STF-13-2: *(continued)*

requests with regard to AGA dues. Rather, AGA provided this information to assist Southwest in its explanation why it is appropriate to recover its AGA dues in rates. Southwest did not ask AGA to provide the information in the form of testimony, and due to time constraints, the Company did not request that AGA reformat its response. Southwest has already provided Staff with all the information it received from AGA, and Southwest is not in possession of the requested additional information.

241-079

EXHIBIT
ALL-STATE LEGAL®
S-28

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 THROUGH ACC-STF-1-99)

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: NOVEMBER 9, 2007

Request No. STF-1-79:

Payroll. Please provide the budgeted and actual range of merit increases and average merit increases for 2003, 2004, 2005, 2006 and 2007 to date.

Respondent: Human Resources

Response:

Please see the attached schedule.

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
CORPORATE SALARY AND WAGE ADJUSTMENTS
IN RESPONSE TO STF-1-79

	Corporate Exempt Salary Adjustments				Corporate Non-exempt Wage Adjustments			
	Budgeted	Actual	Range Min	Range Max	GWA Budgeted	GWA Actual	Steps Budgeted	Steps Actual
2003	3.75%	3.68%	0.00%	8.09%	2.0%	2.0%	1.89%	1.89%
2004	3.50%	3.32%	0.00%	8.90%	2.0%	2.0%	2.10%	2.10%
2005	3.50%	3.33%	0.00%	15.38%	2.0%	2.0%	1.92%	1.92%
2006	3.50%	3.37%	0.00%	10.00%	2.7%	2.7%	2.38%	2.38%
2007	3.70%	3.85%	0.00%	18.00%	3.0%	3.0%	2.29%	2.29%

GWA = general wage increase.

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
ARIZONA SALARY AND WAGE ADJUSTMENTS
IN RESPONSE TO STF-1-79

	Arizona Exempt Salary Adjustments				Arizona Non-exempt Wage Adjustments			
	Budgeted	Actual	Range Min	Range Max	GWA Budgeted	GWA Actual	Steps Budgeted	Steps Actual
2003	3.75%	3.49%	0.00%	9.38%	2.0%	2.0%	1.89%	1.89%
2004	3.50%	3.23%	0.00%	7.00%	2.0%	2.0%	2.10%	2.10%
2005	3.50%	3.26%	0.00%	5.92%	2.0%	2.0%	1.92%	1.92%
2006	3.50%	3.20%	0.00%	7.77%	2.7%	2.7%	2.38%	2.38%
2007	3.70%	3.50%	0.00%	8.75%	3.0%	3.0%	2.29%	2.29%

GWA = general wage increase.

313-018

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
***
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-13
(ACC-STF-13-1 THROUGH ACC-STF-13-25)

EXHIBIT
S-24
ADMITTED

ALL-STATE LEGAL®

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MAY 13, 2008

Request No. ACC-STF-13-18:

Injuries and damages. On its internal accounting and budgeting reports for 2006, please show exactly how Southwest allocated the cost of the May 2005 gas leak fire between its operations in the various jurisdictions (Arizona, Nevada, California, FERC and other). Include specific documents and workpapers showing the allocation.

Respondent: Revenue Requirements

Response:

Attached is a worksheet which details the self-insured charges recorded for the year 2005 and charged directly to rate jurisdictions. The $1 million self-insured retention related to the May 2005 incident was charged directly to Arizona operations in October 2005. The $10 million aggregate was charged to System Allocable in December 2005. Also attached is a copy of the December 2005 monthly operating report for Southwest's corporate staff departments, including General Counsel, which includes the Legal Department. The December 2005 current month charges of $11,357,229 includes the $10 million self-insured aggregate.

SOUTHWEST GAS ORATION
ACCOUNT 925 INURIES AND DAMAGES
SELF-INSURED RETENTIONS
FOR THE TWELVE MONTHS ENDED DECEMBER 2005
RESPONSE TO STAFF DATA REQUEST NO. STF-13.18

ORC	RRC	RLC	FERC	ACTIVITY	Proj. Prog.	CE	DESCRIPTION	JE	REF	PERIOD	DOLLARS	Receiving Responsibility Centers (RLC): System Allocable RLC Blank	No. Calif. 103	So. Calif. 104	Northern Nevada 105	Southern Nevada 106	Paiute 107	Arizona 108	South Lake Tahoe 110
8633	8633	106	9250	0001		718	INJURIES AND DAMAGES	318	AMH	01/05	75,000					75,000			
8633	8633	106	9250	0001		718	INJURIES AND DAMAGES	318	AMH	03/05	25,000					25,000			
8633	8633	106	9250	0001		718	INJURIES AND DAMAGES	318	AMH	05/05	75,000					75,000			
8633	8633	106	9250	0001		718	INJURIES AND DAMAGES	318	AMH	07/05	75,000					75,000			
8633	8633	106	9250	0001		718	INJURIES AND DAMAGES	318	AMH	09/05	100,000					100,000			
8633	8633	106	9250	0001		718	INJURIES AND DAMAGES	318	AMH	09/05	17,000					17,000			
8633	8633	106	9250	0001		718	INJURIES AND DAMAGES	373	AMH	10/05	200,000					200,000			
8633	8633	106	9250	0001		718	INJURIES AND DAMAGES	373	AMH	10/05	(75,000)					(75,000)			
8633	8633	106	9250	0001		718	INJURIES AND DAMAGES	318	AMH	11/05	250,000					250,000			
8633	8633	108	9250	0001		718	INJURIES AND DAMAGES	318	AMH	01/05	200,000							200,000	
8633	8633	108	9250	0001		718	INJURIES AND DAMAGES	318	AMH	01/05	(15,509)							(15,509)	
8633	8633	108	9250	1832		718	INJURIES AND DAMAGES	318	AMH	01/05	75,000							75,000	
8633	8633	108	9250	0001		718	INJURIES AND DAMAGES	318	AMH	02/05	100,000							100,000	
8633	8633	108	9250	0001		718	INJURIES AND DAMAGES	318	AMH	02/05	100,000							100,000	
8633	8633	108	9250	0001		718	INJURIES AND DAMAGES	318	AMH	02/05	(29,749)							(29,749)	
8633	8633	108	9250	0001		718	INJURIES AND DAMAGES	318	AMH	03/05	325,000							325,000	
8633	8633	108	9250	0001		718	INJURIES AND DAMAGES	318	AMH	03/05	75,000							75,000	
8633	8633	108	9250	0001		718	INJURIES AND DAMAGES	318	AMH	03/05	(75,000)							(75,000)	
8633	8633	108	9250	1832		718	INJURIES AND DAMAGES	318	AMH	03/05	(15,000)							(15,000)	
8633	8633	108	9250	0001		718	INJURIES AND DAMAGES	318	AMH	04/05	(79,097)							(79,097)	
8633	8633	108	9250	0001		718	INJURIES AND DAMAGES	318	AMH	04/05	(0)							(0)	
8633	8633	108	9250	0001		718	RECLASS INJURIES & DAMA	377	AMH	05/05	75,000							75,000	
8633	8633	108	9250	1832		718	RECLASS INJURIES & DAMA	377	AMH	05/05	(75,000)							(75,000)	
8633	8633	108	9250	0001		718	INJURIES AND DAMAGES	379	KEV1	06/05	75,000							75,000	
8633	8633	108	9250	0001		718	INJURIES AND DAMAGES	318	AMH	07/05	75,000							75,000	
8633	8633	108	9250	0001		718	INJURIES AND DAMAGES	318	AMH	07/05	100,000							100,000	
8633	8633	108	9250	0001		718	INJURIES AND DAMAGES	318	AMH	07/05	(182,154)							(182,154)	
8633	8633	108	9250	0001		718	INJURIES AND DAMAGES	318	AMH	08/05	50,000							50,000	
8633	8633	108	9250	0001		718	INJURIES AND DAMAGES	318	AMH	08/05	(50,000)							(50,000)	
8633	8633	108	9250	0001		718	INJURIES AND DAMAGES	318	AMH	08/05	35,930							35,930	
8633	8633	108	9250	0001		718	INJURIES AND DAMAGES	373	AMH	10/05	1,000,000							1,000,000	
8633	8633	108	9250	0001		718	INJURIES AND DAMAGES	373	AMH	10/05	(12,300)							(12,300)	
8633	8633	108	9250	0001		718	INJURIES AND DAMAGES	373	AMH	10/05	135,000							135,000	
8633	8633	108	9250	1832		718	INJURIES AND DAMAGES	373	AMH	10/05	(85,000)							(85,000)	
8633	8633	108	9250	0001		718	INJURIES AND DAMAGES	318	AMH	11/05	(75,000)							(75,000)	
8633	8633	108	9250	0001		718	INJURIES AND DAMAGES	318	AMH	11/05	(26,000)							(26,000)	
8633	8633	108	9250	0001		718	INJURIES AND DAMAGES	318	AMH	11/05	(75,000)							(75,000)	
8633	8633	108	9250	0001		718	INJURIES AND DAMAGES	387	AMH	12/05	(30,897)							(30,897)	
8633	8633		9250	0001		718	INJURIES AND DAMAGES	318	AMH	01/05	(57,500)	(57,500)							
8633	8633		9250	0001		718	INJURY/DAMAGE ADJUSTMEN	382	AMH	09/05	100,000	100,000							
8633	8633		9250	0001		718	INJURIES AND DAMAGES	387	AMH	12/05	10,000,000	10,000,000							
								TOTAL			12,379,724	10,042,500	-	-	-	742,000	-	1,595,224	-

Note: Southwest's accounting system related to charges from corporate automatically default to System Allocable unless the Receiving Responsibilty Center (PLC) has the number 103 through 110 in the Acct. Code Key The Originating Responsibility Center (ORC) 8633 is the Corporation Legal Risk Management Department. The $1 million self-insured retention was recorded and charged directly to Arizona in October 2005. The $10 million aggregate was charged to System Allocable (RLC Blank) in December 2005. The absence of a number in the RLC automatically defaults to System Allocable.

	DEFERRED AND OTHER COSTS		OPERATIONS		MAINTENANCE		CONSTRUCTION	
	ACTUAL	OVER(UNDER) BUDGET	ACTUAL	OVER(UNDER) BUDGET	ACTUAL	OVER(UNDER) BUDGET	ACTUAL	OVER(UNDER) BUDGET
CURRENT MONTH								
Operations	$ 3,752	$ (3,238)	$ 64,293	$ 8,225	$ -	$ -	$ -	$ -
Engineering	396,099	78,325	956,428	214,297	-	(99,749)	150,300	(230,283)
Information services	104,686	43,429	2,139,167	68,508	-	-	1,621,891	1,527,558
Corporate & admin serv.	117,543	26,560	404,816	45,296	465,188	334,183	355,190	355,747
Customer relations	29,656	(1,860)	377,899	5,304	-	-	-	(3,619)
Controller	41,351	(7,534)	1,054,782	94,087	-	-	-	-
Finance	109,860	74,382	292,312	(35,056)	-	-	-	-
General counsel	42,770	24,071	11,357,229	9,949,525	-	-	12,607	11,107
Materials management	90,562	(662)	-	-	-	-	-	-
Reg. affairs & systems planning	326,807	167,200	560,235	112,617	-	-	1,484	1,484
Gas resources & energy svcs	31,858	5,369	433,605	(34,965)	239	239	-	(1,375)
Executive	60,976	52,613	65,136	1,475	-	-	-	-
Marketing	12,671	2,311	485,578	187,199	-	-	(11,605)	(11,605)
Energy efficient technology	71,589	35,942	134,823	3,346	-	-	142,097	142,097
Human resources	9,993	(17,539)	271,005	45,333	-	-	-	-
Corporate common	(1,347,074)	(1,233,998)	1,373,116	(312,364)	217,883	(6,283)	-	(19,670)
Total incurred costs	103,099	(754,629)	19,970,424	10,352,827	683,310	228,390	2,271,964	1,771,441
Applied in/out	(2)	(2)	(2)	(2)	(2)	(2)	(828,164)	(824,432)
TOTAL	$ 103,097	$ (754,631)	$ 19,970,422	$ 10,352,825	$ 683,308	$ 228,388	$ 1,443,800	$ 947,009
YEAR TO DATE								
Operations	$ 47,806	$ (5,547)	$ 1,037,338	$ 206,150	$ -	$ -	$ -	$ -
Engineering	2,666,666	(1,056,690)	10,471,381	781,849	324,740	(872,260)	2,505,711	(3,371,739)
Information services	1,362,784	46,659	26,883,393	(539,063)	-	-	5,735,178	(3,339,389)
Corporate & admin serv.	1,315,482	38,626	4,637,285	171,255	1,947,929	154,369	9,316,831	1,853,766
Customer relations	406,858	18,323	4,768,331	(56,571)	-	-	6,442	(36,988)
Controller	572,338	46,812	13,556,402	953,714	-	-	-	(25,000)
Finance	6,256,934	5,865,956	5,232,083	445,838	924	(1,806)	21,706	21,706
General counsel	353,053	19,979	28,583,642	11,473,719	-	-	21,808	2,808
Materials management	1,246,101	72,498	-	-	-	-	104,316	6,316
Reg. affairs & systems planning	1,427,433	(1,013,842)	6,105,791	16,499	-	-	30,245	26,245
Gas resources & energy svcs	470,976	54,733	5,621,304	(267,930)	239	239	-	(84,500)
Executive	654,978	30,890	1,933,736	171,148	-	-	-	-
Marketing	249,176	(19,034)	3,649,348	(33,636)	-	-	120,997	(4,003)
Energy efficient technology	383,574	(45,498)	1,688,581	64,979	-	-	202,144	(153,056)
Human resources	225,797	15,237	2,842,914	(95,272)	-	-	-	-
Corporate common	(2,588,614)	(723,977)	4,556,818	(1,575,912)	(46,178)	97,367	-	(255,713)
Total incurred costs	15,051,342	3,345,125	121,568,347	11,716,767	2,227,654	(622,091)	18,065,378	(5,359,547)
Applied in/out	(3)	(3)	-	-	(1)	(1)	(9,645,507)	(3,469,562)
TOTAL	$ 15,051,339	$ 3,345,122	$ 121,568,347	$ 11,716,767	$ 2,227,653	$ (622,092)	$ 8,419,871	$ (8,829,109)

ACC- STAFF - 13-18

BEFORE THE ARIZONA CORPORATION COMMISSION

EXHIBIT S-25
ALL-STATE LEGAL®

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 ITS PROPERTIES THROUGHOUT ARIZONA.	DOCKET NO. G-01551A-07-0504 **NOTICE OF FILING UPDATED RATE DESIGN SCHEDULES OF STAFF WITNESS FRANK RADIGAN**

The Utilities Division ("Staff") hereby files the revised Rate Design schedules of Staff Witness Frank Radigan which have been updated to reflect the changes to Staff Witness Ralph Smith's proposed revenue requirement in his Surrebuttal Testimony.

RESPECTFULLY SUBMITTED this 4th day of June, 2008.

Maureen A. Scott, Senior Staff Counsel
Kevin O. Torrey, Staff Attorney
Charles H. Hains, Staff Attorney
Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Original and thirteen (13) copies
of the foregoing filed this
2nd day of June 2008 with:

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

Copies of the foregoing mailed
this 4th day of June 2008 to:

Debra Jacobson
Southwest Gas Corporation
Post Office Box 98510
Las Vegas, Nevada 89193-8510

Karen S. Haller
Southwest Gas Corporation
5241 Spring Mountain Road
Las Vegas, Nevada 89150

Scott S. Wakefield, Chief Counsel
RUCO
1110 West Washington, Suite 220
Phoenix, Arizona 85007

Timothy M. Hogan
Arizona Center for Law in the Public Interest
202 East McDowell Road, Suite 153
Phoenix, Arizona 85004
Attorneys for SWEEP

Jeff Schlegel
SWEEP Arizona Representative
1167 West Samalayuca Drive
Tucson, Arizona 85704-3224

Michael M. Grant
Gallagher & Kennedy
2575 East Camelback Road
Phoenix, Arizona 85016-9225
Attorneys for AIC

Gary Yaquinto
Arizona Investment Council
2100 North Central Avenue, Suite 210
Phoenix, Arizona 85004

Joseph Banchy
The Meadows HOA
6644 East Calle Alegria
Tucson, Arizona 85715

Karyn Christine

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	MM/MHP	General Gas Service Small	General Gas Service Medium	General Gas Service Large	General Gas Service Trans. Eligible	Air-Conditioning	Street Lighting	Small CNG	Large CNG	Residential CNG	Electric Generation	Essential Agricultural	Gas Engines	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	
1	Margin at Requested System Rate of Return [1]	$ 449,454,506	$ 334,945,916	$ 8,586,001	$ 631,232	$ 8,497,184	$ 24,128,839	$ 33,785,216	$ 16,399,330	$ 63,058	$ 129,738	$ 23,454	$ 243,288	$ 37,732	$ 1,382,427	$ 1,640,387	$ 1,910,883	1
2	Margin at Present Rates [2]	$ 399,234,678	$ 258,980,486	$ 7,115,996	$ 972,083	$ 7,867,842	$ 24,310,776	$ 53,003,981	$ 20,048,838	$ 123,887	$ 55,850	$ 36,474	$ 404,846	$ 25,468	$ 2,529,330	$ 2,194,924	$ 2,959,319	2
3	Difference (Line 1 minus Line 2)	$ 50,219,828											$ 466,909					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	0.50879	2.32293	0.64308	0.60074	1.48034	0.54656	0.52832	0.74658	5
6	Adjusted Percentage Increase (Line 4 X Line 5)		16.26818%	15.18532%	8.16823%	13.58557%	12.48454%	8.01798%	9.64209%	6.41260%	29.22023%	8.08880%	7.55676%	18.62118%	6.87517%	6.64572%	9.39123%	6
7	Adjusted Percentage Increase $ (Line 2 X Line 6)	$ 54,267,003	$ 42,132,929	$ 1,080,526	$ 79,403	$ 1,068,664	$ 3,035,185	$ 4,249,851	$ 1,937,088	$ 7,932	$ 16,319	$ 2,950	$ 30,601	$ 4,746	$ 173,896	$ 206,345	$ 240,370	7
8	Adjusted Margin Requirement (Line 2 + Line 7)	$ 453,501,681	$ 301,122,818	$ 8,196,122	$ 1,051,486	$ 8,936,506	$ 27,345,961	$ 57,253,832	$ 22,025,724	$ 131,828	$ 72,189	$ 39,424	$ 435,547	$ 30,235	$ 2,703,226	$ 3,311,269	$ 2,799,689	8
9	Margin at One-Half System Rate of Return	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	9
10	Greater of Percentage Increase or One-Half System Rate of Return	$ 453,501,681	$ 301,122,818	$ 8,196,122	$ 1,051,496	$ 8,936,506	$ 27,345,961	$ 57,253,832	$ 22,025,724	$ 131,829	$ 72,180	$ 39,424	$ 436,347	$ 30,235	$ 2,703,226	$ 3,311,269	$ 2,799,909	10
9	(Over) / Under Collection [3]	(4,047,176)	(2,798,669)	(76,176)	(9,773)	(83,057)	(254,156)	(532,123)	(204,710)	(1,223)	(671)	(366)	(4,048)	(281)	(25,124)	(30,779)	(26,022)	9
10	Margin Requirement (Greater of Line 9 or Line 10 plus Line 11)	$ 449,454,506	$ 298,324,149	$ 8,119,946	$ 1,041,723	$ 8,853,449	$ 27,091,806	$ 56,721,708	$ 21,821,015	$ 130,406	$ 71,499	$ 39,058	$ 431,499	$ 29,954	$ 2,678,102	$ 3,280,493	$ 2,773,887	10
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	$ 27,091,806	$ 56,721,708	$ 21,821,015	$ 130,406	$ 71,499	$ 39,058	$ 431,499	$ 29,954	$ 2,678,102	$ 3,280,493	$ 2,773,887	10
11	Proposed Dollar Increase in Margin	$ 50,219,828	$ 39,334,290	$ 1,004,350	$ 69,630	$ 985,807	$ 2,781,029	$ 3,717,727	$ 1,732,376	$ 6,709	$ 15,649	$ 2,584	$ 26,563	$ 4,486	$ 148,772	$ 173,569	$ 214,348	11
12	Proposed Percentage Increase in Margin	12.58%	15.19%	14.11%	7.16%	12.53%	11.44%	7.01%	8.82%	5.42%	28.02%	7.08%	6.56%	17.52%	5.88%	5.65%	8.37%	12
13	Rate of Return at Present Rates	6.68%	3.95%	5.69%	20.15%	7.80%	9.56%	21.06%	14.97%	28.83%	-0.71%	22.12%	23.21%	2.11%	25.45%	27.53%	17.22%	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	(0.11)	3.31	3.47	0.32	3.81	4.12	2.58	14
15	Rate of Return at Proposed Rates	9.45%	6.91%	5.09%	22.31%	11.01%	12.23%	23.36%	17.12%	30.72%	1.58%	23.00%	25.64%	4.63%	27.52%	29.86%	18.82%	15
16	Proposed Rate of Return Indices	1.00	0.73	0.54	2.36	1.18	1.29	2.47	1.81	3.25	0.17	2.43	2.71	0.51	2.91	3.14	2.10	16
	Rate of Return at Current Rates																	
1	Rate Base	$ 1,094,790,048	828,233,236	21,664,065	1,925,083	18,519,876	82,808,741	98,004,771	48,298,221	190,832	414,177	61,903	697,093	96,804	4,265,169	4,848,767	4,943,410	1
2	Net Income	$ 73,180,107	32,740,373	1,232,923	387,851	1,444,483	8,978,457	20,642,525	7,227,852	54,547	(2,831)	13,695	161,818	2,041	1,090,719	1,334,713	851,021	2
3	Rate of Return	6.68%	3.95%	5.69%	20.15%	7.80%	9.55%	21.06%	14.97%	28.63%	-0.71%	22.12%	23.21%	2.11%	25.45%	27.53%	17.22%	3
4	Index Rate of Return		0.59	0.85	3.01	1.17	1.43	3.16	2.24	4.28	-0.11	3.31	3.47	0.32	3.81	4.12	2.58	4
	Reallocation to Bring Service Classes within Tolerance of Overall Rate of Return																	
5	Rate of Return within +/- 10%		6.01%	6.01%	7.35%	7.35%	7.35%	7.35%	7.35%	7.35%	6.01%	7.35%	7.35%	6.01%	7.35%	7.35%	7.35%	5
6	Net Income At Tolerance	$ 99,083,716	$ 49,793,382	$ 1,302,444	$ 141,455	$ 1,360,848	$ 4,600,490	$ 7,201,391	$ 3,548,806	$ 14,008	$ 24,900	$ 4,549	$ 51,222	$ 5,820	$ 314,874	$ 356,287	$ 363,242	6
7	Over/(Under) Collection	$ 4,096,380	$ 2,952,549	$ 77,230	$ 8,388	$ 80,693	$ 272,791	$ 427,014	$ 210,430	$ 831	$ 1,476	$ 270	$ 3,037	$ 346	$ 18,671	$ 21,126	$ 21,539	7
8	Adj. Net Income	$ 73,180,107	$ 52,745,931	$ 1,379,673	$ 149,843	$ 1,441,541	$ 4,873,281	$ 7,628,404	$ 3,759,236	$ 14,838	$ 26,377	$ 4,818	$ 54,260	$ 6,166	$ 333,545	$ 377,414	$ 384,781	8
			6.37%	6.37%	7.78%	7.78%	7.78%	7.78%	7.78%	7.78%	6.37%	7.78%	7.78%	6.37%	7.78%	7.78%	7.78%	
	Allocation of Revenue Increase																	
9	Revenue Increase	$ 28,363,105																9
10	Conversion Factor	1.6586																10
11	Impact on Net Income of Revenue Increase	$ 17,100,830	$ 12,225,586	$ 322,400	$ 35,018	$ 336,857	$ 1,136,782	$ 1,782,595	$ 878,453	$ 3,487	$ 6,164	$ 1,126	$ 12,679	$ 1,441	$ 77,942	$ 88,164	$ 88,815	11
12	Conversion Factor	1.6586																12
13	Allocated Revenue Increase		$ 20,443,236	$ 534,733	$ 58,078	$ 558,712	$ 1,884,784	$ 2,956,613	$ 1,457,003	$ 9,751	$ 10,223	$ 1,867	$ 21,030	$ 2,389	$ 129,275	$ 146,278	$ 148,139	13
	Calculation of Untempered Revenue Increase																	
14	Current Delivery Revenues	$ 381,184,838	$ 264,989,549	$ 7,115,508	$ 977,084	$ 7,867,853	$ 24,310,777	$ 53,003,961	$ 20,084,836	$ 123,997	$ 95,850	$ 36,475	$ 404,945	$ 25,488	$ 2,529,330	$ 3,104,924	$ 2,959,820	14
15	Gas Cost	$ 606,052,721	$ 278,106,384	$ 6,554,309	$ 2,083,837	$ 4,702,779	$ 42,637,894	$ 139,414,148	$ 89,668,373	$ 1,006,541	$ 86,334	$ 166,293	$ 1,930,136	$ 72,479	$ 20,163,696	$ 11,900,947	$ 9,549,267	15
16	Total Adjusted Present Revenues	$ 989,241,559	$ 537,096,277	$ 13,669,905	$ 3,055,731	$ 12,570,432	$ 66,948,671	$ 192,418,108	$ 109,757,012	$ 1,130,238	$ 151,884	$ 202,768	$ 2,335,061	$ 97,967	$ 22,693,026	$ 15,005,871	$ 12,108,787	16
17	Proposed Revenues	$ 1,017,604,664	$ 577,545,074	$ 14,351,388	$ 2,875,799	$ 13,126,221	$ 67,732,279	$ 182,340,601	$ 107,746,399	$ 1,096,240	$ 181,215	$ 195,759	$ 2,248,552	$ 104,480	$ 22,065,126	$ 14,194,850	$ 11,791,680	17
18	Revenue Increase	$ 28,363,105	$ 40,448,797	$ 681,483	$ (179,932)	$ 555,789	$ 783,606	$ (10,077,506)	$ (2,011,613)	$ (33,998)	$ 29,331	$ (7,009)	$ (86,529)	$ 6,513	$ (627,906)	$ (811,021)	$ (317,107)	18
19	% Increase	2.8%	7.0%	4.7%	-6.3%	4.2%	1.2%	-5.5%	-1.9%	-3.1%	20.7%	-3.6%	-3.8%	6.3%	-2.8%	-5.7%	-2.7%	19
	Limitation of Rate Increase Due to Rate Impacts																	
20	Limited Increase (no class plus or minus 1% away from average).		3.9%	3.9%	1.9%	3.9%	1.9%	1.9%	1.9%	1.9%	3.9%	1.9%	1.9%	3.9%	1.9%	1.9%	1.9%	20
21	Revenue Resulting from Limiting Increase	$ 30,087,315	$ 20,946,755	$ 533,126	$ 58,050	$ 460,247	$ 1,272,025	$ 3,665,844	$ 2,085,383	$ 21,475	$ 5,616	$ 3,852	$ 44,307	$ 3,821	$ 431,187	$ 288,112	$ 230,087	21
22	Pro-Rated Increase	$ 28,363,105	$ 19,739,497	$ 502,909	$ 54,758	$ 482,460	$ 1,199,827	$ 3,448,726	$ 1,967,184	$ 20,257	$ 5,360	$ 3,634	$ 41,852	$ 3,604	$ 406,726	$ 264,951	$ 217,027	22
23	Impact on Net Income	$ 17,100,630	$ 11,913,358	$ 303,213	$ 33,021	$ 278,825	$ 723,456	$ 2,079,299	$ 1,186,061	$ 12,214	$ 3,365	$ 2,191	$ 25,233	$ 2,173	$ 245,224	$ 162,156	$ 130,848	23
24	Adjusted Net Income	$ 90,280,737	$ 44,653,732	$ 1,536,136	$ 420,872	$ 1,723,268	$ 6,701,916	$ 22,741,824	$ 8,413,933	$ 66,801	$ 434	$ 15,986	$ 187,052	$ 4,214	$ 1,335,942	$ 1,496,869	$ 981,870	24
25	Rate of Return	8.29%	5.39%	7.09%	21.86%	9.31%	10.70%	23.20%	17.42%	36.04%	0.10%	25.86%	26.83%	4.35%	31.18%	30.87%	19.86%	25
26	Index Rate of Return		0.65	0.86	2.95	1.13	1.30	2.81	2.11	4.25	0.01	3.11	3.25	0.53	3.76	3.74	2.41	26
			0.58	0.85	3.01	1.17	1.43	3.18	2.24	4.28	-0.11	3.31	3.47	0.32	3.81	4.12	2.58	
	Margin at Proposed Rates	$ 427,597,783	$ 278,746,368	$ 7,618,508	$ 1,026,061	$ 8,330,102	$ 25,510,703	$ 56,482,707	$ 22,066,823	$ 143,954	$ 61,436	$ 40,106	$ 446,796	$ 29,062	$ 2,936,068	$ 3,373,975	$ 2,776,546	

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

Line No.	Description (a)	Proposed Schedule Number (b)	Increase/(Decrease) [1] Dollars (e)	Percent (f)	Line No.
	Sales Service				
1	Residential Gas Service	G-5	$ 19,339,773	7.67%	1
2	Multi-Family Residential Gas Service	G-6	478,973	7.22%	2
3	Low Income Residential Gas Service	G-10	414,935	6.15%	3
4	Low Income Multi-Family Residential	G-11	23,903	4.98%	4
5	Special Residential Gas Service	G-15	4,531	6.45%	5
6	Master Metered Mobile Home Park Gas Service	G-20	54,776	5.63%	6
	General Gas Service	G-25			
7	Small		462,439	5.88%	7
8	Medium		1,199,770	4.94%	8
9	Large		3,449,366	6.51%	9
10	Transporation Eligible		1,967,127	9.79%	10
11	Optional Gas Service	G-30	0	0.00%	11
12	Air Conditioning Gas Service	G-40	20,258	16.38%	12
13	Street Lighting Gas Service	G-45	5,581	9.99%	13
	Gas Service for Compression on Customer's Premises	G-55			
14	Small		2,923	8.01%	14
15	Large		43,897	10.84%	15
16	Residential		2,272	8.91%	16
17	Electric Generation Gas Service	G-60	406,651	16.08%	17
18	Small Essential Agriculture User Gas Service	G-75	268,999	8.66%	18
19	Natural Gas Engine Gas Service	G-80	217,006	8.48%	19
20	Total Sales and Full Margin Transportation		$ 28,363,180	7.38%	20
21	Special Contract Service	B-1	0	0.00%	21
22	Other Operating Revenue		0	0.00%	22
23	Total Arizona Revenue		$ 28,363,180	7.10%	23

[1] Schedule H-1, Sheet 1.

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 Present Rates [1]	Proposed Rates [2]	Increase/(Decrease) Dollars	Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Sales Service						
1	Residential Gas Service	G-5	$ 522,983,992	$ 542,323,765	$ 19,339,773	3.70%	1
2	Multi-Family Residential Gas Service	G-6	12,732,540	13,211,513	478,973	3.76%	2
3	Low Income Residential Gas Service	G-10	13,909,416	14,324,351	414,935	2.98%	3
4	Low Income Multi-Family Residential	G-11	937,365	961,268	23,903	2.55%	4
5	Special Residential Gas Service	G-15	202,869	207,400	4,531	2.23%	5
6	Master Metered Mobile Home Park Gas Service	G-20	3,055,730	3,110,506	54,776	1.79%	6
	General Gas Service	G-25					
7	Small		12,570,421	13,032,860	462,439	3.68%	7
8	Medium		66,948,670	68,148,440	1,199,770	1.79%	8
9	Large		192,418,129	195,867,495	3,449,366	1.79%	9
10	Transporation Eligible		109,757,012	111,724,139	1,967,127	1.79%	10
11	Optional Gas Service	G-30	44,143,512	44,143,512	0	0.00%	11
12	Air Conditioning Gas Service	G-40	1,130,238	1,150,495	20,257	1.79%	12
13	Street Lighting Gas Service	G-45	151,684	157,265	5,581	3.68%	13
	Gas Service for Compression on Customer's Premises	G-55					
14	Small		202,767	205,690	2,923	1.44%	14
15	Large		2,335,082	2,378,979	43,897	1.88%	15
16	Residential		97,968	100,240	2,272	2.32%	16
17	Electric Generation Gas Service	G-60	22,693,026	23,099,677	406,651	1.79%	17
18	Small Essential Agriculture User Gas Service	G-75	15,005,871	15,274,870	268,999	1.79%	18
19	Natural Gas Engine Gas Service	G-80	12,108,786	12,325,792	217,006	1.79%	19
20							20
21	Total Gas Sales		$1,033,385,078	$ 1,061,748,257	$ 28,363,179	2.74%	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		$1,048,174,913	$ 1,076,538,092	$ 28,363,179	2.71%	24
25	Total Requirement			$ 1,076,538,017			25
26	Over/(Under) Requirement			$ 75			26

[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.

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 Present Rates [1]	Margin Proposed Rates [2]	Increase/(Decrease) Dollars	Increase/(Decrease) Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Sales Service						
1	Residential Gas Service	G-5	$ 252,170,209	$ 271,509,982	$ 19,339,773	7.67%	1
2	Multi-Family Residential Gas Service	G-6	6,635,205	7,114,178	478,973	7.22%	2
3	Low Income Residential Gas Service	G-10	6,749,399	7,164,334	414,935	6.15%	3
4	Low Income Multi-Family Residential	G-11	480,391	504,294	23,903	4.98%	4
5	Special Residential Gas Service	G-15	70,281	74,812	4,531	6.45%	5
6	Master Metered Mobile Home Park Gas Service	G-20	972,093	1,026,869	54,776	5.63%	6
	General Gas Service	G-25					
7	Small		7,867,642	8,330,081	462,439	5.88%	7
8	Medium		24,310,776	25,510,546	1,199,770	4.94%	8
9	Large		53,003,981	56,453,347	3,449,366	6.51%	9
10	Transporation Eligible		20,088,639	22,055,766	1,967,127	9.79%	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	143,955	20,258	16.38%	12
13	Street Lighting Gas Service	G-45	55,850	61,431	5,581	9.99%	13
	Gas Service for Compression on Customer's Premises	G-55					
14	Small		36,474	39,397	2,923	8.01%	14
15	Large		404,946	448,843	43,897	10.84%	15
16	Residential		25,489	27,761	2,272	8.91%	16
17	Electric Generation Gas Service	G-60	2,529,330	2,935,981	406,651	16.08%	17
18	Small Essential Agriculture User Gas Service	G-75	3,104,924	3,373,923	268,999	8.66%	18
19	Natural Gas Engine Gas Service	G-80	2,559,519	2,776,525	217,006	8.48%	19
20	Total Sales and Full Margin Transportation		$ 384,444,843	$ 412,808,023	$ 28,363,180	7.38%	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	$ 427,597,858	$ 28,363,180	7.10%	23
24	Total Requirement			$ 427,597,783			24
25	Over/(Under) Requirement			$ 75			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	$ 270,813,783	$ 0	0.00%	1
2	Multi-Family Residential Gas Service	G-6	6,097,335	6,097,335	0	0.00%	2
3	Low Income Residential Gas Service	G-10	7,160,017	7,160,017	0	0.00%	3
4	Low Income Multi-Family Residential	G-11	456,974	456,974	0	0.00%	4
5	Special Residential Gas Service	G-15	132,588	132,588	0	0.00%	5
6	Total Residential		$ 284,660,697	$ 284,660,697	$ 0	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		4,702,779	4,702,779	0	0.00%	8
9	Medium		42,637,894	42,637,894	0	0.00%	9
10	Large		139,414,148	139,414,148	0	0.00%	10
11	Transporation Eligible		89,668,373	89,668,373	0	0.00%	11
12	Optional Gas Service	G-30	40,887,514	40,887,514	0	0.00%	12
13	Air Conditioning Gas Service	G-40	1,006,541	1,006,540	(1)	(0.00%)	13
14	Street Lighting Gas Service	G-45	95,834	95,834	0	0.00%	14
	Gas Service for Compression on Customer's Premises	G-55					
15	Small		166,293	166,293	0	0.00%	15
16	Large		1,930,136	1,930,136	0	0.00%	16
17	Residential		72,479	72,479	0	0.00%	17
18	Electric Generation Gas Service	G-60	20,163,696	20,163,696	0	0.00%	18
19	Small Essential Agriculture User Gas Service	G-75	11,900,947	11,900,947	0	0.00%	19
20	Natural Gas Engine Gas Service	G-80	9,549,267	9,549,267	0	0.00%	20
21	Total Gas Sales		$ 648,940,235	$ 648,940,234	$(1)	(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		$ 648,940,235	$ 648,940,234	$(1)	(0.00%)	24

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

Staff Revenue Proof

Attachment___(FWR-2)

SOUTHWES[illegible] CORPORATION
ARIZONA DIVISION
SUMMARY OF PRESENT AND PROPOSED REVENUES BY RATE COMPONENT
FOR THE TWELVE MONTHS ENDED APRIL 30, 2007

Line No.	Description (a)	Proposed Schedule Number (b)	Billing Determinants: Number of Bills (c)	Billing Determinants: Sales (Therms) (d)	Basic Service Charge [1] (e)	Commodity Charge [1] (f)	Revenue at Proposed Rates: Basic Service Charge (g)	Revenue at Proposed Rates: Commodity Charge (h)	Revenue at Proposed Rates: Total Margin (i)	Revenue at Proposed Rates: Gas Cost [2] (j)	Revenue at Proposed Rates: Total Revenue (k)	Revenue at Present Rates [3] (l)	Increase / Decrease: Dollars (m)	Increase / Decrease: Percent (n)	Line No.
	Single-Family Residential Gas Service	G-5													
	Summer (May - October)														
1	Basic Service Charge per Month		5,107,859		$ 10.70		$ 54,654,091		$ 54,654,091		$ 54,654,091	$ 49,546,232	$ 5,107,859		1
	Commodity Charge per Therm														
2	First 15 Therms			48,048,640		$ 0.55810		$ 26,815,754	26,815,754	$ 45,016,291	71,832,045	71,058,654	773,391		2
3	Over 15 Therms			16,007,105		0.55810		8,933,501	8,933,501	14,996,896	23,930,397	23,016,455	913,942		3
	Winter (November - April)														
4	Basic Service Charge per Month		5,190,171		$ 10.70		$ 55,534,830		$ 55,534,830		$ 55,534,830	$ 50,344,659	$ 5,190,171		4
	Commodity Charge per Therm														
5	First 35 Therms			133,956,357		0.55810		74,760,507	74,760,507	125,502,371	200,262,878	198,106,717	2,156,161		5
6	Over 35 Therms			91,044,013		0.55810		50,811,299	50,811,299	85,298,225	136,109,524	130,911,275	5,198,249		6
7	Total Single-Family Residential Gas Service		10,298,030	289,056,115			$ 110,188,921	$ 161,321,061	$ 271,509,982	$ 270,813,783	$ 542,323,765	$ 522,983,992	$ 19,339,773	3.70%	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		$ 0.55810		$ 836,994	836,994	$ 1,240,112	2,077,106	2,052,966	24,140		9
10	Over 15 Therms			343,792		0.55810		191,869	191,869	284,278	476,147	456,518	19,629		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		0.55810		2,360,658	2,360,658	3,497,614	5,858,272	5,790,188	68,084		12
13	Next 115 Therms			2,532,839		0.55810		1,413,567	1,413,567	2,094,379	3,507,946	3,363,331	144,615		13
14	Over 150 Therms			52,769		0.55810		29,450	29,450	43,634	73,084	70,071	3,013		14
15	Total Low Income Single-Family Residential Gas Service		310,906	8,658,972			$ 2,331,796	$ 4,832,538	$ 7,164,334	$ 7,160,017	$ 14,324,351	$ 13,909,416	$ 414,935	2.98%	15
	Multi-Family Residential Gas Service	G-6													
	Summer (May - October)														
16	Basic Service Charge per Month		182,409		$ 9.70		$ 1,769,367		$ 1,769,367		$ 1,769,367	$ 1,586,958	$ 182,409		16
	Commodity Charge per Therm														
17	First 7 Therms			1,044,432		$ 0.54083		$ 564,856	564,856	$ 978,518	1,543,374	1,544,600	(1,226)		17
18	Over 7 Therms			950,005		0.54083		513,787	513,787	890,050	1,403,837	1,366,003	37,834		18
	Winter (November - April)														
19	Basic Service Charge per Month		188,153		$ 9.70		$ 1,825,084		$ 1,825,084		$ 1,825,084	$ 1,636,931	$ 188,153		19
	Commodity Charge per Therm														
20	First 18 Therms			2,633,090		0.54083		1,424,044	1,424,044	2,466,916	3,890,960	3,894,051	(3,091)		20
21	Over 18 Therms			1,880,532		0.54083		1,017,040	1,017,040	1,761,851	2,778,891	2,703,997	74,894		21
22	Total Multi-Family Residential Gas Service		370,562	6,508,059			$ 3,594,451	$ 3,519,727	$ 7,114,178	$ 6,097,335	$ 13,211,513	$ 12,732,540	$ 478,973	3.76%	22
	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		$ 0.54083		$ 43,170	43,170	$ 66,004	109,174	109,258	(84)		2
3	Over 7 Therms			78,071		0.54083		42,223	42,223	64,556	106,779	103,670	3,109		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		0.54083		112,482	112,482	171,978	284,460	284,704	(244)		5
6	Next 132 Therms			186,423		0.54083		100,822	100,822	154,151	254,973	247,549	7,424		6
7	Over 150 Therms			345		0.54083		187	187	285	472	458	14		7
8	Total Low Income Multi-Family Residential Gas Service		27,388	552,643			$ 205,410	$ 298,884	$ 504,294	$ 456,974	$ 961,268	$ 937,365	$ 23,903	2.55%	8
	Special Residential Gas Service for A/C	G-15													
	Summer (May - October)														
9	Basic Service Charge per Month		648		$ 10.70		$ 6,934		$ 6,934		$ 6,934	$ 6,286	$ 648		9
	Commodity Charge per Therm														
10	First 15 Therms			7,899		$ 0.55810		$ 4,408	4,408	$ 7,400	11,808	11,681	127		10
11	Over 15 Therms			65,327		$ 0.28200		18,422	18,422	61,204	79,626	79,626	0		11

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

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 (a)	Proposed Schedule Number (b)	Billing Determinants: Number of Bills (c)	Billing Determinants: Sales (Therms) (d)	Basic Service Charge [1] (e)	Commodity Charge [1] (f)	Revenue at Proposed Rates: Basic Service Charge (g)	Revenue at Proposed Rates: Commodity Charge (h)	Revenue at Proposed Rates: Total Margin (i)	Revenue at Proposed Rates: Gas Cost [2] (j)	Revenue at Proposed Rates: Total Revenue (k)	Revenue at Present Rates [3] (l)	Increase / Decrease: Dollars (m)	Increase / Decrease: Percent (n)	Line No.
	Winter (November - April)														
12	Basic Service Charge per Month		648		$ 10.70		$ 6,934		$ 6,934		$ 6,934	$ 6,286	$ 848		12
	Commodity Charge per Therm														
13	First 35 Therms			19,309		$ 0.55810		10,776	10,776	18,090	28,866	28,555	311		13
14	Over 35 Therms			48,985		$ 0.55810		27,338	27,338	45,894	73,232	70,435	2,797		14
15	Total Special Residential Gas Service		1,296	141,520			$ 13,867	$ 60,945	$ 74,812	$ 132,588	$ 207,400	$ 202,869	$ 4,531	2.23%	16
16	Total Residential Gas Service		11,008,182	304,917,309			$116,334,445	$ 170,033,155	$ 286,367,800	$ 284,660,697	$ 571,028,297	$ 550,766,182	$ 20,262,115	3.68%	16
	Master Metered Mobile Home Park Gas Service	G-20													
17	Basic Service Charge per Month		1,968		$ 66.00		$ 129,888		$ 129,888		$ 129,888	$ 118,080	$ 11,808		17
	Commodity Charge per Therm All Usage														
18	All Usage			2,223,993		$ 0.40332		$ 896,981	896,981	2,083,637	2,980,618	2,937,650	42,968		18
19	Total MMMHP Gas Service		1,968	2,223,993			$ 129,888	$ 896,981	$ 1,026,869	$ 2,083,637	$ 3,110,506	3,055,730	54,778	1.79%	19
	General Gas Service - Small	G-25(S)													
20	Basic Service Charge		201,805		$ 27.50		$ 5,549,638		$ 5,549,638		$ 5,549,638	$ 5,045,125	504,513		20
	Commodity Charge per Therm All Usage														
21	Transportation Customers			10,138		$ 0.55379		$ 5,614	5,614	$ 8,383	13,997	14,082	-85		21
22	Sales Customers			5,010,616		0.55379		2,774,829	$ 2,774,829	4,694,396	7,469,225	7,511,214	-41,989		22
23	Total Small General Gas Service		201,805	5,020,754			$ 5,549,638	$ 2,780,443	$ 8,330,081	$ 4,702,779	$ 13,032,660	$ 12,570,421	$ 462,439	3.68%	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		$ 0.37515		$ 64,663	64,663	$ 142,527	207,190	210,351	-3,161		25
26	Sales Customers			45,357,904		0.37515		17,016,018	17,016,018	42,495,367	59,511,385	60,343,249	-831,864		26
27	Total Medium General Gas Service		193,790	45,530,269			$ 8,429,865	$ 17,080,881	$ 25,510,546	$ 42,637,894	$ 68,148,440	$ 66,948,670	$ 1,199,770	1.79%	27
	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		0.28663		1,019,494	1,019,494	$ 2,941,106	3,960,600	3,908,955	51,645		2
3	Sales Customers			145,666,025		0.28663		41,752,253	41,752,253	136,473,042	178,225,295	176,110,224	2,115,071		3
4	Total Large General Gas Service		85,510	149,222,854			13,681,600	42,771,747	56,453,347	139,414,148	195,867,495	$ 192,418,129	3,449,366	1.79%	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	0.062340			9,578,196	9,578,196		9,578,196	9,578,201	(5)		6
	Commodity Charge per Therm All Usage														
7	Transportation Customers			32,517,415		$ 0.10416		$ 3,387,014	3,387,014	$ 26,888,325	30,275,339	29,799,609	475,730		7
8	Sales Customers			67,008,985		$ 0.10416		$ 6,979,656	6,979,656	62,780,048	69,759,704	68,779,362	980,342		8
9	Total Transportation Eligible General Gas Service		2,222	99,526,400			$ 2,110,900	$ 19,944,866	$ 22,055,766	$ 89,668,373	$ 111,724,139	$ 109,757,012	$ 1,967,127	1.79%	9
10	Total General Gas Service		483,327	298,300,277			$ 28,772,003	$ 82,577,737	$ 112,348,740	$ 276,423,194	$ 388,772,934	$ 381,694,232	$ 7,078,702	1.85%	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		27.50		5,445		5,445		5,445	4,950	495		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		$ 0.10680		$ 39,942	39,942	$ 309,246	349,188	346,271	2,917		17
18	Sales Customers			744,265		0.10680		79,488	79,488	697,294	776,782	770,976	5,806		18
19	Total Air Conditioning Gas Service		318	1,118,252			$ 24,525	$ 119,430	$ 143,955	$ 1,006,640	$ 1,160,495	$ 1,130,238	$ 20,257	1.79%	19

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

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)	Basic Service Charge [1]	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)	
	Street Lighting Gas Service	G-45													
	Commodity Charge per Therm														
	of Rated Capacity														
20	All Usage		324	102,289		$ 0.60056		$ 61,431	61,431	95,834	157,265	151,684	5,581		20
21	Total Street Lighting Gas Service		324	102,289			$ 0	$ 61,431	$ 61,431	$ 95,834	$ 157,265	$ 151,684	$ 5,581	3.68%	21
	Gas Service for Compression on Customer's Premises	G-55													
	Basic Service Charge														
22	Small		252		27.50		$ 6,930		$ 6,930		$ 6,930	$ 6,300	$ 630		22
23	Large		288		250.00		72,000		72,000		72,000	54,720	17,280		23
24	Residential		1,272		10.70		13,610		13,610		13,610	12,338	1,272		24
	Commodity Charge per Therm All Usage														
25	Transportation Customers			0		$ 0.18292		$ 0	0	$ 0	0	0	0		25
	Sales Customers														
26	Small			177,495		0.18292		32,467	32,467	166,293	198,760	196,467	2,283		26
27	Large			2,060,152		0.18292		376,843	376,843	1,930,136	2,306,979	2,280,362	26,617		27
28	Residential			77,361		0.18292		14,151	14,151	72,479	86,630	85,630	1,000		28
29	Total CNG Gas Service		1,812	2,315,008			$ 92,540	$ 423,461	$ 516,001	$ 2,166,908	$ 2,684,909	$ 2,635,817	$ 49,092	1.86%	29
	Electric Generation Gas Service	G-60													
	Basic Service Charge														
1	General Service - Small		36		$ 27.50		$ 990		$ 990		$ 990	$ 900	$ 90		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		950.00		79,800		79,800		79,800	60,480	19,320		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		$ 0.13190		$ 0	0	$ 0	0	0	0		6
7	Sales Customers			21,521,946		0.13190		2,838,745	2,838,745	20,163,696	23,002,441	22,617,198	385,243		7
8	Total Electric Generation Gas Service		252	21,521,946			$ 97,236	$ 2,838,745	$ 2,935,981	$ 20,163,696	$ 23,099,677	$ 22,693,026	$ 406,651	1.79%	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		$ 0.24031		$ 1,494,242	1,494,242	$ 5,141,582	6,635,824	6,528,191	107,633		10
11	Sales Customers			7,214,684		0.24031		1,733,761	1,733,761	6,759,365	8,493,126	8,368,240	124,886		11
12	Total Essential Agricultural Gas Service		1,216	13,432,660			$ 145,920	$ 3,228,003	$ 3,373,923	$ 11,900,947	$ 15,274,870	$ 15,005,871	$ 268,999	1.79%	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		$ 0.18766		$ 0	0	$ 0	0	0	0		15
16	Sales Customers			13,070,981		0.18766		2,452,900	2,452,900	9,549,267	12,002,167	11,862,831	139,336		16
17	Total Natural Gas Engine Gas Service		5,105	13,070,981			$ 323,625	$ 2,452,900	$ 2,776,525	$ 9,549,267	$ 12,325,792	$ 12,108,766	$ 217,006	1.79%	17
18	Total Tariff Sales		11,502,504	658,002,715			$146,920,182	$ 262,631,843	$ 409,552,025	$ 608,052,720	$ 1,017,604,745	$ 989,241,566	$ 28,363,179	2.87%	18
19	Optional Gas Service	G-30	84	49,447,344			$ 120,540	$ 3,135,458	3,255,998	$ 40,887,514	$ 44,143,512	$ 44,143,512	$ 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			$ 159,751,801	$ 267,846,057	$ 427,597,858	$ 648,940,234	$ 1,076,538,092	$ 1,048,174,913	$ 28,363,179	2.71%	22
23	Total Revenue Requirement								$ 427,597,783	$ 648,940,234	$ 1,076,538,017				23
24	Over/(Under)								$75	$ 0	$75				24

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

Staff Bill Comparison

Attachment___(FWR-3)

SOUTHWEST GAS CORPORATION
ARIZONA DIVISION
PROPOSED vs. CURRENTLY EFFECTIVE RATES
G - 5 – 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	Minimum Bill	0	9.70		10.70	$	1.00	10.31%	1
2	75 Percent Average Use	12	27.45	$	28.64	$	1.19	4.34%	2
3	Average Summer Use [1]	16	33.36	$	34.62		1.26	3.78%	3
4	125 Percent Average Use	20	39.28	$	40.60		1.32	3.36%	4
5	150 Percent Average Use	24	45.19	$	46.58		1.39	3.08%	5
	Winter Season Bills								
6	Minimum Bill	0	9.70	$	10.70	$	1.00	10.31%	6
7	75 Percent Average Use	42	71.53	$	73.49	$	1.96	2.74%	7
8	Average Winter Use [1]	56	91.66	$	94.42		2.76	3.01%	8
9	125 Percent Average Use	70	111.79	$	115.35		3.56	3.18%	9
10	150 Percent Average Use	84	131.92	$	136.28		4.36	3.31%	10

Effective Tariff Rates [2]		Amount
Basic Service Charge per Month	$	9.70
Commodity Charge Summer		
First 15 Therms		0.54200
Over 15 Therms		0.50100
Commodity Charge Winter		
First 35 Therms		0.54200
Over 35 Therms		0.50100
Gas Cost	$	0.93689

Proposed Tariff Rates [3]		
Basic Service Charge per Month	$	10.70
Commodity Charge Summer		
First 15 Therms		0.55810
Over 15 Therms		0.55810
Commodity Charge Winter		
First 35 Therms		0.55810
Over 35 Therms		0.55810
Gas Cost	$	0.93689

[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
G - 6 -- 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	Minimum Bill	0	8.70	$	9.70	$	1.00	11.49%	1
2	75 Percent Average Use	9	22.01	$	23.15	$	1.14	5.18%	2
3	Average Summer Use [1]	12	26.45	$	27.64		1.19	4.50%	3
4	125 Percent Average Use	15	30.88	$	32.12		1.24	4.02%	4
5	150 Percent Average Use	18	35.32	$	36.61		1.29	3.65%	5
	Winter Season Bills								
6	Minimum Bill	0	8.70	$	9.70	$	1.00	11.49%	6
7	75 Percent Average Use	23	42.71	$	44.08	$	1.37	3.21%	7
8	Average Winter Use [1]	30	53.07	$	54.55		1.48	2.79%	8
9	125 Percent Average Use	38	64.90	$	66.51		1.61	2.48%	9
10	150 Percent Average Use	45	75.05	$	76.97		1.92	2.56%	10

Effective Tariff Rates [2]		Amount
Basic Service Charge per Month	$	8.70
Commodity Charge Summer		
First 20 Therms	$	0.54200
Over 20 Therms		0.50100
Commodity Charge Winter		
First 40 Therms	$	0.54200
Over 40 Therms		0.50100
Gas Cost		0.93689

Proposed Tariff Rates [3]		
Basic Service Charge per Month	$	9.70
Commodity Charge Summer		
First 7 Therms	$	0.54083
Over 7 Therms	$	0.54083
Commodity Charge Winter		
First 18 Therms	$	0.54083
Over 18 Therms	$	0.54083
Gas Cost	$	0.93689

[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
G - 55 – GAS SERVICE FOR COMPRESSION ON CUSTOMER PREMISES - SMALL

Line No.	Description (a)	Monthly Consumption (Therms) (b)	Monthly Bill: At Currently Effective Rates (c)	Monthly Bill: At Proposed Tariff Rates (d)	Increase/(Decrease): Dollars (e)	Increase/(Decrease): Percent (f)	Line No.
	Summer Season Bills						
1	Minimum Bill	0	$ 25.00	$ 27.50	$ 2.50	10.00%	1
2	75 Percent Average Use	5	$ 30.53	$ 33.10	$ 2.56	8.40%	2
3	Average Summer Use [1]	7	$ 32.75	$ 35.34	2.59	7.91%	3
4	125 Percent Average Use	9	$ 34.96	$ 37.58	2.62	7.48%	4
5	150 Percent Average Use	11	$ 37.18	$ 39.82	2.64	7.11%	5
	Winter Season Bills						
6	Minimum Bill	0	$ 25.00	$ 27.50	$ 2.50	10.00%	6
7	75 Percent Average Use	19	$ 46.03	$ 48.78	2.75	5.96%	7
8	Average Winter Use [1]	25	$ 52.67	$ 55.50	2.82	5.36%	8
9	125 Percent Average Use	31	$ 59.31	$ 62.21	2.90	4.89%	9
10	150 Percent Average Use	38	$ 67.06	$ 70.05	2.99	4.46%	10

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 25.00
Commodity Charge	
All Usage	$ 0.17000
Gas Cost	$ 0.93689

Proposed Tariff Rates [3]	Amount
Basic Service Charge	$ 27.50
Commodity Charge	
All Usage	$ 0.18292
Gas Cost	$ 0.93689

[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
G - 55 -- GAS SERVICE FOR COMPRESSION ON CUSTOMER PREMISES - LARGE

Line No.	Description (a)	Monthly Consumption (Therms) (b)	Monthly Bill At Currently Effective Rates (c)	Monthly Bill At Proposed Tariff Rates (d)	Increase/(Decrease) Dollars (e)	Increase/(Decrease) Percent (f)	Line No.
	Summer Season Bills						
1	Minimum Bill	0	$ 190.00	$ 250.00	$ 60.00	31.58%	1
2	75 Percent Average Use	7,560	$ 8,558.09	$ 8,715.76	$ 157.68	1.84%	2
3	Average Summer Use [1]	10,080	$ 11,347.45	$ 11,537.68	190.23	1.68%	3
4	125 Percent Average Use	12,600	$ 14,136.81	$ 14,359.61	222.79	1.58%	4
5	150 Percent Average Use	18,900	$ 21,110.22	$ 21,414.41	304.19	1.44%	5
	Winter Season Bills						
6	Minimum Bill	0	$ 190.00	$ 250.00	60.00	31.58%	6
7	75 Percent Average Use	9,041	$ 10,197.39	$ 10,374.20	176.81	1.73%	7
8	Average Winter Use [1]	12,055	$ 13,533.56	$ 13,749.31	215.75	1.59%	8
9	125 Percent Average Use	15,069	$ 16,869.73	$ 17,124.42	254.69	1.51%	9
10	150 Percent Average Use	22,604	$ 25,210.14	$ 25,562.19	352.04	1.40%	10

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 190.00
Commodity Charge All Usage	0.1700
Gas Cost	$ 0.93689

Proposed Tariff Rates [3]	
Basic Service Charge	$ 250.00
Commodity Charge All Usage	0.18292
Gas Cost	$ 0.93689

[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
G - 55 -- 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	Minimum Bill	0	$ 9.70	$ 10.70	$ 1.00	10.31%	1
2	75 Percent Average Use	45	$ 59.51	$ 61.09	$ 1.58	2.66%	2
3	Average Summer Use [1]	60	$ 76.11	$ 77.89	1.78	2.33%	3
4	125 Percent Average Use	75	$ 92.72	$ 94.69	1.97	2.12%	4
5	150 Percent Average Use	113	$ 134.78	$ 137.24	2.46	1.83%	5
	Winter Season Bills						
6	Minimum Bill	0	$ 9.70	$ 10.70	1.00	10.31%	6
7	75 Percent Average Use	45	$ 59.51	$ 61.09	1.58	2.66%	7
8	Average Winter Use [1]	60	$ 76.11	$ 77.89	1.78	2.33%	8
9	125 Percent Average Use	75	$ 92.72	$ 94.69	1.97	2.12%	9
10	150 Percent Average Use	90	$ 109.32	$ 111.48	2.16	1.98%	10

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 9.70
Commodity Charge	
All Usage	0.1700
Gas Cost	$ 0.93689

Proposed Tariff Rates [3]	
Basic Service Charge	$ 10.70
Commodity Charge	
All Usage	0.18292
Gas Cost	$ 0.93689

[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
G - 75 -- ESSENTIAL AGRICULTURAL USER GAS SERVICE

Line No.	Description (a)	Monthly Consumption (Therms) (b)	Monthly Bill At Currently Effective Rates (c)	Monthly Bill At Proposed Tariff Rates (d)	Increase/(Decrease) Dollars (e)	Increase/(Decrease) Percent (f)	Line No.
	Summer Season Bills						
1	Minimum Bill	0	$ 90.00	$ 120.00	$ 30.00	33.33%	1
2	75 Percent Average Use	4,774	$ 5,455.74	$ 5,568.38	$ 112.64	2.06%	2
3	Average Summer Use [1]	6,365	$ 7,243.95	$ 7,384.12	140.18	1.94%	3
4	125 Percent Average Use	7,956	$ 9,032.15	$ 9,199.87	167.72	1.86%	4
5	150 Percent Average Use	11,934	$ 13,503.23	$ 13,739.80	236.58	1.75%	5
	Winter Season Bills						
6	Minimum Bill	0	$ 90.00	$ 120.00	30.00	33.33%	6
7	75 Percent Average Use	5,217	$ 5,953.65	$ 6,073.96	120.31	2.02%	7
8	Average Winter Use [1]	6,956	$ 7,908.20	$ 8,058.61	150.41	1.90%	8
9	125 Percent Average Use	8,695	$ 9,862.75	$ 10,043.26	180.51	1.83%	9
10	150 Percent Average Use	13,043	$ 14,749.69	$ 15,005.46	255.77	1.73%	10

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 90.00
Commodity Charge	
All Usage	$ 0.22300
Gas Cost	$ 0.90095

Proposed Tariff Rates [3]	
Basic Service Charge	$ 120.00
Commodity Charge	
All Usage	$ 0.24031
Gas Cost	$ 0.90095

[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
G - 80 -- NATURAL GAS ENGINE GAS SERVICE--PEAK SEASON

Line No.	Description (a)	Monthly Consumption (Therms) (a)	Monthly Bill At Currently Effective Rates (b)	Monthly Bill At Proposed Tariff Rates (c)	Increase/(Decrease) Dollars (d)	Increase/(Decrease) Percent (e)	Line No.
	Summer Season Bills						
1	Minimum Bill	0	$ 95.00	$ 125.00	$ 30.00	31.58%	
2	75 Percent Average Use	1,988	$ 1,898.80	$ 1,949.98	$ 51.18	2.70%	
3	Average Summer Use [1]	2,650	$ 2,500.06	$ 2,558.31	58.25	2.33%	
4	125 Percent Average Use	3,313	$ 3,101.33	$ 3,166.64	65.31	2.11%	
5	150 Percent Average Use	3,313	$ 3,101.33	$ 3,166.64	65.31	2.11%	
	Winter Season Bills						
6	Minimum Bill	0	$ 0.00	$ 0.00	0.00	0.00%	
7	75 Percent Average Use	1,043	$ 946.60	$ 957.71	11.11	1.17%	
8	Average Winter Use [1]	1,391	$ 1,262.43	$ 1,277.26	14.83	1.17%	
9	125 Percent Average Use	1,739	$ 1,578.26	$ 1,596.80	18.54	1.17%	
10	150 Percent Average Use	2,609	$ 2,367.85	$ 2,395.66	27.81	1.17%	

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 95.00
Commodity Charge	
All Usage	$ 0.17700
Gas Cost	$ 0.73057

Proposed Tariff Rates [3]	
Basic Service Charge	$ 125.00
Commodity Charge	
All Usage	$ 0.18766
Gas Cost	$ 0.73057

[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
G - 20 – MASTER METERED MOBILE HOME PARK GAS SERVICE

			Monthly Bill				
Line No.	Description	Monthly Consumption (Therms)	At Currently Effective Rates	At Proposed Tariff Rates	Increase/(Decrease) Dollars	Percent	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
	Summer Season Bills						
1	Minimum Bill	0	60.00	66.00	$ 6.00	10.00%	
2	75 Percent Average Use	354	527.60	540.43	$ 12.83	2.43%	1
3	Average Summer Use [1]	472	683.46	698.58	15.12	2.21%	2
4	125 Percent Average Use	590	839.33	856.72	17.39	2.07%	3
5	150 Percent Average Use	885	1,228.99	1,252.09	23.10	1.88%	
	Winter Season Bills						
6	Minimum Bill	0	60.00	66.00	6.00	10.00%	
7	75 Percent Average Use	1,341	1,831.31	1,863.22	31.91	1.74%	4
8	Average Winter Use [1]	1,788	2,421.75	2,462.30	40.55	1.67%	5
9	125 Percent Average Use	2,235	3,012.19	3,061.37	49.18	1.63%	6
10	150 Percent Average Use	3,353	4,488.94	4,559.72	70.78	1.58%	7

Effective Tariff Rates [2]		Amount
Basic Service Charge	$	60.00
Commodity Charge		
All Usage	$	0.38400
Gas Cost, all therms	$	0.93689
Proposed Tariff Rates [3]		
Basic Service Charge	$	66.00
Commodity Charge		
All Usage	$	0.40332
Gas Cost, all therms	$	0.93689

[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
G - 25(S) – 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	Minimum Bill	0	$ 25.00	$ 27.50	$ 2.50	10.00%	1
2	75 Percent Average Use	8	$ 36.99	$ 39.42	$ 2.43	6.58%	2
3	Average Summer Use [1]	10	$ 30.62	$ 33.04	2.42	7.89%	3
4	125 Percent Average Use	13	$ 44.48	$ 46.88	2.39	5.37%	4
5	150 Percent Average Use	20	$ 54.98	$ 57.31	2.33	4.24%	5
	Winter Season Bills						
6	Minimum Bill	0	$ 25.00	$ 27.50	2.50	10.00%	6
7	75 Percent Average Use	29	$ 68.47	$ 70.72	2.26	3.30%	7
8	Average Winter Use [1]	39	$ 83.45	$ 85.63	2.17	2.60%	8
9	125 Percent Average Use	49	$ 98.44	$ 100.53	2.09	2.12%	9
10	150 Percent Average Use	74	$ 135.91	$ 137.79	1.88	1.38%	10

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 25.00
Commodity Charge	
All Usage	$ 0.56217
Gas Cost, all themrs	$ 0.93667
Proposed Tariff Rates [3]	
Basic Service Charge	$ 27.50
Commodity Charge	
All Usage	$ 0.55379
Gas Cost, all themrs	$ 0.93667

[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
G - 25(M) -- GENERAL GAS SERVICE - MEDIUM

Line No.	Description (a)	Monthly Consumption (Therms) (b)	Monthly Bill At Currently Effective Rates (c)	Monthly Bill At Proposed Tariff Rates (d)	Increase/(Decrease) Dollars (e)	Increase/(Decrease) Percent (f)	Line No.
	Summer Season Bills						
1	Minimum Bill	0	$ 33.00	$ 43.50	$ 10.50	31.82%	1
2	75 Percent Average Use	115	$ 185.95	$ 194.34	$ 8.39	4.51%	2
3	Average Summer Use [1]	153	$ 236.48	$ 244.18	7.69	3.25%	3
4	125 Percent Average Use	191	$ 287.02	$ 294.02	7.00	2.44%	4
5	150 Percent Average Use	287	$ 414.70	$ 419.94	$ 5.24	1.26%	5
	Winter Season Bills						
6	Minimum Bill	0	$ 33.00	$ 43.50	10.50	31.82%	6
7	75 Percent Average Use	236	$ 346.87	$ 353.04	6.17	1.78%	7
8	Average Winter Use [1]	315	$ 451.94	$ 456.66	4.72	1.05%	8
9	125 Percent Average Use	394	$ 557.01	$ 560.28	3.27	0.59%	9
10	150 Percent Average Use	591	$ 819.01	$ 818.67	(0.34)	(0.04%)	10

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 33.00
Commodity Charge	
All Usage	$ 0.39349
Gas Cost, all therms	$ 0.93647
Proposed Tariff Rates [3]	
Basic Service Charge	$ 43.50
Commodity Charge	
All Usage	$ 0.37515
Gas Cost, all therms	$ 0.93647

[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
G - 25(L) -- GENERAL GAS SERVICE - LARGE

Line No.	Description (a)	Monthly Consumption (Therms) (b)	Monthly Bill At Currently Effective Rates (c)	Monthly Bill At Proposed Tariff Rates (d)	Increase/(Decrease) Dollars (e)	Increase/(Decrease) Percent (f)	Line No.
	Summer Season Bills						
1	Minimum Bill	0	$ 145.00	$ 160.00	$ 15.00	10.34%	1
2	75 Percent Average Use	929	$ 1,265.73	$ 1,294.21	$ 28.49	2.25%	2
3	Average Summer Use [1]	1,239	$ 1,639.70	$ 1,672.69	32.99	2.01%	3
4	125 Percent Average Use	1,549	$ 2,013.68	$ 2,051.17	37.49	1.86%	4
5	150 Percent Average Use	1,936	$ 2,480.55	$ 2,523.66	43.11	1.74%	5
	Winter Season Bills						
6	Minimum Bill	0	$ 145.00	$ 160.00	15.00	10.34%	6
7	75 Percent Average Use	1,665	$ 2,153.62	$ 2,192.80	39.18	1.82%	7
8	Average Winter Use [1]	2,220	$ 2,823.16	$ 2,870.39	47.23	1.67%	8
9	125 Percent Average Use	2,775	$ 3,492.70	$ 3,547.99	55.29	1.58%	9
10	150 Percent Average Use	3,469	$ 4,329.93	$ 4,395.30	65.37	1.51%	10

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 145.00
Commodity Charge	
All Usage	$ 0.27211
Gas Cost, all themrs	$ 0.93427
Proposed Tariff Rates [3]	
Basic Service Charge	$ 160.00
Commodity Charge	
All Usage	$ 0.28663
Gas Cost, all themrs	$ 0.93427

[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
G - 40 -- AIR CONDITIONING 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)	
1	Minimum Bill	0	$ 25.00	$ 27.50	$ 2.50	10.00%	1
2	75 Percent Average Use	2,638	$ 2,757.68	$ 2,780.75	$ 23.08	0.84%	2
3	Average Use [1]	3,517	$ 3,668.23	$ 3,698.16	29.93	0.82%	3
4	125 Percent Average Use	4,396	$ 4,578.77	$ 4,615.56	36.79	0.80%	4
5	150 Percent Average Use	5,495	$ 5,717.22	$ 5,762.58	45.36	0.79%	5

Effective Tariff Rates [2]	Amount
Basic Service Charge	$ 25.00
Commodity Charge	
All Usage	$ 0.09900
Gas Cost, all themrs	$ 0.93689
Proposed Tariff Rates [3]	
Basic Service Charge	$ 27.50
Commodity Charge	
All Usage	$ 0.10680
Gas Cost, all themrs	$ 0.93689

[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 (a)	Monthly Consumption (Therms) (b)	Monthly Bill At Currently Effective Rates (c)	Monthly Bill At Proposed Tariff Rates (d)	Increase/(Decrease) Dollars (e)	Increase/(Decrease) Percent (f)	Line No.
	Summer Season Bills						
1	Minimum Bill	0	$ 7.00	$ 7.50	$ 0.50	7.14%	1
2	75 Percent Average Use	9	$ 19.32	$ 19.96	$ 0.64	3.33%	2
3	Average Summer Use [1]	12	$ 23.42	$ 24.12	0.70	2.98%	3
4	125 Percent Average Use	15	$ 27.53	$ 28.27	0.74	2.69%	4
5	150 Percent Average Use	23	$ 38.16	$ 39.35	1.20	3.13%	5
	Winter Season Bills						
6	Minimum Bill	0	7.00	$ 7.50	0.50	7.14%	6
7	75 Percent Average Use	32	50.80	$ 51.82	1.02	2.01%	7
8	Average Winter Use [1]	43	65.54	$ 67.05	1.52	2.32%	8
9	125 Percent Average Use	54	80.14	$ 82.29	2.15	2.68%	9
10	150 Percent Average Use	81	116.00	$ 119.68	3.69	3.18%	10

Effective Tariff Rates [2]	Amount
Basic Service Charge per Month	$ 7.00
Commodity Charge Summer	
First 15 Therms	$ 0.54200
Over 15 Therms	0.50100
Commodity Charge Winter	
First 35 Therms	$ 0.54200
Next 115 Therms	0.50100
Over 150 Therms	0.50100
Gas Cost, all therms	0.82689

Proposed Tariff Rates [3]	
Basic Service Charge per Month	$ 7.50
Commodity Charge Summer	
All Usage	$ 0.55810
Over 15 Therms	0.55810
Commodity Charge Winter	
First 35 Therms	$ 0.55810
Next 115 Therms	0.55810
Over 150 Therms	0.55810
Gas Cost, all therms	0.82689

[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 (a)	Monthly Consumption (Therms) (b)	Monthly Bill At Currently Effective Rates (c)		Monthly Bill At Proposed Tariff Rates (d)		Increase/(Decrease) Dollars (e)	Increase/(Decrease) Percent (f)	Line No.
	Summer Season Bills								
1	Minimum Bill	0	7.00	$	7.50	$	0.50	7.14%	1
2	75 Percent Average Use	9	19.24	$	19.81	$	0.57	2.95%	2
3	Average Summer Use [1]	12	23.22	$	23.91		0.69	2.97%	3
4	125 Percent Average Use	15	27.20	$	28.02		0.81	2.99%	4
5	150 Percent Average Use	23	37.83	$	38.96	$	1.13	2.98%	5
	Winter Season Bills								
6	Minimum Bill	0	7.00	$	7.50	$	0.50	7.14%	6
7	75 Percent Average Use	22	36.50	$	37.59	$	1.09	2.98%	7
8	Average Winter Use [1]	29	45.80	$	47.16		1.36	2.98%	8
9	125 Percent Average Use	36	55.09	$	56.74		1.65	2.99%	9
10	150 Percent Average Use	45	67.04	$	69.05	$	2.01	2.99%	10

Effective Tariff Rates [2]		Amount
Basic Service Charge per Month	$	7.00
Commodity Charge Summer		
First 7 Therms	$	0.54200
Over 7 Therms		0.50100
Commodity Charge Winter		
First 18 Therms	$	0.54200
Next 132 Therms		0.50100
Over 150 Therms		0.50100
Gas Cost, all therms		0.82689
Proposed Tariff Rates [3]		
Basic Service Charge per Month	$	7.50
Commodity Charge Summer		
First 7 Therms	$	0.54083
Over 7 Therms		0.54083
Commodity Charge Winter		
First 18 Therms	$	0.54083
Next 132 Therms		0.54083
Over 150 Therms		0.54083
Gas Cost, all therms		0.82689

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

EXHIBIT
S-26

249-008

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-2
(ACC-STF-2-1 THROUGH ACC-STF-2-22)

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: DECEMBER 19, 2007

Request No. STF-2-8:

Please provide copy of all reports on Southwest Gas by security analysts for the period 2003 to the present.

Respondent: Treasury Services

Response: ***Supplemental Attachment – March 19, 2008***

Supplemental Attachment – March 6, 2008

Southwest's security analysts' reports for 2004-2007 were provided in the response to Staff data request no. STF-1-11. The security analysts' reports for 2003 are attached.

Update
Data Request No. STF-2-8

JPMorgan

North America Equity Research
05 March 2008

Southwest Gas Corp.

Relief on the Horizon

Overweight

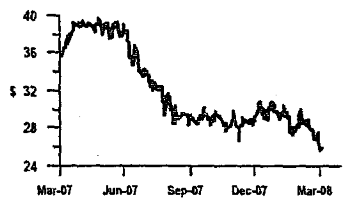
$25.87
04 March 2008

Natural Gas Distribution & Pipelines

Brooke Glenn Mullin[AC]
(1-212) 622-1774
brooke.glennmullin@jpmchase.com

Erica N Liu
(1-212) 622-5247
erica.n.liu@jpmchase.com

Price Performance



	YTD	-1M	-3M	-12M
Absolute	-13.1%	-13.4%	-12.8%	-27.3%

Source: RIMES, Reuters.

Southwest Gas expects customer growth of 1.5-3% over the next two years until problems in the housing market abate. A more normalized growth rate reduces capital expenditures, helps mitigate cost creep associated with serving the growing demand and thereby should reduce the impact of regulatory lag caused in part by rate making in AZ which utilizes a historical test-year.

- **Our focus remains on the company's outstanding rate cases in AZ and CA and a potential filing in NV.** In AZ, SWX is requesting $50.2m in rate relief and weather normalization and revenue decoupling. Hearings in AZ are set to begin Jun-08 and in CA, hearings have been proposed for Aug-08. Following the completion of the rule making docket on revenue normalization in 3Q08, we anticipate a potential NV rate case filing sometime in 1H09.

- **SWX has reduced its three-year capital expenditure forecast and associated equity issuance to $850 million with $70-80 million equity financed from the prior outlook of $880 million and $100-125 million of equity financing.**

- **The performance at Construction Services in 2007 returned to more normalized levels from record earnings seen in 2006 and we expect this normalized earnings contribution to continue in 2008.** Although a weaker economic environment in 2008 could have an adverse impact on this business, Construction Services' geographic diversity and focus on maintenance and pipeline replacement work on aging utility infrastructure should limit the negative effects of a pullback in the housing market.

- **We are maintaining our Overweight rating and our 2008 EPS of $2.15 per share.** We believe SWX should benefit from double digit earnings growth in 2009 due to the benefit of anticipated rate relief in AZ and CA.

Southwest Gas Corp. (SWX;SWX US)

	2007A	2008E
EPS ($)		
Q1 (Mar)	1.19	
Q2 (Jun)	(0.01)	
Q3 (Sep)	(0.22)	
Q4 (Dec)	1.00	
FY	1.96	2.15
P/E FY	13.2	12.0

Source: Company data, Reuters and JPMorgan estimates. Note: JPMorgan estimates rounded to nearest $0.05.

Company Data	
Price ($)	25.87
Date Of Price	04 Mar 08
52-week Range ($)	39.77 - 25.23
Mkt Cap ($ bn)	1.06
Fiscal Year End	Dec
Shares O/S (mn)	41
Div. Yield	3.5%

See page 7 for analyst certification and important disclosures, including investment banking relationships.

Brooke Glenn Mullin
(1-212) 622-1774
brooke.glennmullin@jpmchase.com

Fourth Quarter Update

Focus on AZ Rate Case: Hearing in Jun-08

Our focus remains on the company's Arizona rate case filing which is needed to recover additional capital and expenses incurred during the past few years as the company's load was growing at a rate above 3% a year. Additionally, the rate case includes proposed rate design changes, specifically normalizing mechanisms. Staff and intervenor groups are expected to submit testimony by 3/21/08 (rate design testimony due by 4/11/08) followed by SWX's rebuttal testimony by 5/9/08. After another round of rebuttals, hearings are scheduled to begin on 6/13/08 and a decision is anticipated before the start of the winter 2008/2009 heating season. While we believe rates will go into effect before the utility's heating season, we anticipate a later effective date than the company's request of 10/1/08.

Filed for $50.2m Rate Relief in AZ

On 8/31/07 the company filed with the Arizona Corporation Commission (ACC) for a rate increase of $50.2 million to be implemented by 10/1/08. The rate request was based on a proposed rate base of roughly $1.1 billion, a return on equity (ROE) of 11.25% and an assumed capital structure of 45% equity. The company also requested various mechanisms to help limit the relationship between revenues and volumes. These options include increasing the utility's basic service charge by $3.10 to $12.80 and adjustments to its volumetric rates. Southwest Gas' proposal would allow the utility to recover all margin in the first block in addition to a portion of gas costs, with the remaining cost of gas to be recovered in the second block rate. The increase in service charge and shift in margin to the first block would essentially serve to mitigate earnings fluctuations. The company has also proposed weather normalization and revenue decoupling. As the company has offered several alternative options, it is more likely that one or more of these suggestions will be adopted. Regarding weather normalization and decoupling, while these requests were both denied by the Commission in the company's previous rate case, subsequently the AZ Commissioners have encouraged the company to work with Staff to address rate design issues. As a result, these proposed mechanisms may be better received in this case. Additionally, while AZ is one of the least progressive states, since the company's last rate case several years ago decoupling has become accepted by more jurisdictions and has received the endorsement of various industry groups like the American Gas Association. This national move towards decoupling may make such measures more palatable to the ACC.

JPMorgan Estimates $25m in Rate Relief

We believe the company will receive around $25 million in relief to reflect increased investment, costs and a slightly higher allowed return. We assume that rates are implemented prior to the start of the 2008/2009 heating season though we anticipate a later effective date than the company's request of 10/1/08. This assumption is based on an assumed capital structure of around 43% equity which is lower than the company's request but is in line with Southwest Gas' actual equity layer at the time of filing. Additionally we have assumed a lower than requested ROE in the range of 10.0%. While our assumed allowed ROE is higher than the company's current allowed ROE of 9.5%, it is in line with the 10.0% ROE granted in the UNS Gas rate case from Nov-07 and is lower than those rates allowed for electric utilities in the state. Our estimates assume that due to Arizona's use of a historical test-year in determining rates, the company will continue to see regulatory lag which will result in the company under-earning its allowed return in the first year of implementation. This assumption may be conservative as the moderating growth rate should help to reduce the lag effect. Additionally, if the company is successful in achieving changes to its rate design the amount of regulatory lag could be reduced.

CA Rate Case: Hearing in Aug-08

In Dec-07 Southwest Gas filed a general rate case with the California Public Utilities Commission (CPUC) requesting a revenue increase of $9.1 million with a proposed effective date on 1/1/09. The rate request was based on a 47% equity capital structure and an 11.5% ROE on a combined rate base of $210 million. In connection with this filing, the company requested that authorized levels of margins revert to seasonal adjusted recognition rather than in equal monthly amounts throughout the year. This filing also proposes a post test-year ratemaking mechanism or an attrition mechanism similar to their current mechanism for 2010-2013 in order to account for inflation, capital expenditures and customer growth between rate cases. Hearings are anticipated to begin in Aug-08.

Rate Design Changes Pending in NV; Potential Rate Case

Currently in Nevada, a rule making docket is underway to develop programs and methods to implement legislation passed in Jun-07 to support utility efforts to promote conservation while keeping the utilities financially whole. Once these rules are established, Southwest Gas intends to evaluate its need to file a rate case. The last time Southwest Gas applied for a weather normalization adjustment outside of a rate case, the Nevada Commission rejected the request despite support by Staff and the consumer advocate. With the supportive legislation and current efforts to establish rules for implementation to be complete by 3Q08, the company could potentially receive a weather normalization adjustment in its next rate case. Though the company has not committed to a filing, we anticipate a potential filing during the first half of 2009. If the rules are established and the company is able to file early in 2009, based on the Nevada Commission's history, new rates could be in place for the winter of 2009/2010.

Slowing Customer Growth; Reduced Equity Issuance Need

Southwest Gas highlighted a decline in its customer growth rate to below 3% in 2007, a decline attributable to problems in the housing market. Specifically, unoccupied homes and associated inactive meters accounted for a significant portion of the year-over-year decline. The large inventory of existing homes is expected to place downward pressure on new construction. As such, for the next two years the company anticipates growth in the range of 1.5-3% until the housing market returns to more normal levels. A more normalized growth rate reduces capital expenditures, mitigates cost creep associated with serving the growing demand and thereby should reduce the impact of regulatory lag caused in part by rate making in AZ which utilizes a historical test-year. On a related issue, we note that Southwest Gas has placed meters in approximately 20,000-30,000 homes that are currently vacant. The company highlighted that once these houses are occupied and gas meters turned on, Southwest Gas will begin bringing on new customers at no cost. As the capital for these meters are already included in the company's AZ rate case, these new customer additions would be incremental to earnings. Along with the decline in the company's customer growth forecast, Southwest Gas has revised its 2008-2010 capital

Brooke Glenn Mullin
(1-212) 622-1774
brooke.glennmullin@jpmchase.com

expenditure forecast as disclosed in the 2007 10K. SWX forecasts capex of $850 million with $70-80 million equity financed. That is a reduction from the prior three-year outlook of $880 million and $100-125 million of equity financing. The reduction in their equity financing needs equates to about 2.8% of outstanding shares and is a positive development for shareholders.

More Normalized Returns at Construction Services

According to management, the performance of the Construction Services segment in 2007 returned to more normalized levels from record earnings seen in 2006 and we expect this normalized earnings contribution to continue in 2008. While a weaker economic environment in 2008 could have an adverse impact on this business, particularly on the amount of work received under existing blanket contracts, the amount of bid work and the equipment resale market, we have assumed a flattening trend. Construction Services remains focused on pursuing maintenance and pipeline replacement work on aging utility infrastructure which should be relatively unaffected by a pullback in the housing market. Additionally, this segment operates beyond the southwest which is seeing more of the housing problem. Diversity of operations provides some protection during this weak housing environment.

Quarterly Results

On 2/27/08 Southwest Gas reported recurring 4Q07 earnings of $1.00 per diluted share which was lower than our estimate of $1.10 and consensus of $1.06. Lower than anticipated earnings was largely attributable to warmer than normal weather and not an indication of deteriorating fundamentals. Warmer weather reduced 4Q07 earnings by $8 million or $0.07 per share.

Table 1: 4Q07 Results

SWX 4Q07A	JPM 4Q07E	Cons. 4Q07E	Guidance* 2008
$1.00	$1.10	$1.06	NA

Source: Company report, FirstCall and JPMorgan estimates. Note: JPMorgan estimate rounded to nearest $0.05.
*The company does not provide earnings guidance.

Dates to Watch

Date	Event
3/21/08	AZ rate case: Staff & intervenor group testimony submittal due (excluding rate design matter)
4/11/08	AZ rate case: Staff & intervenor group testimony on rate design matter submittal due
5/9/08	AZ rate case: SWX rebuttal testimony due
5/27/08	AZ rate case: Staff & intervenor group surrebuttal due
6/9/08	AZ rate case: SWX rejoinder due
6/13/08	AZ rate case: hearings scheduled
3Q08	NV rate design rule making docket expected to be complete in 3Q08
Aug-08	CA rate case: proposed hearings to begin
4Q08	Electronic Meter Reading (ERTS) project expected to be complete ahead of schedule (originally targeting '09)
12/1/08	AZ rate case: new rates in AZ assumed to go into effect (SWX request for effective date starting 10/1/08)
1H09	Potential NV rate case filing
1/1/09	CA rate case: new rates in CA assumed to go into effect
4Q09	New rates in NV assumed to go into effect depending on workshop outcome

Source: Company report and JPMorgan estimates.

Brooke Glenn Mullin
(1-212) 622-1774
brooke.glennmullin@jpmchase.com

Valuation

We are maintaining our Overweight rating and our 2008 EPS of $2.15 per share. We believe SWX should benefit from double digit earnings growth in 2009 due to the benefit of anticipated rate relief in AZ and CA.

As discussed above our rate case assumptions may be conservative. We are estimating that Arizona gets rate relief by 12/1/08. In Nevada we are assuming no effect in 2008 as the timing of this filing is yet to be determined. In Arizona we are expecting the Commission to increase the allowed ROE to 10%, in line with the rate case outcomes for other gas utilities in the state. Yet, we are projecting that the company will continue to under-earn their allowed return. Additionally we are assuming actual equity whereas the company has asked for a target equity which is 2% higher than our estimates. If the company were to receive a higher authorized ROE or greater equity layer, we could see upside to our growth projections. Likewise, if Southwest Gas is able to earn closer to its allowed return due to the implementation of various rate design changes, this could also result in an improvement.

Our primary valuation method is a sum-of-the-parts analysis as we believe it best reflects the different growth and risk profiles of the various businesses. We also use a forward P/E multiple for the LDC group. Southwest Gas is currently trading at 12.0x our 2008 estimate which is a 12% discount to the group at 13.7x. We believe this is unwarranted due to the earnings growth potential in 2009 from the full effect of its rate cases.

Table 2: Sum-of-the-Parts Valuation

$ in millions, except per share data

	2008E EBITDA	Low Case Multiple	Low Case EV	High Case Multiple	High Case EV
Natural Gas Operations	380	6.3x	2,375	7.3x	2,755
Construction Services	42	5.5x	229	6.6x	274
2008E Debt			(1,392)		(1,392)
Equity Value			1,212		1,637
Share Count (MM)			44		44
Equity Value ($/share) (Rounded)			$27.45		$37.10

Source: JPMorgan estimates.

Investment Risks

We are assuming that the Southwest, including the metropolitan areas of Las Vegas, Tucson and Phoenix, continues to have above average customer growth to support the above average demand growth for the forecast period. If that trend were to reverse, the stock could under perform. We have also assumed that the construction company is able to retain its utility customers and that the movement to replace and update pipeline systems for safety continues for the forecast period. If that were not to happen, both work volumes and margins could fall at the construction business, potentially causing the stock to under perform. Lastly, we assume that the recent improvement we have seen in the regulatory environment holds and that the company receives timely treatment in future rate cases. Specifically, if the Arizona case takes longer than 15 months, our estimates would likely be high.

Brooke Glenn Mullin
(1-212) 622-1774
brooke.glennmullin@jpmchase.com

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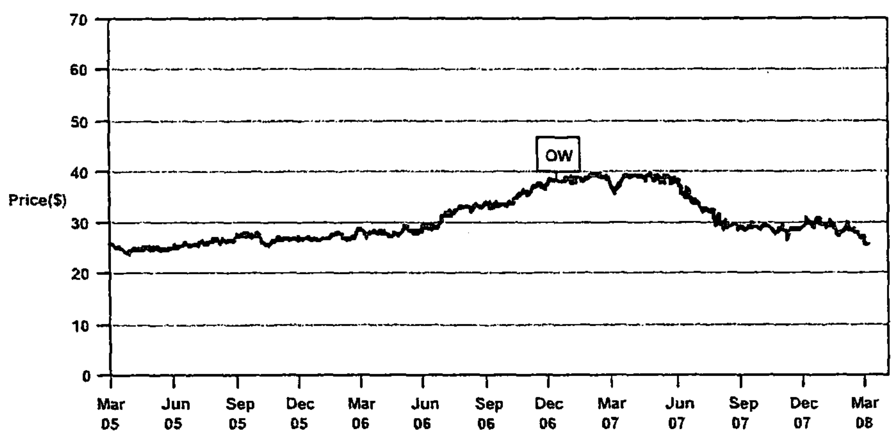
- **Non-Investment Banking Compensation:** An affiliate of JPMSI has received compensation in the past 12 months for products or services other than investment banking from Southwest Gas Corp..

Southwest Gas Corp. (SWX) Price Chart



Date	Rating	Share Price ($)	Price Target ($)
15-Dec-06	OW	38.42	-

Source: Reuters and JPMorgan; price data adjusted for stock splits and dividends.
Initiated coverage Dec 15, 2006. This chart shows JPMorgan's continuing coverage of this stock; the current analyst may or may not have covered it over the entire period.
JPMorgan ratings: OW = Overweight, N = Neutral, UW = Underweight.

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JPMorgan Equity Research Ratings Distribution, as of December 31, 2007

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JPM Global Equity Research Coverage	45%	41%	14%
IB clients*	50%	51%	38%
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IB clients*	71%	64%	49%

*Percentage of investment banking clients in each rating category.
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Brooke Glenn Mullin
(1-212) 622-1774
brooke.glennmullin@jpmchase.com

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"Other Disclosures" last revised February 6, 2008.

UBS

Global Equity Research

Americas

Gas Utilities

UBS Investment Research

Southwest Gas

12-month rating	Buy *Unchanged*
12m price target	US$38.00 *Prior:US$40.00*
Price	US$25.87

RIC: SWX.N BBG: SWX US

5 March 2008

4Q Results Lighter Than Anticipated

■ Warm November, Weak Construction Revenues Produce 4Q Miss

SWX realized recurring 4Q07 EPS of $1.00, well below our $1.23 EPS estimate and the $1.08 First Call consensus estimate. Extremely warm weather, particularly in Nov (AZ service territory experienced its warmest Nov in recorded history), and a sharp YOY decline in construction revenues were largely responsible for the miss. SWX also realized recurring 2007 EPS of $1.96, compared to $2.05 in 2006.

■ Dynamic Times Ahead; Dividend Increased Roughly 5%

The current housing glut in SWX's service territory (mgmt estimates there are ~25K vacant homes) presents a near-term challenge for the community and the company. However, continued economic development in Las Vegas and Phoenix, further implementation of ERT technology, and pending rate cases present growth opportunities. Accordingly, the Board recently approved a 4.7% dividend increase, which builds upon the 4.9% increase in 2007, the company's first since 1994.

■ Lowering 2008 and 2009 EPS Estimates; Introducing 2010

We are lowering our 2008 and 2009 EPS estimates to $2.12 and $2.24, from $2.30 and $2.47, respectively. These changes primarily reflect reduced expectations for customer growth and construction revenues, partially offset by lower anticipated interest expense as 2007 debt levels were lower than anticipated. We are also introducing a 2010 EPS estimate of $2.39.

■ Valuation: Trimming Price Target to $38; ~51% Total Return Potential

We are trimming our DCF-derived price target to $38, from $40, to reflect lower expected earnings, partially offset by lower than expect debt levels.

Highlights (US$m)	12/06	12/07	12/08E	12/09E	12/10E
Revenues	1,727.39	1,814.77	1,883.52	1,978.89	2,074.66
EBIT (UBS)	168.65	196.34	209.91	226.87	239.22
Net Income (UBS)	83.86	83.25	91.69	98.26	105.92
EPS (UBS, US$)	2.05	1.96	2.12	2.24	2.39
Net DPS (UBS, US$)	0.82	0.85	0.89	0.95	0.99

Profitability & Valuation	5-yr hist av.	12/07	12/08E	12/09E	12/10E
EBIT margin %	11.0	10.8	11.1	11.5	11.5
ROIC (EBIT) %	-	9.9	10.1	10.4	11.1
EV/EBITDA (core) x	6.9	6.8	5.7	5.3	5.0
PE (UBS) x	-	17.3	12.2	11.5	10.8
Net dividend yield %	3.3	2.5	3.4	3.7	3.8

Source: Company accounts, Thomson Financial, UBS estimates. (UBS) valuations are stated before goodwill-related charges and other adjustments for abnormal and economic items at the analysts' judgement.

Valuations: based on an average share price that year, (E): based on a share price of US$25.87 on 04 Mar 2008 18:56 EST

Ronald J. Barone
Analyst
ronald.barone@ubs.com
+1-212-713 3848

Shneur Z. Gershuni, CFA
Analyst
Shneur.Gershuni@ubs.com
+1-212-713 3974

Christopher P. Sighinolfi
Associate Analyst
Christopher.Sighinolfi@ubs.com
+1-212-713 2239

Trading data	
52-wk range	US$39.63-25.59
Market cap.	US$1.10bn
Shares o/s	42.5m (COM)
Free float	99%
Avg. daily volume ('000)	153
Avg. daily value (US$m)	4.4

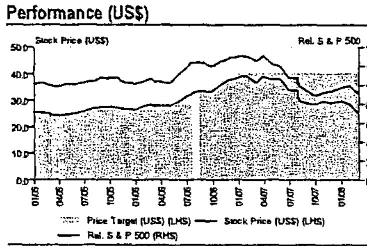
Balance sheet data 12/08E	
Shareholders' equity	US$1.04bn
P/BV (UBS)	1.1x
Net Cash (debt)	(US$1.43bn)

Forecast returns	
Forecast price appreciation	+46.9%
Forecast dividend yield	3.7%
Forecast stock return	+50.6%
Market return assumption	6.7%
Forecast excess return	+43.9%

EPS (UBS, US$)

	12/08E			12/07
	From	To	Cons.	Actual
Q1E	-	1.20	1.20	1.17
Q2E	-	(0.01)	0.00	(0.01)
Q3E	-	(0.23)	(0.22)	(0.22)
Q4E	-	1.16	1.12	1.00
12/08E	2.30	2.12	2.14	
12/09E	2.47	2.24	2.36	

Performance (US$)



Source: UBS

www.ubs.com/investmentresearch

■ Southwest Gas

Southwest Gas supplies natural gas to over 1,752,000 customers in California, Nevada, and Arizona. It operates in one of the fastest growing regions of the country and current enjoys customer growth that it is well above the national average.

■ Statement of Risk

Risks to our estimates and price target include: 1) unfavorable regulatory decisions; 2) mild weather; 3) customer conservation; and 4) higher than expected levels of uncollectible accounts.

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UBS 12-Month Rating	Rating Category	Coverage[1]	IB Services[2]
Buy	Buy	55%	39%
Neutral	Hold/Neutral	36%	36%
Sell	Sell	8%	20%
UBS Short-Term Rating	**Rating Category**	**Coverage[3]**	**IB Services[4]**
Buy	Buy	less than 1%	25%
Sell	Sell	less than 1%	50%

1:Percentage of companies under coverage globally within the 12-month rating category.
2:Percentage of companies within the 12-month rating category for which investment banking (IB) services were provided within the past 12 months.
3:Percentage of companies under coverage globally within the Short-Term rating category.
4:Percentage of companies within the Short-Term rating category for which investment banking (IB) services were provided within the past 12 months.

Source: UBS. Rating allocations are as of 31 December 2007.

UBS Investment Research: Global Equity Rating Definitions

UBS 12-Month Rating	Definition
Buy	FSR is > 6% above the MRA.
Neutral	FSR is between -6% and 6% of the MRA.
Sell	FSR is > 6% below the MRA.
UBS Short-Term Rating	**Definition**
Buy	Buy: Stock price expected to rise within three months from the time the rating was assigned because of a specific catalyst or event.
Sell	Sell: Stock price expected to fall within three months from the time the rating was assigned because of a specific catalyst or event.

KEY DEFINITIONS

Forecast Stock Return (FSR) is defined as expected percentage price appreciation plus gross dividend yield over the next 12 months.

Market Return Assumption (MRA) is defined as the one-year local market interest rate plus 5% (a proxy for, and not a forecast of, the equity risk premium).

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Company Disclosures

Company Name	Reuters	12-mo rating	Short-term rating	Price	Price date
Southwest Gas[16]	SWX.N	Buy	N/A	US$25.87	04 Mar 2008

Source: UBS. All prices as of local market close.
Ratings in this table are the most current published ratings prior to this report. They may be more recent than the stock pricing date

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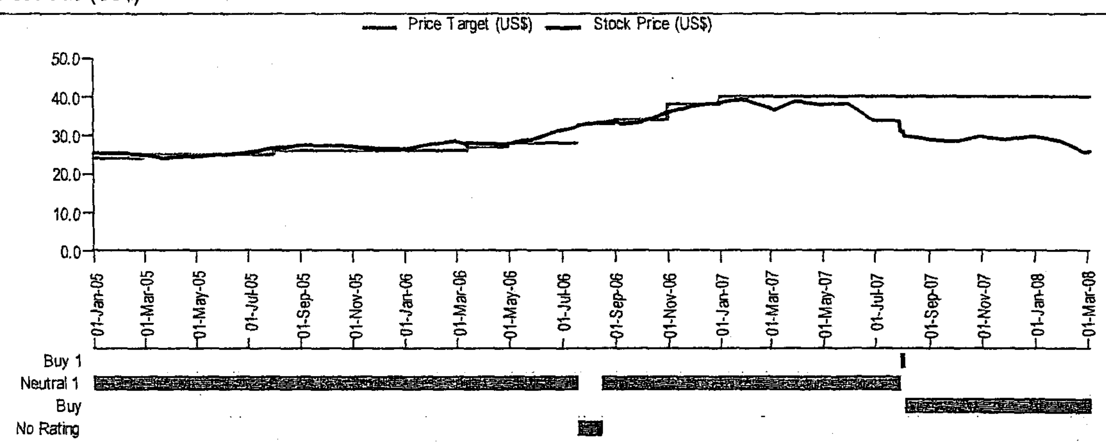
Southwest Gas (US$)



Source: UBS; as of 04 Mar 2008

Note: On August 4, 2007 UBS revised its rating system. (See 'UBS Investment Research: Global Equity Rating Definitions' table for details). From September 9, 2006 through August 3, 2007 the UBS ratings and their definitions were: Buy 1 = FSR is > 6% above the MRA, higher degree of predictability; Buy 2 = FSR is > 6% above the MRA, lower degree of predictability; Neutral 1 = FSR is between -6% and 6% of the MRA, higher degree of predictability; Neutral 2 = FSR is between -6% and 6% of the MRA, lower degree of predictability; Reduce 1 = FSR is > 6% below the MRA, higher degree of predictability; Reduce 2 = FSR is > 6% below the MRA, lower degree of predictability. The predictability level indicates an analyst's conviction in the FSR. A predictability level of '1' means that the analyst's estimate of FSR is in the middle of a narrower, or smaller, range of possibilities. A predictability level of '2' means that the analyst's estimate of FSR is in the middle of a broader, or larger, range of possibilities. From October 13, 2003 through September 8, 2006 the percentage band criteria used in the rating system was 10%.

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UBS

Company Focus

SMALL & MID CAP

6 March 2008 | 12 pages

Southwest Gas Corp (SWX)

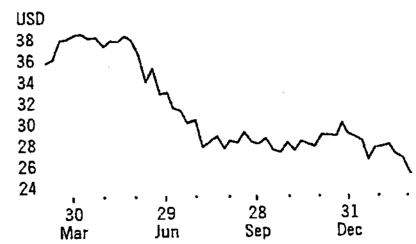
Change in opinion ☑
Rating change ☑
Estimate change ☑

Slowing Growth is a Good Thing; Upgrade to Buy

- **Why Now?** — We are upgrading SWX to Buy from Hold. Over the last 3 years the fundamentals for SWX have improved enormously with CFO per customer up 16%, capex per customer down 1% (expected to fall 27% by '11) & overall returns on rate base (ROR) up 50 bps. Despite these improvements, SWX is down 30% since mid-summer compared to 15% for a portfolio of gas utilities.
- **What's Wrong?** — We believe the housing downturn in AZ, NV and CA has led some to believe that SWX will be negatively impacted by lower customer growth (6% previously down to 3% on the high-end). We think differently. First, we had always assumed that customer growth would trend back to normal levels. Second, during times of high customer growth, SWX struggled to earn its cost of capital because of historical test years in its rate cases (EVA negative). We estimate a one to two year lull in housing growth will enable SWX to push ROR above its costs of capital creating positive EVA.
- **Catalysts** — SWX filed for a $50 mm rate increase in AZ. We estimate they get at least $14 mm of this increase with the potential to achieve slightly over $30 mm. Historically, Arizona has been a difficult regulatory environment, however recent changes in state legislation may provide SWX the opportunity to gain constructive regulatory mechanisms in the form of decoupling.
- **Valuation** — With 7% EPS growth and a 3.5% dividend yield, SWX ranks 2 out of 23 in our valuation screen of defensive utilities. Our Target price is $37 using our pyramid analysis implies a 15.0x P/E multiple on '09 earnings and a 6.5x EV/EBITDA multiple on '09 EBITDA.

Buy/High Risk	**1H**
from Hold/High Risk	
Price (06 Mar 08)	US$25.19
Target price	US$37.00
Expected share price return	46.9%
Expected dividend yield	3.6%
Expected total return	**50.5%**
Market Cap	US$1,084M

Price Performance (RIC: SWX.N, BB: SWX US)



EPS	Q1	Q2	Q3	Q4	FY	FC Cons
2007A	1.17A	-0.01A	-0.22A	1.00A	1.96A	1.95A
2008E	**1.22E**	**-0.01E**	**-0.19E**	**1.15E**	**2.17E**	**2.08E**
Previous	1.27E	0.01E	-0.17E	1.10E	2.21E	na
2009E	**1.31E**	**0.05E**	**-0.14E**	**1.17E**	**2.39E**	**2.23E**
Previous	1.34E	0.05E	-0.13E	1.11E	2.37E	na
2010E	**1.32E**	**0.05E**	**-0.14E**	**1.18E**	**2.41E**	**2.39E**
Previous	1.35E	0.06E	-0.12E	1.12E	2.41E	na

Source: Powered by dataCentral. FC Cons: First Call Consensus.

Faisel Khan, CFA
+1-212-816-2825
faisel.khan@citi.com

Barry Klein, CPA
barry.klein@citi.com

See Appendix A-1 for Analyst Certification and important disclosures.

Fiscal year end 31-Dec	2006	2007	2008E	2009E	2010E
Valuation Ratios					
P/E adjusted (x)	12.7	12.9	11.6	10.6	10.5
EV/EBITDA adjusted (x)	6.6	6.1	5.8	5.6	5.5
P/BV (x)	1.2	1.1	1.0	1.0	0.9
Dividend yield (%)	3.3	3.4	3.6	3.6	3.6
Per Share Data (US$)					
EPS adjusted	1.98	1.96	2.17	2.39	2.41
EPS reported	2.05	1.96	2.17	2.39	2.41
BVPS	21.68	23.05	24.57	26.25	27.90
DPS	0.82	0.85	0.90	0.90	0.90
Profit & Loss (US$M)					
Net sales	2,025	2,152	1,892	1,840	1,880
Operating expenses	-1,819	-1,932	-1,650	-1,577	-1,610
EBIT	**205**	**221**	**242**	**263**	**270**
Net interest expense	-96	-96	-98	-100	-100
Non-operating/exceptionals	14	7	6	6	6
Pre-tax profit	**124**	**131**	**150**	**170**	**176**
Tax	-43	-48	-55	-63	-65
Extraord./Min.Int./Pref.div.	3	0	0	0	0
Reported net income	**84**	**83**	**94**	**107**	**111**
Adjusted earnings	81	83	94	107	111
Adjusted EBITDA	374	403	427	451	461
Growth Rates (%)					
Sales	18.1	6.3	-12.1	-2.7	2.2
EBIT adjusted	27.9	7.4	9.6	8.7	2.6
EBITDA adjusted	18.2	7.7	6.0	5.7	2.1
EPS adjusted	51.2	-1.3	10.9	9.9	0.9
Cash Flow (US$M)					
Operating cash flow	**281**	**348**	**266**	**278**	**301**
Depreciation/amortization	169	183	185	189	191
Net working capital	25	66	-14	-18	-1
Investing cash flow	**-312**	**-332**	**-306**	**-303**	**-282**
Capital expenditure	-345	-341	-306	-303	-282
Acquisitions/disposals	0	0	0	0	0
Financing cash flow	**20**	**-3**	**2**	**1**	**-2**
Borrowings	-19	-1	0	0	0
Dividends paid	-34	-36	-39	-40	-41
Change in cash	**-11**	**13**	**-37**	**-24**	**17**
Balance Sheet (US$M)					
Total assets	**3,485**	**3,670**	**3,758**	**3,861**	**3,977**
Cash & cash equivalent	19	32	0	0	17
Accounts receivable	226	204	203	197	201
Net fixed assets	2,668	2,845	2,966	3,080	3,171
Total liabilities	**2,584**	**2,687**	**2,678**	**2,673**	**2,679**
Accounts payable	266	221	210	188	193
Total Debt	1,414	1,413	1,419	1,443	1,443
Shareholders' funds	**901**	**984**	**1,080**	**1,188**	**1,297**
Profitability/Solvency Ratios (%)					
EBITDA margin adjusted	18.5	18.7	22.6	24.5	24.5
ROE adjusted	9.8	8.8	9.2	9.4	8.9
ROIC adjusted	5.7	5.6	5.8	6.0	5.9
Net debt to equity	154.8	140.4	131.3	121.4	109.8
Total debt to capital	61.1	59.0	56.8	54.8	52.6

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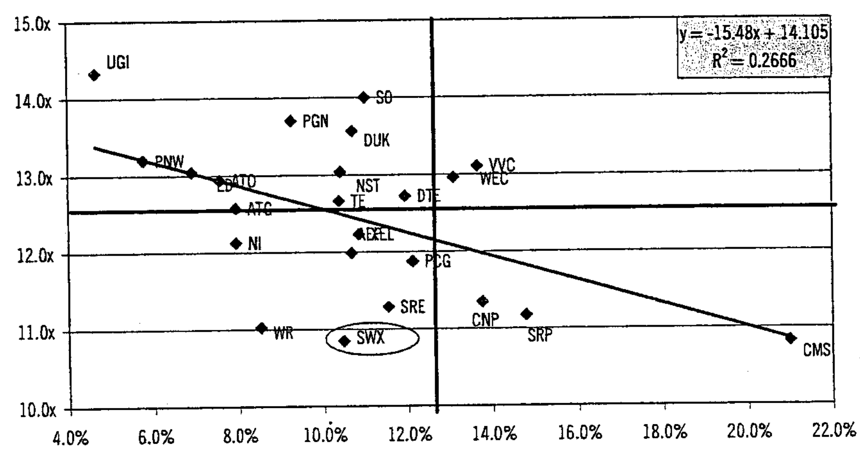
Higher Yielding Names Outperforming

We analyzed 23 utility names coverage by Citi to examine the relationship between valuation, yield and growth. Broadly, the results indicate that recently higher yielding stocks trade at a premium, even to those with higher short-term total return (yield plus earnings growth). Our analysis shows that Southwest Gas trades at a 13% discount to the group when taking into account growth through 2010.

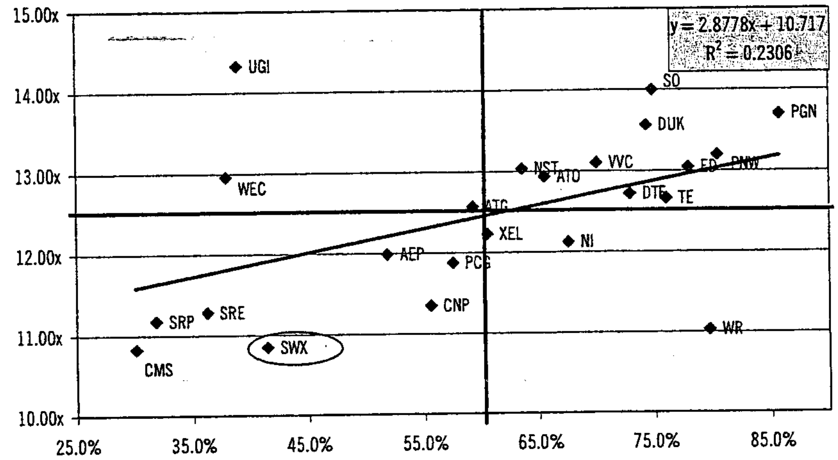
Figure 1. '09 P/E Ratio vs. FY '07E-'10E EPS Growth + Yield as of 3/6/2008



Source: Citi Investment Research, DataCentral

Ironically, Southwest Gas also trades at a 9% discount to the group when taking into account its '08 payout ratio of 41%. Our analysis indicates the Company should trade at an 11.9x '08 P/E multiple based upon its payout ratio, yet it only trades at 10.8x.

Figure 2. Citi Investment Research '09E P/E Ratio vs. '08E Payout Ratio

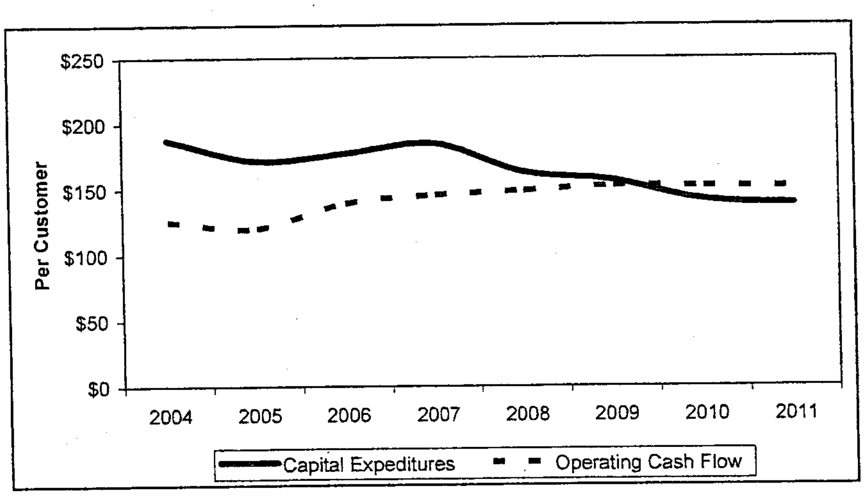


Source: Citi Investment Research

Cash In vs. Cash Out

With extensive capital growth in Arizona and Nevada over the past few years, we have seen a situation where capex per customer has been exceeding operating cash flows per customer. However, since 2004 we have seen this difference narrow. Going forward, we expect operating cash flows per customer to exceed capex per customer. This will improve overall ROIC.

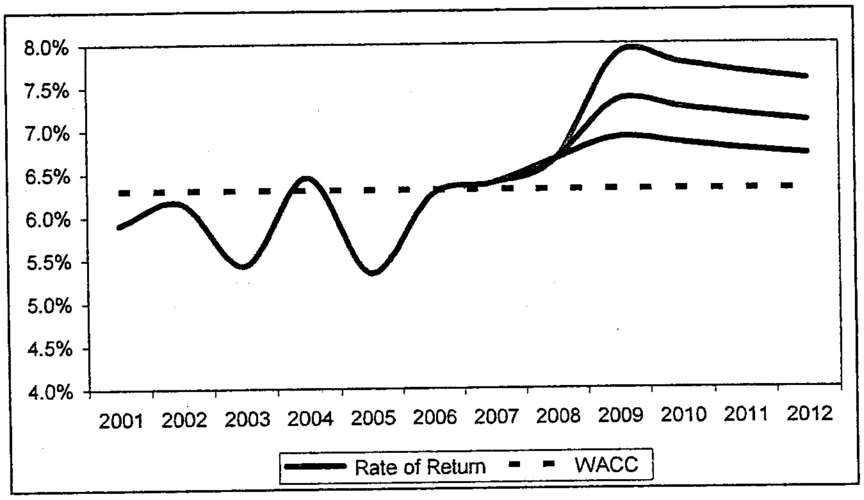
Figure 3. SWX Operating Cash Flow Per Customer Vs. Capex Per Customer



Source: Citi Investment Research, Company Reports

Historically, SWX achieved returns below its cost of capital. With slowing growth in its service territories resulting in reduced regulatory lag, we expect the spread between rate of return and cost of capital to expand going forward.

Figure 4. Rate of Return at Varying AZ Rate Increase Assumptions ($14mm, $30mm, $50mm) vs. WACC



Source: Citi Investment Research, Company Reports

Regulatory

About 90% of SWX's earnings are dependent on timely recovery of capital expenditures at its gas utilities.

Arizona

Southwest Gas recently filed for a $50 million rate increase in its Arizona service area, along with requests for weather normalization and decoupling mechanisms. These rate mechanisms are increasingly important considering the Company's sensitivity to weather, which impacted earnings during the year by $0.18 per share or nearly 10% of total earnings.

Going forward, we assume normal weather, but a mechanism insulating earnings from weather fluctuations would enable SWX to more consistently achieve its allowed returns on equity. Furthermore, implementation of decoupling mechanisms would stabilize earnings in the wake of customer conservation.

We expect a decision by early October, prior to this year's heating season.

Figure 5. Arizona Rate Case Schedule

Event	Date
Staff / Intervenor Cost of Service Testimony	3/29/2008
Staff / Intervenor Rate Mechanism Testimony	4/11/2008
Southwest Gas Rebuttal Testimony	5/9/2008
Staff / Intervenor Rebuttal Testimony	5/27/2008
Rejoinder Testimony	6/9/2008
Pre-hearing Conference	6/13/2008
Expected Decision	10/1/2008

Source: Citi Investment Research, Regulatory Data

SWX's $50 million rate increase is premised upon an ROE of 11.25% (45% equity) on a rate base of nearly $1.1 billion. This is compared with the utility's current authorized ROE of 9.5% (40% equity) on a rate base of about $925 million. We estimate the utility commission will at least approve a rate increase of $13.9 million, based on an ROE of 9.5% (42% equity) on a rate base of $1.081 billion (excluding working capital). We feel a fair return would be closer to $30 million as the Company expects this amount would cover capital and O&M increases since its previous rate case. Our lower number reflects a highly politicized regulatory environment in Arizona.

Figure 6. Arizona Rate Case – Potential Outcomes

	Citi Est	Practical	SWX
Test Year Rate Base	$1.081 billion	$1.081 billion	$1.095 billion
Expected Increase	$13.9 million	$30.0 million	$50.2 million

Source: Citi Investment Research, RRA Focus

Nevada

A Nevada law approving decoupling for utilities has been passed and the Company believes details on implementation will be provided by the end of summer. The utility will need to file with the Commission to approve decoupling. Therefore, we expect the Company to file for a rate increase and decoupling by the beginning of 4Q. Assuming a 6 to 7 month rate case timetable, we now estimate rate relief of $3.6 million in 2Q 2009, compared with 4Q 2008 previously. The negative impact on earnings due to timing of rate relief will be $0.01 per share in 2008 and 2009.

California

In October, Southwest Gas filed for a $9.1 million rate increase in its California service area as part of a state required filing. SWX's rate request is premised upon an 11.5% ROE (47% equity) for a rate base of $210 million and would become effective the beginning of 2009. We believe the utility is already earning a fair return and thus provide no incremental change to rates.

Southwest Gas files an attrition filing annually to update rates based upon capital spent between rate cases. The Commission recently approved a $2 million rate attrition increase, effective the beginning of 2008. This increase will add $0.03 per share to our estimates going forward.

Southwest Gas Corp

Company description

Southwest Gas Corporation (SWX) distributes natural gas to 1.8 million customers through local utilities in California, Nevada, and Arizona; transports gas for its affiliates and third parties on interstate pipelines; and is involved in the installation of natural gas distribution piping across the United States.

Investment strategy

We rate SWX Buy/High Risk (1H) with a $37 target price.

Our Hold rating for SWX is premised on the company obtaining a reasonable rate of return on its regulated asset base. SWX's regulated customer base grew by 28%, and its asset base grew by 48%, mostly through organic growth over the past five years. This type of growth within a regulatory framework inevitably leaves shareholders exposed to regulatory lag; however, utilities are entitled to just and reasonable rates, and we believe an inflection point has been reached, allowing SWX to catch up. Last year, SWX earned a 8% ROE on its entire asset base compared with its allowed return of between 10% and 11%.

Moderating customer growth and upcoming rate relief could help to mitigate the impact of regulatory lag in the coming years.

Valuation

We use several valuation scenarios to reach our target price of $37 per share.

Our NAV analysis results in a value of $37.28 per share. We apply a 1.3x–1.6x multiple to a combined authorized rate base of roughly $1.8 billion for the regulated local distribution companies and pipelines in California, Arizona, and Nevada. We derive our rate base multiple from our analysis of historical transactions in the pipeline and gas utility sector.

We utilize a combined dividend discount model for the regulated earnings at SWX and DCF analysis for the unregulated construction business. This analysis results in a value of $29.76 per share

Our long-term P/E multiple of 16.2x (2011 EPS) is based on an analysis of historical blended gas multiples. We derive the multiple from a peer group of 29 stocks in the natural gas sector over the last eleven years. Our blended EV/EBITDA (2011 EBITDA) multiple of 8.3x is based on the same gas industry peer group used above. Our P/E and EV/EBITDA analyses yield values of $28.02 and $40.06, respectively.

The average of these values yields a value of $33.78 per share. With a cost of equity at 8.9%, our 12-month target price of $37 per share.

Risks

Our High Risk rating for SWX is based the company's exposure to a difficult regulatory body in Arizona, the need to raise equity to fund the capex program (i.e., negative free cash flow), Moody's negative credit watch outlook, high sensitivity of earnings to changes in weather, the stock's relative lack of trading liquidity, and the relatively low market capitalization of the company compared with other utilities. These concerns are partially offset by a stable regulated earnings stream from the transmission pipelines and natural gas utilities which account for 92% of 2007 operating income. Risks to the shares attaining our target price include:

Population growth - Housing demand could slow to a rate below estimates or increase above our estimates, causing us to revise our estimates and valuation.

Capital investment recovery - SWX spends capital to maintain and expand its operations. The company will continue to rely on state regulatory commissions to recover costs in excess of depreciation. While we believe SWX's relationship with the ACC has been more productive those of other utilities operating in the state, the ACC and, for that matter, the other commissions may not allow the company to earn a reasonable rate of return on its rate base.

Capital Markets - SWX is a relatively small utility in terms of market capitalization and daily volumes. This may impact its ability to access the capital markets.

Appendix A-1

Analyst Certification

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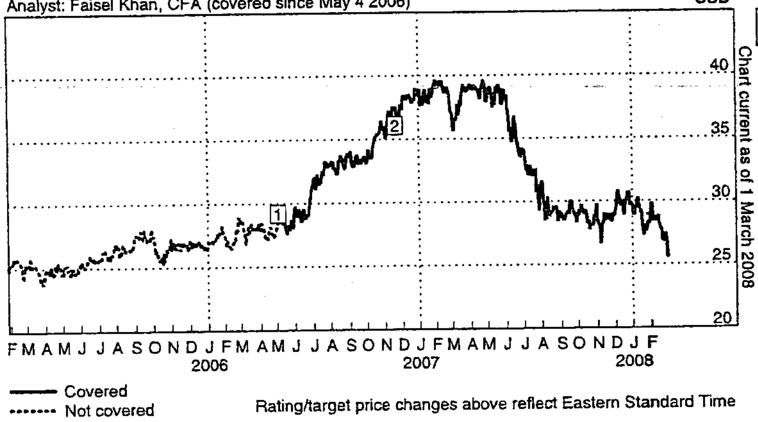
IMPORTANT DISCLOSURES

Southwest Gas Corp (SWX)

Ratings and Target Price History - Fundamental Research

Analyst: Faisel Khan, CFA (covered since May 4 2006)



#	Date	Rating	Target Price	Closing Price
1:	3 May 06	*1H	*35.00	28.68
2:	20 Nov 06	*2H	*37.00	37.55

*Indicates change.

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ADDITIONAL INFORMATION IS AVAILABLE UPON REQUEST

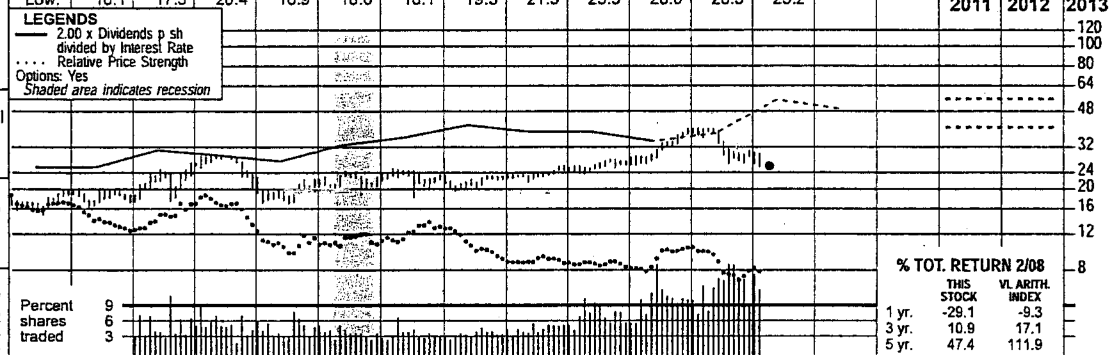
SOUTHWEST GAS NYSE-SWX

RECENT PRICE 25.87 | P/E RATIO 12.9 (Trailing: 13.3; Median: 19.0) | RELATIVE P/E RATIO 0.83 | DIV'D YLD 3.5% | VALUE LINE

TIMELINESS 4 Raised 11/9/07
SAFETY 3 Lowered 1/4/91
TECHNICAL 2 Raised 2/15/08
BETA .90 (1.00 = Market)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
High:	20.3	26.9	29.5	23.0	24.7	25.3	23.6	26.2	28.1	39.4	39.9	30.5
Low:	16.1	17.3	20.4	16.9	18.6	18.1	19.3	21.5	23.5	26.0	26.5	25.2

LEGENDS
— 2.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession



Target Price Range 2011 | 2012 | 2013

2011-13 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+115%)	23%
Low	40	(+55%)	14%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	1	1	0	0	1	0	0	1

Institutional Decisions

	2Q2007	3Q2007	4Q2007
to Buy	93	85	82
to Sell	79	95	84
Hld's(000)	32178	32940	34975

Percent shares traded 9 6 3

% TOT. RETURN 2/08

	THIS STOCK	VL ARITH. INDEX
1 yr.	-29.1	-9.3
3 yr.	10.9	17.1
5 yr.	47.4	111.9

1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	© VALUE LINE PUB., INC.	11-13
25.93	25.68	28.16	23.03	24.09	26.73	30.17	30.24	32.61	42.98	39.68	35.96	40.14	43.59	48.47	50.00	52.95	55.55	Revenues per sh A	61.45
3.34	3.24	5.09	2.65	3.00	3.85	4.48	4.45	4.57	4.79	5.07	5.11	5.57	5.20	5.97	6.18	6.35	6.65	"Cash Flow" per sh	7.40
.81	.63	1.22	.10	.25	.77	1.65	1.27	1.21	1.15	1.16	1.13	1.66	1.25	1.98	1.95	2.05	2.20	Earnings per sh A B	2.65
.70	.74	.80	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.86	.90	.94	Div'ds Decl'd per sh C ■	1.06
5.02	5.43	6.64	6.79	8.19	6.19	6.40	7.41	7.04	8.17	8.50	7.03	8.23	7.49	8.27	7.92	8.40	8.65	Cap'l Spending per sh	9.90
15.99	15.96	16.38	14.55	14.20	14.09	15.67	16.31	16.82	17.27	17.91	18.42	19.18	19.10	21.58	22.85	23.30	23.35	Book Value per sh	26.05
20.60	21.00	21.28	24.47	26.73	27.39	30.41	30.99	31.71	32.49	33.29	34.23	36.79	39.33	41.77	43.04	44.00	45.00	Common Shs Outst'g D	48.00
16.6	26.5	14.0	NMF	69.3	24.1	13.2	21.1	16.0	19.0	19.9	19.2	14.3	20.6	15.9	17.3	Bold figures are	Value Line estimates	Avg Ann'l P/E Ratio	18.0
1.01	1.57	.92	NMF	4.34	1.39	.69	1.20	1.04	.97	1.09	1.09	.76	1.10	.86	.91			Relative P/E Ratio	1.20
5.2%	4.4%	4.7%	5.4%	4.7%	4.4%	3.8%	3.1%	4.2%	3.8%	3.6%	3.8%	3.5%	3.2%	2.6%	2.6%			Avg Ann'l Div'd Yield	2.2%

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009		11-13
	917.3	936.9	1034.1	1396.7	1320.9	1231.0	1477.1	1714.3	2024.7	2152.1	2330	2500	Revenues ($mill) A	2950
	47.5	39.3	38.3	37.2	38.6	38.5	58.9	48.1	80.5	83.3	90.0	100	Net Profit ($mill)	125
	43.4%	35.5%	26.2%	34.5%	32.8%	30.5%	34.8%	29.7%	37.3%	36.5%	35.0%	35.0%	Income Tax Rate	35.0%
	5.2%	4.2%	3.7%	2.7%	2.9%	3.1%	4.0%	2.8%	4.0%	3.9%	3.9%	4.0%	Net Profit Margin	4.2%
	60.2%	60.3%	60.2%	56.2%	62.5%	66.0%	64.2%	63.8%	60.6%	58.1%	57.0%	56.5%	Long-Term Debt Ratio	52.0%
	35.3%	35.5%	35.8%	39.6%	34.1%	34.0%	35.8%	36.2%	39.4%	41.9%	43.0%	43.5%	Common Equity Ratio	48.0%
	1349.3	1424.7	1489.9	1417.6	1748.3	1851.6	1968.6	2076.0	2287.8	2349.8	2375	2400	Total Capital ($mill)	2600
	1459.4	1581.1	1686.1	1825.6	1979.5	2175.7	2336.0	2489.1	2668.1	2845.3	3000	3150	Net Plant ($mill)	3600
	5.8%	4.8%	4.6%	5.1%	4.3%	4.2%	5.0%	4.3%	5.5%	5.6%	6.0%	6.0%	Return on Total Cap'l	6.5%
	8.9%	7.0%	6.5%	6.0%	5.9%	6.1%	8.3%	6.4%	8.9%	8.5%	9.0%	9.5%	Return on Shr. Equity	10.0%
	10.0%	7.8%	7.2%	6.6%	6.5%	6.1%	8.3%	6.4%	8.9%	8.5%	9.0%	9.5%	Return on Com Equity	10.0%
	5.0%	2.8%	2.4%	1.9%	1.9%	1.7%	4.3%	2.2%	5.2%	4.8%	5.0%	5.5%	Retained to Com Eq	6.0%
	50%	64%	67%	71%	70%	72%	49%	65%	42%	44%	44%	42%	All Div'ds to Net Prof	41%

CAPITAL STRUCTURE as of 12/31/07

Total Debt $1413.1 mill. Due in 5 Yrs $616.0 mill.
LT Debt $1366.0 mill. LT Interest $93.0 mill.
(Total interest coverage: 2.4x)

Pension Assets-12/07 $441.7 mill. Oblig. $546.4 mill.

Pfd Stock None

Common Stock 43,044,024 shs. as of 2/15/08

MARKET CAP: $1.1 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2005	2006	12/31/07
Cash Assets	29.6	18.8	32.0
Other	513.1	482.8	470.5
Current Assets	542.7	501.6	502.5
Accts Payable	259.5	265.7	220.7
Debt Due	107.2	27.5	47.1
Other	254.3	202.9	260.1
Current Liab.	621.0	496.1	527.9
Fix. Chg. Cov.	167%	220%	229%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '05-'07 to '11-'13
Revenues	6.0%	4.5%	4.5%
"Cash Flow"	4.5%	4.0%	4.0%
Earnings	12.0%	6.0%	7.5%
Dividends	--	--	4.0%
Book Value	3.0%	3.5%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	542.9	361.1	313.3	497.0	1714.3
2006	676.9	430.9	351.8	565.1	2024.7
2007	793.7	426.6	371.5	560.3	2152.1
2008	850	460	400	620	2330
2009	880	510	450	660	2500

Cal-endar	EARNINGS PER SHARE B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.88	d.07	d.43	.87	1.25
2006	1.11	.02	d.26	1.11	1.98
2007	1.17	d.01	d.22	1.00	1.95
2008	1.20	Nil	d.20	1.05	2.05
2009	1.20	.05	d.15	1.10	2.20

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2004	.205	.205	.205	.205	.82
2005	.205	.205	.205	.205	.82
2006	.205	.205	.205	.205	.82
2007	.205	.215	.215	.215	.85
2008	.215	.225			

BUSINESS: Southwest Gas Corporation is a regulated gas distributor serving approximately 1.8 million customers in sections of Arizona, Nevada, and California. Comprised of two business segments: natural gas operations and construction services. 2007 margin mix: residential and small commercial, 86%; large commercial and industrial, 5%; transportation, 9%. Total throughput: 2.4 billion therms. Sold PriMerit Bank in July of 1996. Has 5,073 employees. Officers & Directors own roughly 1.4% of common stock (3/07 Proxy). Chairman: LeRoy C. Hanneman, Jr. Chief Executive Officer: Jeffrey W. Shaw. Incorporated: California. Address: 5241 Spring Mountain Road, Las Vegas, Nevada 89193. Telephone: 702-876-7237. Internet: www.swgas.com.

Southwest Gas reported unimpressive performance for the fourth quarter. Share earnings fell roughly 10% from the prior year's period. The company experienced softness in heating demand, owing to warmer-than-usual temperatures during the period. This was partially offset by modest growth in the customer base. Overall, 2007 earnings came in slightly below the 2006 figure. Looking forward, conditions may remain somewhat challenging in the current year. We anticipate relatively slow customer growth, due partly to the downturn in the housing market. Thus, we have lowered our bottom-line estimate by $0.20 a share, to $2.05.

The company remains focused on procuring rate relief and improving rate design. In order to address weather-related volatility, Southwest has included several proposed rate design changes in its most recently filed Arizona rate case. The utility is seeking a rate hike of $50.2 million (nearly 5%). It has asked the commission to implement the new rates at the start of October. The company has also filed a rate case application with California, requesting a $9.1 million increase in operating revenues, beginning in January of 2009. Such approved revenue increases help Southwest Gas to cope with higher operating expenses, and provide the company with greater earnings stability. Indeed, a full year of rate relief in 2009 should produce healthy growth in earnings, to $2.20 per share.

The board of directors has increased the dividend. Starting with the June payout, the quarterly dividend is now $0.225 a share, an increase of 4.7%. This follows a similar increase last year. However, this issue's current dividend yield of roughly 3.5% is not a standout by utility standards.

Shares of Southwest Gas are ranked unfavorably in our momentum-based system. Looking further out, we anticipate solid share-earnings growth over the pull to 2011-2013. At the present quotation, this stock offers impressive total return potential for the coming years, and may appeal to patient investors. That said, conservative accounts are advised not to overweight this issue, considering the regulatory risks.

Michael Napoli, CPA *March 14, 2008*

(A) Incl. income for PriMerit Bank on the equity basis through 1994. (B) Based on avg. shares outstand. thru. '96, then diluted. Excl. nonrec. gains (losses): '93, 8¢; '97, 16¢; '02, (10¢); '05, (11¢); '06, 7¢. Incl. asset writedown: '93, 44¢. Excl. loss from disc. ops.: '95, 75¢. Totals may not sum due to rounding. Next egs. report due late April. (C) Dividends historically paid early March, June, September, December. ■ Div'd reinvest. plan avail. (D) In millions.

Company's Financial Strength	B
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	65

S-27

249-016

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-2
(ACC-STF-2-1 THROUGH ACC-STF-2-22)

EXHIBIT
S-27
ADMITTED

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: DECEMBER 19, 2007

Request No. STF-2-16:

Please identify each utility regulatory rate proceeding in which Mr. Hanley has provided cost of capital testimony since 2000 and provide the following information:

i. Name of utility
j. Name of regulatory jurisdiction
k. Docket number
l. Date of testimony
m. Cost of equity recommended
n. Cost of equity approved.

Respondent: Treasury Services

Response:

Please see the requested information attached.

Attachment to Response to STF-DP-2.16

Frank J. Hanley's Cost of Capital Testimony from January 2000 through December 2007

Client	Type of Testimony Provided by Mr. Hanley	Regulatory Body	Docket Number	Recommended by Mr. Hanley: Date of Filing	Recommended by Mr. Hanley: ROE	Recommended by Mr. Hanley: Common Equity Ratio	Authorized by Regulatory Body: Date of Order	Authorized by Regulatory Body: ROE	Authorized by Regulatory Body: Common Equity Ratio
United Water Idaho	Direct - ROE	Idaho Public Utility Commission	UW-W-00-1	02/02/00	11.300 %	43.070 %	NA	NA %	NA %
PG Energy	Direct - ROE	Pennsylvania Public Utility Commission	C-R-005119	04/03/00	12.800	50.000	12/07/00	-- (1)	-- (1)
Southwest Gas Corporation	Direct - ROE	Arizona Corporation Commission	D-G-01551-A-00-0309	05/05/00	12.800	42.000	10/24/01	11.000	40.000
T.W. Phillips Gas and Oil Company	Direct - ROE	Pennsylvania Public Utility Commission	R-00005459	07/14/00	13.400	50.010	Early 2001	-- (1)	-- (1)
Tesoro Alaska Company (RE: TAPS Carriers) *	Direct - Cap. St. & ROE	Regulatory Commission of Alaska	P-97-4	12/13/00	14.000 (2)	50.500	11/27/02	14.750	50.500
Tesoro Alaska Company (RE: TAPS Carriers) *	Direct - Cap. St. & ROE	Regulatory Commission of Alaska	P-97-4	12/13/00	13.250 (3)	50.500	11/27/02	14.360	50.500
Tesoro Alaska Company (RE: TAPS Carriers) *	Direct - Cap. St. & ROE	Regulatory Commission of Alaska	P-97-4	12/13/00	12.250 (4)	50.500	11/27/02	13.010	50.500
Tesoro Alaska Company (RE: TAPS Carriers) *	Direct - Cap. St. & ROE	Regulatory Commission of Alaska	P-97-4	12/13/00	12.500 (5)	50.500	11/27/02	13.460	50.500
Mountaineer Gas Company	Direct - ROE	West Virginia Public Service Commission	C-01-0011-G-42T	03/02/01	13.000 (6)	50.000	10/31/01	-- (1)	-- (1)
Mountaineer Gas Company	Direct - ROE	West Virginia Public Service Commission	C-01-0011-G-42T	03/02/01	17.950 (7)	50.000	10/31/01	-- (1)	-- (1)
J. L. Properties (RE: Golden Heart Utilities)	Direct - ROE	Regulatory Commission of Alaska	U-00-115 / U-00-116	03/05/01	12.850	50.000	09/24/01	13.85	70.00
Saltville Gas Storage Company L.L.C	Direct - ROE	Virginia State Corporation Commission	PUE010585	12/21/01	15.000	35.000	NA	NA	NA
Southwest Gas Corporation	Direct - ROE	Public Service Commission of Nevada	D-01-7023	07/13/01	12.500	42.000	12/1/2001	-- (1)	-- (1)
Interstate Power and Light Company (Electric)	Direct - ROE	Iowa Department of Commerce- Utilities Board	D-RPU-02-3	03/29/02	12.250	51.322	04/15/03	11.150	47.203
Tesoro Alaska Company (RE: Olympic Pipeline)	Direct - Cap. St. & ROE	Federal Energy Regulation Commission	IS01-441-003	04/22/02	13.750	46.400	NA	NA	NA
Virgin Islands Public Service Commission (RE: Virgin Islands Innovative Telephone Co.)	Direct - ROE	Virgin Island Public Services Commission	Docket No. 532	04/29/02	15.400	45.570	NA	16.570	69.260
Tesoro Refining and Marketing Company (RE: Olympic Pipeline)	Direct - Cap. St. & ROE	Washington Utilities & Transportation Commission	TO-011472	05/13/02	13.000	46.400	NA	NA	NA
Interstate Power and Light Company (Gas)	Direct - ROE	Iowa Department of Commerce- Utilities Board	D-RPU-02-7	07/15/02	12.100	51.322	05/15/03	11.050	47.838
Arkansas Western Gas Company	Direct - ROE	Arkansas Public Service Commission	D-02-227-U	11/08/02	12.900	39.040	09/17/03	9.900	35.200
J L Properties Inc (RE: Golden Heart Utilities)	Direct - ROE	Regulatory Commission of Alaska	U-02-13 / U-02-14	11/22/02	12.650 (8)	53.670	NA	NA	NA
J L Properties Inc (RE: Golden Heart Utilities)	Direct - ROE	Regulatory Commission of Alaska	U-02-13 / U-02-14	11/22/02	12.650 (9)	50.960	NA	NA	NA
National Fuel Gas Distribution Corp.	Direct - ROE	Pennsylvania Public Utility Commission	C-R-00038168	04/16/03	12.750	53.000	12/23/03	-- (1)	-- (1)
Interstate Power and Light Company (Electric)	Direct - ROE	Minnesota Public Utility Commission	D-E-001/GR-03-767	05/19/03	12.300	47.261	04/05/04	11.250	47.150
Tesoro Alaska Company (RE: TAPS Carriers) *	Direct - Cap. St. & ROE	Alaska Pubic Utility Commission	P-03-4	09/03/03	12.950 (10)	49.480	06/10/04 (13)	--	--
Tesoro Alaska Company (RE: TAPS Carriers) *	Direct - Cap. St. & ROE	Alaska Pubic Utility Commission	P-03-4	09/03/03	13.525 (11)	50.120	06/10/04 (13)	--	--
Tesoro Alaska Company (RE: TAPS Carriers) *	Direct - Cap. St. & ROE	Alaska Pubic Utility Commission	P-03-4	09/03/03	15.050 (12)	51.660	06/10/04 (13)	--	--
Southwest Gas Corp. (Northern Nevada Div.)	Direct - ROE	Public Service Commission of Nevada	D-04-3011	03/08/04	11.750 (14)	42.000	08/26/04	10.500	40.000
Southwest Gas Corp. (Southern Nevada Div.)	Direct - ROE	Public Service Commission of Nevada	D-04-3011	03/08/04	11.750 (14)	42.000	08/26/04	10.500	40.000
City of Vernon, California	Direct - ROE	Federal Energy Regulation Commission	EL-00-105-007/ER-00-2019-007	04/28/04	12.065	45.800	NA	NA	NA
National Fuel Gas Distribution Corp.	Direct - Cap. St. & ROE	New York Public Service Commission	C-04-G-1047	08/27/04	11.875	51.090	07/22/05	-- (1)	-- (1)
National Fuel Gas Distribution Corp.	Direct - Cap. St. & ROE	Pennsylvania Public Utility Commission	C-R-00049656	09/15/04	11.875	51.500	03/30/05	-- (1)	-- (1)
Southwest Gas Corporation	Direct - ROE	Arizona Corporation Commission	G-01551A-04-0876	12/08/04	11.950 (15)	42.000	02/23/06	9.500	40.000
Southwest Gas Corporation	Direct - ROE	Arizona Corporation Commission	G-01551A-04-0876	12/08/04	11.700 (16)	42.000	02/23/06	9.500	40.000
Mountaineer Gas Holdings, LP	Direct - ROE	West Virginia Public Service Commission	04-1595-G-42T	02/09/05	12.250 (17)	41.210	08/11/05	-- (1)	-- (1)
Interstate Power & Light (Gas)	Direct - ROE	Iowa Utilities Board	RPU-05-1	04/15/05	11.500	51.423	10/14/05	10.400 (1)	49.350
Interstate Power and Light Co. (Electric)	Direct - ROE	Minnesota Public Utilities Commission	E001/GR-05-748	05/16/05	11.500	50.664	03/03/06	10.390 (1)	49.100
Anadarko Petroleum Corporation (Re: TAPS Carriers) *	Direct - ROE	Federal Energy Regulatory Commission	IS05-82-000	12/07/05	12.160	45.000	05/17/07 (18)	12.160 (18)	45.000 (18)
PG Energy	Direct - ROE	Pennsylvania Public Utility Commission	R-00061365	04/13/06	11.950	46.000	11/30/06	-- (1)	-- (1)
Missouri Gas Energy	Direct - ROE	Missouri Public Service Commission	GR-2006-0422	05/01/06	11.950	46.000	03/22/07	10.500	36.060 (19)
National Fuel Gas Dist. Corp.	Direct - ROE	Pennsylvania Public Utility Commission	R-00061493	05/15/06	12.000 - 12.250 (20)	51.500	12/04/06	-- (1)	-- (1)
New England Gas Company	Direct - ROE	Massachusetts Department of Tel. and Energy	DPU-07-46	07/17/06	12.150	46.000	07/31/07	-- (1, 21)	-- (1, 21)
Washington Gas Light Company	Direct - ROE	Virginia State Corporation Commission	PUE-2006-00059	09/15/06	10.750 - 11.750 (22)	55.560 (22)	09/19/07	10.000 (1, 23)	-- (1)
Washington Gas Light Company	Direct - ROE	District of Columbia Public Service Commission	Docket No. 1054	12/21/06	10.580 - 11.580 (24)	55.480 (24)	12/28/07 (25)	9.700 (1, 25)	-- (1, 25)

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Frank J. Hanley's Cost of Capital Testimony from January 2000 through December 2007

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National Fuel Gas Dist. Corp.	Direct - Cap. St. & ROE	New York Public Service Commission	07-G-0141	01/29/07	11.150 - 11.650 (26)	51.500	12/21/07	(27)	9.100	44.350
Washington Gas Light Company	Direct - ROE	Maryland Public Service Commission	Docket No. 9104	04/20/07	10.500 - 11.500 (28)	56.040 (28)	11/16/07		10.000	53.020
Corning Natural Gas Corp.	Direct - Cap. St. & ROE	New York Public Service Commission	07-G-0772	06/30/07	11.000 - 12.000 (29)	48.350	12/13/07	(30)	10.000	- - (30)
Southwest Gas Corporation	Direct - ROE	Arizona Corporation Commission	G-0155A-07-0504	08/31/07	11.250	45.000	NA	(31)	NA	NA
Interstate Power and Light Co. (Wind Farm Project)	Direct - ROE	Iowa Utilities Board	RPU-07-5	09/28/07	12.300	NA	NA	(32)	11.700 %(1, 32)	NA (32)

NA = Not Available

TAPS = Trans Alaska Pipeline System

Notes:

(1) Order followed stipulation or settlement by the parties. Decision particulars not necessarily precedent-setting or specifically adopted by the regulatory body. ROE or Common Equity Ratio may not be specified.

(2) Applicable to the Year 2000.

(3) Applicable to the Year 1999.

(4) Applicable to the Year 1998.

(5) Applicable to the Year 1997.

(6) Applicable with a Traditional Regulatory Ratemaking Safety Net.

(7) Applicable to an extended period without the protection of the Traditional Regulatory Ratemaking Safety Net.

(8) Applicable to Water Utility Operations.

(9) Applicable to Wastewater Utility Operations.

(10) Going forward based upon August 2003.

(11) Applicable to the Year 2002.

(12) Applicable to the Year 2001.

(13) The TAPS Carriers' tariff filings were rejected. The permanent tariff rates determined in Docket No. 97-4 remain in effect until the Commission approves revised rates.

(14) Mr. Hanley's recommended ROE was 11.50%, if the requested Margin Per Customer Balancing Provision was approved.

(15) Recommendation without protection against weather and / or change in volumes.

(16) Recommended common equity cost rate assuming approval of the requested Conservation Margin Tracker (CMT).

(17) Mr. Hanley recommended a common equity cost rate of 12.25%, while Mountaineer Gas Holding requested only 11.90%.

(18) ALJ's recommended decision. Awaiting FERC final order.

(19) Parent company capital structure was utilized.

(20) Mr. Hanley's recommended range of common equity cost rate was 12.00% - 12.25%. NFGDC chose to request the high end of the range, or 12.25%, as explained in the testimony of NFGDC Witness Eric Meinl.

(21) On June 8, 2007, Southern Union Company dba New England Gas Company filed a petition with the Massachusetts Department of Telecommunications and Energy (MDTE) seeking approval of an offer of settlement entered into with the Attorney General of the Commonwealth and the Low-Income Energy Affordability Network (LEAN). On July 31, 2007, the MDTE issued an order approving the settlement, which is silent regarding cost of capital issues. Settlement agreement was reached before the direct testimonies of the Attorney General and LEAN were filed.

(22) Mr. Hanley recommended a common equity cost rate of 11.25%, the midpoint of a range of 10.75% - 11.75%. It was applicable to the Company's 55.56% common equity ratio, part of the capital structure supported by Company Witness Vincent L. Ammann.

(23) The settlement and SCC order did not specify parameters upon which the stipulated increase was based, but it did specify that a reasonable equity return for the company was 10%, the mid-point of a 9.5%-to-10.5% range. The settlement and SCC order also provide for implementation of a four-year performance-based rate (PBR) plan that includes an earnings sharing mechanism (ESM), and a weather normalization adjustment (WNA). The ESM allows the Company to retain earnings up to a 10.50% ROE before sharing commences.

(24) Mr. Hanley recommended a common equity cost rate of 11.08%, the midpoint of a range of 10.58% - 11.58%. It is applicable to the Company's 55.48% common equity ratio, part of the capital structure supported by Company Witness Vincent L. Ammann. As of part of the settlement agreement discussed on Note 25, WGL withdrew its application for Revenue Normalization Adjustment Clause (RNA), which was reflected in the recommended ROE. Furthermore, as part of the settlement agreement WGL withdrew its application for a Performance-Based Rate Plan (PBR).

(25) On December 14,2007, WGL filed a joint motion for approval of a non-unanimous settlement in the proceeding. On December 28, 2007, the District of Columbia Public Service Commission approve the non-unanimous settlement agreement. As of part of the settlement agreement WGL withdrew its application for approval of a PBR plan. Furthermore, WGL withdrew its application for a approval of a RNA. However, the settling parties agree that Washington Gas may seek approval of a RNA through a separate formal proceeding after the Commission has issued its initial decision on the proposed "Bill Stabilization Adjustment" in the Potomac Electric Power Company rate proceeding. The settlement agreement does not expressly state a specific return on common equity or common equity ratio. However, according to the order, based on the capital structure ratios and cost figures for long-term debt, short-term debt, and preferred stock proposed by Washington Gas, approval of the Settlement would result in a 9.70% return on common equity.

(26) Mr. Hanley's recommended range of common equity cost rate depending upon whether the requested CIP (See Note 27) was approved or not.

(27) On September 19, 2007, the PSC approved the Conservation Incentive Program (CIP), which allowed National Fuel Gas Distribution Corporation to move forward in developing the program in detail. On October 31, 2007, NFG's announced that as part of its CIP, rebates will be available for qualifying natural gas equipment, beginning with purchases made on or after November 1, 2007. The CIP represents a substantial commitment to running extensive programs promoting the benefits of conservation through education, rebate offers and targeted low-income initiatives. The other issues still included in the request filed in January 2007 were addressed in the final order issued by the New York Public Service Commission on December 21, 2007.

(28) Mr. Hanley's recommended common equity cost rate was 11.00%, the midpoint of a range of 10.50% - 11.50%, which was applicable to the Company's 56.040% common equity ratio, part of the capital structure supported by Company Witness Vincent L. Ammann. A RNA (See Note 24) has been and is in place.

(29) Mr. Hanley's recommended range of common equity cost rate was based upon a range which is 50 basis points above and below the 11.50% indicated common equity cost rate after adjustment for unique risk. 11.00% = 11.50% - 0.50% and 12.00% = 11.50% + 0.50%.

(30) On October 22, 2007, a procedural conference was held to discuss Corning's request that the rate case be treated as a mini rate case on an accelerated basis. The active parties (Corning, Multiple interveners and Bath) did not oppose this case being converted to a mini and staff acting in an advisory capacity. In addition, a deadline of November 27, 2007 was agreed to by the parties attending the conference with no replies. A final decision by the New York Public Service Commission was issued on December 13, 2007. Although the order established a 10.0% Allowed ROE, it does not state the common equity ratio associated with such ROE.

(31) This instant proceeding is still in progress. Testimonies of other parties have not been filed.

(32) On November 8, 2007, the Consumer Advocate Division of the Iowa Department of Justice filed with the Iowa Utilities Board a "Motion to Suspend Procedural Schedule" in this docket. In support of the motion the Consumer Advocate stated that it had negotiated with IPL a settlement of all issues in this case. The signatories of the settlement agreement agreed that the allowed rate of return on common equity capital on the portion of the IPL Wind Project shall be 11.700%. On November 19, 2007, the Iowa Utilities Board issued an order suspending procedural schedule. Awaiting final order by the Iowa Utilities Board.