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AZ CORP COMMISSION
DOCKET CONTROL

COMMISSIONERS
MIKE GLEASON, Chairman
WILLIAM A. MUNDELL
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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 **STAFF'S NOTICE OF FILING SURREBUTTAL TESTIMONY**

The Utilities Division ("Staff") hereby files the Surrebuttal Testimonies of Ralph C. Smith; Corky Hanson; Frank W. Radigan; David C. Parcell; Phillip S. Teumim; Robert G. Gray; Rita R. Beale; and Stephen L. Thumb.

RESPECTFULLY SUBMITTED this 27th day of May, 2008.

Maureen Scott

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

Arizona Corporation Commission
DOCKETED

MAY 27 2008

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Original and thirteen (13) copies of the foregoing filed this 27th day of May 2008 with:

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Copies of the foregoing mailed
this 27th day of May 2008 to:

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SURREBUTTAL
TESTIMONY
OF

RALPH C. SMITH
CORKY HANSON
FRANK W. RADIGAN
DAVID C. PARCELL
PHILLIP S. TEUMIM
ROBERT G.GRAY
RITA R. BEALE
STEPHEN L. THUMB

DOCKET NO. G-01551A-07-0504

IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS OPERATIONS THROUGHOUT ARIZONA

MAY 27, 2008

SMITH

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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ATTACHMENTS

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 <u>steel pipe replacement, similar to Yuma Manors pipe</u>.* (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]

[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,*

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[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

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[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?

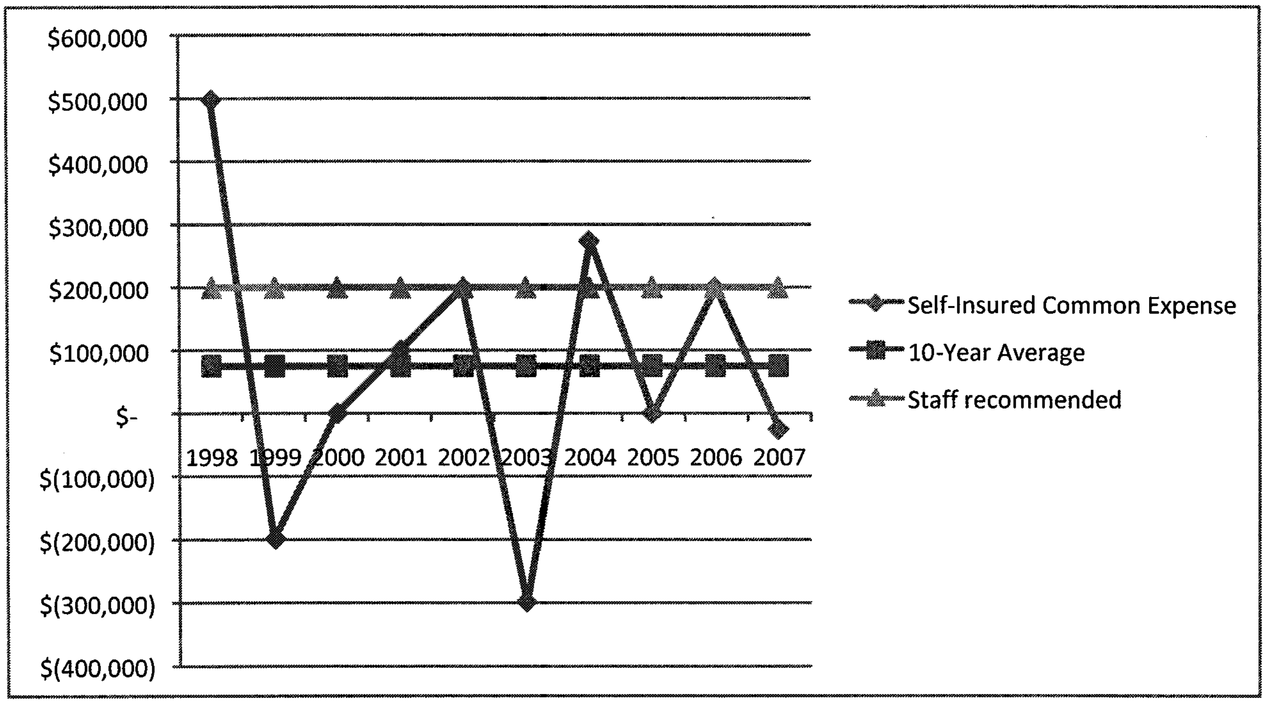
A. No. Staff conducted an investigation, the details of which are provided in the response to data request STF-13-20 (provided in Attachment RCS-8) which concluded that the cause of the explosion and fire was natural gas leaking from a buried main in the alley behind a duplex apartment in Tucson; however,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

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

Test Year Ended April 30, 2007

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

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

Test Year Ended April 30, 2007

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

Line No.	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

		Original Cost			RCND		
Line No.	Description	As Adjusted by SWG (A)	Staff Adjustments (B)	As Adjusted by Staff (C)	As Adjusted by SWG (D)	Staff Adjustments (E)	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	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	$ (1,579,978)	$ (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
Page 1 of 1

Line No.	Description	As Adjusted by Company (A)	Staff Adjustments (B)	As Adjusted by Staff (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 C-1	Gain on Sale of Utility Property C-2	Management Incentive Program C-3 Revised	Stock Based Compensation C-4	Supplemental Executive Retirement Expense 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

Test Year Ended April 30, 2007

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

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

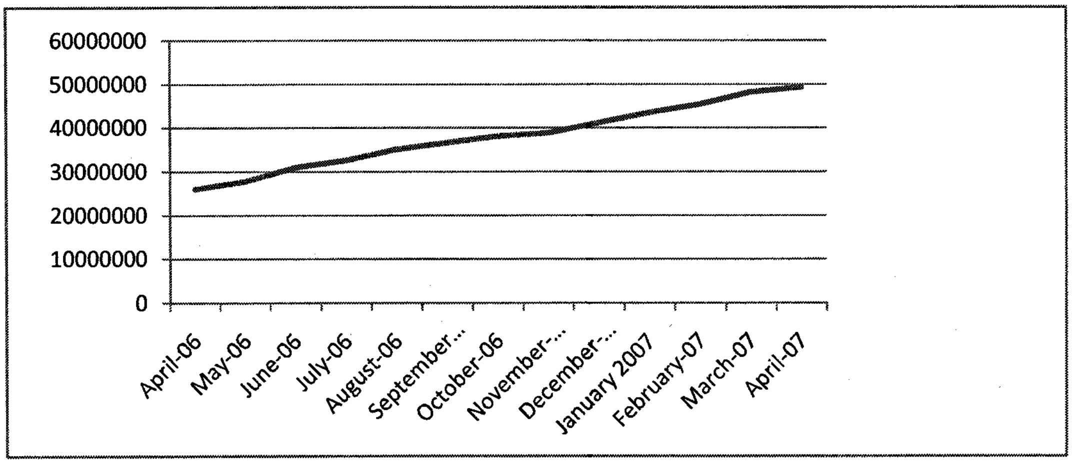
Test Year Ended April 30, 2007

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

Line No.	Description		Amount	Reference
			(A)	
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	Monthly Change
		(B)	(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

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

Test Year Ended April 30, 2007

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

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

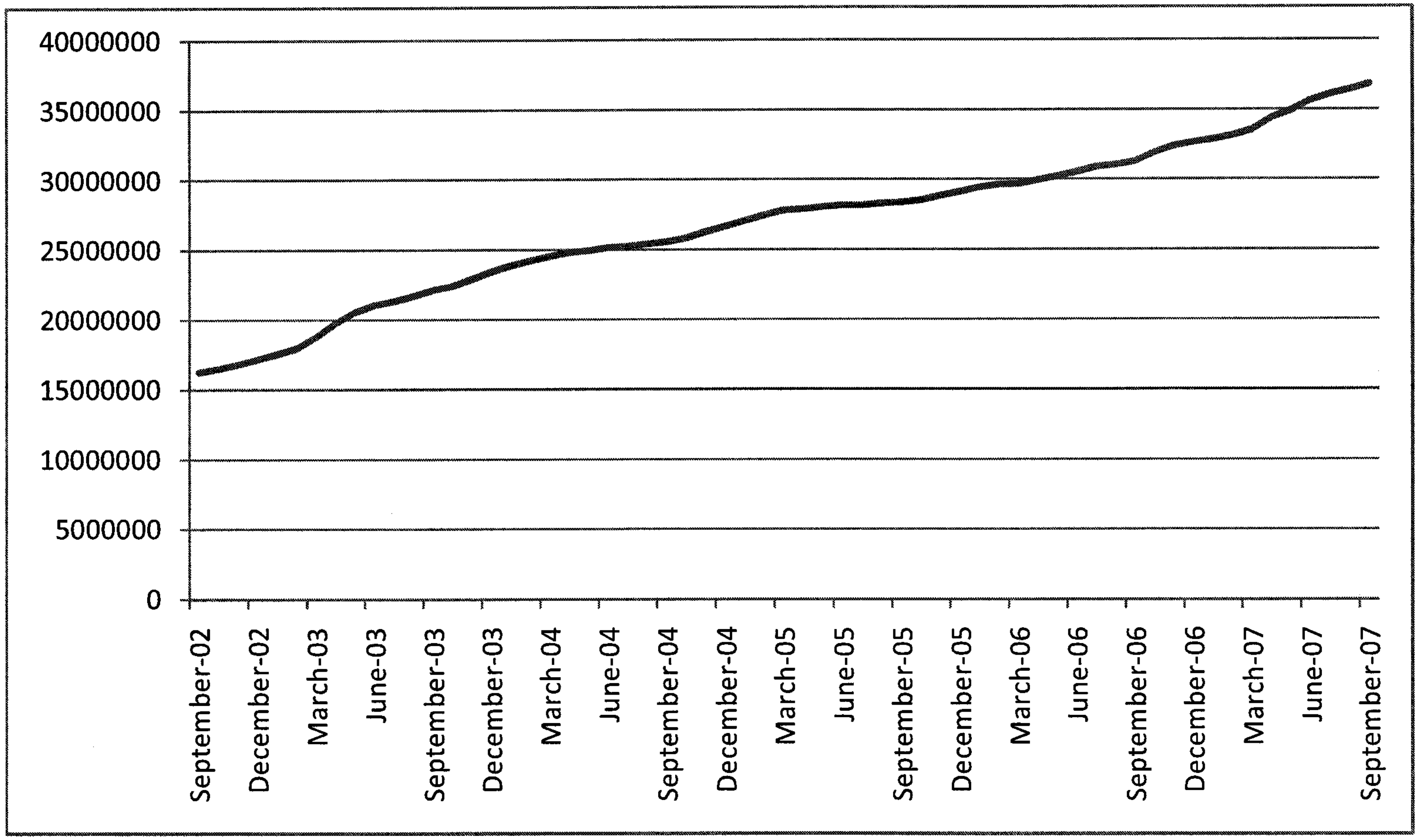
Line No.	Month		Amount		Monthly Change
			(A)		(B)
1	September-02	$	16,250,822		
2	October-02	$	16,492,184	$	241,362
3	November-02	$	16,804,948	$	312,764
4	December-02	$	17,151,007	$	346,059
5	January-03	$	17,539,415	$	388,408
6	February-03	$	17,955,206	$	415,791
7	March-03	$	18,771,907	$	816,701
8	April-03	$	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

Docket No. G-01551A-07-0504
Schedule B-5

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

		System Allocable			RCN Deferred Taxes for Acct 190		
Line No.	Year	Total Acct 190 Deferred Tax Asset at 4/30/07	4-Factor	Total Acct 190 Deferred Tax Asset at 4/30/07 for Arizona	H -W Index	Ratio to Current Index	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

Line No.	Description	Southwest Proposed Amount (A)	Staff Proposed Amount (B)	Staff Adjustment (C)	Reference
	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

		Arizona			System Allocable					Total	RCN Deferred Taxes		
Line No.	Year	Total Federal 282 Deferred Tax Liability at 4/30/07	Total State 282 Deferred Tax Liability at 4/30/07	Total Arizona Recorded Deferred Tax Liability at 4/30/07	Total Federal 282 Deferred Tax Liability at 4/30/07	Total Acct 190 Deferred Tax Asset at 4/30/07	Total System Allocable at 4/30/07	4-Factor	Total Recorded Deferred Tax Liability at 4/30/07	Total AZ Recorded Deferred Tax Liability at 4/30/07	H -W Index	Ratio to Current Index	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

Docket No. G-01551A-07-0504
Schedule B-8
Page 1 of 1

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

Test Year Ended April 30, 2007

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

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

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

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
Page 1 of 1

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)

Test Year Ended April 30, 2007

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

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

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

		March 2005 NARUC Audit Report for Year Ended 12/31/02		AGA 2007 Budget			AGA 2008 Budget		
Line No.	NARUC Operating Expense Category	% of Dues	Recommended Disallowance	% of Dues	With G&A Allocated	Recommended Disallowance	% of Dues	With G&A Allocated	Recommended Disallowance
		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(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

			12 Months Ended April 30, 2007						
Line No.	Description	FERC Account	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

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	$ 2,579,781	$ (851,717)	
				Col.B - Col.A	Col.C - Col.A		
	Components of Company's proposed adjustments to Account 925, I&J Expense:						
20	SWG Adjustment 7, Out of Period Expenses			$ 253,324	$ 253,324	$ 253,324	
21	SWG Adjustment 10, Self Insured Retention Normalization			$ 2,228,455 b	$ 2,318,148 b	$ 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)	$ (851,717)
						L.23, Col.D - Col.B	

Notes and Source

A SWG response to Staff data request STF-9-14
B Derived from SWG filing, Schedule C-2, Company Adjustment Nos. 7, 10 and 12 and response to STF-9-14
C SWG response to Staff data request STF-9-14
D See page 2 of this schedule for Staff analysis of ten years of recorded expense for
a Paiute allocation used by SWG in its filing does not calculate exactly to 3.96%
b SWG Adjustment 10, Self Insured Retention Normalization

Line	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	$ 2,438,624	$ 1,388,765	
			L.27, Col.B - Col.A To Line 21	L.27, Col.C - Col.A		
				Line 16 Less line 22		
30	Paiute allocation	$ (223,984) Line 16		$ (344,460)	$ (236,011)	$ (12,027)
31	Change in Paiute allocation from test year recorded			$ (120,476)	$ (12,027)	
32	Company's proposed corrected adjustment, net of change in Paiute allocation			$ 2,318,148		$ (851,717) c
				To Line 21		
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

Line No.	Description	Year	Total Expense Recorded		Total Expense Recorded Without Extreme Expense from May 2005 Leaking Gas Line Fire		Staff Proposed	
			Arizona	Common	Arizona	Common	Arizona	Common
			(A)	(B)	(C)	(D)	(E)	(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

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

Test Year Ended April 30, 2007

Line No.	Description	Amount (A)	Reference
	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

Line	Account	2004 (B)	2005 (C)	2006 (D)	2007 (E)	Average (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	Estimated Asset Amount	Service Life	Annual Amortization	Asset Amount	Actual In-Service Date	Annual Amortization	Plant	Annual Amortization
		(A)	(B)	(C)	(D)	(E)	(F)	(H)	(I) E - B	(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

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)

Response to STF-6-49: *(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] (a)	Annual Amortization (b)	CWIP Balance @4/30/07 (c)	Estimated In-Service Date (d)	Estimated Asset Amount (e)	Service Life (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)

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

Request No. ACC-STF-13-12:

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.

Respondent: Revenue Requirements

Response:

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.

SOUTHWEST GAS CORPORATION
ARIZONA GENERAL RATE CASE
INCENTIVE PROGRAMS
IN RESPONSE TO DATA REQUEST NO. RUCO-1-10
UPDATED 3/25/08

	DATE		CORP		AZ	Account
MIP						
Eligiblity: Sr Mgrs and Above	2004	$	5,699,300			920
	2005		5,681,550			920
	2006		5,241,806			920
	12ME Apr 07		5,919,502			920
Exempt Special Incentive						
Eligibility: All non-incentive	2004	$	150,700			920
exempts with at least 6	2005		148,450			920
mos. service	2006		154,500			920
	12ME Apr 07		151,250			920
Service Planning						
Quality Incentive Award	2004	$	168,035	$	431,425	903
Eligiblity: service planners,	2005		140,171		465,150	903
their supvs and managers,	2006		143,865		367,534	903
industrial gas engineers	12ME Apr 07		137,522		290,004	903
Stock Option Expense						
Expense that must be	2004		-			n/a
recognized on Southwest's	2005		-			n/a
books	2006		1,493,694			920
	12ME Apr 07		1,507,520			920

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	Reference	Allocation Percent	System Allocable	10-Year Total	Total Arizona Accrual	Line No.
	(a)	(b)	(c)	(d)	(d)	(e)	
	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.

STF-13-13
Sheet 4 of 5

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

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

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	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

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: Paiute & 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

313-015

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.

313-017

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.

313-019

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	Reference	Allocation Percent	System Allocable	10-Year Total	Total Arizona Accrual	Line No.
	(a)	(b)	(c)	(d)	(d)	(e)	
	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						$\boxed{5,000,000}$		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	Total Payout	Less Expense	Indemnity Payments	Southwest Gas Liability < $1MM	Southwest Gas Liability $1MM SIR	Southwest Gas Liability $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	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

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

		Southwest Gas Liability						
Line No.	Rate Jurisdiction	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

TABLE OF CONTENTS

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

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

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 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
   - O Meter Set
   - O Service Line
   - O Other: ____________
   - O Pressure Limiting and Regulating Facility
2. Failure occurred on
   - ⦿ Body of pipe
   - O Pipe Seam
   - O Joint
   - O Component
   - O Other: ____________
3. Material involved *(pipe, fitting, or other component)*
   - O Steel
   - O Cast/Wrought Iron
   - ⦿ Polyethelene Plastic (complete all items that apply in a-c)
   - O Other Plastic (complete all items that apply in a-c)
   - Plastic failure was: ☐ a.ductile ☒ b.brittle ☐ c.joint failure
   - O 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
   - O Under pavement
   - ⦿ Under ground
   - O Inside/under building
   - O In open ditch
   - O Above ground
   - O Under water
   - O 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
   - O Bare
   - O Coated
   - O Unknown

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

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

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

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

F2 – NATURAL FORCES N/A

3. ☐ Earth Movement ⇒ O Earthquake O Subsidence O Landslide O Other: ____________
4. ☐ Lightning
5. ☐ Heavy Rains/Floods ⇒ O Washouts O Flotation O Mudslide O Scouring O Other: ____________
6. ☐ Temperature ⇒ O Thermal stress O Frost heave O Frozen components O 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
     O General Public O Government O Excavator other than Operator/subcontractor
   - b. Type: O Road Work O Pipeline O Water O Electric O Sewer O Phone/Cable/Fiber O Landowner O Railroad O Building Construction O Other: ____________
   - c. Did operator get prior notification of excavation activity?
     O No O Yes: Date received: / / / mo. / / / day / / / yr.
     Notification received from: O One Call System O Excavator O General Contractor O Landowner
   - d. Was pipeline marked?
     O No O Yes *(If Yes, check applicable items i – iv)*
     - i. Temporary markings: O Flags O Stakes O Paint
     - ii. Permanent markings: O Yes O No
     - iii. Marks were *(check one)* O Accurate O Not Accurate
     - iv. Were marks made within required time? O Yes O No

F4 – OTHER OUTSIDE FORCE DAMAGE N/A

10. ☐ Fire/Explosion as primary cause of failure ⇒ Fire/Explosion cause: O Man made O 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? 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

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

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

INCIDENT REPORT - GAS DISTRIBUTION SYSTEM

[illegible]

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 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

Form RSPA F 7100.1 (03-05)

Reproduction of this form is permitted

PART C – ORIGIN OF THE INCIDENT

1. Incident occurred on
   - ⊙ Main O Meter Set
   - O Service Line O Other: ______
   - O Pressure Limiting and Regulating Facility
2. Failure occurred on
   - ⊙ Body of pipe O Pipe Seam
   - O Joint O Component
   - O Other: ______
3. Material involved *(pipe, fitting, or other component)*
   - O Steel
   - O Cast/Wrought Iron
   - ⊙ Polyethelene Plastic (complete all items that apply in a-c)
   - O Other Plastic (complete all items that apply in a-c)
   - Plastic failure was: ☐ a.ductile ☒ b.brittle ☐ c.joint failure
   - O 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
   - O Under pavement
   - ⊙ Under ground
   - O Inside/under building
   - O In open ditch
   - O Above ground
   - O Under water
   - O 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
   - O Bare
   - O Coated
   - O Unknown

b. Visual Examination
   - O Localized Pitting
   - O General Corrosion
   - O Other: ______

c. Cause of Corrosion
   - O Galvanic O Stray Current
   - O Improper Cathodic Protection
   - O Microbiological
   - O Other: ______

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

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

F2 – NATURAL FORCES N/A

3. ☐ Earth Movement ⇒ O Earthquake O Subsidence O Landslide O Other: ______
4. ☐ Lightning
5. ☐ Heavy Rains/Floods ⇒ O Washouts O Flotation O Mudslide O Scouring O Other: ______
6. ☐ Temperature ⇒ O Thermal stress O Frost heave O Frozen components O 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
     O General Public O Government O Excavator other than Operator/subcontractor
   - b. Type: O Road Work O Pipeline O Water O Electric O Sewer O Phone/Cable/Fiber O Landowner O Railroad O Building Construction O Other: ______
   - c. Did operator get prior notification of excavation activity?
     O No O Yes: Date received: / / / mo. / / / day / / / yr.
     Notification received from: O One Call System O Excavator O General Contractor O Landowner
   - d. Was pipeline marked?
     O No O Yes *(If Yes, check applicable items i – iv)*
     - i. Temporary markings: O Flags O Stakes O Paint
     - ii. Permanent markings: O Yes O No
     - iii. Marks were *(check one)* O Accurate O Not Accurate
     - iv. Were marks made within required time? O Yes O No

F4 – OTHER OUTSIDE FORCE DAMAGE N/A

10. ☐ Fire/Explosion as primary cause of failure ⇒ Fire/Explosion cause: O Man made O 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. ☒ 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:

☒ 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

Amended Return

RETURN DUE 1/20/2008	CITY LICENSE NO. 84017643	
DELINQUENT IF RECEIVED AFTER 1/31/2008	PERIOD FROM 1207	M THRU 1207

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 botton 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 ~~478,918.18~~	2.0% ~~1.8%~~	10,536.20 ~~8,620.53~~
	6					Equals (=)	~~626,505.67~~
	7					Plus (+)	0.00
	8					Equals (=)	~~626,505.67~~
	9	ENTER EXCESS CITY TAX COLLECTED (from line B1 on Page 2)				Plus (+)	0.00
	10					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.

Reporting Period 12/07 - 12/07 M License No. 84017643M

Do not write in this area

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					

Line	Description		Amount
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) 350-8659
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.

			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	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	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
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

[signature]	01/09/08	
Taxpayer's Signature	Date	Paid Preparer's Signature
Laura Hoffman, Sr. Tax Accountant	(702) 876-7039	
Print Name	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 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.

Business Description	Line	Activity #	Column 1 Gross	Column 2 Allowable pg 2 - Deductions	Column 3 = Net Taxable	Column 4 x Tax Rate	Column 5 = 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		Column 1	Column 2	Column 3	Column 4	Column 5
	Business Description	Business Class Code	Gross Receipts / Use Taxable Purchases	From Sch. A, on back - Deductions	= Net Taxable	x Tax Rate	= 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: [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 CHANDLER and list your license number on your check.

4615125699

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	

GLENDALE

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

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	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 Add'l 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)

PRIVILEGE (SALES) and USE TAX RETURN

LICENSE NO.
2573
REPORTING PERIOD
Dec 2007
DUE BY THE 20th OF
Jan 2008

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						

Line			
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

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

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

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 10-48
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

Business Description	Line	Bus. Class	Column 1 Gross	Column 2 - Deductions	Column 3 = Net Taxable	Column 4 x Tax Rate	Column 5 = 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: 880085720
☒ EIN ☐ SSN

PERIOD BEGINNING: 04012007
PERIOD ENDING: 04302007

TAXPAYER INFORMATION

☐ Amended Return ☒ Multipage Return ☐ One-Time On ☐ Final

DOR USE ONLY ☒ LABELED RETURN

SOUTHWEST GAS CORP
C/O TAX DEPT
PO BOX 98510
LAS VEGAS, NV 89193-8510

21-2233

10011009297c04061050

POSTMARK DATE

☐ Address Changed

RECEIVED DATE

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	-
Subtotal				3,576,850.91	-	3,576,850.91		228,426.21		-

II. TAX COMPUTATION

		Line	Amount
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.

PAID PREPARER'S SIGNATURE (OTHER THAN TAXPAYER)

5/18/07

TAXPAYER'S SIGNATURE DATE
Laura Hoffman, Sr. Tax Accountant

PAID PREPARER'S EIN OR SSN

Please make check payable to Arizona Department of Revenue

ansaction Privilege, Use, and Severance Tax Return (TPT-1) LICENSE NO: 11 009297-C

RANSACTION 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
0	UTILITIES	LAP	004	91,372.88		91,372.88	.06600	6,030.61	0.000560	-
1	RETAIL	LAP	017	-		-	.06600	-	0.000560	-
2	UTILITIES	MAH	004	90,365.08		90,365.08	.06300	5,693.00	0.000560	-
3	RETAIL	MAH	017	-		-	.06300	-	0.000560	-
4	USE TAX	MAH	029	-		-	.05600	-	N/A	N/A
5	UTILITIES	MAO	004	59,414.76		59,414.76	.06300	3,743.13	0.000560	-
6	RETAIL	MAO	017	-		-	.06300	-	0.000560	-
7	USE TAX	MAO	029	-		-	.05600	-	N/A	N/A
8	UTILITIES	MAR	004	41,829,621.27		41,829,621.27	.06300	2,635,266.14	0.000560	-
9	RENTAL-REAL	MAR	013	-		-	.00500	-	N/A	N/A
0	RETAIL	MAR	017	28.89		28.89	.06300	1.82	0.000560	-
1	USE TAX	MAR	029	2,971,567.86		2,971,567.86	.05600	166,407.80	N/A	N/A
2	UTILITIES	MAT	004	3,737.94		3,737.94	.06300	235.49	0.000560	-
3	RETAIL	MAT	017	-		-	.06300	-	0.000560	-
4	USE TAX	MAT	029	-		-	.05600	-	N/A	N/A
5	UTILITIES	MOF	004	8,378.80		8,378.80	.05850	490.16	0.000560	-
6	RETAIL	MOF	017	-		-	.05850	-	N/A	N/A
7	UTILITIES	MOH	004	826,741.37		826,741.37	.05850	48,364.37	0.000560	-
8	RETAIL	MOH	017	-		-	.05850	-	0.000560	-
9	USE TAX	MOH	029	97,973.21		97,973.21	.05600	5,486.50	N/A	N/A
0	UTILITIES	PAD	004	223,172.46		223,172.46	.06100	13,613.52	0.000560	-
1	UTILITIES	PMA	004	17,400,128.69		17,400,128.69	.06100	1,061,407.85	0.000560	-
2	USE TAX	PMA	029	398,010.71		398,010.71	.05600	22,288.60	N/A	N/A
3	UTILITIES	PMN	004	18,745.41		18,745.41	.06100	1,143.47	0.000560	-
4	RETAIL	PMN	017	-		-	.06100	-	0.000560	-
5	USE TAX	PMN	029	-		-	.05600	-	N/A	N/A
ubtotal				65,548,566.34	-	65,548,566.34		4,063,722.32		-

ransaction Privilege, Use, and Severance Tax Return (TPT-1) LICENSE NO 11 009297-C

RANSACTION 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	-
10	RETAIL	PNL	017	-		-	.06600	-	0.000560	-
11	USE TAX	PNL	029	641,111.61		641,111.61	.05600	35,902.25	N/A	N/A
12	UTILITIES	YMA	004	1,607,264.63		1,607,264.63	.06700	107,686.73	0.000560	-
13	RETAIL	YMA	017	99.85		99.85	.06700	6.69	0.000560	-
14	USE TAX	YMA	029	667,497.86		667,497.86	.05600	37,379.88	N/A	N/A
15	APACHE JUNCT	AJ	000	-		-	.02200	-	N/A	N/A
16	APACHE JUNCT	AJ	001	246,026.56		246,026.56	.03200	7,872.85	N/A	N/A
17	BISBEE	BB	000	196,990.00		196,990.00	.02500	4,924.75	N/A	N/A
18	BUCKEYE	BE	000	10,798.00		10,798.00	.02000	215.96	N/A	N/A
19	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
23	CLIFTON	CF	000	65,475.67		65,475.67	.03000	1,964.27	N/A	N/A
24	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		-

ADOR 20-1040 (11/03)

ransaction Privilege, Use, and Severance Tax Return (TPT-1) LICENSE NO 009297-C

RANSACTION DETAIL (ADDITIONAL TRANSACTIONS)

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	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
10	MARANA	MA	000	-		-	.02000	-	N/A	N/A
11	MARANA	MA	004	504,840.50		504,840.50	.04000	20,193.62	N/A	N/A
12	MAMMOTH	MH	000	-		-	.02000	-	N/A	N/A
13	MIAMI	MM	000	-		-	.02500	-	N/A	N/A
14	MARICOPA	MP	000	463,396.00		463,396.00	.02000	9,267.92	N/A	N/A
15	ORO VALLEY	OR	000	828,380.50		828,380.50	.02000	16,567.61	N/A	N/A
16	PAGE	PG	000	154,840.33		154,840.33	.03000	4,645.21	N/A	N/A
17	PAGE	PG	002	586.00		586.00	.03000	17.58	N/A	N/A
18	PARKER	PK	000	68,617.50		68,617.50	.02000	1,372.35	N/A	N/A
19	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
23	SUPERIOR	SI	000	58,696.00		58,696.00	.02000	1,173.92	N/A	N/A
24	SOMERTON	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		-

HANSON

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

CORKY HANSON

SENIOR PIPELINE SAFETY INSPECTOR

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

MAY 27, 2008

EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-07-0504

Nothing Southwest Gas Corporation ("Company") witness Schmitz stated in his Rebuttal Testimony has caused me to change my position that the Company's negligence in repairing the pipeline led to a "public safety concern" and the need for early replacement of the pipeline. The costs associated with the replacement of the pipeline should, therefore, be disallowed as discussed in Staff witness Ralph Smith's testimony, since they were caused by the Company's own negligence.

Q. Did you provide Direct Testimony in this case?

A. Yes. My Direct Testimony related to the need to replace the Manors subdivision's pipeline distribution system in Yuma, Arizona due to the Company's negligence in making earlier repairs to the pipeline.

Q. Have you reviewed the Surrebuttal Testimony dated May 9, 2008 provided by Mr. Jerome Schmitz?

A. Yes.

Q. Do you concur with the testimony provided by Mr. Schmitz concerning corrosion leaks?

A. No. Mr. Schmitz is apparently attempting to compare corrosion leaks (pipeline failures) with outside force (excavation activities) or third-party damage, but the two are not related. A corrosion leak is a failure only affecting steel pipeline while excavation damages from outside forces impact all pipeline materials. Mr. Schmitz also states that he would characterize my statement that "pipe corrosion is one of the leading causes of pipeline failures" as vague and misleading. He states that corrosion accounts for only 14.2 percent of all leaks. However, when reviewing the Rebuttal Exhibit JTS-1, if outside force by excavation, other outside forces and natural forces are removed from the equation, corrosion leaks constitute the second highest percentage of all remaining leaks for steel pipelines.

Q. Do you agree that Southwest Gas ("SWG") was acting as a prudent operator in its decision to replace the ground bed to maintain a safe and reliable system?

A. Yes, but that is not the issue. The issue is that the actions taken by the Company in making repairs to the rectifier system were faulty and resulted in the pipeline's corrosion at an accelerated rate.

Q. Is it still your belief that had SWG properly installed the rectifier and ground bed that this system would not have needed replacement at this time?

A. Yes, nothing Mr. Schmitz states in his Rebuttal Testimony has caused me to change my position. As I stated in my original response to the SWG data request dated April 28, 2008, based on my review of the leak survey records between 2002 and 2005 there is no indication that this system was not in a safe operating condition.

Q. Do you agree with SWG testimony that states any extension of service life to a pipe of this vintage is a possible consequence of actions done to remain compliant with the pipeline safety regulations?

A. Yes, absolutely. However, properly installed, cathodic protection has the potential to extend the life of a buried pipe of any vintage. Unfortunately, in this case, after the improper re-initializing of the Manors rectifier by reversing the polarity on the system any possibility for extending the service life of the system was irrevocably eliminated.

Q. Mr. Schmitz stated that you made too many assumptions in concluding that the system would have had a significant remaining life but for the faulty repair. Do you agree?

A. No. I am aware that a pipeline does not operate in a constant environment. But my analysis of all of the facts in this case support the conclusion that but for the faulty repair, the pipeline would have had a significant remaining life yet. Those facts included the Company's own actions which were geared toward prolonging the system's life. The fact that SWG's replaced the CP ground bed to restore CP to the Manor's system, indicates that the Company itself thought the service life of the system could be extended, and replacement was unnecessary.

Q. Do you agree that SWG acted as a prudent operator in replacing the Yuma Manors pipeline system to address what SWG states was an immediate public safety concern?

A. Yes, of course. Once a public safety issue arises, the Company has an obligation to take immediate corrective action. But the "immediate public safety concern" arose here solely as a result of the improper actions originally taken by SWG personnel when they incorrectly installed and reinitialized the rectifier.

Q. Do you agree with Mr. Schmitz's testimony that a disallowance in this case sends the wrong policy message and would encourage operators to expend minimal investment to maintain the pipes rather than replacing them?

A. Not at all. The Company is under an obligation to maintain its system so that it operates in a safe and reliable manner. The message the Staff intends to send is that repairs to pipelines need to be done correctly. If repairs are not done properly, public safety concerns arise. In this case, improper repairs led to an unusual increase in leakage which the Company noticed in early 2007, and which in the Company's own words created an "immediate public safety concern".

Q. Does this conclude your Surrebuttal Testimony?

A. Yes, it does.

RADIGAN

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

FRANK W. RADIGAN

ON BEHALF OF

THE ARIZONA CORPORATION COMMISSION,

UTILITIES DIVISION STAFF

MAY 27, 2008

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EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-07-0504

Class Cost of Service/Revenue Allocation – The Class Cost of Service Study has been reasonably conducted and follows generally accepted guidelines for such studies but Staff and the Company disagree on the allocation of revenue among the classes. The Company's use of the proportional cost responsibility method results in an allocation of costs that impose large increases on some rate classes and customers. The Company argues that the criticism is unwarranted, however, because the cited examples of large increases do not have anything to do with revenue allocation but rather with the Company's rate design. In this Surrebuttal Testimony, I demonstrate that the Company actually has the process backwards -- revenue allocation considerations should come first and rate design considerations second. The desire to let rate design considerations drive revenue allocation is moving in the wrong direction from the results of the cost of service study. The allocation of any revenue increase should be done in a two step process with the first step being the rate of return for each class to within 10 percent of the overall average rate of return. The second step of the allocation process is to temper the rate increase so that no class receives more than 1 percent more or 1 percent less than the overall average increase of 2.8 percent.

Revenue Decoupling/Volumetric Rate Design – The Company's Rebuttal Testimony clearly shows that its proposals for a Revenue Decoupling provision, a Weather Normalization provision, and changes to the Volumetric Rate design, are being proposed once again solely to provide the Company a fixed revenue stream. There has been no demonstration of any relationship that any of these proposals are necessary due to the effect of energy conservation. The Company proposals should be rejected as this exact issue has already been considered and rejected by the Commission in the Company's last rate case. The Company has failed in this case to address both the Commission's and Staff's concerns from its last rate case. The Commission found that the Company was requesting that customers provide a guaranteed method of revenue recovery and neither the law nor sound public policy requires such a result.

INTRODUCTION

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

A. My name is Frank W. Radigan. I am a principal in the Hudson River Energy Group, a consulting firm providing services regarding the electric utility industry and specializing in the fields of rates, planning and utility economics. My office address is 237 Schoolhouse Road, Albany, New York 12203.

Q. Are you the same Frank Radigan that previously provided testimony in this proceeding?

A. Yes. I previously provided testimony on the subject of Revenue Allocation, Rate Design and Revenue Decoupling. The Surrebuttal Testimony presented here is on those subjects as well. Specifically, I will address the Rebuttal Testimonies of Southwest Gas Corporation ("Company") Witnesses Montgomery, Miller and Congdon on these rate design issues.

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff").

COST OF SERVICE STUDY/REVENUE ALLOCATION

Q. Did the Company prepare and present a Cost of Service Study in this case?

A. Yes and I agree that it should be used as the basis for allocating rates. Where Staff and the Company disagree is on the allocation of revenue among the classes.

In my Direct Testimony I noted that the Company's use of proportional cost responsibility method ("PCRM") resulted in an allocation of costs that impose large increases on some rate classes and customers. I noted that the Company proposed that the Residential A/C Service Class (G-15) receive a 12.2 percent increase which is over 2.5 times the overall proposed increase of 4.8 percent. For the Street Lighting Class (G-45) the Company is proposing an increase of 10.4 percent or 2.2 times the overall average increase of 4.8 percent (Congdon Workpapers). While these proposed increases bring the rate of return for these service classes closer to the overall average rate of return, the Company's changes to other rates does not. For example, for the Multi-Family Residential Service Class (G-6) the Company proposes to increase revenues from this class by 1.5 percent or 0.3 times the overall average increase.

In Rebuttal Testimony, Company Witness Congdon concedes that certain of its proposed rate changes do not have anything to do with revenue allocation but rather with the Company's rate design. For example, Mr. Congdon notes that the 12.2 percent increase in the rates for G-15 come from its proposal to eliminate the declining block rate for residential customers. For G-6, Mr. Congdon states that the relatively small increase is due to the fact that the commodity charges for Single Family Residential (G-5) and Multi-Family Residential (G-6) are the same and the Company proposes not to change this relationship. (Congdon Rebuttal, page 19).

Q. Do you agree with the Company's logic?

A. No, in my opinion, the Company has the process backwards. Revenue allocation should come first and rate design second. In both cases, Mr. Congdon cites his desire to let rate design considerations drive revenue allocation. However, this results in the proposed rates moving in the wrong direction. The clearest example of how incorrect this methodology is for Multi-Family Residential Service Class (G-6). This service classification was established in the Company's last rate case because it was noted that the Company's costs were different to serve these larger customers. As the Commission noted in its Decision No. 68487 "...We agree with Southwest Gas that customers in multi-family dwellings deserve a separate rate categorization to reflect their lower usage characteristics and relatively lower cost to serve as a class" (page 39). Under current rate, G-6 is earning a rate of return of 5.69 percent or 0.85 times the overall rate of return of 6.68 percent. The 0.85 times is known as the indexed rate of return with a 1.00 meaning that the service class is earning the ideal overall rate of return. Under the Company's proposed rates, the rate of return would be 5.09 percent or 0.59 percent the overall rate of return of 9.45 percent. By tying the commodity rates of the G-6 to G-5, the indexed rate of return is getting lower and the Company is actually moving in the wrong direction from a cost of service basis.

As I noted in my Direct Testimony, the cost of service is one of a number of factors considered in revenue allocation and rate design. I further testified that the Company's proposed revenue allocation should be tempered so that no service class received more than 1 percent more or less than the overall increase. The results of this allocation process both temper the rate increase to any one class and improve the indexed rate of return for each service class. There is nothing in the Company's Rebuttal Testimony that causes me to change my opinion.

REVENUE DECOUPLING/VOLUMETRIC RATE DESIGN

Q. Could you please provide a general overview of the Company's Rebuttal Testimony with respect to revenue decoupling before commenting on the specific details?

A. Yes, the Company has provided Rebuttal Testimony from Company witnesses Montgomery, Miller and Congdon. While the Rebuttal Testimony is lengthy and addresses many minute details of why the arguments put forth by Staff and RUCO

Witness Rigsby are unreasonable, the sum total of the Company's presentation is unconvincing. When the Company's Rebuttal Testimony is read completely, and in conjunction with the Company's original filing, it is clear that what the only thing the Company wants to achieve through its proposed rate design is avoidance of financial risk, nothing more nothing less.

Q. What leads you to this conclusion?

A. The Company has put forth a myriad of risk-reducing rate design proposals in this case. Unfortunately, the proposals result in shifting almost all risk that shareholders now bear onto the shoulders of the ratepayers. These risk shifting proposals take the form of a Revenue Decoupling Provision ("RDAP"), a Weather Normalization Adjustment Provision ("WNAP"), a Volumetric Rate Design, and proposals that would protect the Company against declines in usage which have not been proven to exist with any certainty.

The Commission has no obligation to provide guarantees to a Company that it will a certain level of profits. The Commission must only allow the Company an opportunity to earn a reasonable return on its fair value rate base. The Staff's rate design proposals in this case accomplish this in my opinion.

Q. Is the Company's position reasonable?

A. Not at all. None of the arguments or facts set forth by the Company in this case are new. In SWG's last rate case, the Commission rejected virtually the same proposals, the Company is asking for here (although the names of these proposals in this case are different).

The Commission said it best when it rejected the same proposals by SWG in its last rate case: "...The Company is requesting that customers provide a guaranteed method of recovering authorized revenues, thereby virtually eliminating the Company's attendant risk. Neither the law nor sound public policy requires such a result and we decline to adopt the Company's CMT in this case" (Decision 68487, page 34).

The Commission also allowed the Company the opportunity to present its case regarding revenue decoupling in a stakeholder collaborative. That collaborative demonstrated that the biggest factor the Company faced was weather risk, a risk that is inherent in providing utility service. The Company simply has not met its burden of proof that its revenue allocation and rate design proposals are just and reasonable or in the public interest.

Q. What about the Company's claim that usage is declining and therefore revenue decoupling is appropriate?

A. The Company is only presenting one piece of the puzzle when discussing the risks in setting rates on a historic test year basis. It is true that if customer usage does continue to decline from the test year level after rates are set, the Company will lose margin revenue and it will put pressure on SWG's ability to earn its authorized rate of return. What is also true, however, is that the Company will also be allowed to retain any revenues from increased customer growth above test year levels. In the 2006 annual report to stockholders, the Company reported that 35,000 customers were added in Arizona. Based on the Company's latest estimated net margin figures these customers would provide an additional $9.9 million in net income to the Company. This is 57 percent more than the lost net margin due to declining usage. Therefore, given that the same annual report shows that the Company has experienced customer growth of over 5 percent per year for the last five years, it is reasonable to expect that net margins will continue to grow.

Because the Company can both gain and lose from changes in test year revenue and expense levels, it is inappropriate given the Company the type of financial assurances that it is seeking.

Q. Has the Company presented any studies in this case to demonstrate its position that usage is declining to such an extent that it should be considered in setting rates?

A. No. Average customer usage is affected by many factors including weather, economic conditions, average household size, average house age, and customer use. You cannot just conclude that because you see declining customer usage from one year to the next that it will continue to decline. The increase in customers noted above could result in households that are smaller than the existing average, or their energy need may vary and they could have more efficient homes, or more efficient appliances. All of these factors would contribute to a decline in the average use per customer.

Given the customer growth that the Company has experienced over the last few years, this could greatly contribute to usage as well. And, these same customers could have larger household sizes, they could use gas for cooking with indoor and outdoor kitchens, and they could live in large homes which are less efficient and have more appliances, which are less efficient. Only a study would establish usage trends with any certainty. Sales forecasts of average use per customer are generally complex econometric models that measure the impact of such things as the economy, customer usage patterns and housing starts. This is the type of study that is necessary to fully answer the Commission's questions as to when and to what level customer usage actually will decline or increase. Until this type of study is prepared and presented, the Company's arguments to use updated usage data cannot be considered "known and measurable".

Q. Please comment on Mr. Brooks Congdon's Rebuttal Testimony?

A. In reply to my Direct Testimony on decoupling and the fact that no evidence was provided in this case on the issue of SWG's claims of continued declining customer usage, the level of any decline and whether conservation efforts were the cause, Mr. Congdon relies upon the Direct Testimony of Company witness Cattanach (Congdon rebuttal, pages 6-7). But, I took the Direct Testimony of Mr. Cattanach into account when I prepared my Direct Testimony on decoupling. In my opinion, Mr. Cattanach's testimony does not provide any of the information necessary for the Commission to make an informed decision on this matter. Mr. Cattanach's exhibits show average use per customer for selected historic years. It does not show that the declining usage will continue, it does not show what the projected end level customer usage will be, and it does not demonstrate that energy conservation efforts are the cause for this declining usage, if in fact it exists.

Q, Could you please comment on Mr. Congdon's testimony that the fact that no consensus was reached in the collaborative process should not be used as a basis to reject all of the Company's rate design proposals?

A. Yes, Mr. Congdon states that through the collaborative process, the Company gained a better appreciation of the stakeholders' concerns and attempted to address those concerns. Mr. Congdon states that in order to address RUCO's concerns that weather and conservation related changes be separately addressed, the Company proposed the RDAP and WNAP. In order to address others concerns regarding large increase in fixed charges, SWG developed its Volumetric Rate Design proposal, to include accounting changes for non-gas and gas costs. In sum, the Company believes that it fully responded to the Commission's directives in Decision No. 68487 and the concerns raised in the collaboration (Congdon rebuttal, pages 10-11).

But I don't agree. The Commission stated in Decision No. 68487: "There is conflicting evidence in the record as to whether the recent level of declining per customer usage will continue into the foreseeable future, and whether conservation efforts are the direct cause of Southwest Gas' inability to earn its authorized return from such customers.... We encourage the parties to this proceeding to seek rate design alternatives that will truly encourage conservation efforts, while at the same time providing benefits to all affected stakeholders. To that end, Southwest Gas should coordinate its efforts to pursue implementation of a decoupling mechanism through discussions with Staff, RUCO, SWEEP/NRDC, and any other interested parties" (Decision 68487, page 34).

I do not see that the Company has done anything to address the Commission's concerns from Decision No. 68487. The same conflicting evidence as to usage that was in the last case, is also in this case. The Company in this case, and in the collaborative process, has simply not done the type of studies necessary to demonstrate that declining usage will continue into the foreseeable future; nor has it shown that conservation efforts are a direct cause of its' alleged inability to earn its authorized return; and it has not developed a rate design that will truly encourage conservation efforts. Unfortunately the only thing that has changed between now and the last case is that the risk shifting proposals by the Company have just multiplied. For the same public policy reasons that the Commission rejected the Company's revenue decoupling proposals in the last case, they should be rejected here.

All of this said, however, the Company should not come away with the notion that any proposal that it puts forward will be opposed. It is not the case that anything that is good for the Company is bad for customers. The regulatory process is a balance of shareholder and customer concerns. Weather risk is a normal operating risk. Rate of return kickers should not be handed out willy nilly. Overly complex rate designs can cause problems of their own. And energy conservation efforts that are being done because of good public policy should not be done at the expense of utility shareholders. And for "known and measurable" losses, the Company should be compensated. One of the fundamental problems here, and it is the Company's problem as it has the burden of proof, is that it has done nothing to establish that the alleged conditions are the "known and measurable".

Q. Please comment on the Rebuttal Testimony of Ralph E. Miller?

A. At page 5 of his Rebuttal Testimony Mr. Miller disagrees with my statement that there has been no showing in this case that a lack of revenue decoupling is a major obstacle to energy efficiency. Unfortunately, Mr. Miller provides no hard evidence to support his position but rather repeats the theories that he presented in his Direct Testimony. He also does not respond to the concerns the Commission expressed on this point in the Company's last rate case.

In the Company's last case it proposed a Conservation Margin Tracker similar to its decoupling proposal in this case. There the Commission found "....the likely effect of adopting the proposed CMT is that residential customers will be required to pay for gas that they have not used in prior years, a phenomenon that could result in disincentives for such customers to undertake conservation efforts. We are also concerned with the dramatic impact that could be experienced by customers faced with a surcharge for not using "enough" gas the prior year...we decline to adopt the Company's CMT in this case" (Decision 68487, page 34).

Q. Mr. Miller also testifies that you did not comment on the proposed WNAP. Could you comment on the Company's proposed WNAP?

A. Yes, Mr. Miller states that I did not address the merits of weather-related revenue decoupling from the perspective of customers (Miller Rebuttal Testimony, page 12). Mr. Miller also states that I appear to misunderstand the WNAP in that there is no one month lag in its application but rather it is applied in the given month when there is variation in weather from the normal (Miller Rebuttal, pages15-16).

My initial reading of the WNAP tariff led me to believe that there was a one month lag for purposes of gathering the necessary data. It appears that the Company intends to do it all on the same bill, i.e., measure how much less the customer used and add surcharge for the shortfall. Again this is simply a risk shifting measure designed to provide a guaranteed revenue stream to the Company. I can anticipate a significant increase in customer complaints the first month that this surcharge would take effect. Interestingly, the Company has not proposed any concomitant decrease in the return on equity to reflect the much lower risk faced by the utility if the WNAP were to be adopted.

I do not believe that customers will benefit from a weather-related decoupling mechanism. I, like the Commission in the Company's last rate case, believe there is no benefit to surcharging customers because they did not use enough gas in a given month or season. The WNAP should be rejected by the Commission.

Q. Does witness Smith's revision to Staff's proposed revenue requirement impact the rates you are proposing on behalf of Staff?

A. Yes. However, I did not receive the revised number soon enough to adjust the rates that I had calculated before I filed this testimony. I intend to file a late filed exhibit in the next week with my recalculations based upon the revised revenue requirement. The revisions should not have a significant impact upon the rates I have already calculated.

Q. Please summarize your recommendations.

A. My testimony includes the following recommendations:

1. The allocation of any revenue increase should be done in a two step process with the first step being the rate of return for each class to within 10 percent of the overall average rate of return. The second step of the allocation process is to temper the rate increase so that no class receives more than 1 percent more or 1 percent less than the overall average increase of 2.8 percent.

2. The Company's proposals for a full Revenue Decoupling provision, a Weather Normalization provision, its new Volumetric Rate Design, its proposal to account for declining residential average use and its proposal to increase the return on equity if its first four rate design proposals are not accepted should all be rejected as the Company is simply using these mechanisms to shift as much risk as possible to ratepayers. The Company has not addressed the Commission's concerns in Decision No. 68487. The Commission found that the Company is requesting that customers provide a guaranteed method of recovering authorized revenues and neither the law nor sound public policy requires such a result. Further, the exact issue has already been heard and dealt with by the Commission in the Company's last rate case.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes it does.

PARCELL

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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EXHIBITS

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	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%	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.

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.

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

	5-Year Historic Growth Rates				Est'd '05-'07 to '11-'13 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%	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.

Exhibit DCP-8
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Updated

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
Hanley 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

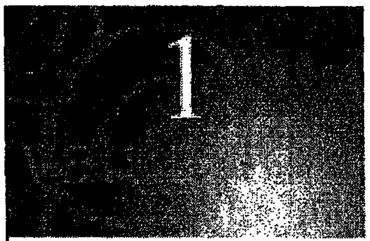
The total return on a fund from a certain period of time up to the present.

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

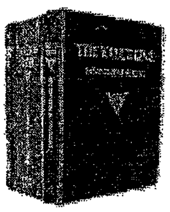
About Value Line

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

Glossary

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

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Beijing	+86.10.6569.2919
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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.

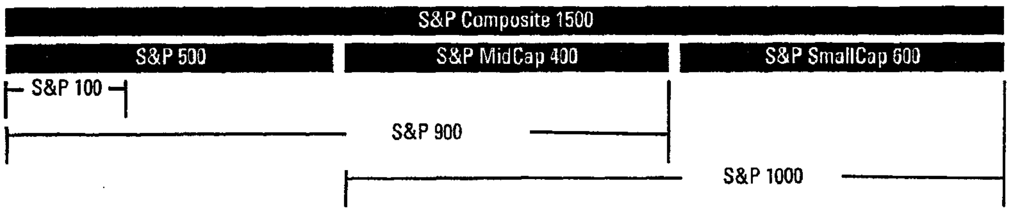
CRITERIA FOR INDEX REMOVALS

- 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



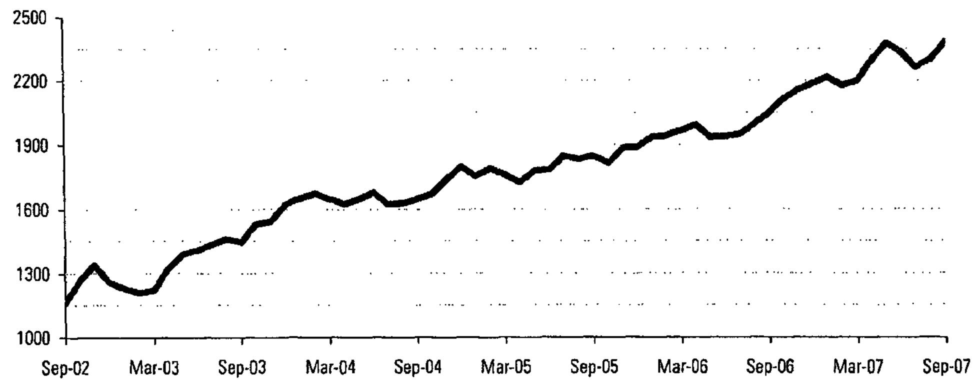
09/30/2007

The large cap segment of the U.S. equities market, covering approximately 75% of the U.S. equities market.

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



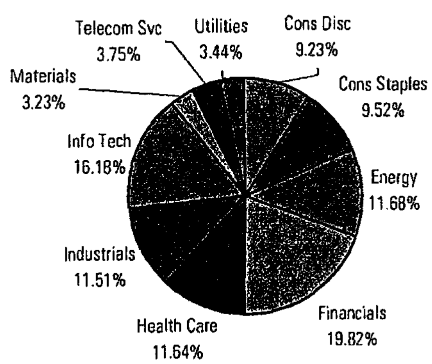
Top 10 Companies

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.

TEUMIM

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

PHILLIP S. TEUMIM

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

MAY 27, 2008

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SOUTHWEST GAS CORPORATION
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My Surrebuttal Testimony responds to the Rebuttal Testimony of Southwest Gas Corporation ("SWG") witness Mashas and SWEEP witness Schlegel with respect to my Direct Testimony on Line Extension and Hook-up Fees and Demand Side Management ("DSM") expenditures.

My recommendations that SWG file an explanation, with sample calculations, of how it is implementing its Line Extension tariff provisions and explain the changes made to the ICM over the last 10 years has not changed based upon the testimony of SWG witness Mashas.

With respect to DSM funding levels, I recommend that the Commission increase the approved funding levels for cost-effective programs to a much more modest level than proposed by SWEEP witness Schlegel.

INTRODUCTION

Q. Please state your name and business affiliation.

A. My name is Phillip S. Teumim. I am a principal in the firm Phillip S. Teumim LLC, 37 Ruxton Road, Delmar NY 12054, a management and regulatory consulting firm providing consulting services on utility matters. I am appearing on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division ("Staff").

Q. Have you testified previously in this proceeding?

A. Yes, I have previously submitted Direct Testimony.

Q. What is the purpose of your Surrebuttal Testimony?

A. I will respond to certain points raised by Southwest Gas Corporation ("SWG" or "Company") Witness Mashas and SWEEP Witness Shlegel with respect to my Direct Testimony regarding Line Extension and Hook-up fees and Demand Side Management ("DSM") expenditures, respectively.

LINE EXTENSION FEES

Q. What was Company Witness Mashas' response to your testimony regarding the Company's Tariff Rule No. 6 which governs the Company's Line Extension policies and procedures?

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.

DSM EXPENDITURES

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.

Q. Does that conclude your Surrebuttal Testimony?

A. Yes, it does.

GRAY

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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SOUTHWEST GAS CORPORATION
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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.

BEALE

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

SURREBUTTAL

TESTIMONY

OF

RITA R. BEALE

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

MAY 27, 2008

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SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-07-0504

Southwest Gas accepted eight of my ten management recommendations in my Direct Testimony. This Surrebuttal Testimony addresses further reasons why it is in the best interest of Southwest Gas Corporation ("SWG" or "Company") to also adopt the final two recommendations namely:

- SWG should strive to more fully document its internal strategies, policies, and procedures to effectively manage the risk of its gas supply portfolio. During my review, SWG was deficient in this area. Such documents should be centralized rather than dispersed and easy for all employees to locate inside the Company. The goal is to help SWG move *toward* attaining Industry Best Practices in incremental steps. Best Practices allow for different sets of external and internal risk disclosure, if desired – with different levels of detail. External documents need to comply with whatever are the stated requirements. Internal documents serve to

    - acknowledge the prevailing views of the Board of Directors
    - communicate expectations to all employees
    - provide a framework of management control
    - instill discipline around all employees to increase chances of success.

- SWG is also missing a Limits and Controls document and needs one. This testimony tries to elaborate on the requirements and importance of such a document.

1. INTRODUCTION

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

A. My name is Rita Beale. I am a Principal employed with Energy Ventures Analysis, Inc. ("EVA"). My business address is 1901 N. Moore Street, Suite 1200, Arlington, VA 22209-1706.

Q. What is the purpose of your Surrebuttal Testimony?

A. The purpose of my Surrebuttal is to respond to the Rebuttal Testimony of Southwest Gas Corporation ("SWG" or "Company") as it relates to my Direct Testimony.

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff, together with Mr. Stephen Thumb of EVA. In our Direct Testimonies, we addressed SWG's gas procurement policies, procedures and practices.

Q. How is your testimony organized?

A. My Surrebuttal Testimony follows the order of recommendations as addressed and numbered by SWG witness William N. Moody with one clarification.

Q. What is the clarification?

A. Of the fifteen recommendations made by EVA and referenced by SWG witness William N. Moody, he misattributes all of them to Mr. Stephen Thumb. Aside from ensuring the record is correct, I believe this does not affect the core substance of the issues addressed by EVA and SWG. The first five recommendations are from Mr. Thumb and relate primarily to SWG's gas transportation and delivery portfolio (hereinafter, referred to as

Nos. 1 through 5). The next ten recommendations are mine and relate to SWG's gas supply portfolio, general risk management practices, and transaction audit policies (hereinafter, referred to as Nos. 6 through 15).

II. SUMMARY OF SOUTHWEST GAS REBUTTAL TESTIMONY

Q. Please summarize the relevant SWG Rebuttal Testimony.

A. EVA reviewed the Rebuttal Testimony provided by SWG witness William N. Moody. Of my ten management recommendations, SWG accepted eight with acceptable timelines for implementation. A detailed discussion of each of the recommendation is found in Exhibit RRB-2 of my Direct Testimony. The eight recommendations SWG accepted are:

(7) Clarify the Arizona Price Stability Purchases ("APSP") supply element by documenting required timing and volumes for the next one to two years forward. Some companies have found the use of living appendices (to the company policies, for instance) helpful to update forward time windows and volume ranges that may change frequently. If there is uncertainty, then windows of time and ranges of volume or duration can be established instead.

(8) Clarify the precise nature of the APSP strategy. Is it a programmatic hedge, a judgmental hedge, or a hybrid of the two? The precise strategy should be recognized and declared in company policies and procedures to guide employees and decision makers, as well as the ACC's oversight.

(9) Company policies regarding the 'unbuying' of gas, as well as the reasons for the policies, should be reevaluated, and then explicitly documented in official company policies and procedures.

(10) Ensure all confirmations with gas suppliers, also known as Exhibit A, include deal transaction dates.

(11) Ensure all confirmations with suppliers, also known as Exhibit A, include dates of the internal approval next to the signature authorization.

(12) Considerably shorten the time lapsed between deal execution and deal confirmation with gas supplier.

(13) Include a list of attendees present during the solicitation and purchase of the APSP fixed price gas supply element (as well as during selection and approval of the index gas supply element) to ensure independence, proper monitoring, and to improve the quality of the audit trail.

(14) A review of the liquidated damages terms in supply contracts were found to be acceptable.

Q. Please summarize any recommendations rejected by SWG?

A. SWG rejected two of the recommendations that I made, however I believe without merit. These specifically are:

(6) Consolidate all strategies, policies, and procedures into a minimal number of documents with sufficient detail such that new employees could read and immediately perform the bulk of their work.

(7) Designate the Arizona Dispatch Guidelines as the buyers' limits and authorization to execute and meet the forecasted daily demand requirement in company policies and procedures.

III. RESPONSE TO SOUTHWEST GAS

Q. Do you agree with Mr. Moody's assessment that SWG's grouping of its policies, strategies, and procedures is sufficient as filed in the annual documentation with the Commission?

A. I agree with Mr. Moody that filing Company policies, strategies, and procedures with the Commission makes them "easily and readily accessible" for the Commission and its Staff. However the goal of my recommendations is to help SWG move *toward* attaining Industry Best Practices in incremental steps. SWG is fairly deficient in this area.

Q. Are the Annual Gas Procurement Plans filed with the Commission sufficient?

A. No. This may seem like a subtle topic, but SWG is missing a major point. It speaks volumes about the culture of a company and the level of risk management infrastructure that prevails within a company. Best Practices dictate that well-run companies (especially public companies per Sarbanes Oxley) have complete sets of internal policies and procedures that have been reviewed and authorized by the Board of Directors. Such documents serve to:

- acknowledge the prevailing views of the Board of Directors
- communicate expectations to all employees
- provide a framework of management control
- instill discipline around all employees to increase chances of success.

My personal impression (gained during the interview process) is that while the Gas Supply Department may have many solid policies, many are not documented. It seems to me that Gas Supply has been responding to various Commission requirements over time and that in the process has built up its inventory of existing policies and procedures. The overarching goal should be to document Company policies and procedures, and then hand them over if/when the Commission calls upon or needs them, or retain them as confidential during audits if necessary. Best Practices allow different sets of external and internal risk disclosure if desired – with different levels of detail if desired. Typically companies that must live in a competitive environment have become the most conscious of the importance of managing risk through Best Practices.[1] My philosophy is that ratepayers and shareholders should expect nothing less. Of course I believe that internal documented strategies and policies should be tailored to the unique risks embedded in the company business. Also I respectfully disagree that requiring an ACC docket search is a "logical", "convenient", or effective way for management and employees to operate a business, even if the business happens to be regulated by the ACC.

Q. What are some of the deficiencies?

A. First EVA believes the "Annual Gas Procurement Plan" represents only a <u>partial</u> grouping of the materials that should be documented internally for effective risk management. A "consolidated" grouping is desired, but I don't believe that SWG has yet implemented this concept. In fact it took a number of data requests to mine the existing inventory of SWG's documents. Also materials submitted in the past fall short of acceptable levels of documentation, as discussed thoroughly in Exhibit RRB-2 of my Direct Testimony and also acknowledged by SWG's acceptance of my other recommendations (numbers 7, 8, 10, 11, 12, 13, and 14). The above enumerated items need to be discussed in the

[1] Edited by Marc Lore & Lev Borodovsky, *GARP's The Professional's Handbook of Financial Risk Management,* Sponsored by KPMG, 2000.

Company's internal policies and procedures. My impression is that oddly there is more published about SWG's procurement strategies in reviews created by external consultants (authored by Ralph Miller, July 2006) and prior Commission Staff reports (authored by William Gehlen) than in any internal SWG Company document. This is not an acceptable condition for employees that are depended upon to execute company policies and manage the market risk of SWG. Having strategies and policies spelled out does not diminish one's level of professionalism; it may enhance it. It's also an effective tool to help orient new employees.

Q. Are there any other documents that should be added for completeness?

A. SWG is also missing a Limits and Controls document. "Limits and controls represent the mechanism by which a firm's risk appetite is articulated and communicated to different constituencies – senior management, business line management, traders and other risk takers, risk managers and operations personnel".[2] This is a formal statement of the allowable commodities, instruments, quantities, and markets, etc. in which its buyers can execute, as authorized by the Board of Directors. In the instance of SWG, quantities are a significant part of what is missing from the SWG policies. Such a document could be issued monthly or as needed, but should be reaffirmed at least annually by the Board.

Q. Why did you mention the Arizona Dispatch Guideline?

A. The *Arizona Dispatch Guideline* as described to EVA appeared to be the closest thing that SWG has to a Limits and Controls document. EVA recommended this as a preliminary Limits and Controls document because it is pre-existing and was created by a group outside of Gas Purchasing by the Planning Department that has some independence and has already evaluated the logical order of economic supply dispatch by supplier contract.

[2] Edited by Marc Lore & Lev Borodovsky, *GARP's The Professional's Handbook of Financial Risk Management,* Sponsored by KPMG, 2000, page 604.

It lists the approved and executed supply contracts that can be called upon and is passed to the gas buyers monthly. It is a fairly "live" representation on paper of what the gas buyers are likely to be purchasing during the month, ceteris paribus, after evaluating each day's changing demand forecast and the intraday demand forecast. SWG needs to create an acceptable Limits and Controls document.

Q. Is the *Department and Staff Responsibilities-Portfolio Selection Procedures* sufficient to serve as a Limits and Controls document?

A. The document *Department and Staff Responsibilities-Portfolio Selection Procedures,* referred to by Mr. Moody in his Rebuttal Testimony is typical of a staff procedures document, not a Limits and Controls document. Every area of SWG involved in energy commodity purchasing should have procedures documents. Most companies today translate these procedures into multiple process maps which tend to be easier to follow, again in line with Best Practices.

Q. Do you still recommend that SW Gas should adopt recommendations #6 and #9 of your direct testimony and as discussed above?

A. Yes I do.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes, it does.

THUMB

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

SURREBUTTAL

TESTIMONY

OF

STEPHEN L. THUMB

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

MAY 27, 2008

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EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-07-0504

Southwest Gas witness Moody expressly accepted three of the five management recommendations in my Direct Testimony. This Surrebuttal Testimony primarily addresses my Recommendations Nos. 2 and 5 which the Company did not expressly acknowledge to be acceptable. Recommendation No. 2 addressed the amount of documentation required for Transportation only ("T-1") customers. I conclude that if Southwest Gas Corporation ("SWG") effectively implements its new SWG tariff for Arizona T-1 customers, it may only upon occasion need to examine supply contracts when and if there is a question of whether the T-1 customer is the source of a specific El Paso penalty or charge. In such instances, a review of the T-1 customers' gas supply contracts may need to occur. With respect to my Recommendation No. 5 which pertained to LNG supply diversification, the Company's comments are in line with my recommendation and I do not see any real difference between Staff and the Company on this issue.

1. INTRODUCTION

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

A. My name is Stephen L. Thumb. I am a Principal employed with Energy Ventures Analysis, Inc. ("EVA"). My business address is 1901 N. Moore Street, Suite 1200, Arlington, VA 22209-1706.

Q. Did you submit a Direct Testimony in this case?

A. Yes. My Direct Testimony, and that of Staff witness Rita Beale, addressed the gas procurement policies, procedures and practices of Southwest Gas Corporation ("SWG" or "Company"). My Direct Testimony focused on SWG's interstate pipeline capacity portfolio, and the Company's management of its pipeline capacity, as well as the pipeline penalties incurred during this period.

Q. What is the purpose of your Surrebuttal Testimony?

A. The purpose of my Surrebuttal Testimony is to respond to the Rebuttal Testimony of SWG witness William N. Moody as it relates to my Direct Testimony.

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff, together with Ms. Rita Beale of EVA.

Q. How is your testimony organized?

A. My Surrebuttal Testimony follows the order of recommendations as addressed and numbered by Company witness Mr. Moody with one clarification.

Q. What is the clarification?

A. Of the fifteen recommendations made by EVA and referenced by Mr. Moody, he misattributes all of them to me. Aside from ensuring the record is correct, I believe this does not affect the core substance of the issues addressed by EVA and SWG. The first five recommendations are mine and relate primarily to SWG's gas transportation and delivery portfolio (hereinafter, referred to as Nos. 1 through 5). The next ten recommendations are from Ms. Beale and relate to SWG's gas supply portfolio, general risk management practices, and transaction audit policies (hereinafter, referred to as Nos. 6 through 15).

II. SUMMARY OF SWG REBUTTAL TESTIMONY

Q. Please summarize the relevant SWG Rebuttal Testimony.

A. EVA reviewed SWG's Rebuttal Testimony as provided by Company witness Moody. Of the five recommendations that I offered, SWG expressly accepted three of them with acceptable timelines for implementation. A more complete discussion of each of the recommendations can be found in Exhibit SLT-2 of my Direct Testimony. The three SWG accepted are:

(1) As SWG continues to attempt to diversify its interstate pipeline capacity portfolio, SWG should continue seeking access to storage capacity, particularly market-area storage capacity.

(3) SWG should make its Daily Forecasting Accuracy Improvement Task Force a permanent entity. SWG's policies should also require ongoing validation and back-testing of its daily load forecast, along with its required frequency.

(4) Until the point that market-area storage becomes a reality in Arizona, it is recommended that the ACC develop and implement policies that would promote the sharing of gas supplies among the major users of interstate pipeline capacity in Arizona during extreme conditions, including gas LDCs and electric utilities.

Q. Regarding recommendation number four above, do you have any changes to this recommendation?

A. Yes. While I am not changing the general intent of this recommendation to promote sharing of gas supplies, I am now recommending that SWG work with other Arizona utilities and Commission Staff to develop and implement policies to promote the sharing of gas supplies. Given the context of this recommendation, in a SWG rate proceeding, it is more appropriate to direct the recommendation toward the Company and its actions. The specific new wording of the fourth recommendation is as follows:

"(4) Until the point that market-area storage becomes a reality in Arizona, it is recommended that SWG work with other Arizona utilities and the Commission Staff to develop and implement policies that would promote the sharing of gas supplies among the major users of interstate pipeline capacity in Arizona during extreme conditions."

Q. Please summarize any recommendations rejected by SWG?

A. SWG rejected my recommendation No. 2 which was that "SW Gas should increase the documentation and requirements for its transportation-only (T-1) customers." While SWG did not expressly accept my recommendation No. 5, to track the likelihood of LNG imports entering the Company's gas market and consider gaining access to such supplies, for diversifications purposes and to reduce its dependence on the San Juan basin, its plans, comments and timetable are in line with my recommendation. I see no real difference between Staff and the Company on my recommendation No. 5.

III. RESPONSE TO SWG

A. EVA Recommendation 2: Documentation Requirement for Transportation Only (T-1) Customers

Q. Why does SWG believe your recommendation No. 2 is unnecessary?

A. SWG believes its existing practice of quarterly verification of customer interstate capacity contracts is an efficient and effective method of collecting the necessary information and ensuring that all allocations of charges and penalties incurred by SWG as a point operator are accurate and should not be modified.

Q. Do you think the existing practices as described by Mr. Moody are sufficient to monitor the T-1 customers?

A. EVA did not review the procedures of the Key Accounts Management ("KAM") Department performed on a quarterly basis for monitoring upstream capacity and transportation rights on El Paso Pipeline. This process may now be sufficient particularly in view of the new SWG tariff for Arizona customers implemented in 2007 that clearly establishes that transportation customers are responsible for any upstream charges or penalties occasioned by their action. This new tariff language was not in place during the audit period, and it is possible that T-1 customers may have exacerbated some of the penalties or charges paid by SWG during the audit period.

Q. Do you think SWG needs to monitor the gas supply contracts of T-1 customers?

A. If SWG effectively implements the new tariff language mentioned above, then it may upon occasion need to examine the supply contracts of a T-1 customer when and if there is some question of whether that customer was the source of a specific El Paso penalty or charge. In such instances, a review of gas supply contracts may be necessary to implement this portion of the tariff.

B. EVA Recommendation 5: Accessing LNG Supplies

Q. What was Company witness Moody's response to EVA Recommendation No. 5:

A. Company witness Moody essentially agreed with the recommendation but stated that at this time there is a continuing uncertainty about the regularity and reliability of supplies that may be available from the western LNG market. In the short-term (1-3 years), he believes Arizona customers participation should be indirect. As the market matures with pricing and reliability in full view, direct acquisition of this supply should be reviewed and considered.

Q. Do you have any comments on accessing LNG supplies?

A. SWG plans, comments, and timetable on implementing access to LNG supplies, as discussed in Mr. Moody's Rebuttal Testimony, are perfectly acceptable and in line with my recommendation .

Q. Does this conclude your Surrebuttal Testimony?

A. Yes, it does.