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Transcript Exhibit(s)

Docket #(s): G-01551A-10-0458

Arizona Corporation Commission
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Date: August 17, 2011

Re: Southwest Gas Corporation / Rates
G-01551A-10-0458
August 10, 12, and 15, 2011
Volumes I through III, Concluded

STATUS OF ORIGINAL EXHIBITS

FILED WITH DOCKET CONTROL

Arizona Investment Council (AIC Exhibits)

1 through 3

Cynthia Zwick (Zwick Exhibits)

1 and 2

Natural Resource Defense Council (NRDC Exhibits)

1 and 2

Residential Utility Consumer Office (RUCO Exhibits)

1, 2, 3 (Administrative Notice), 4 through 16

Southwest Energy Efficiency Project (SWEEP Exhibits)

1 and 2

Southwest Gas Corporation (A Exhibits)

1 through 18

Please note, to comply with Docket Control's filing requirements, we removed Exhibits A-1 through A-13 from binders. We removed and made copies of any tabs included within the exhibits.

Staff (S Exhibits)

1, 3, 5 through 9, 11, 12

CORRECTIONS TO INDEX OF EXHIBITS

Please see attached corrected page 512. Under the column "No.", Line 17.5 has been corrected from RUCO-3 to RUCO-4. Line 18.5 has been corrected from RUCO-4 to RUCO-5. Only the column "No." needed correction. We apologize for the inconvenience.

EXHIBITS RETURNED TO PARTIES

Residential Utility Consumer Office (RUCO Exhibits)

17 Not admitted

EXHIBITS NOT UTILIZED
Not given to Court Reporter

Staff (S Exhibits)

10

CONFIDENTIAL EXHIBITS
Given to ACALJ Nodes

Staff (S Exhibits)

2 and 4

Copy to:

Mr. Dwight D. Nodes, ACALJ
Mr. Justin Lee Brown, Southwest Gas Corp.
Ms. Robin Mitchell, Staff
Mr. Daniel Pozefsky, RUCO
Mr. Michael M. Grant, AIC
Mr. Timothy Hogan, SWEEP
Mr. Timothy Sabo, TEP
Ms. Laura E. Sanchez, NRDC
Ms. Cynthia Zwick

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
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 ITS PROPERTIES THROUGHOUT ARIZONA	)	DOCKET NO. G-01551A-10-0458

PUBLIC

DIRECT

TESTIMONY

OF

RALPH C. SMITH

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

JUNE 10, 2011

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EXHIBIT
S-1
ADMITTED

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EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-10-0458

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

- The Company's proposed revenue requirement
- Adjustments to test year data
- Rate base
- Test year revenues, expenses, and net operating income
- The Company's request for special accounting and deferrals
- The need for an updated depreciation rate study from Southwest in its next Arizona rate case

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

- The Company's proposed revenue requirement of a base rate increase of $73.2 million is overstated. On original cost rate base ("OCRB") Staff's calculations show a jurisdictional revenue deficiency of $47.0 million. Staff recommends a base rate increase of not more than $54.9 million on adjusted fair value rate base ("FVRB"). This recommended increased amount is a percentage increase of 13.4 percent on adjusted base rate revenue at current rates of $410.9 million, and is based on Staff's second alternative for the revenue requirement on FVRB ("Alternative 2"). On adjusted FVRB under Staff's first alternative ("Alternative 1"), which uses a fair value rate of return ("FVROR") of 6.69 percent, Staff recommends a base rate increase of $47.0 million. Under Alternative 2, Staff's alternative method to calculate the FVROR, the FVROR for SWG is 7.02 percent as recommended by Staff witness David Parcell, and the jurisdictional revenue deficiency is approximately $54.9 million. The testimony of Staff witness Parcell addresses the determination of the FVROR. In its filing, Southwest did not calculate a revenue deficiency for OCRB and based its recommended revenue increase solely on FVRB. Southwest has requested an additional rate increase on FVRB of approximately $7.8 million. Staff's FVROR "Alternative 2" produces an additional rate increase on FVRB of approximately $7.9 million.

- The following adjustments to Southwest's proposed OCRB and Reconstructed Cost New Depreciated ("RCND") rate base should be made:

Summary of Staff Adjustments to Rate Base		OCRB	RCND RB
Adj. No.	Description	Increase (Decrease)	Increase (Decrease)
B-1	Corrections to Completed Construction Not Classified	$ (1,066,657)	$ (1,066,657)
B-2	Yuma Manors Pipe Replacement	$ (225,445)	$ (225,445)
B-3	Cash Working Capital	$ (468,000)	$ (468,000)
B-4	Accumulated Deferred Income Taxes - Bonus Tax Depreciation on CCNC	$ (1,286,985)	$ (1,286,985)
B-5	Remove Corporate Aircraft Costs	$ (352,892)	$ (352,892)
B-6	Remove One-Half of Prepaid D&O Insurance	$ (185,097)	$ (185,097)
	Total of Staff Adjustments	**$ (3,585,076)**	**$ (3,585,076)**
	SWGas Proposed Rate Base (Original Cost and RCND)	$ 1,073,700,633	$ 1,839,334,300
	Staff Proposed Rate Base (Original Cost and RCND)	**$ 1,070,115,558**	**$ 1,835,749,225**

- Staff is recommending the following adjustments to Southwest's proposed revenues, expenses and net operating income:

Summary of Staff Adjustments to Net Operating Income		Pre-Tax Adj. to Revenue or Expense	Net Operating Income
Adj. No.	Description	Increase (Decrease)	Increase (Decrease)
C-1	CCNC Correction Depreciation and Property Tax Expense	$ (102,079)	$ 61,728
C-2	Yuma Manors Pipe Replacement	$ (17,447)	$ 10,550
C-3	Management Incentive Program	$ (1,899,807)	$ 1,148,828
C-4	Restricted Stock/Unit Plan	$ (1,033,723)	$ 625,101
C-5	Supplemental Executive Retirement Expense	$ (1,725,839)	$ 1,043,629
C-6	American Gas Association Dues	$ (90,898)	$ 54,967
C-7	Loss on Sale of Employee Homes for Relocation Expense	$ (503,620)	$ 304,543
C-8	Test Year Rent Charged to Affiliate IntelliChoice Energy LLC	$ (13,156)	$ 7,956
C-9	Gas Heat Pump Development Expenses	$ (711,287)	$ 430,121
C-10	Interest Synchronization	$ -	$ (56,377)
C-11	Directors' and Officers' Liability Insurance	$ (386,402)	$ 233,660
C-12	Self-Insurance Retention Expense	$ (579,774)	$ 350,594
C-13	Leased Aircraft Operating Costs	$ (193,893)	$ 117,249
C-14	COYL Leak Detection Survey	$ 1,000,000	$ (604,708)
Total of Staff's Adjustments to Net Operating Income		$ (6,257,925)	$ 3,727,841
	Adjusted Net Operating Income per Southwest Gas		$ 65,065,829
	Adjusted Net Operating Income per Staff		**$ 68,793,670**

Southwest has requested to modify the write-off requirements related to the replacement of AHD pipe established in Decision No. 58693. Staff recommends that such requested modification be denied. Southwest projects it will have completed the AHD pipe replacements by mid-year 2013. Consequently, leaving the Settlement and Order that had been in place from Decision No. 58693 for one additional rate case cycle should alleviate the need to modify the previous write-off percentages for replacement of AHD pipe. Should the Commission allow the modification, Staff recommends that the modification should become effective as of the date of the Commission's Order in this case. Southwest should continue to comply with Decision No. 58693 from July 1, 2010 through the date of the Commission's final decision in this case.

Staff recommends that the Company's proposal to defer depreciation expense, carrying costs, and property taxes resulting from removing the remainder of AHD pipe from July 1, 2010 through mid-year 2013 be denied.

Staff recommends that the Company's request for accounting authority to defer $10 million of cost for replacing 5,000 customer owned yard lines ("COYL") with Southwest Gas owned facilities be denied at this time. Staff recommends that the Company perform a leak detection survey and, if necessary, request a deferral order upon completion.

The Company has not conducted a depreciation study for its Arizona utility plant in approximately 23 years. Staff recommends that the Company be ordered to file updated depreciation rate studies in its next general rate case. Any changes to System Allocable plant depreciation rates should not be instituted for book purposes until such depreciation rates have been authorized by the Arizona Corporation Commission. Southwest should also file an updated depreciation study for System Allocable plant in its next Arizona rate case.

I. 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. Please describe Larkin & Associates.

A. Larkin & Associates is a Certified Public Accounting and Regulatory Consulting firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin & Associates has extensive experience in the utility regulatory field as expert witnesses in over 400 regulatory proceedings including numerous telephone, water and sewer, gas, and electric matters.

Q. Mr. Smith, please summarize your educational background.

A. I received a Bachelor of Science degree in Business Administration (Accounting Major) with distinction from the University of Michigan - Dearborn, in April 1979. I passed all parts of the Certified Public Accountant ("CPA") examination in my first sitting in 1979, received my CPA license in 1981, and received a certified financial planning certificate in 1983. I also have a Master of Science in Taxation from Walsh College, 1981, and a law degree (J.D.) cum laude from Wayne State University, 1986. In addition, I have attended a variety of continuing education courses in conjunction with maintaining my accountancy license. I am a licensed CPA and attorney in the State of Michigan. I am also a Certified Financial Planner™ professional and a Certified Rate of Return Analyst ("CRRA"). Since 1981, I have been a member of the Michigan Association of Certified Public Accountants. I am also a member of the Michigan Bar Association and the Society of Utility and

Regulatory Financial Analysts ("SURFA"). I have also been a member of the American Bar Association ("ABA"), and the ABA sections on Public Utility Law and Taxation.

Q. Please summarize your professional experience.

A. Subsequent to graduation from the University of Michigan, and after a short period of installing a computerized accounting system for a Southfield, Michigan realty management firm, I accepted a position as an auditor with the predecessor CPA firm to Larkin & Associates in July 1979. Before becoming involved in utility regulation where the majority of my time for the past 31 years has been spent, I performed audit, accounting, and tax work for a wide variety of businesses that were clients of the firm.

During my service in the regulatory section of our firm, I have been involved in rate cases and other regulatory matters concerning electric, gas, telephone, water, and sewer utility companies. My present work consists primarily of analyzing rate case and regulatory filings of public utility companies before various regulatory commissions, and, where appropriate, preparing testimony and schedules relating to the issues for presentation before these regulatory agencies.

I have performed work in the field of utility regulation on behalf of industry, state attorney generals, consumer groups, municipalities, and public service commission staffs concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Indiana, Illinois, Kansas, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Virginia, Washington, Washington D.C.,

West Virginia, and Canada as well as the Federal Energy Regulatory Commission and various state and federal courts of law.

Q. Have you prepared an attachment summarizing your educational background and regulatory experience?

A. Yes. Attachment RCS-1 provides details concerning my experience and qualifications.

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").

Q. Have you previously testified before the Arizona Corporation Commission?

A. Yes. I have testified before the Commission previously on a number of occasions. Recently, I testified before the Commission in Docket No. E-01345A-06-0009, involving an emergency rate increase request by Arizona Public Service Company ("APS"), and concerning APS's proposed depreciation rates in Docket Nos. E-01345A-05-0816, E-01345A-05-0826 and E-01345A-05-0827, a proceeding involving APS base rates and other matters. I also testified before the Commission in the a recent UNS Gas, Inc. rate case, Docket Nos. G-04204A-06-0463, G-04204A-06-0013 and G-04204A-05-0831, and in the a recent UNS Electric, Inc. rate case Docket No. E-04204A-06-0783. In addition, I testified before the Commission in Southwest Gas Corporation's ("Southwest" or "SWG" or "Company") last base rate case, Docket No. G-01551A-07-0504.

Q. What is the purpose of the 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.

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

A. Yes. Attachments RCS-2 through RCS-5 contain the results of my analysis and copies of selected documents that are referenced in my testimony.

II. REVENUE REQUIREMENT

Q. What issues are addressed in your testimony?

A. My testimony addresses the Company's proposed revenue requirement and selected other issues.

Q. What revenue increase has been requested by SWG?

A. SWG is requesting an increase in base rate revenues of $73.2 million, or approximately 17.8 percent, based on adjusted base rate revenues at current rates of $410.91 million. The revenue amount is from Company Schedule C-1 in Southwest's filing and is also shown on Staff Schedule C on Attachment RCS-2.

Q. What revenue increase does Staff recommend?

A. Staff recommends a revenue increase of not more than $54.9 million on adjusted fair value rate base using the alternative fair value rate of return ("FVROR") recommendation of Staff witness Parcell. As shown on Schedule A, on original cost rate base ("OCRB") my calculations show a jurisdictional revenue deficiency of $47.0 million. On adjusted fair value rate base ("FVRB") under Staff's proposed fair value rate of return of 7.02 percent, Staff recommends a base rate increase of $54.9 million. Attachment RCS-2, Schedule D, shows the development of Staff's recommended FVROR to be applied to FVRB. The testimony of Staff witness David Parcell addresses the determination of the FVROR.

A. Test Year

Q. What test year is being used in this case?

A. SWG's filing is based on the historic test year ended June 30, 2010. Staff's calculations use the same historic test year.

Q. Could you please discuss the test year concept?

A. Yes. In Arizona, a historic test year approach is used. Various adjustments are made to the historic test year amounts to ensure that there is a matching of investment, revenues and expenses. Rate base items, such as plant in service and accumulated depreciation, are based on the actual level as of the end of the historic test year. Several rate base items that tend to fluctuate from month to month, such as materials and supplies and prepayments, are based on a test year average level. Since end of test year net plant in service is used, revenues are annualized based on end of test year customer levels. Additionally, certain expenses, such as depreciation and payroll costs, are annualized based on end of test year levels. This is to ensure that the going-forward revenue and expense levels are matched with the investment (net plant-in-service) used to serve those customers.

As time goes forward, changes in a company's cost structure will occur. For example, rate base will increase as new plant is added to serve new customers, revenue will increase as customers are added, expenses will fluctuate, etc. It is very important to be consistent with a test period approach to ensure that there is a consistent matching between investment, revenues and costs. Any adjustments that reach beyond the end of the historic test year must be very carefully considered before being adopted.

B. Summary of Company Proposed and Staff Adjusted Revenue Requirement

Q. What did your review of SWG's filing indicate?

A. My review of SWG's filing indicated that the Company's request for a revenue increase is overstated. As shown on Attachment RCS-2, Schedule A, based on the FVROR recommended by Staff witness David Parcell and the adjustments to SWG's rate base and net operating income, Staff has calculated a jurisdictional base rate revenue requirement deficiency on FVRB of $54.9 million using the FVROR of 7.02 percent. SWG should be authorized a base rate increase of not more than $54.9 million in this case.

C. Organization of Staff Accounting Schedules

Q. How are Staff's accounting schedules organized?

A. Staff's accounting schedules are presented in Attachment RCS-2. They are organized into summary schedules and adjustment schedules. The summary schedules consist of Schedules A, A-1, B, B.1, C, C.1 and D. Attachment RCS-2 also contains rate base adjustment Schedules B-1 through B-4 and net operating income adjustment Schedules C-1 through C-14.

Q. What is shown on Schedule A of Attachment RCS-2?

A. Attachment RCS-2 presents the Staff Accounting Schedules and revenue requirement determination. Schedule A presents the overall financial summary reflecting the recommended adjustments. This schedule presents the change in the Company's gross revenue requirement needed for the Company to have the opportunity to earn Staff's recommended rate of return on Staff's proposed OCRB and FVRB. The rate base and operating income amounts are taken from Schedules B and C, respectively. The weighted average cost of capital ("WACC") for OCRB of 9.08 percent, as presented in the prefiled testimony of Staff witness Parcell, is provided on Schedule D for convenience, as are the

derivation of Staff's recommended FVROR alternatives. Column D of Schedule A presents Staff's determination of the base rate revenue deficiency on FVRB using Staff's recommended fair value rate of return. Schedule D presents the original cost and fair value rate of return recommended in the prefiled testimony of Mr. Parcell.

The operating income deficiency shown on line 5 of Schedule A is obtained by subtracting the operating income available on line 4 (operating income as adjusted) from the required operating income on line 3. Line 7 represents the gross revenue requirement, which is obtained by multiplying the income deficiency by the gross revenue conversion factor ("GRCF"). The derivation of the GRCF is shown on Schedule A-1.

Q. How does the GRCF recommended by Staff compare with the GRCF contained in SWG's filing?

A. As shown on Schedule A-1, Staff recommends a GRCF of 1.6579. This is the same as the GRCF of 1.6579 used in SWG's filing.

Q. What is shown on Schedule B?

A. Schedule B presents SWG's proposed adjusted test year OCRB and FVRB and Staff's proposed adjusted test year OCRB and FVRB. The beginning rate base amounts presented on Schedule B are taken from the Company's filing for the test year, specifically SWG Schedule B-1. Staff's recommended adjustments to rate base are summarized on Schedule B.1. Schedule B.1 presents the adjustments to Southwest's proposed OCRB base, and another Schedule B.1 for Reconstruction Cost New Depreciated ("RCND") rate base adjustments.

Schedules B-1 through B-6 provide further support and calculations for the rate base adjustments Staff is recommending.

Q. What is shown on Schedule C?

A. The starting point on Schedule C is SWG's adjusted test year net operating income, as provided on Company Schedule C-1. Staff's recommended adjustments to SWG's adjusted test year revenues and expenses are summarized on Schedule C.1. Each of the adjustments is discussed in my testimony.

Schedules C-1 through C-14 provide further support and calculations for the net operating income adjustments Staff is recommending.

Q. What is shown on Schedule D?

A. Schedule D summarizes the capital structure and cost of capital that was proposed by SWG and the capital structure and cost of capital that is recommended by Staff witness Parcell. Schedule D also presents the derivation of Staff's recommended FVROR for use with the Staff's adjusted FVRB.

D. Return on Fair Value Rate Base

Q. How was the fair value basis of rate base determined?

A. As shown on Attachment RCS-2, Schedule B, the FVRB was determined by averaging OCRB and RCND. For purposes of this presentation, the Company's RCND information was used as the starting point for Staff's derivation of the FVRB. Adjustments were made to the RCND rate base as shown on Attachment RCS-2, Schedule B.1 (RCND).

Q. How did SWG determine the rate of return to apply to FVRB in its filing?

A. In SWG's filing, as shown on Schedule A-1, the Company applied its proposed FVROR to its adjusted FVRB. On that Schedule in the Fair Value column, Southwest calculates an increase in gross revenue requirements of $73.2 million.

Q. Describe the change in the Commission method of calculating operating income as it relates to the calculation of the FVROR.

A. Prior to a recent Arizona Court of Appeals decision,[1] the Commission had determined operating income by multiplying the WACC by the OCRB. The resulting product was then divided by the FVRB to determine a FVROR. The Arizona Court of Appeals found that the Commission did not comply with Article 15, Section 14 of the Arizona Constitution when it set rates based original cost instead of fair value. However, the Court noted: "If the Commission determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology." The Commission, in Decision No. 70441 adopted a FVROR based on the WACC modified to reflect a 2.00 percent reduction to the cost of equity, but not to the cost of debt. In Decision No. 71308, the Commission calculated the FVROR by subtracting an inflation factor from both the debt and equity components of the WACC.

Q. How has Staff calculated the FVROR and addressed the ruling in the Court of Appeals decision for purposes of the current SWG rate case?

A. Staff is presenting two alternatives for the FVROR as shown on Schedule D. The results of each of those alternatives for the FVROR are shown on Schedule A in columns D1 and D2. Schedule D of Attachment RCS-2 shows the derivation of the fair value rate of return

[1] *Chaparral City Water* Co *v Ariz Corp. Comm'n*, 1 CA-CC 05-0002 (Ariz. App. Feb. 13,2007)

for application to the FVRB. On Schedule A of Attachment RCS-2, Staff's adjustment to the weighted cost of capital as described by Mr. Parcell in his Direct Testimony was applied. Based on Staff witness Parcell's recommendation concerning the FVROR, Staff recommends a revenue requirement increase of not more than the $54.9 million shown on Schedule A in column D2. This equates to an increase of not more than 13.4 percent over Southwest's current base rate revenues.

III. RATE BASE

Q. Have you prepared a schedule that summarizes Staff's proposed adjustments to rate base?

A. Yes. As noted above, the adjusted rate base is shown on Schedule B and the adjustments to SWG's proposed rate base are shown on Schedule B.1. A comparison of the Company's proposed rate base and Staff's recommended rate base on an Original Cost and Fair Value basis is presented below:

Summary of Rate Base	Company	Staff	Difference
Original Cost Rate Base	$ 1,073,700,633	$ 1,070,115,558	$ (3,585,076)
RCND Rate Base	$ 1,839,334,300	$ 1,835,749,225	$ (3,585,076)
Fair Value Rate Base	$ 1,456,517,468	$ 1,452,932,391	$ (3,585,077)

Adjustments To Original Cost Rate Base

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

A. Staff has made six adjustments to Southwest's proposed original cost rate base. These have been designated as Staff Adjustments B-1 through B-6:

Summary of Staff Adjustments to Rate Base		OCRB	RCND RB
Adj. No.	Description	Increase (Decrease)	Increase (Decrease)
B-1	Corrections to Completed Construction Not Classified	$ (1,066,657)	$ (1,066,657)
B-2	Yuma Manors Pipe Replacement	$ (225,445)	$ (225,445)
B-3	Cash Working Capital	$ (468,000)	$ (468,000)
B-4	Accumulated Deferred Income Taxes - Bonus Tax Depreciation on CCNC	$ (1,286,985)	$ (1,286,985)
B-5	Remove Corporate Aircraft Costs	$ (352,892)	$ (352,892)
B-6	Remove One-Half of Prepaid D&O Insurance	$ (185,097)	$ (185,097)
	Total of Staff Adjustments	**$ (3,585,076)**	**$ (3,585,076)**
	SWGas Proposed Rate Base (Original Cost and RCND)	$ 1,073,700,633	$ 1,839,334,300
	Staff Proposed Rate Base (Original Cost and RCND)	**$ 1,070,115,558**	**$ 1,835,749,225**

Each adjustment is discussed below.

B-1 Corrections to Completed Construction Not Classified

Q. Please explain the adjustment for Completed Construction Not Classified.

A. This adjustment consists of two components, (1) a direct adjustment and (2) a system allocable adjustment.

The Company's filing included an adjustment (No. 17) to include in rate base Completed Construction Not Classified ("CCNC") of $2,806,169 of distribution and general plant that was supposed to be in service by June 30, 2010, the end of the test year. In response to Staff discovery, including STF-6-7(a) and (c), the Company indicated that two work orders have not closed and should be removed from the Company's original adjustment, which should be reduced to $2,695,762. The reduction of $110,407 is shown on Schedule B-1, line 3.

The Company's response to data request STF-6-7(d) stated that: "The Company is removing the $1,700,000 cost of the SCADA system originally included in Adjustment 17 in System Allocable Account 303." The Company's response to data request STF-6-19(a) states that: "The ... SCADA System, has not yet been placed into service; therefore, the

Company is no longer requesting that this item be included in rate base or amortization expense in this proceeding, reducing the plant in service increase to $4,139,131." The second part of the adjustment removes the $1.7 million. Applying the four-factor allocator of 56.25 percent, this reduces rate base by $956,250, as shown on Schedule B-1, line 8.

The total adjustment for CCNC reduces Southwest's filed jurisdictional rate base by $1,066,657, as shown on Schedule B-1, line 11.

Q. Is there a related adjustment to expenses?

A. Yes. The related adjustment to Depreciation Expense is presented on Schedule C-1, page 1, and the related adjustment for property taxes is presented on Schedule C-1, page 2. Those adjustments are discussed, below, in the section on net operating income adjustments.

B-2 Yuma Manors Pipe Replacement

Q. Please explain the adjustment for the Yuma Manors Pipe Replacement.

A. Staff's concerns regarding Southwest's deficient pipe maintenance were originally addressed in the testimony of Staff engineer Corky Hanson in Southwest's last rate case, Docket No. G-01551A-07-0504. The Commission's Decision No. 70665 in that case at page 8 found that:

> Based on all of the evidence and arguments presented by the parties, we find that in this proceeding $546,224 should be removed from rate base of which the cost for expediting the Yuma Manors pipeline replacement ($320,779) should be permanently disallowed from inclusion in the Company's rate base. The remaining $225,445 will be potentially included in rate base in the Company's next general rate case. We believe this disallowance gives appropriate recognition and weighting to the competing arguments presented by the Company and Staff and presents a reasonable resolution of this issue.

As described in the Direct Testimony of SWG witness Mashas at page 21, Southwest wrote off $320,779 of that disallowed amount and has permanently removed that from rate base. Southwest is requesting inclusion in rate base of the remaining $225,445. The testimony of Staff witness Frye presents reasons for why Staff believes the $225,445 should continue to be excluded from Southwest's rate base. On Schedule B-3, I have reflected the continued exclusion of the $225,445 from jurisdictional rate base.

Q. Is there an adjustment to operating expenses related to this adjustment?

A. Yes. Staff Adjustment C-2 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-3 Working Capital

Q. Have you reviewed the Company's request for a working capital allowance?

A. Yes. The Company's proposed working capital request of approximately $10.19 million consists of three separate subcomponents. The subcomponents are:

(1) a negative cash working capital balance of $4.47 million based on a lead/lag study;
(2) a thirteen-month average materials and supplies balance of $9.9 million; and
(3) a thirteen-month average prepayments balance of $4.7 million.

Q. How does that compare with the Company's request for a working capital allowance in its last rate case, Docket No. G-01551A-07-0504?

A. It is substantially higher than the Company's proposed working capital request of approximately $5.68 million from its last rate case, Docket No. G-01551A-07-0504. In its last case, the Company's negative cash working capital balance was $10.38 million based

on a lead/lag study. In that prior case, SWG had also proposed a thirteen-month average materials and supplies balance of $12.39 million, and a thirteen-month average prepayments balance of $3.68 million.

B-3.1 Cash Working Capital

Q. What is cash working capital?

A. Cash working capital is the cash needed by the Company to cover its day-to-day operations. If the Company's cash expenditures, on an aggregate basis, precede the cash recovery of expenses, investors must provide cash working capital. In that situation a positive cash working capital requirement exists. On the other hand, if revenues are typically received prior to when expenditures are made, on average, then ratepayers provide the cash working capital to the utility, and the negative cash working capital allowance is reflected as a reduction to rate base. In this case, the cash working capital requirement is a reduction to rate base as ratepayers are essentially supplying these funds.

Q. Does SWG have a positive or negative cash working capital requirement?

A. SWG has a negative cash working capital requirement. In other words, ratepayers are essentially supplying the funds used for the day-to-day operations of the Company. On average, revenues from ratepayers are received prior to the time when the utility pays the associated expenditures.

Q. Did SWG present a lead/lag study in support of its cash working capital requirement?

A. Yes, SWG performed a lead/lag study to calculate the cash working capital requirement in this case. The Company provided its lead/lag study calculations with the work papers provided in the case.

Q. Has SWG made any revisions to the cash working capital calculation included in its filing?

A. No, none of which I am aware.

Q. Are you recommending any revisions to SWG's cash working capital request?

A. Yes. At this time, as shown on Schedule B-3, I have reflected the impact of Staff's adjustments to operating expenses and impacts on revenue based taxes. I also propose to synchronize the calculation of cash working capital with Staff's recommended revenue increase.[2]

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

A. As shown on Schedule B-3, at this time I have decreased SWG's filed cash working capital by approximately $468,000.

Q. What revenue lag does Southwest propose and what are its components?

A. Southwest proposes a total revenue lag of 38.22 days, based on the following three components:

Description	Lag Days
Cycle	15.21
Read to Bill	2.90
Bill to Collection	20.12
Total revenue lag days	38.22

Q. Do you have any concerns about apparent omissions in Southwest's lead-lag study?

A. Yes. It appears that Southwest has omitted reflecting the additional cash payment lag associated with revenue-based taxes and assessments. I have reviewed lead-lag studies for

[2] Such synchronization has not yet been reflected at this time, but would be incorporated in Staff's Surrebuttal filing.

other Arizona utilities, including UNS Gas, UNS Electric and Tucson Electric Power Company. Those lead-lag studies have included a component for the additional cash payment lag related to the payment of revenue-based taxes and assessments. 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. How did Southwest consider revenue-based taxes in its lead-lag study?

A. Southwest considered revenue-based taxes in its lead-lag study by adding such taxes to billed revenues in order to calculate the 20.12 day billing to collection lag. However, based on my review to date, it does not appear that Southwest reflected the additional payment lag associated with such taxes as a source of ratepayer-provided funds. Consequently, at a later point in this proceeding, such as with Staff's Surrebuttal Testimony, it may be necessary to incorporate an adjustment to cash working capital for the impact of the payment lag associated with revenue-based taxes and assessments.

<u>B-4 Accumulated Deferred Income Taxes - Bonus Tax Depreciation on CCNC</u>

Q. Please explain the adjustment for Accumulated Deferred Income Taxes for Bonus Tax Depreciation on CCNC.

A. As described above, the Company's rate base has been adjusted to include only CCNC that was in service by June 30, 2010, the end of the test year. As described in Southwest's response to data request STF-6-7(d), the Company forgot to include the impact on

Accumulated Deferred Income Taxes ("ADIT") for the related income tax depreciation. The Company's response to data request STF-1-26 calculated the bonus tax depreciation related to the CCNC to be $704,030. The Company's response to data request STF-6-7(d) states:

> In preparing the response to this data request, it came to the Company's attention that the $704,030 was not included. The Company's Schedule B-6, Sheet 3 of 3, Line 4, Col. (c) should be increased by $704,030 to $211,498,218. This correction is needed only if the Commission accepts the Company's adjusted proposed $2,771,114 CCNC Adjustment No. 17.

As shown on Schedule B-2, ADIT in Account 282 has been increased to reflect the tax depreciation (in this case bonus tax depreciation) on the CCNC that has been included in rate base. Because the amount of CCNC included in rate base was approximately 3.93 percent lower than Southwest's as-filed amount, I reduced the Company's calculated $704,030 amount similarly by 3.93 percent. As shown on Schedule B-2, line 3, this adjustment increases federal ADIT (which is cost-free, ratepayer-provided capital) and reduces Southwest's as-filed rate base by $676,330.

There is a similar adjustment for the System Allocable amount of federal ADIT. As described in the Company's response to data request STF-6-7(d):

> Not reflected was the impact of bonus depreciation on the Corporate CCNC reflected in Adjustment No. 17. Schedule B-6, Sheet 3 of 3, Line 7, Col. (c) should be increased by $1,085,609 to $16,668,826 which is an amount before allocation to Arizona. Again, this adjustment is only appropriate if the $4,139,131 adjusted CCNC Adjustment No. 17, is accepted by the Commission.

As shown on Schedule B-2, lines 6-8, when the four-factor allocator of 46.25 percent is applied to the increase in federal ADIT of $1,085,609, the reduction to Arizona jurisdictional rate base is $610,655.

Q. What is the combined reduction to Arizona jurisdictional rate base for the federal ADIT on the CCNC amounts?

A. As shown on Schedule B-2, line 11, the total reduction to Arizona jurisdictional rate base for the federal ADIT on the CCNC amounts is $1,286,985.

B-5 Corporate Aircraft Costs

Q. Please explain the adjustment for Corporate Aircraft Costs.

A. As shown on Schedule B-5, the costs included in rate base as system allocable plant charged to Arizona for a corporate aircraft hanger and equipment are removed from Arizona rate base, reducing rate base by a net amount of $352,892. The hanger and aircraft equipment is located at 155 E. Reno, Suite D-12, Las Vegas, Nevada, and is unnecessary for the provision of utility service to Arizona customers.

B-6 Prepaid Directors' and Officers' Liability Insurance

Q. Please explain the adjustment for Prepaid Directors and Officers' Liability Insurance.

A. This adjustment, as shown on Schedule B-6, removes one-half, or $185,097, of the rate base amount for Prepaid Directors and Officers' Liability Insurance that Southwest identified in its response to data request STF 6-9, to reflect a 50-50 sharing of such cost between shareholders and ratepayers. The sharing of this cost is addressed in additional detail in conjunction with a related adjustment to expense, Staff Adjustment C-11, below.

Adjustments To Reconstruction Cost New Depreciated Rate Base

Q. Please describe Staff's adjustments to RCND rate base.

A. Staff's adjustments to Southwest's proposed RCND rate base are shown on Attachment RCS-2, Schedule B.1 (RCND). In each instance, the RCND adjustment amounts are the same as Staff's adjustments to OCRB.

IV. ADJUSTMENTS TO OPERATING INCOME

Q. Please describe how you have summarized Staff's proposed adjustments to operating income.

A. Schedule C summarizes Staff's recommended net operating income. Schedule C.1 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. SWG's proposed adjusted test year net operating income is $65.066 million, whereas Staff's recommended adjusted net operating income is $69.794 million. The recommended adjustments to operating income are discussed below in the same order as they appear on Schedule C.1.

C-1 CCNC Correction Depreciation and Property Tax Expense

Q. Please explain Staff Adjustment C-1.

A. This adjustment is related to Adjustment B-1. As shown on Schedule C-1, page 1, it removes $99,843 of Depreciation Expense and, on page 2 of that schedule, $21,603 of Property Tax Expense related to the adjustment to the correction for Completed Construction Not Classified.

C-2 Yuma Manors Depreciation and Property Tax Expense

Q. Please explain the adjustment for Yuma Manors Depreciation and Property Tax Expense.

A. This adjustment is shown on Schedule C-2 and reduces Depreciation Expense by $10,053 and Property Tax Expense by $4,566 related to the removal from rate base of $225,445 for Yuma Manors plant that was discussed above in conjunction with Staff Adjustment B-2.

C-3 Management Incentive Program Expense

Q. Please explain Staff Adjustment C-3.

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 Southwest is reduced by $1.768 million. Related payroll tax expense is decreased by $131,558.

Q. Please explain why a 50 percent allocation to shareholders is appropriate for an incentive compensation program, such as Southwest'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 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. What changes has SWG made to its MIP since the end of the test year in its last Arizona rate case?

A. The Company's response to data request STF-6-1 indicates that SWG made two modifications to the MIP since the end of the test year (April 30, 2007) in its last Arizona rate case, Docket No. G-01551A-07-0504: (1) in 2008, the five performance measures of the MIP were replaced with four; and (2) in 2009, the eligibility threshold for the non-officer (30 percent) tier was increased and a level for technical managers (10 percent tier) was created.

Q. What are the four performance measures used in the Southwest Gas MIP?

A. The Company's response to data request STF-6-1 describes the four performance measures as follows:

> The MIP is variable compensation at-risk each year based on the performance relative to four measures that define the goals and benchmarks of the MIP, all designed to align the interests of customers, SWG management and shareholders. The measures are: (1) customer satisfaction; (2) customer-to employee ratio; (3) return on equity; and (4) operating costs.
>
> **Customer Satisfaction**
>
> The customer satisfaction performance measure is a standard measure of performance in the utility industry and SWG is an industry leader in this area. SWG routinely performs in the low-to-mid 90's under this metric. Performance is currently measured monthly by an independent third-party, and the process is periodically audited by the SWG Internal Audit department. The target for this measure is set at 85 percent and is measured individually for each SWG operating division. This measure is a direct representation of the quality and efficiency of the service provided to SWG customers.
>
> The customer satisfaction metric measures the quality, efficiency and reliability of service provided to SWG customers by capturing satisfaction levels of customers following recent contact with SWG. The goal of this metric is to maintain and enhance the customer experience by developing a

solid service relationship upon which customers can depend. The information collected through the tracking program provides management with a tool to improve customer satisfaction and provides awareness of areas which may need attention while further solidifying an efficient and dependable customer service relationship.

Customer-to-Employee Ratio

The customer-to-employee ratio performance measure compares the actual prior year customer-to-employee ratio to an established benchmark. This is a standard productivity measure in the utility industry. Labor costs plus loadings represent nearly two-thirds of SWGs' total operations and maintenance expense. The SWG customer-to-employee ratio has shown consistent improvement during the past 10 years.

The customer-to-employee ratio illustrates a company's ability to operate efficiently. Therefore, a favorable customer-to-employee ratio indicates that a company is achieving increased efficiencies while at the same time controlling labor costs. The executive management team at SWG takes a hands-on approach to managing employee headcount, which includes reduction through attrition, detailed reviews of position requests and challenging employees to develop and embrace change (including technological advances) that yields higher productivity.

Return of Equity (ROE)

The ROE performance measure considers the authorized weighted average ROE of the returns utilized to establish rates in each of the regulatory jurisdictions in which SWG operates and is theoretically the ROE that SWG should be able to achieve on a company-wide basis. Over the last 10 years, SWG has experienced an actual average ROE of 6.9 percent, compared to an average authorized weighted average ROE of 10.8 percent for the same period. The target for this measure represents 80 percent of the Company-wide authorized weighted-average ROE.

ROE is the total measure of SWG's performance and annually measures SWG's ability to manage costs. Indeed, SWG must judiciously manage costs in order to maximize earnings (ROE), which, in turn, benefits customers by minimizing rate increases.

Operating Costs

The operating costs performance measure quantifies management effectiveness in controlling operation and maintenance costs. The use of the rolling 10-year average used in prior years was replaced with a target that reflects estimated inflation and a growth factor. The inflation factor is

> determined by the Blue Chip Economic Indicators publication and the growth factor is based on customer growth.
>
> As previously noted, the operating costs performance measure quantifies management effectiveness in controlling operating costs. The target for this measure is based on productivity efficiencies and is dependent upon management to act prudently to support cost containment, which, in turn, benefits customers by providing a reasonable cost of service.

Q. Has the Company indicated that these performance measures are designed to address the interests of both customers and shareholders?

A. Yes. For example, SWG's response to STF-11-10(a) states in part that:

> **... the mix of performance measures and their respective targets are designed to address the interests of both customers and shareholders** through the Company's financial performance, increased productivity and customer satisfaction. (Emphasis supplied.)

Q. What is the current tier structure used in the Southwest Gas MIP and how does that compare with the previous tier structure that was in place at the time of the Company's last rate case?

A. The Company's response to data request STF-6-1 compares the previous and current MIP participant tier structure in the following table:

Position	Previous	Current [1]
CEO	115%	115%
President	100%	100%
Executive Officers	90%	90%
Sr. Officers	75%	75%
Officers	50%	50%
Non-Officers [2]	30%	30%
Technical Manager [3]		10%

[1] Effective beginning in the 2009 plan year
[2] Eligibility threshold increased to positions with 775 Hay Points versus 700 Hay Points
[3] New tier added for Technical Managers, encompassing positions between 677 and774 Hay Points

Q. Please briefly discuss the key provisions of the MIP.

A. SWG's MIP provides variable compensation to executives for the achievement of specific goals and performance objectives important to both the short-term and long-term success of the Company. A summary of the MIP award triggers is presented in the following table:

[redacted]

As described above, the MIP award is at risk each year based on performance relative to four measures. These annual performance measures, which are equally weighted, include (1) customer satisfaction, (2) customer to employee ratio, (3) return on equity ("ROE"), and (4) operating costs. Each of these measurements has a threshold, target and a maximum. At target, each measurement contributes 25 percent towards the total award for the year. An award under a specific criterion may be given within a range from 70 percent at threshold to 140 percent at maximum. There is no award under specific criteria for performance under the threshold, and there is no incremental value for performance over the maximum for any of the four criteria.

Q. How much of the MIP is cash and how much is stock?

A. The Company's MIP provides that:

[redacted]

In summary, subject to the restriction period on the long-term component, the MIP is 40 percent cash and 60 percent stock.

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

A. As noted above, one of the four MIP award criteria relates 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 is no incentive award under the MIP for that year.

Q. What Southwest management personnel are eligible for the MIP award, and how is it distributed?

A. According to SWG's response to STF-1-50[3], the MIP award opportunity is measured as a percentage of base salary and varies by title as follows:

Position	Percentage of Base Salary
CEO	115%
President	100%
Executive VP	90%
Senior VP	75%
Vice President	50%
Non-Officers	
Director/Senior Manager	30%
Key Management Employees	10%

Forty percent of the total award earned under the MIP is paid in cash immediately following the financial close of the most current calendar year. The remaining 60 percent is awarded through the issuance of performance shares, which are issued to the executives and key management employees three years into the future.

Q. Does Southwest 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. Data request STF 1-92 asked[4]:

[3] See Attachment RCS-3.
[4] Id.

> Are there any aspects of the Company's accounting adjustments and revenue requirement claim which represents a conscious deviation from the principles and policies established in prior Commission Orders? If so, identify each area of deviation, and for each deviation explain the Company's perception of the principle established in the prior Commission orders, how the Company's proposed treatment in this rate case deviates from the principles established in the prior Commission orders, and the dollar impact resulting from such deviation. Show which accounts are affected and the dollar impact on each account for each such deviation.

Southwest's response to this data request referred to STF 1-56 and STF 1-57. STF 1-57 states in part that "Southwest is requesting full cost recovery of its Management Incentive Program and Supplemental Executive Retirement Plan."[5]

Q. What reasoning does SWG give for its request to recover 100 percent of its MIP costs despite prior Commission Orders?

A. In her Direct Testimony at page 19, Company witness Gaffin stated that the Company's compensation packages are designed to maintain a dedicated and consistent executive team to ensure the implementation of the operations and strategic plans of the organization. Ms. Gaffin also states that the compensation packages are reasonable and well-balanced with below market base salaries, and competitive.

Additionally, as described in Ms. Gaffin's Testimony at pages 2-3, SWG employed Towers Watson to assess the competitiveness of SWG's compensation packages with peer group companies. Towers Watson compared the total compensation (base salary, bonus, other, restricted stock awards, options awards, non-equity incentive plan, long term incentive payout and all other compensation) and concluded that its management and executive employees are compensated within a reasonable range. Based in part on the analysis shown in her Confidential Exhibit__SLG-1, Ms. Gaffin concludes that Southwest's executive compensation package is prudent and reasonable.

[5] I discuss Staff's recommended adjustment for the SERP, below, in conjunction with Staff Adjustment C-5.

Q. Does the methodology for comparing the executive compensation used by Ms. Gaffin address the criteria that the Commission has found important in deciding issues concerning utility incentive compensation in recent cases?

A. No. Her methodology ignores the criteria the Commission has found important in deciding this issue in recent cases. In Decision No. 68487 (February 23, 2006), the Commission adopted Staff's recommendation for an equal sharing of costs associated with the Company's MIP expense. For example, in reaching its conclusion regarding SWG's MIP, the Commission stated in part on page 18 of Decision No. 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.

Additionally, in Decision No. 70665 (December 24, 2008), at page 16, the Commission stated that:

> In the last Southwest Gas rate case, as well as several subsequent cases, we disallowed 50 percent of management incentive compensation on the basis that such programs provided approximately equal benefits to shareholders and ratepayers because the performance goals relate to financial performance and cost containment goals as well as customer service elements. (Decision No. 68487 at 18.) In that Decision, we stated:
>
> In Decision No. 64172, the Commission adopted Staff's recommendation regarding MIP expenses based on Staff's claim that two of the five performance goals were tied to return on equity and thus primarily benefited shareholders. 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 resolution.
>
> (Id.) We believe the same rationale exists in this case to adopt the position ... to disallow 50 percent of the Company's proposed MIP costs.
>
> (Footnotes omitted)

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

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

A. Yes. In referencing the SWG's executive compensation philosophy, Ms. Gaffin states in her Direct Testimony at page 4, lines 25-27 that:

> "...executives are not paid in excess of what their performance merits and aligns the interests of executives with the customers and shareholders..."

Additionally, as noted above, SWG's response to STF-11-10(a) states in part that:

> **... the mix of performance measures and their respective targets are designed to address the interests of both customers and shareholders** through the Company's financial performance, increased productivity and customer satisfaction. (Emphasis supplied.)

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 two Southwest Gas rate cases that a different result concerning the sharing of MIP expense should occur?

A. No, I don't believe so. 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 Nos. 68487 and 70665.

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. Gaffin?

A. No. The 50/50 sharing of Southwest's MIP program cost ordered by the Commission in Decision Nos. 68487 and 70665 should continue to apply in the current Southwest Gas rate case.

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

A. Yes, it was. In Decision No. 70011 (November 27, 2007), in a 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.

Similarly, in Decision No. 71623 (April 14, 2010), in the most recent UNS Gas rate case, Docket No. G-04204-08-0571, the Commission stated in part on page 30 that:

> We believe that the Staff and RUCO recommendations to require a 50/50 sharing of incentive compensation costs provides a reasonable balancing of the interests between ratepayers and shareholders.

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

A. Yes. SWG's response to data request STF 17-2(a) identifies $3.536 million as MIP compensation expense charged to Arizona jurisdictional operations.[6] [redacted]

Q. Has the Commission disallowed other utilities' stock based compensation in other recent decisions?

A. Yes. In Decision No. 69663, from an 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

[6] See Attachment RCS-3.

> 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, 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 Decision No. 71448 (December 30, 2009), the most current APS rate case, the Commission adopted a settlement reached between the parties which had restricted the inclusion of cash and stock based incentive compensation in rates to the amounts recommended by Staff.

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

A. Staff recommends continuing the 50 percent allocation to shareholders ordered for Southwest by the Commission in Decision Nos. 68487 and 70665. This results in a reduction to test year expense of $1,768,249 for MIP expense and $131,558 for related payroll tax expense for a total reduction to operating expenses of $1,899,807.

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

Q. Please describe Southwest's stock-based compensation plans.

A. Southwest has two stock-based compensation plans: (1) the Restricted Stock/Unit Plan ("RSUP") and the MIP. The Restricted Stock/Unit Plan replaced the stock-option based

compensation in May 2007. As described above, Southwest's MIP incentive compensation also includes a stock-based component. However, in this section of testimony I will address only Southwest's Stock-Based Compensation (Other than MIP).

Q. Please describe Southwest's Restricted Stock/Unit Plan.

A. The RSUP is available to officers and other key management employees, with the purpose of "enhancing the competitive position of the total direct compensation and to further align customer, management, and shareholder interests, while sustaining a strong commitment to the long-term financial success of the Company and further encouraging management with ownership of Company stock." The three-year average of the MIP percent of target achieved is used to calculate the RSUP distribution. The amounts granted range from 50 to 150 percent of target. The minimum three-year average MIP achievement of 90 percent is required for RSUP distribution. The distribution is converted to restricted share units based on the current market price of the date the distribution is approved.

Q. What Southwest management personnel are eligible for the RSUP, and how is it distributed?

A. As stated above, the RSUP is available to officers and other key management employees. According to SWG's response to STF-1-50, the RSUP award opportunity is measured as a percentage of year-end base salary and varies by title as follows:

Position	% of Base Salary	% Value Range Distribution
CEO	45	22.5 to 67.5
President	30	15.0 to 45.0
Executive VP	25	12.5 to 37.5
Senior VP	20	10.0 to 30.0
Vice President	15	7.5 to 22.5
Other Participants	10	5.0 to 15.0

These units, similar to MIP, have a three-year vesting period, with 40 percent for the first year, and 30 percent for years two and three.

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

A. Yes, but it was replaced since then with the RSUP.

Q. Please explain Staff Adjustment C-4.

A. As shown on Schedule C-4, this adjustment decreases test year expense by $1,033,723 to reflect the removal of Southwest's RSUP compensation expense that is allocated to Arizona operations.[7] The expense of providing 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

Q. Please explain Staff Adjustment C-5.

A. This adjustment removes 100 percent of the expense for the Supplemental Executive Retirement Plan ("SERP"). 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 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

[7] See, SWG's response to STF-6-5; this amount for RSUP is after the allocation to Arizona.

that the Company 401(k) contribution as a percent of salary may be smaller for a highly paid executive than for other employees.

The response to STF 1-50 states that benefits will equal 60 percent of annual compensation for senior executives and 50 percent for all other officers, when added to the benefits received under the basic retirement plan. The amount of compensation is calculated as the 12-month average of the highest 36 months of salary. Officers must be at least 55 years of age and have a minimum of 20 years of service with SWG. Being an unqualified plan, payments of SERP are not guaranteed. Workpaper C-2, Adjustment No. 3, Sheet 5, states that SWG is requesting $1.42 million for recovery in the test year, but that is only for a portion of the SERP cost charged and allocated to Southwest's Arizona jurisdictional operations. The Company's response to data request STF-17-1 shows estimated SERP expense charged to Arizona jurisdictional operations of $1.726 million.

Q. Is participation in the SERP limited to a select group of highly paid executives?

A. Yes. The Company's confidential response to data request STF-6-3 lists the SERP participants and their respective salary levels. The list provided in response to STF-6-3 by Southwest includes information for two executives who retired during the test year. Southwest's labor annualization adjusted test year expenses to remove the salaries for the retired executives.

Q. Did Southwest provide test year SERP information by participant?

A. No. The Company's response to data request STF-6-4, which had requested that information, provided an actuarial report and stated that SERP expense is a total company amount that is allocated to each ratemaking jurisdiction using the labor loading process.

Additionally: "Test year SERP expense by participant is not information that is used by the Company, and is not readily available to the Company."

Q. Does the actuarial report provided by the Company indicate the number of active participants and their average compensation?

A. Yes. Page 5 of the Hewitt Associates actuarial report for the Southwest Gas SERP for 2010 shows that as of August 1, 2008 there were 17 active participants with average compensation of $240,802. At August 1, 2009, there were 20 active participants with average compensation of $255,494.[8]

Q. Was Southwest's SERP expense disallowed by the Commission in the Company's last two rate cases?

A. Yes. In Decision No. 68487, the Commission adopted a recommendation by RUCO to remove SERP expense. In reaching its conclusion regarding SERP, the Commission stated on page 19 of Decision No. 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.

[8] The actuarial report at page 5 also indicates that, as of August 1, 2008 and 2009, respectively, there were 29 and 31 retirees/beneficiaries, with average annual benefits of $80,180 and $74,215, respectively.

Similarly, SERP was disallowed by the Commission in Decision No. 70665, based on the discussion at pages 16-18. At page 18, the Commission stated that: "... we agree with the recommendations of Staff and RUCO that the request for inclusion of SERP expenses should be denied. We therefore adopt the recommendations of Staff and RUCO on this issue."

Q. Has Southwest indicated that its SERP has changed since the Commission ruled on this expense in Decision No. 70665?

A. No. In fact, Southwest's response to data request STF-6-2 states that: "No changes have been made to the Supplemental Executive Retirement Plan since SWG's last rate case, Docket No. G-01551A-07-0504."

Q. Was SERP expense also disallowed in the Commission's two most recent decisions 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.

Similarly, in Decision No. 71623, at page 34, the Commission stated:

> We see no reason to depart from the rationale on this issue ..., that ratepayers should not be required to fund the retirement benefits of a few select executives whose salaries exceed current IRS limits. ... as has been stated in prior cases, the Company's shareholders may provide these additional benefits but ratepayers should not be subject to this additional burden.

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 $1.726 million.

C-6 American Gas Association Dues

Q. Please explain Staff's proposed adjustment for American Gas Association ("AGA") dues.

A. This adjustment is shown on Schedule C-6 and reduces test year expense by $80,138 to reflect the removal of 40 percent of AGA dues.

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 while SWG's filing reflected the removal of only 6.09 percent of the AGA dues. Southwest proposes to only remove the lobbying portion of AGA dues.

Q. Do you agree with Southwest's adjustment to remove only 6.09 percent of AGA dues?

A. No. While the marketing and lobbying-related portion of the AGA dues should be removed from rates, SWG should continue to demonstrate that the remainder of the dues are legitimate test year expenses. Decision No. 68487 also provided a clear directive from

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 Southwest's most recent Arizona rate case, Docket No. G-01551A-07-0504, the issue of AGA dues was addressed at some length. In Decision No. 70665, the Commission found at page 12 that:

> ... Staff's recommended disallowance of 40 percent of AGA dues represents a reasonable approximation of the amount for which ratepayers receive no supportable benefit. The documentation offered by the Company to justify the AGA dues, including the alleged monetary savings to members, consists primarily of information provided by the AGA itself and must be viewed in that context. As Staff witness Ralph Smith indicated, several other states have disallowed AGA dues in substantially higher amounts than the amount proposed by Southwest Gas. Mr. Smith also pointed out that Staff's recommended disallowance is approximately the same percentage as that attained by totaling up AGA activities for Public Affairs, Corporate Affairs, half of General Counsel expenses, and marketing under a 2005 NARUC audit. Further, application of the 2007 and 2008 AGA dues would result in even greater disallowances under these categories. We therefore adopt Staff's recommendation to disallow 40 percent of the Company's AGA dues.

Q. What information did Southwest provide concerning the specific benefits of AGA activities to the Company and Arizona ratepayers?

A. Southwest witness Randi Aldridge addresses AGA activities in her Direct Testimony at pages 13-17. However, she did not provide any quantification of claimed savings, or 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.

Q. Please comment on the support for AGA dues reflected by Southwest in this current rate case.

A. The information provided by Company witness Aldridge in direct testimony to support the Company's claim for AGA dues is even less than what was provided by the Company in its last rate case. In Southwest's last Arizona rate case, SWG provided an Exhibit RLA-2 containing a one-page listing and description of the AGA's functions as listed in the March 2005 Annual Audit report to the National Association of Regulatory Utility Commissioners ("NARUC"). In the last case and in the current case, however, the Company did not include the percentage of AGA activities related to each function.

Q. Does the information provided by Southwest show that 93.91 percent (100 percent minus the Company's 6.09 percent disallowance for lobbying) of AGA dues-funded activities are beneficial to the Company and/or to its Arizona ratepayers?

A. No. Southwest has demonstrated that there is some benefit of AGA membership to the Company and to Arizona ratepayers from some of the AGA's functions. However, the Company has failed to demonstrate that ratepayers should fund activities conducted through an industry organization that would be subject to disallowance if conducted directly by the utility. The Company has failed to demonstrate that a disallowance of AGA dues of only 6.09 percent is adequate. Other jurisdictions have used a significantly higher disallowance percentage for gas utility AGA dues than Southwest is proposing here.

Q. To your knowledge, what percentage disallowance for utility AGA dues has been used in other recent utility rate cases?

A. In a recent UNS Gas rate case, as described on pages 32-33 of Decision No. 70011, UNS Gas had initially included $41,854 for AGA dues, and RUCO witness Moore

recommended a partial disallowance of $1,523, based on an ABA/NARUC Oversight Committee Report indicating that 1.54 percent of AGA dues were for marketing and 2.10 percent of dues were for lobbying activities. UNS Gas agreed with that adjustment, and it was ultimately adopted by the Commission. At pages 33-34 of Decision No. 70011, however, the Commission also stated that:

> Mr. Smith raises a valid point regarding the nature of AGA dues and whether a higher percentage of such dues should be disallowed as related to activities that are not necessary for the provision of services to UNS customers. However, we believe it is reasonable, in this case, to allow $40,311 ($41,854 - $1,523), in accordance with RUCO's recommendation. As we indicated in the Southwest Gas Order, however, we expect UNS in its next rate case to provide more detailed support for the allowance of AGA dues and how the AGA's activities benefit the Company's customers aside from marketing and lobbying efforts.

AGA dues disallowances have been made in gas utility rate cases in Michigan and California. In California, it appears that a disallowance of 25 percent of Pacific Gas and Electric Company's AGA dues was made by the Company itself in its filing in Application 05-12-002 (filed 12/2/05) as related to lobbying in the broader sense. In a more recent California rate case, Application No. 06-12-009, involving San Diego Gas and Electric, that utility appears to have proposed a 2 percent AGA dues disallowance for lobbying in the narrowest sense; DRA proposed that the entire cost of SDG&E's AGA dues be excluded; and UCAN supported either the full disallowance or a 25 percent disallowance based on the result from the PG&E rate case and their review of AGA activities information.

In a Michigan case involving Consumers Energy Company's gas utility operations[9], that utility conceded to a PSC Staff adjustment to disallow 16.17 percent of the AGA dues.

Q. How did you determine the percent disallowance for AGA dues?

A. This was based upon a review of information in the two most recent NARUC sponsored Audit Reports of the Expenditures of the American Gas Association, as well as the components by function of the AGA's 2007 and 2008 budgets, that were used in Southwest's last Arizona rate case, plus a review of subsequent AGA budget information that Southwest provided in response to data requests in the current rate case, including the Company's response to data request STF 6-21. I also relied upon a Florida PSC Staff memorandum, discussed in more detail below, which contained a 40 percent AGA dues disallowance. Copies of relevant pages from the NARUC-sponsored audit reports are provided in Attachment RCS-3. AGA 2007 and 2008 budget information, by component, is summarized on Schedule C-6, page 2, which is similar to the analysis I had filed in Southwest's last rate case, Docket No. G-01551A-07-0504, in support of the recommended adjustment to AGA dues. Additionally, Schedule C-6, page 3, presents information on AGA actual expenditure information from 2001 through 2009, and for forecast 2010, which was provided by Southwest in response to data request STF-6-21. Page 3 also shows the percentages by category, before and after the allocation of AGA administrative and general expenditures, and shows calculated disallowance percentages. This supports the reasonableness of the continuation of the 40 percent AGA dues disallowance.

[9] Michigan PSC Case No. U-13000.

Q. What is the purpose of the NARUC-sponsored audits of AGA expenditures?

A. The purpose of the NARUC-sponsored audits of AGA expenditures is to provide regulatory commissions with information that is useful in helping them decide which, if any, of the costs of the association should be approved for inclusion in utility rates. As stated in the June 2001 memo to the Chairs and Chief Accountants of the State Regulatory Commissions included with the NARUC-sponsored audit of 1999 AGA expenditures: "Often, state commissioners review the costs of the association charged or allocated to the utilities in their jurisdiction in accordance with the policies of their commission for treatment of costs directly incurred by the state's utilities for similar activities." The NARUC-sponsored audit categorizes the AGA expenditures and, as stated in the aforementioned memo, "these expense categories may be viewed by some State commissions as potential vehicles for charging ratepayers with such costs as lobbying, advocacy or promotional activities which may not be to their benefit."

Q. Have other regulatory commissions required similar adjustments to utility-incurred AGA dues, based on the results of the NARUC-sponsored audits?

A. Yes. As an example, I have included in Attachment RCS-3 an excerpt from a Florida Public Service Commission Staff Memorandum (dated 12/23/03) in a City Gas Company rate case addressing this issue. As stated in that document:

> In City Gas's last rate case, *In re: Request for rate increase by City Gas Company of Florida*, Docket No. 000768-GU, Order No. PSC-01-0316-PAA-GU, issued February 5, 2001, the Company removed $4,045 for AGA dues for lobbying. The Commission removed an additional combined amount of $4,970 for memberships, dues and contributions. *In re: Application for a rate increase by City Gas Company of Florida*, Docket No. 940276-GU, Order No. PSC-94-0957-FOF-GU, issued August 9, 1994, for interim purposes, the Commission disallowed 40% of AGA dues. This order stated that the percentage was based on the 1993 National Association of Regulatory Commission's (NARUC) Audit Report on the Expenditures of the American Gas Association (Audit Report). Order No.

PSC-94-0957-FOF-GU further stated that this reduction was consistent with adjustments made in rate cases involving other gas companies. In the final order in Docket No. 940276-GU, Order No. PSC-94-1570-FOF-GU, issued December 19, 1994, the Commission removed 40.48% of AGA dues "which were related to lobbying and advertising that did not meet the criteria of being informational or educational in nature." In re: Request for rate increase by Florida Division of Chesapeake Utilities Corporation, Docket No. 000108-GU, Order No. PSC-00-2263-FOF-GU, issued November 28, 2000, the Commission removed 45.10% of AGA dues.

The latest NARUC Audit Report on AGA expenditures that Staff was able to locate is dated June, 2001, for the twelve-month period ended December 31, 1999. By a review of the Summary of Expenses, it appears that 41.65% of 1999 AGA expenditures are for lobbying and advertising. Staff has not been able to locate a more recent NARUC Audit Report of the AGA expenditures. However, because approximately 40% appears to have been consistent over a number of years, Staff believes it is not unreasonable to assume that 40% is representative of 2003 and 2004 expenditures and recommends that 40% of AGA dues be disallowed in this proceeding.
From information supplied by the Company, AGA dues were $39,277 in 2003. According to recommendations in Issue 44 and 45, Account 921 should be trended on inflation only at 2.0% for 2004. On that basis the 2004 amount is $40,063 ($39,277 x 1.02). Disallowing 40% would result in disallowing $16,025 for 2004. The Company's $2,847 adjustment reduces Staff's adjustment to $13,178 ($16,025 - $2,847) for 2004. This position follows past Commission practice of placing charitable contributions and advertising that is not informational or educational in nature below the line.

Based on the above analysis, Account 921, Office Supplies and Expenses, should be reduced by an additional $13,178 for AGA membership dues related to charitable contributions and advertising that is not informational or educational in nature.

The Company is in agreement with this adjustment.

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 $90,898 in test year expense for AGA membership dues.

C-7 Loss on Sale of Employee Homes for Relocation Expense

Q. Please explain Staff Adjustment C-7.

A. During the test year ending June 30, 2010, the Company charged to Arizona operations expense of $503,620.[10] As shown on Schedule C-7, page 2, that amount is abnormally high in comparison with all prior years other than 2008 and with a five-year average. As shown on Schedule C-7, page 1, Staff Adjustment C-7 adjusts expense in two phases.

First, the test year amount is adjusted to a more normal level, based on a five-year average. The Company's Arizona jurisdictional operating expense is reduced by $243,931.

Second, the remaining expense related to losses incurred on the sale of employee homes is removed from the test year, reducing test year expense by $259,688. The total reduction to test year expense is $503,620.

Q. What is Staff's reason for totally removing the expense related to losses incurred on the sale of employee homes?

A. The Company should not be incurring cost related to losses on the sale of employee homes related to relocation expense unless there is a net benefit being produced by the relocation, and the incurrence of this additional relocation expense. Staff sees no evidence that these additional relocation costs related to losses on the sale of employee homes have produced any net cost savings for Arizona ratepayers.

[10] Southwest Gas' response to data request STF-6-29.

C-8 Test Year Rent Charged to Affiliate IntelliChoice Energy LLC

Q. Please explain Staff Adjustment C-8.

A. IntelliChoice Energy LLC ("ICE") is a non-regulated affiliate of Southwest Gas that is using space in a Southwest Gas building. ICE should be reimbursing SWG for rent and utilities. Per SWG's response to data request STF-11-1(n), due to a billing error, ICE was not billed for its portion of rent and utilities during the test year. SWG identified the amount of rent that was not reimbursed in that response. The Arizona jurisdictional amounts identified in that response, which total $13,156 are removed from test year expense.

C-9 Gas Heat Pump Development Expenses

Q. Have Southwest Gas' ratepayers been funding gas heat pump development?

A. Yes. Southwest Gas' ratepayers been funding gas heat pump ("GHP") development by the inclusion of research and development ("R&D") costs in operating expenses which are included in Southwest Gas' base rates, and also by R&D costs related to gas heat pump development which have been recovered by the Company in the R&D surcharge.

Q. Has Southwest Gas recently transferred virtually all of its assets related to gas heat pump development into a non-regulated subsidiary?

A. Yes. A new non-regulated subsidiary of Southwest's wholly owned subsidiary Northern Pipe Line Company ("NPLC") was formed. The new non-regulated subsidiary, IntelliChoice Energy LLC, is two-thirds owned by NPLC and one-third owned by Tommis Young, a non-affiliated contractor, who, under various company names had been receiving funding from Southwest Gas related to GHP research. Upon the formation of ICE, Southwest Gas transferred assets and intellectual property to ICE. The purpose of

ICE is to commercially develop and sell GHP, including gas engine driven air conditioning ("GEDAC").

Q. What department at Southwest had been involved in gas heat pump development?

A. Southwest's Energy Efficient Technology Department ("EETD") had been involved in the development of gas heat pumps.

Q. Did Staff ask Southwest Gas to identify all rate base and income statement amounts related to gas heat pump development?

A. Yes. Data request STF-11-1(b) requested Southwest Gas to identify all rate base and income statement amounts, by account, related to gas-fired heat pump technology, for the test year as well as calendar years, 2008, 2009 and 2010.

Q. What information did Southwest Gas provide?

A. Southwest Gas provided its EETD expenditures, by account, for each period in an attachment to its response to data request STF-11-1, along with the following explanation:

[redacted]

The information provided by Southwest Gas is summarized on Schedule C-9, page 2. As shown there, for the three years, the Company expended over [redacted] on GHP project activities.[11] Southwest Gas' response to data request STF-11-1(h) shows the amounts for

[11] Of this total, approximately [*BEGIN CONFIDENTIAL*] $3 million [*END CONFIDENTIAL*] appears to be from Arizona, using information supplied by Southwest in response to data request STF-11-1, and Arizona allocations derived from Southwest's response to data request STF-11-21.

GHP development that it estimates were included in rates charged to Arizona ratepayers. That information provided by the Company plus a cumulative column is shown in the following table:

[redacted]

According to the information provided by Southwest in response to data request STF-11-1(h), Arizona ratepayers have funded approximately [redacted] for GHP development through 2010.

Q. Why is the funding of GHP development by Southwest Gas' Arizona ratepayers a concern?

A. It is a concern because the funding has gone toward the development of gas-fired equipment that will be sold in a competitive market to compete with non-regulated electric equipment. Ratepayer funding for gas-on-electric competition or commercial development of competitive products has generally been disfavored. Additionally, and

perhaps more importantly in this instance, under Southwest's recent arrangements, the GHP equipment will be commercialized and sold by a non-regulated subsidiary, without any apparent compensation to Southwest Gas or its ratepayers for the significant development funding incurred to date.

Q. Has Staff asked Southwest to explain how the Company and its subsidiaries, including but not limited to NPLC and IntelliChoice Energy LLC will account for the revenue produced by commercialization of gas heat pumps?

A. Yes. This request was made in data request STF-11-1(g).

Q. What was Southwest's response?

A. Southwest's response to data request STF-11-1(g) stated that:

[redacted]

To date, Staff is unaware of Southwest Gas proposing a methodology or plan for sharing any benefits of GHP commercialization or royalties from the sale of GEDAC units with Arizona ratepayers.

Q. Has Southwest Gas provided other information concerning the development of GHP and the transfer of assets and intellectual property to ICE?

A. Yes. Southwest Gas has provided other information in response to a number of Staff data requests including STF-1-98, STF-7-17, and STF-11-1. Copies of those non-confidential and confidential responses are included in Attachments RCS-3 and RCS-4 to my Direct Testimony, respectively.

Q. What is Staff's recommendation?

A. Staff has the following recommendation:

1) Because Southwest Gas has elected to transfer commercial development of GHP into a non-regulated subsidiary without compensation to Arizona ratepayers who have funded a substantial portion of the development costs to date, all GHP development costs should be removed from the Company's test year operating expenses in the current Southwest Gas rate case.

2) No additional GHP development costs should be recoverable by Southwest Gas via the R&D surcharge.

3) Southwest Gas should be ordered to prepare an accounting for all GHP development costs that have been funded by Arizona ratepayers through base rates and the R&D surcharge through the date of the Commission's final order in this case; that accounting should be filed by the Company within 30 days of the final order.

4) Southwest should record the Arizona ratepayer funding for GHP development as a regulatory liability, to be returned to ratepayers, as commercial development occurs and revenues and royalties are received.

5) Southwest Gas should be ordered to prepare a plan to reimburse Arizona ratepayers for *their funding* of GHP development costs, and a methodology to share the benefit of commercialization revenues and royalties from the development of GEDAC units with Southwest's Arizona ratepayers. Southwest's plan and sharing methodology should be subject to comment from interested parties to the current rate case.

Q. Please explain Staff Adjustment C-9.

A. This adjustment removes the GHP development cost from test year operating expenses, using the information provided by SWG in response to data requests STF-11-1 and STF-11-21 to identify the amounts. Test year expenses are reduced by $711,287, as shown on Schedule C-9, page 1.

Q. How was the issue of Southwest Gas' funding of GHP development and commercialization addressed in the Company's most recent Nevada rate case?

A. In Southwest Gas' most recent Nevada rate case, Docket No. 09-04003, the issue is addressed at pages 19-21 of the Nevada Commission's October 28, 2009 Order. Page 19 describes the Nevada Staff's alternative recommendation to remove the test year costs of Southwest's EETD. The Nevada Staff proposed removing Southwest's internal R&D costs from ratemaking because Southwest's competitive ventures should be separated from its monopoly services to prevent cross-subsidization of competitive products by utility customers. The Nevada Staff referenced statements made by Southwest concerning

the function of the EETD and its role in development of products that are commercially viable. Pages 20-21, at paragraph 71, of the Nevada Commission's Order state that:

> The Commission finds that Staff's alternative recommendation, that Southwest's EETD costs should be removed from the cost of service, should be granted. Ratepayers generally should not subsidize the competitive activities of a regulated monopoly. Southwest demonstrated that the EETD's research efforts are directed at developing competitive products that do not fit the Commission's definition of energy efficiency pursuant to [citations omitted] because they are not directed at the end result of a reduction to the use of natural gas. Additionally, Southwest was not able to provide information regarding how EETD activities might dovetail with the Conservation and Energy Efficiency Plan.

Q. Do some of the concerns identified in Southwest's last Nevada rate case also exist in the current Southwest Arizona rate case regarding EETD costs and gas heat pump development costs?

A. Yes. Similar concerns that ratepayers generally should not subsidize the competitive activities of a regulated monopoly and that Southwest's (and now the non-regulated affiliate, ICE's) research efforts are directed at developing competitive products that are not directed at the end result of a reduction to the use of natural gas, also exist in the current SWG Arizona rate case.

Q. How does the removal of the Company's EETD costs in the most recent Nevada rate case compare with the Staff's recommendation in the current Southwest Arizona rate case?

A. As shown on Schedule C-9, page 1, of the total $2,015,843 EETD expenses in the test year (before jurisdictional allocation), Staff's recommendation is to remove the portion of that related to GHP development and commercialization, which Southwest has quantified at 65 percent. Consequently, 65 percent of the $2,015,843 EETD expenses, or

$1,310,298, is being removed. Of the $1,310,298 being removed for GHP development, the Arizona jurisdictional amount shown on Schedule C-9, page 1, column C, is $711,287.

C-10 Interest Synchronization

Q. Please explain your interest synchronization adjustment.

A. The interest synchronization adjustment applies the weighted cost of debt to the calculation of test year income tax expense. After adjustments, Staff's 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. This adjustment increases income tax expense by the amount shown on Schedule C-10 and decreases the Company' achieved operating income by a similar amount.

C-11 Directors and Officers Liability Insurance Expense

Q. Please explain the adjustment for Directors and Officers Liability Insurance Expense.

A. As shown on Schedule C-11, this adjustment allocates 50 percent of the cost of Directors and Officers Liability Insurance (D&O Insurance) to shareholders, reducing test year expense by $386,403.

Q. Why should the cost of this expense be shared between shareholders and ratepayers?

A. This type of insurance coverage usually comes into play when a shareholder sues the officers and directors of a public company, such as Southwest. Thus, it helps protect the officers and directors from the costs of a shareholder lawsuit. Shareholders benefit from payouts under the policy that would reduce the cost not recoverable from ratepayers. On the other hand, ratepayers benefit from this because having such insurance improves the

ability of the corporation to attract and retain qualified directors and officers and enables the directors and officers to make decisions without fear of personal liability. Consequently, it is reasonable for shareholders to bear some of the cost for the D&O Insurance.

Q. Was this adjustment made in Southwest Gas' last Arizona rate case?

A. To my knowledge it was not; however, it was made in Southwest's most recent Nevada rate case, Nevada PSC Docket No. 09-04003, order dated October 29, 2009, which was more recent. Southwest's D&O Insurance expense is a "system allocable" expense, meaning that it is incurred at Southwest's corporate headquarters and the cost is allocated to the divisions. Thus, a portion of the same Southwest D&O Insurance expense that was recently disallowed in Nevada is being allocated to Arizona.

Q. Have other regulatory commissions besides Nevada made a similar adjustment for sharing of D&O Liability Insurance Expense between shareholders and ratepayers?

A. Yes. The Nevada Commission order in Southwest's last rate case, at page 47, paragraph 157, cites two states (Arkansas and California) that have required a sharing of D&O Liability Insurance Expense between ratepayers and shareholders on a 50-50 basis.[12] We are aware that at least two other commissions (Connecticut and Florida) that have made adjustments for a ratepayer and shareholder sharing of D&O Insurance expense. Connecticut has also required shareholders to share a portion of the cost of D&O Insurance expense, with the shareholder portion varying from 50 percent to 75 percent in different cases.

[12] To date, we have not located the Arkansas and California commission orders which required that sharing.

Q. Have you included an attachment with excerpts from to the orders of which you are aware which have made such findings concerning sharing of D&O Insurance Expense between shareholders and ratepayers?

A. Yes. Attachment RCS-5 contains excerpts from such orders that we have currently located.

Q. Please summarize your adjustment to expense for D&O Insurance sharing between shareholders and ratepayers.

A. As shown on Schedule C-11, SWG's proposed test year expense for D&O Insurance should be reduced by $386,403 to reflect an allocation of 50 percent of this expense to shareholders.

Q. Is there a related adjustment to rate base?

A. Yes. A related adjustment to rate base is shown on Schedule B-6 to remove 50 percent of the prepaid amount for D&O Insurance.

C-12 Self Insurance Expense

Q. Please explain your adjustment for Self-Insurance expense.

A. This adjustment is shown on Schedule C-12, and reduces Southwest's proposed expense for self-insurance expense in Account 925 by $579,774.

As shown on Schedule C-12, page 1, line 1, during the test year, Southwest recorded an expense for self insurance in two parts: (1) $537,500 for Arizona direct and (2) $275,000 for System Allocable. After allocations, this equates to a total Arizona expense of $686,263, as shown in column F.

As shown on Schedule C-12, page 1, line 2, Southwest is requesting an expense for self insurance of: (1) $834,961 for Arizona direct and (2) $1 million for System Allocable, for a total Arizona expense of $1,375,917. As shown on line 3, Southwest's request for Arizona direct, System Allocable and total Arizona, equate to increases over the respective test recorded amounts of 55.3 percent, 263.6 percent, and 100.5 percent. Southwest's pro forma adjustment would thus effectively increase the test year recorded expense allocated to the Arizona jurisdiction by over 100 percent.

In contrast with SWG's proposals, as shown on Schedule C-12, page 1, line 5, Staff recommends a normalized allowance for self-insurance of $796,143. This represents an increase of $109,880 or approximately 16.0 percent, over the test year recorded amount, on an Arizona jurisdictional basis.

Q. How was this issue addressed in Southwest's last Arizona rate case?

A. In Southwest's last rate case, Docket No. G-01551A-07-0504, there was an issue with Southwest's derived pro forma requested self insurance expense, because it had included an extremely abnormal cost relating to a May 2005 incident. Southwest's current request has not removed that impact. Because of a May 2005 leaking gas line fire that resulted in significant injuries and property loss, for which Southwest incurred an abnormal and extremely high payment to settle the related litigation, even the ten-year average for the "common" reserve for self-insurance expense proposed by Southwest is not representative. Ratepayers should pay for a normalized level of insurance expense, but should not be required to pay for extremely high litigation payments that the utility incurred related to the May 2005 leaking gas line fire.

In response to data request STF-6-12, Southwest provided a calculation of the allowance for self-insurance similar to the one presented by Staff and accepted by the Commission in Southwest's last rate case. That Southwest calculation shows an adjustment to decrease the amount of self-insurance reserve expense requested by the Company in the current rate case by $507,121. For the normalized "common" amount, however, it used an annual allowance of $275,000 per year, which is considerably higher than the 2010 amount of $150,000, and is considerably higher than the ten-year average (excluding the extreme May 2005 leaking gas line fire) of $51,363. Rather than use $275,000 as the "common" amount, therefore, as shown on Schedule C-12, page 2, column F, Staff used a $150,000 annual allowance for the "common" reserve for self-insurance expense. The $150,000 equals the Company's recorded amount in 2010. It compares with the ten-year average of $57,450 shown on Schedule C-12, page 2, column D, which is without the massive impact of the May 2005 leaking gas line fire litigation settlement. As one can see from the annual amounts listed on Schedule C-12, columns B and D, the annual expense rates from a negative $300,000 in years 2003 and 2008, to a positive $275,000 in years 2004 and 2009. The $10.367 million in 2005 relating to the May 2005 leaking gas line fire (listed for 2005 in Column B) is an extreme anomaly in comparison with all of the other amounts.

Q. Please explain why Southwest'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, because the expense 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 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. Second, the Company has not demonstrated that the May 2005 leaking gas line fire was not due to its own negligence. Ratepayers should not be burdened with extra costs that may have been incurred as the result of negligence by the utility.

Q. Please explain the other information shown on Schedule C-12, page 2.

A. Lines 17-19 show a derivation of the adjustment to Southwest's proposed reserve for self-insurance expense, as filed, under three scenarios: (1) using a 10-year average, without adjustment for the May 2005 leaking gas line fire; (2) using a 10-year average, with the extreme and abnormal amount of over $10 million related to the May 2005 leaking gas line fire removed; and (3) using normalized self-insurance expense of $713,828 for Arizona Direct and $150,000 for common allocated. Line 19 shows the approximate net adjustment to Southwest's as-filed pro forma expense, under each of the above.

Q. Please summarize Staff's adjustment for Injuries and Damages Expense.

A. As shown on Schedule C-12, page 1, column G, Southwest's as-filed pro forma expense for self-insurance (Account 925) should be reduced by $579,774.

C-13 Leased Aircraft Operating Costs

Q. Please explain your adjustment for Leased Aircraft Operating Costs.

A. This adjustment normalizes the expense for Southwest's leased aircraft operating costs. Southwest does not own aircraft, but does lease aircraft for its business operations. The expense for the test year of $873,055 (before allocations) is significantly higher than for any year in the four-year period, 2004 through 2007, and is 74 percent higher than the four-year average. As shown on Schedule C-13, the test year expense for leased aircraft is

adjusted downward by $174,261 to a normalized amount. Additionally, depreciation expense on an aircraft hanger and equipment of $19,632 is removed, for a total adjustment to reduce test year operating expense by $193,893.

Q. How was the normalized amount determined?

A. I used the four-year period, 2004 through 2007, which was the basis for the leased aircraft cost allowance from Southwest's last rate case. The amount from that case was adjusted upward by 10 percent.

Q. Has Southwest demonstrated that it needs to lease aircraft or that the other expenses relating to such aircraft are cost-justified?

A. No. Had a normalized amount for leased aircraft expense not been allowed in Southwest's last rate case, I would probably be recommending an adjustment to remove all such leased aircraft related cost from the test year.

C-14 COYL Leak Detection Survey

Q. Please explain your adjustment for a Customer Owned Yard Line ("COYL") Leak Detection Survey.

A. A detailed discussion of the COYL issue and Southwest's proposed $10 million pilot program related to replacing COYL with facilities owned by Southwest is presented in a subsequent section of my testimony[13], and is also addressed in Staff witness Frye's Testimony. This adjustment reflects Staff witness Frye's recommendation that, instead of implementing the Company's proposed pilot program, that the Company be required to conduct a leak detection survey of the COYL. It provides for an annual expense of $1 million, based on the Company's estimate of a total cost for a COYL leak detection survey

[13] See section V-C, below.

of $3 million, that was provided in Southwest's response to data request STF 20-3. Southwest's interval between rate cases is three years, so the annual allowance for ratemaking purposes is based on one-third of the total survey cost estimate. As shown on Schedule C-14, this adjustment increases operating expenses by $1 million.

V. THE COMPANY'S REQUESTS FOR SPECIAL ACCOUNTING APPROVALS AND DEFERRALS

Q. What special accounting approvals and deferrals has Southwest asked the Commission to approve?

A. Southwest witness Mashas' Direct Testimony identifies the following special accounting approvals and deferrals which the Company is asking the Commission to approve.

1) At pages 16-17 of his Direct Testimony, the Company is requesting that the Commission to reconsider the write-off requirements for AHD pipe replacement by permitting Southwest Gas to discontinue the write-offs beginning with the end of the test year in this proceeding.

2) At pages 18-19 of his Direct Testimony, Mr. Mashas states that the replacement of all AHD pipe is expected to be completed by mid-year 2013 and he presents a Company proposal to defer depreciation expense, carrying costs, and property taxes resulting from removing the remainder of AHD pipe from July 1, 2010 through mid-year 2013.

3) At pages 19-21 of his Direct Testimony, Mr. Mashas presents a Company proposal to defer depreciation expense, carrying costs, property taxes and incremental expenses related to the Company's proposed installation of Southwest facilities to

replace COYL. Southwest witness Schmitz presents testimony describing Southwest's proposed COYL pilot program.

Staff is also presenting a witness from its Pipeline Safety Section to present Staff's non-accounting related analysis of these Company proposals.

A. Write-off Requirements for AHD Pipe Replacement

Q. What types of early vintage plastic pipe ("EVPP") has Southwest Gas had in its distribution system?

A. The Direct Testimony of Company witness Schmitz at page 6 states that Southwest characterizes the following pipe types as EVPP:

- ABS – Acrylonitrile Butadiene Styrene pipe;
- AA – Aldyl A pipe;
- AHD – Aldyl High Density pipe; and
- PVC – Polyvinyl Chloride pipe.

Q. What was the genesis of Southwest's pipe replacement write-offs?

A. A series of prior Commission orders dating back to the 1980s and early 1990s addressed issues with respect to the deficient installation and maintenance of pipe by predecessors to Southwest. As a result of the problems relating primarily to the initial installation of such pipe by the predecessors, the Commission has required Southwest to write-off specified percentages of the replacement costs for such pipe. Decision No. 57075 (August 31, 1990), for example, at pages 31-45 addresses issues with pipe replacements for Southwest after Southwest acquired the Southern Arizona gas distribution system from Tucson Gas

and Electric Company[14] in 1979 and the Central Arizona gas distribution system from Arizona Public Service Company ("APS") in 1984. Additionally, Decision No. 58693 (July 7, 1994) approved a settlement between Staff, RUCO and Southwest Gas concerning, among other things, write-offs of Plant in Service for pipe replacements related to defective materials and/or installation. The agreement approved by the Commission in Decision No. 58693 specified as follows, as it applied to Aldyl A ("AA") and Aldyl HD ("AHD") pipe replacements in future Southwest Gas rate cases:

> In future Southwest rate cases for the Southern Division gas properties, Southwest shall exclude from rate base an additional portion of capitalized expenditures associated with replacements of Aldyl A, [and] Aldyl HD ... pipe related to defective materials and/or installation. For such capitalized expenditures during the period July 1, 1993 through June 30, 1994, the rate base exclusion shall be based on the following percentages: 36 percent for Aldyl A, 75 percent for Aldyl HD .... During each successive twelve month period following June 1994, the foregoing percentages shall be reduced incrementally by one percent.

Q. What has Southwest Gas proposed in the current rate case for ending the Commission's write-off requirements for AHD pipe replacements?

A. At page 15 of his Direct Testimony, Mr. Mashas states that with respect to the replacement of its early vintage plastic pipe ("EVPP"):

> Two of the EVPP materials (AHD and AA) carry a legacy pipe write-off practice emanating from Commission decisions from nearly twenty years ago. Southwest Gas has written-off $8,176,962, or approximately 27 percent, of the $29,898,711 spent to replace AHD pipe from 2007 through June 2010. The Company has also written-off $274,000, or approximately 5.5 percent, of the $5,002,307 spent to replace AA. Since the write-off percent for AA goes to zero in 2013, and given the priority of its replacement, the directives from prior Commission decisions regarding AA will have a very small future impact on the Company.

[14] Now Tucson Electric Power Company ("TEP").

At pages 15-16, Mr. Mashas addresses various write-off scenarios with respect to four different AHD replacement time periods. At page 16, he states that: "The Company is not requesting the Commission's prior decision concerning AHD write-off to be changed retroactively, and understands that AHD replacement from 2007 through the end of the test year has resulted in an unavoidable $8,177,675 write-off." At pages 16-17, he nevertheless asks the Commission "to reconsider the write-off requirements for AHD pipe replacement by permitting Southwest Gas to discontinue the write-offs beginning with the end of the test in this proceeding, and finding that the $8,177,675 that has already been written-off should be permanently removed from rate base, representing a reasonable sharing of these replacement costs between shareholders and customers." At page 17, Mr. Mashas states that the pipe has continued to age in the 20 years since the Commission first considered this issue, and its removal would no longer be considered premature.

Q. Does another Southwest witness also address the Company's proposal with respect to pipe replacement?

A. Yes. Southwest witness Schmitz presents testimony from an operations perspective supporting the Company's request for rate relief for its pipe replacement program. At page 2, lines 10-11, he states that: "Southwest Gas is requesting specific rate treatment consistent with its distribution pipeline integrity management program and its EVPP." He discusses Southwest's EVPP, its distribution pipeline integrity management program, and the federal regulations for a Distribution Integrity Management Program ("DIMP"), and leaves the details of Southwest's request for specific rate treatment to Mr. Mashas.

Q. What does Mr. Schmitz state concerning Southwest's overall strategy for pipe replacement?

A. At page 7 of his testimony Mr. Schmitz states that:

> Southwest Gas' overall risk-based strategy is based on evaluating threats to the integrity of its pipeline system so that it can apply available resources to mitigate risk in a cost-effective and efficient manner. Since 1986, Southwest Gas has been monitoring leak rates of various distribution pipe types. While this leak analysis has provided performance measures for all types of pipe in the overall [Distribution Pipeline Integrity] DPI process, it has provided the basis for the pipe replacement strategy for the 20-year plan to replace all EVPP. ABS pipe was a top priority pipe based on its historically poor performance. All of the ABS pipe has now been replaced. Considering all risk factors including leak rates AHD pipe has the highest replacement priority of the remaining EVPP. Both AA and PVC pipe will continue to be replaced as well, driven by DPI assessments. Once the AHD pipe replacement is completed, the AA and PVC pipe replacement will occur similar to the AHD replacement based on the relative risk of each of those pipe types at that time.

Q. Where does Southwest present information on the amount of Arizona pipe it has replaced under its 20-year plan?

A. Southwest presents information in Exhibit No. __(RAM-5) attached to Mr. Mashas' testimony.

Q. Is this Southwest's first attempt at ending or modifying prior Commission orders relating to write-off requirements for replacing plastic pipe?

A. No. Decision No. 68487 (February 23, 2006), at pages 7-9, addressed a previous attempt by Southwest to modify Decision No. 58693 to stop the pipe write-off schedule required by that Decision to allow the affected write-offs to cease when the specific type of pipe reached an average life of 40 years.

Q. Did the Commission adopt Southwest's request in Decision No. 68487?

A. No. Decision No. 68487, at page 7, noted that:

> In Decision No. 58693 (July 7, 1994), the Commission adopted a Settlement Agreement between Southwest Gas, Staff and RUCO which

> required Southwest to write-off a certain percentage of the replacement cost of defective pipe, and provided that the pipe replacement percentage write-off amounts would decline annually until the amounts reached zero (Decision No. 58693, at 3-4 ...)

Decision No. 68487 states further at page 8 that:

> ... both the Settlement and the Order specifically state 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 Aldyl A, Aldyl HD, ... related to defective materials and/or installation.' (Decision No. 58693, at 3).

At page 9, Decision No. 68487 states that:

> The Company may not unilaterally alter the terms of a Settlement Agreement and Commission Order simply because it has an understanding of the terms of the agreement that may differ from the belief of another party. Rather, the Company could seek an amendment to the requirements of the prior Order if it believed the terms are no longer applicable, which it has properly done in this docket. However, we agree with RUCO that Southwest Gas must continue to comply with the requirements of the prior Order until such a time as those requirements are modified by the Commission.

Based on the evidence in that case (Docket No. G-01551A-04-0876), the Commission did not adopt Southwest's request to modify the Settlement and Order that had been in place from Decision No. 58693.

Q. Has Southwest presented a compelling need in the current rate case to modify the Settlement and Order that had been in place from Decision No. 58693?

A. No. Lacking compelling evidence or a compelling reason for modifying that Settlement and Order, would suggest that it should continue unmodified.

Q. Do you have any other comments?

A. Yes. First, to the extent that Southwest is replacing AHD pipe in 2011 or 2012, the replacements will presumably qualify for bonus federal income tax depreciation applicable in those years. The availability of this additional tax benefit, which will be enjoyed by Southwest between rate cases, will alleviate the burden of the write-offs.

Second, Southwest can influence and control to some extent the remaining write-offs related to AHD pipe by determining when they are made.

Third, much of the pipe replacement and installation work is contracted by Southwest to its non-regulated affiliate, NPLC, which is a wholly owned subsidiary of Southwest. So, even though Southwest is still incurring write-offs with respect to the replacement of AHD pipe that relates back to the initial defective materials and/or installation that was addressed in Decision No. 58693, et al, Southwest receives a benefit from having much of the pipe replacement work done by its affiliate.

Fourth, Southwest projects it will have completed the AHD pipe replacements by mid-year 2013. Consequently, leaving the Settlement and Order that had been in place from Decision No. 58693 for one additional rate case cycle should alleviate the need to modify the previously write-off percentages for replacement of AHD pipe.

Finally, if the Settlement and Order that had been in place from Decision No. 58693 were to be modified in the current Southwest gas rate case, the modification should become effective as of the date of the Commission's Order in this proceeding. Southwest should continue to comply with Decision No. 58693 from July 1, 2010 through the date of the Commission's final decision in this case.

B. Company's Accounting Deferral Proposal Related to Removing the Remainder of AHD Pipe

Q. What is the Company's accounting deferral proposal related to removing the remainder of AHD pipe?

A. As noted above, at pages 18-19 of his direct testimony, Mr. Mashas states that the replacement of all AHD pipe is expected to be completed by mid-year 2013 and he presents a Company proposal to defer depreciation expense, carrying costs, and property taxes resulting from removing the remainder of AHD pipe from July 1, 2010 through mid-year 2013.

Q. What rationale has Southwest presented as the basis for this accounting proposal?

A. At pages 18-19, Mr. Mashas' presents the Company's rationale for requesting that deferral as follows:

> The capital expenditures required to replace the AHD, as part of its plan to replace EVPP, are non-revenue producing. The carrying costs, depreciation and property taxes associated with these replacement costs contribute to the Company's inability to earn its Commission authorized ROR, which in turn has a negative impact on the Company's credit ratings and ultimately impacts the terms the Company is able to receive when refinancing and issuing debt.
>
> The deferral of depreciation expense is justified for another reason. Depreciation expense is accumulated in Account 108, Accumulated Provision for Depreciation, which in turn is an offset to rate base. The Company does not earn a return on amounts included in Account 108 under the presumption that the customer has provided the funds accumulated in this account. This deferred depreciation represents amounts that the customer did not provide in this case, or any other case, unless the deferral and subsequent recovery is authorized by the Commission. Therefore, without the deferral it would be unfair to use the depreciation expense accumulated in Account 108, as a rate base offset unless these amounts are ultimate recovered from the customer.

Q. What is the effect of accounting deferrals in general?

A. In general, accounting deferrals do not impact current rates, but could cause future rates to be higher than they otherwise would be.

Q. What is the general policy with respect to accounting deferrals?

A. Because they represent a deviation from traditional ratemaking practice, accounting deferrals should generally be discouraged unless a compelling need for such extraordinary treatment has been demonstrated.

Q. Has the Company justified its requested accounting deferral for AHD pipe replacements?

A. No. The rationale presented by the Company is not specific to AHD pipe replacements but is a general rationale that could presumably be applied to any additions by any utility of non-revenue producing plant between rate cases. Moreover, the Company's reasoning as it relates to Depreciation expense does not withstand scrutiny for a number of reasons.

First, there is a concern that the depreciation rates currently being used by Southwest Gas for its Arizona jurisdictional assets are outdated and may not be accurate. The current depreciation rates being used by the Company are based upon a depreciation study of Arizona plant at December 31, 1988. The Company has not had a depreciation rate study for Arizona in approximately 23 years. Without periodic depreciation rate studies, it is difficult to judge whether the depreciation rates being applied by the Company are accurate. Without a recent depreciation rate study for its Arizona jurisdictional gas distribution systems, it is difficult to know whether the Company is over- or under-depreciating its assets. An under-depreciating situation would suggest that the Company

may effectively be deferring depreciation that should be receiving current recognition into future years.

Second, the Company's claim that the customer does not pay for depreciation expense between rate cases lacks support. Customers pay rates that are based upon a revenue requirement. Many factors change between rate cases; however, as long as the utility is earning a positive amount of net income, it is generally assumed that the rates that ratepayers are paying covers all of the Company's operating expenses, which are subtracted from revenues in the determination of net income.

Third, the cost of installing non-revenue producing plant in the second half of 2010, as well as in 2011 and 2012, could be significantly offset by the availability of bonus federal income tax depreciation. Bonus tax depreciation in this period is available at levels of 50 percent and 100 percent, depending on when the plant is installed.

Q. At page 19, lines 16-23, Southwest witness Mashas quotes from Decision No. 57075, page 93, as purported justification for Southwest's proposed accounting deferral. What language appears in Decision No. 57075 immediately preceding the passage quoted by Mr. Mashas when that same language appears on page 43 of that Decision?

A. Pages 43-44 of Decision No. 57075 contain the following language surrounding the quoted passage primarily relied upon by Mr. Mashas (which is shown in italics below):

> **For the Southern division, the uncontroverted record evidence establishes that the inordinately high leak rates have primarily resulted from imprudent actions and improper installation techniques by TEP. The record also establishes that Southwest failed to adequately investigate and test the condition of the system prior to purchase. In these circumstances, it would clearly be unfair and**

> **unreasonable to include in rate base any costs of the replacement program, whether for remedial work or repairs and betterments, which may be related to imprudence or which may be offset by the damages recovered by TEP.**
>
> Although neither the Staff nor RUCO have challenged the full program cost, the amount in dispute at the time of hearing, between $52.5 million and $59.3 million, does exceed the capitalized program costs included in test year plant balances. **The Commission will, accordingly, eliminate all of the program costs from the calculation of the revenue requirement and defer rate recognition to the next rate proceeding, at which time the settlement can be taken into consideration. This adjustment reduces Applicant's adjusted rate base for the Southern division by approximately $20.6 million.** *Until the allowable portion of costs is ultimately determined by the Commission and reflected in rates, Southwest should capitalize in a deferred asset account all interest costs, taxes, and depreciation expense incurred on the Southern division pipeline replacement program. A weighted average interest rate of 10.99%, equal to the approved cost of debt for the Southern division in these proceedings,* should be used to accrue interest on the deferred balance. The extent to which the accumulated interest is a reasonable and allowable cost for ratemaking purposes will be determined by the Commission in the next rate case.
>
> (**Emphasis supplied in bold**; *italics used to indicate passage containing language similar to that relied upon by Southwest witness Mashas at page 19, lines 16-23 of his direct testimony.*)

As can be seen from the above passages, the deferral from Decision No. 57075 was in the context of findings that it would be unfair and unreasonable to include in rate base any costs of the replacement program, whether for remedial work or repairs or betterments, which may be related to imprudence or which may be offset by damages that Southwest recovered from Tucson Electric Power ("TEP"). The deferral was also in the context of removing approximately $20.6 million of pipe replacement program costs from the calculation of the revenue requirement in that prior Southwest Gas rate case. In summary, the passage relied upon by Mr. Mashas has been taken out of context, and certainly does not support a prospective deferral in the current Southwest rate case.

Q. Please summarize Staff's recommendation regarding Southwest's request for accounting deferrals for AHD pipe replacement costs incurred between rate cases.

A. For the reasons stated above, this request by Southwest for an exceptional regulatory treatment of deferring depreciation, property taxes, and carrying costs on pipe replacement costs incurred between rate cases has not been justified and should be denied.

C. Company's Deferral Proposal for Installation of Southwest Facilities to Replace COYL

Q. What is a COYL?

A. A COYL typically begins from the point of delivery connection at Southwest's meter at the property line or public right-of-way, and extends underground from the meter to the house, building or gas utilization equipment where gas is consumed. Southwest does not own the COYL, and the customer is responsible for inspecting and maintaining it. As described by Mr. Schmitz on pages 8-9 of his testimony, although Southwest is not responsible for maintaining the line, Southwest is required to notify customers with COYLs at least once about various information, including the customers' responsibility for maintaining the COYL and that the COYL should be periodically inspected. At page 9, Mr. Schmitz indicates that Southwest reminds customers about COYLs once per month through bill notices.

Q. What has the Company proposed for deferral of costs related to COYL?

A. As noted above, at pages 19-21 of his Direct Testimony, Mr. Mashas presents a Company proposal to defer depreciation expense, carrying costs, property taxes and incremental expenses related to the Company's proposed installation of Southwest facilities to replace customer-owned yard lines. Southwest witness Schmitz presents testimony describing Southwest's proposed COYL pilot program. At page 8, he states that Southwest is proposing a "pilot program" to replace up to 5,000 COYLs to help customers manage their

COYLs. At pages 10-11, he states that upon Commission approval for a COYL replacement pilot program, Southwest proposes the following:

1) Establish a two-year pilot program for COYL replacements;
2) Establish a deferral account to allow Southwest Gas to recover, between rate cases, the incremental costs associated with the pilot program. The prepared testimony of Company witness Robert A. Mashas describes in detail the Company's deferred accounting proposal for the pilot program;
3) Visually inspect selected COYLs;
4) Cap the total pilot program costs at either $10,000,000, the total estimated cost associated with completing the COYL replacement and meter relocation for 5,000 customers, or the total incremental cost associated with the pilot program incurred within two years, whichever occurs first.

Mr. Mashas' testimony at page 20 indicates that the Company believes it can assist customers in managing their COYLs by initiating a pilot program to begin replacing the COYL with a Southwest Gas owned and maintained service line extension. The general body of Southwest's ratepayers would be charged with the COYL replacement costs in future rates.

Q. How are customers with COYLs currently managing them?

A. As described on page 10 of Mr. Schmitz' testimony, when leaks are found on a COYL, the customers have the option of replacing the COYL with a Southwest-owned facility and relocating the meter, calling a licensed plumber to replace or repair the COYL, or discontinuing gas service.

Q. What have affected customers typically chosen in that situation?

A. Mr. Schmitz' testimony at page 10 indicates that, based on 2009 data, only 15 percent of customers who experienced leaks on COYLs elected to replace their COYL with a Southwest-owned facility and relocate the meter. Less than 1 percent discontinued service. Approximately, 70 percent, a significant majority, contacted a licensed plumber who repaired the leak, leaving the meter and COYL intact.

Q. What does this suggest?

A. It suggests that, when faced with the cost of replacing a COYL, a significant majority of customers have chosen to instead, have it repaired by a licensed plumber.

Q. How many COYLs does Southwest estimate are on its Arizona gas distribution system?

A. Southwest witness Schmitz states at page 9, lines 12-15 states that: "Southwest Gas sent a first class bulletin/letter during 2009 and 2010 to approximately 108,000 customers in Arizona who are responsible for the operation and maintenance of their COYLs." This suggests that there are approximately 108,000 COYLs. Staff discovery was issued to Southwest to identify the number and locations of the COYLs. Southwest's response to data request STF-16-7 indicates that the Company's current estimate of the number of COYLs on its system in Arizona is 102,574 and provides the estimated number by district as follows:

Eastern District:	1,944
Mountain District:	2,840
Southeast District:	2,489
Tucson District:	70,406
Valley District:	9,345
Yuma District:	846
Phoenix District:	12,919
Wickenburg District	348
Bullhead District:	1,437
Total:	102,574

Q. What cost does Southwest estimate per COYL replacement?

A. As stated on page 10 of Mr. Schmitz' testimony, Southwest estimates $2,000 per location, where the yard line can be replaced and the meter relocated without the need for major construction activity.

Q. How does that estimate compare with Southwest's actual cost for COYL replacements?

A. It is more than double the Company's actual average cost of COYL replacements for the five-year period through 2010. In response to data request STF-16-8, the Company provided information for 2006 through 2010 on the number of COYL replacements and the annual cost. That information is summarized below:

Number and Cost of COYLs Replaced by Year

Year	No. of COYLs Replaced	Cost	Average Cost per Replaced COYL
2006	498	$ 454,536	$ 912.72
2007	432	$ 412,406	$ 954.64
2008	306	$ 293,778	$ 960.06
2009	322	$ 331,278	$ 1,028.81
2010	272	$ 282,304	$ 1,037.88
Average	366	$ 354,860	$ 969.56

Source: STF-16-8

As shown, the average cost per COYL replacement is about $970. The average cost for the most recent year, 2010, is about $1,038 per COYL replacement.

Q. Has Southwest claimed its proposed COYL replacement program is cost-justified?

A. No. Southwest's testimony does not offer overall cost savings to Arizona ratepayers as justification for this program.

Q. Would this proposed program cause rates to be higher in future rate cases?

A. Presumably Southwest would request recovery of the COYL replacement costs. Thus, the $10 million pilot program cost, or eventually the cost of replacing all approximately 108,000 COYLs (which at an average of $2,000 per replacement, could accumulate to $216,000,000) could find its way into customer rates. That estimate used Southwest's previously identified COYL count of 108,000. Southwest's response to data request STF-16-7(d) states that:

> Southwest Gas estimates that it can replace COYLs at an average cost of $2,000 per service, excluding those residences where there are significant physical obstacles. At 102,574 COYLs, Southwest Gas' best estimate of the total cost to replace COYLs on its system in Arizona is $205 million at current costs.

Replacement of all COYLs could therefore cost more than $205 million, not an insignificant amount to be added to Arizona jurisdictional rate base.

Q. Has Southwest projected that some customers will continue to have the Company replace their COYLs in the absence of its proposed $10 million Pilot Program?

A. Yes. The Company's response to data request STF-16-6 indicates that under its current tariff Southwest performs COYL replacements at the expense of the customer. Per that response, customer contributions for the installation of Southwest Gas facilities to replace

COYLs actually experienced after the test year, and as projected by the Company are as follows:

> Consistent with Arizona Tariff Rule No. 6, section E(6)(b), Southwest Gas performs the replacement of customer owned yard lines (COYL) at the expense of the customer. Customer contributions for the installation of Southwest Gas facilities to replace COYLs are as follows:
>
> June 30, 2010 through December 31, 2010: $159,730
>
> December 31, 2010 through March 31, 2011: $173,966
>
> Projected/budgeted for March 31, 2011 through December 31, 2011: $276,034
>
> Total amount Projected/budgeted for Calendar 2011: $450,000

Q. Has Southwest explained why it selected 5,000 COYLs?

A. Not really. Presumably, a full replacement at a total cost potentially in excess of $205 million was too massive an undertaking, without some type of pilot. However, why 5,000 versus some other level has not been explained by Southwest.

Q. At the rate of replacing 5,000 COYLs every two years, how long would it take to replace all of the COYLs?

A. Southwest's response to data request STF-16-7(e) estimates that it would take approximately 41 years to replace all of the COYLs:

> Given Southwest Gas' estimate of 102,574 COYLs, and assuming that all customers would want their COYL facilities replaced by utility-owned and operated facilities, at a rate of 5,000 replacements every two years as posed in this question, it would take approximately 41 years to replace all COYLs.

Q. Has Southwest explained why it selected a two-year program?

A. Not really.

Q. Could a two-year program term result in a termination of the program between rate cases?

A. It could. In response to data request STF-7-13 Southwest has stated that it has a four-year plan for filing Arizona rate cases. The selection of a two-year program for COYLs may thus not cover the full period between rate cases.

Q. Has Southwest demonstrated a compelling need to replace COYLs?

A. No. There is a concern that some customers may not be inspecting or maintaining their COYLs. However, in situations where leaks have been detected on COYLs, as noted above, the vast majority of the affected customers have chosen to use a licensed plumber to repair the leak, and not to have Southwest replace their COYL and relocate their meter.

Q. Please summarize your recommendation regarding Southwest's request for accounting deferrals up to $10 million for a two-year COYL pilot program.

A. For the reasons stated above, this request by Southwest Gas for an exceptional regulatory treatment of deferring depreciation, property taxes, and incremental costs on a COYL replacement program has not been justified and should be rejected.

VI. NEED FOR AN UPDATED DEPRECIATION RATE STUDY

Q. What is depreciation?

A. The NARUC manual, Public Utility Depreciation Practices[15] defines depreciation as follows:

[15] National Association of Regulatory Utility Commissioners, August 1996.

> As applied to the depreciable plant of utilities, the term depreciation means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes that are known to be in current operation, against which the company is not protected by insurance, and the effect of which can be forecast with reasonable accuracy. Among the causes to be considered are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirement of public authorities.

Q. When was Southwest's last depreciation rate study?

A. The Company's response to data request STF-1-5 states that:

> For corporate (i.e. system allocable) plant, a portion of which is allocated to Arizona, the last approved depreciation study was filed in Nevada during 2007 using a period ended date of December 31, 2006. The system allocable rates approved in Nevada are used in all of Southwest's ratemaking jurisdictions so the appropriate amounts of corporate plant are recovered in rates from Southwest's Arizona, Nevada, and California customers.
>
> At the time of the last depreciation study in Arizona, Arizona had two separate rate jurisdictions: Southern Arizona and Central Arizona. In 1996, the two Arizona rate jurisdictions were combined into one rate jurisdiction and the depreciation rate for the combined jurisdiction was a blended average of the existing rates for the Southern Arizona and Central Arizona jurisdictions. This combined rate is the currently approved rate used in the Arizona rate jurisdiction.

The most recent depreciation rate studies that Southwest provided in response to data request STF-1-5 include:

1) A book depreciation study as of December 31, 1988 of the Central Arizona property;
2) A book depreciation study as of December 31, 1988 of the Southern Arizona property; and

3) A depreciation rate study for System Allocable plant at December 31, 2006, that Southwest indicated it filed in Nevada.

Q. Do you have any concerns related to these depreciation rate studies as they apply to Southwest's Arizona plant?

A. Yes. The depreciation studies being relied upon by Southwest for recording depreciation expense for its Arizona plant are outdated, and would not reflect changes in factors that have affected depreciation rates for such plant occurring over the past 23 years, including changes in pipe installation practices and replacements. Ideally, utility depreciation rates are updated periodically to assure that such depreciation rates are accurate and incorporate the impacts of changing conditions. Because the depreciation rate studies for Southwest's Arizona plant are so outdated, the depreciation rates being used by Southwest with respect to its Arizona plant should be reviewed in detail in Southwest's next Arizona rate case. To facilitate this review, Southwest should be ordered to file a new fully-updated depreciation rate study in the Company's next Arizona rate case.

Q. Do you have any concerns related to these depreciation rate studies as they apply to Southwest's system allocable plant?

A. Yes. It appears from the Company's response to data request STF 1-5 that Southwest may have implemented new depreciation rates, based on a 2007 study, for system allocable plant, without having those new depreciation rates reviewed or approved by the Arizona Corporation Commission. While Southwest's system allocable plant may be primarily located in Nevada, where Southwest has its corporate headquarters, it should also be recognized that Southwest's Arizona jurisdictional operations represent the majority (over 56 percent) of Southwest's total gas utility operations. Accordingly, Southwest should not implement any further changes to depreciation rates on its system allocable plant without

having those rates first reviewed and approved by the jurisdiction in which those rates have the greatest impact, i.e., by the Arizona Corporation Commission.

Q. Does Staff have any recommendations related to these depreciation rate studies?

A. Yes, Staff has the following recommendations:

- None of Southwest's proposals that request deferral of depreciation should be approved. The depreciation rate studies Southwest is using for its Arizona plant both date back to December 31, 1988, and thus should not be the basis for any depreciation expense deferrals until after they are updated.

- Utility depreciation rates should be updated periodically, ideally every three to five years, as conditions change. Because Southwest's Arizona plant depreciation studies are so outdated (the studies of December 31, 1988 Arizona plant are now approximately 23 years old), Southwest should be ordered to file updated depreciation rate studies in its next Arizona rate case.

- Southwest should also file an updated depreciation study for System Allocable plant in its next Arizona rate case.

- Southwest's Arizona jurisdictional operations represent the majority (over 56 percent) of Southwest's total gas utility operations, and consequently changes to depreciation rates on Southwest's system allocable plant would have the greatest impact on Arizona. Because Arizona jurisdictional operations represents over 56 percent of Southwest's total gas utility operations, any changes to System Allocable plant depreciation rates should not be instituted for book purposes until

such depreciation rates have been authorized by the Arizona Corporation Commission.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

Attachment RCS-1
QUALIFICATIONS OF RALPH C. SMITH

Accomplishments

Mr. Smith's professional credentials include being a Certified Financial Planner™ professional, a Certified Rate of Return Analyst, a licensed Certified Public Accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr. Smith has performed work in the field of utility regulation on behalf of industry, public service commission staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Carolina, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Virginia, Washington, Washington DC, West Virginia, Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions.

Project manager in Larkin & Associates' review, on behalf of the Georgia Commission Staff, of the budget and planning activities of Georgia Power Company; supervised 13 professionals; coordinated over 200 interviews with Company budget center managers and executives; organized and edited voluminous audit report; presented testimony before the Commission. Functional areas covered included fossil plant O&M, headquarters and district operations, internal audit, legal, affiliated transactions, and responsibility reporting. All of our findings and recommendations were accepted by the Commission.

Key team member in the firm's management audit of the Anchorage Water and Wastewater Utility on behalf of the Alaska Commission Staff, which assessed the effectiveness of the Utility's operations in several areas; responsible for in-depth investigation and report writing in areas involving information systems, finance and accounting, affiliated relationships and transactions, and use of outside contractors. Testified before the Alaska Commission concerning certain areas of the audit report. AWWU concurred with each of Mr. Smith's 40 plus recommendations for improvement.

Co-consultant in the analysis of the issues surrounding gas transportation performed for the law firm of Cravath, Swaine & Moore in conjunction with the case of Reynolds Metals Co. vs. the Columbia Gas System, Inc.; drafted in-depth report concerning the regulatory treatment at both state and federal levels of issues such as flexible pricing and mandatory gas transportation.

Lead consultant and expert witness in the analysis of the rate increase request of the City of Austin - Electric Utility on behalf of the residential consumers. Among the numerous ratemaking issues addressed were the economies of the Utility's employment of outside services; provided both written and oral testimony outlining recommendations and their bases. Most of Mr. Smith's recommendations were adopted by the City Council and Utility in a settlement.

Key team member performing an analysis of the rate stabilization plan submitted by the Southern Bell Telephone & Telegraph Company to the Florida PSC; performed comprehensive analysis of the Company's projections and budgets which were used as the basis for establishing rates.

Lead consultant in analyzing Southwestern Bell Telephone separations in Missouri; sponsored the complex technical analysis and calculations upon which the firm's testimony in that case was based. He has also assisted in analyzing changes in depreciation methodology for setting telephone rates.

Lead consultant in the review of gas cost recovery reconciliation applications of Michigan Gas Utilities Company, Michigan Consolidated Gas Company, and Consumers Power Company. Drafted recommendations regarding the appropriate rate of interest to be applied to any over or under collections and the proper procedures and allocation methodology to be used to distribute any refunds to customer classes.

Lead consultant in the review of Consumers Power Company's gas cost recovery refund plan. Addressed appropriate interest rate and compounding procedures and proper allocation methodology.

Project manager in the review of the request by Central Maine Power Company for an increase in rates. The major area addressed was the propriety of the Company's ratemaking attrition adjustment in relation to its corporate budgets and projections.

Project manager in an engagement designed to address the impacts of the Tax Reform Act of 1986 on gas distribution utility operations of the Northern States Power Company. Analyzed the reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC, and timing of TRA-related impacts associated with the Company's tax liability.

Project manager and expert witness in the determination of the impacts of the Tax Reform Act of 1986 on the operations of Connecticut Natural Gas Company on behalf of the Connecticut Department of Public Utility Control - Prosecutorial Division, Connecticut Attorney General, and Connecticut Department of Consumer Counsel.

Lead Consultant for The Minnesota Department of Public Service ("DPS") to review the Minnesota Incentive Plan ("Incentive Plan") proposal presented by Northwestern Bell Telephone Company ("NWB") doing business as U S West Communications ("USWC"). Objective was to express an opinion as to whether current rates addressed by the plan were appropriate from a Minnesota intrastate revenue requirements and accounting perspective, and to assist in developing recommended modifications to NWB's proposed Plan.

Performed a variety of analytical and review tasks related to our work effort on this project. Obtained and reviewed data and performed other procedures as necessary (1) to obtain an understanding of the Company's Incentive Plan filing package as it relates to rate base, operating income, revenue requirements, and plan operation, and (2) to formulate an opinion concerning the reasonableness of current rates and of amounts included within the Company's Incentive Plan filing. These procedures included requesting and reviewing extensive discovery, visiting the Company's offices to review data, issuing follow-up information requests in many instances, telephone and on-site discussions with Company representatives, and frequent discussions with counsel and DPS Staff assigned to the project.

Lead Consultant in the regulatory analysis of Jersey Central Power & Light Company for the Department of the Public Advocate, Division of Rate Counsel. Tasks performed included on-site review and audit of Company, identification and analysis of specific issues, preparation of data requests, testimony, and cross examination questions. Testified in Hearings.

Assisted the NARUC Committee on Management Analysis with drafting the Consultant Standards for Management Audits.

Presented training seminars covering public utility accounting, tax reform, ratemaking, affiliated transaction auditing, rate case management, and regulatory policy in Maine, Georgia, Kentucky, and Pennsylvania. Seminars were presented to commission staffs and consumer interest groups.

Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, was involved primarily in utility regulatory consulting, and also in tax planning and tax research for businesses and individuals, tax return preparation and review, and independent audit, review and preparation of financial statements.

Installed computerized accounting system for a realty management firm.

Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.

Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.

Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.

Continuing education required to maintain CPA license and CFP® certificate.

Passed all parts of CPA examination in first sitting, 1979. Received CPA certificate in 1981 and Certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Michigan Bar Association.

American Bar Association, sections on public utility law and taxation.

Partial list of utility cases participated in:

79-228-EL-FAC	Cincinnati Gas & Electric Company (Ohio PUC)
79-231-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
79-535-EL-AIR	East Ohio Gas Company (Ohio PUC)
80-235-EL-FAC	Ohio Edison Company (Ohio PUC)
80-240-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
U-1933*	Tucson Electric Power Company (Arizona Corp. Commission)
U-6794	Michigan Consolidated Gas Co. --16 Refunds (Michigan PSC)
81-0035TP	Southern Bell Telephone Company (Florida PSC)
81-0095TP	General Telephone Company of Florida (Florida PSC)
81-308-EL-EFC	Dayton Power & Light Co.- Fuel Adjustment Clause (Ohio PUC)
810136-EU	Gulf Power Company (Florida PSC)
GR-81-342	Northern States Power Co. -- E-002/Minnesota (Minnesota PUC)
Tr-81-208	Southwestern Bell Telephone Company (Missouri PSC))
U-6949	Detroit Edison Company (Michigan PSC)
8400	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
18328	Alabama Gas Corporation (Alabama PSC)
18416	Alabama Power Company (Alabama PSC)
820100-EU	Florida Power Corporation (Florida PSC)
8624	Kentucky Utilities (Kentucky PSC)
8648	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
U-7236	Detroit Edison - Burlington Northern Refund (Michigan PSC)
U6633-R	Detroit Edison - MRCS Program (Michigan PSC)
U-6797-R	Consumers Power Company -MRCS Program (Michigan PSC)
U-5510-R	Consumers Power Company - Energy conservation Finance Program (Michigan PSC)
82-240E	South Carolina Electric & Gas Company (South Carolina PSC)
7350	Generic Working Capital Hearing (Michigan PSC)
RH-1-83	Westcoast Transmission Co., (National Energy Board of Canada)
820294-TP	Southern Bell Telephone & Telegraph Co. (Florida PSC)
82-165-EL-EFC (Subfile A)	Toledo Edison Company(Ohio PUC)
82-168-EL-EFC	Cleveland Electric Illuminating Company (Ohio PUC)
830012-EU	Tampa Electric Company (Florida PSC)
U-7065	The Detroit Edison Company - Fermi II (Michigan PSC)
8738	Columbia Gas of Kentucky, Inc. (Kentucky PSC)
ER-83-206	Arkansas Power & Light Company (Missouri PSC)
U-4758	The Detroit Edison Company – Refunds (Michigan PSC)
8836	Kentucky American Water Company (Kentucky PSC)
8839	Western Kentucky Gas Company (Kentucky PSC)
83-07-15	Connecticut Light & Power Co. (Connecticut DPU)
81-0485-WS	Palm Coast Utility Corporation (Florida PSC)
U-7650	Consumers Power Co. (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada PSC)
U-6488-R	Detroit Edison Co., FAC & PIPAC Reconciliation (Michigan PSC)
U-15684	Louisiana Power & Light Company (Louisiana PSC)
7395 & U-7397	Campaign Ballot Proposals (Michigan PSC)
820013-WS	Seacoast Utilities (Florida PSC)
U-7660	Detroit Edison Company (Michigan PSC)
83-1039	CP National Corporation (Nevada PSC)
U-7802	Michigan Gas Utilities Company (Michigan PSC)
83-1226	Sierra Pacific Power Company (Nevada PSC)
830465-EI	Florida Power & Light Company (Florida PSC)
U-7777	Michigan Consolidated Gas Company (Michigan PSC)
U-7779	Consumers Power Company (Michigan PSC)

U-7480-R	Michigan Consolidated Gas Company (Michigan PSC)
U-7488-R	Consumers Power Company – Gas (Michigan PSC)
U-7484-R	Michigan Gas Utilities Company (Michigan PSC)
U-7550-R	Detroit Edison Company (Michigan PSC)
U-7477-R**	Indiana & Michigan Electric Company (Michigan PSC)
18978	Continental Telephone Co. of the South Alabama (Alabama PSC)
R-842583	Duquesne Light Company (Pennsylvania PUC)
R-842740	Pennsylvania Power Company (Pennsylvania PUC)
850050-EI	Tampa Electric Company (Florida PSC)
16091	Louisiana Power & Light Company (Louisiana PSC)
19297	Continental Telephone Co. of the South Alabama (Alabama PSC)
76-18788AA &76-18793AA	Detroit Edison - Refund - Appeal of U-4807 (Ingham County, Michigan Circuit Court)
85-53476AA & 85-534785AA	Detroit Edison Refund - Appeal of U-4758 (Ingham County, Michigan Circuit Court)
U-8091/U-8239	Consumers Power Company - Gas Refunds (Michigan PSC)
TR-85-179**	United Telephone Company of Missouri (Missouri PSC)
85-212	Central Maine Power Company (Maine PSC)
ER-85646001 & ER-85647001	New England Power Company (FERC)
850782-EI & 850783-EI	Florida Power & Light Company (Florida PSC)
R-860378	Duquesne Light Company (Pennsylvania PUC)
R-850267	Pennsylvania Power Company (Pennsylvania PUC)
851007-WU & 840419-SU	Florida Cities Water Company (Florida PSC)
G-002/GR-86-160	Northern States Power Company (Minnesota PSC)
7195 (Interim)	Gulf States Utilities Company (Texas PUC)
87-01-03	Connecticut Natural Gas Company (Connecticut PUC))
87-01-02	Southern New England Telephone Company (Connecticut Department of Public Utility Control)
3673-	Georgia Power Company (Georgia PSC)
29484	Long Island Lighting Co. (New York Dept. of Public Service)
U-8924	Consumers Power Company – Gas (Michigan PSC)
Docket No. 1	Austin Electric Utility (City of Austin, Texas)
Docket E-2, Sub 527	Carolina Power & Light Company (North Carolina PUC)
870853	Pennsylvania Gas and Water Company (Pennsylvania PUC)
880069**	Southern Bell Telephone Company (Florida PSC)
U-1954-88-102 T E-1032-88-102	Citizens Utilities Rural Company, Inc. & Citizens Utilities Company, Kingman Telephone Division (Arizona CC)
89-0033	Illinois Bell Telephone Company (Illinois CC)
U-89-2688-T	Puget Sound Power & Light Company (Washington UTC))
R-891364	Philadelphia Electric Company (Pennsylvania PUC)
F.C. 889	Potomac Electric Power Company (District of Columbia PSC)
Case No. 88/546*	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (Supreme Court County of Onondaga, State of New York)
87-11628*	Duquesne Light Company, et al, plaintiffs, against Gulf+ Western, Inc. et al, defendants (Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
890319-EI	Florida Power & Light Company (Florida PSC)
891345-EI	Gulf Power Company (Florida PSC)
ER 8811 0912J	Jersey Central Power & Light Company (BPU)
6531	Hawaiian Electric Company (Hawaii PUCs)

R0901595	Equitable Gas Company (Pennsylvania Consumer Counsel)
90-10	Artesian Water Company (Delaware PSC)
89-12-05	Southern New England Telephone Company (Connecticut PUC)
900329-WS	Southern States Utilities, Inc. (Florida PSC)
90-12-018	Southern California Edison Company (California PUC)
90-E-1185	Long Island Lighting Company (New York DPS)
R-911966	Pennsylvania Gas & Water Company (Pennsylvania PUC)
I.90-07-037, Phase II	(Investigation of OPEBs) Department of the Navy and all Other Federal Executive Agencies (California PUC)
U-1551-90-322	Southwest Gas Corporation (Arizona CC)
U-1656-91-134	Sun City Water Company (Arizona RUCO)
U-2013-91-133	Havasu Water Company (Arizona RUCO)
91-174***	Central Maine Power Company (Department of the Navy and all Other Federal Executive Agencies)
U-1551-89-102 & U-1551-89-103	Southwest Gas Corporation - Rebuttal and PGA Audit (Arizona Corporation Commission)
Docket No. 6998	Hawaiian Electric Company (Hawaii PUC)
TC-91-040A and TC-91-040B	Intrastate Access Charge Methodology, Pool and Rates Local Exchange Carriers Association and South Dakota Independent Telephone Coalition
9911030-WS & 911-67-WS	General Development Utilities - Port Malabar and West Coast Divisions (Florida PSC)
922180	The Peoples Natural Gas Company (Pennsylvania PUC)
7233 and 7243	Hawaiian Nonpension Postretirement Benefits (Hawaiian PUC)
R-00922314 & M-920313C006	Metropolitan Edison Company (Pennsylvania PUC)
R00922428	Pennsylvania American Water Company (Pennsylvania PUC)
E-1032-92-083 & U-1656-92-183	Citizens Utilities Company, Agua Fria Water Division (Arizona Corporation Commission)
92-09-19	Southern New England Telephone Company (Connecticut PUC)
E-1032-92-073	Citizens Utilities Company (Electric Division), (Arizona CC)
UE-92-1262	Puget Sound Power and Light Company (Washington UTC))
92-345	Central Maine Power Company (Maine PUC)
R-932667	Pennsylvania Gas & Water Company (Pennsylvania PUC)
U-93-60**	Matanuska Telephone Association, Inc. (Alaska PUC)
U-93-50**	Anchorage Telephone Utility (Alaska PUC)
U-93-64	PTI Communications (Alaska PUC)
7700	Hawaiian Electric Company, Inc. (Hawaii PUC)
E-1032-93-111 & U-1032-93-193	Citizens Utilities Company - Gas Division (Arizona Corporation Commission)
R-00932670	Pennsylvania American Water Company (Pennsylvania PUC)
U-1514-93-169/ E-1032-93-169	Sale of Assets CC&N from Contel of the West, Inc. to Citizens Utilities Company (Arizona Corporation Commission)
7766	Hawaiian Electric Company, Inc. (Hawaii PUC)
93-2006- GA-AIR*	The East Ohio Gas Company (Ohio PUC)
94-E-0334	Consolidated Edison Company (New York DPS)
94-0270	Inter-State Water Company (Illinois Commerce Commission)
94-0097	Citizens Utilities Company, Kauai Electric Division (Hawaii PUC)
PU-314-94-688	Application for Transfer of Local Exchanges (North Dakota PSC)
94-12-005-Phase I	Pacific Gas & Electric Company (California PUC)
R-953297	UGI Utilities, Inc. - Gas Division (Pennsylvania PUC)
95-03-01	Southern New England Telephone Company (Connecticut PUC)
95-0342	Consumer Illinois Water, Kankakee Water District (Illinois CC)
94-996-EL-AIR	Ohio Power Company (Ohio PUC)
95-1000-E	South Carolina Electric & Gas Company (South Carolina PSC)

Non-Docketed Staff Investigation	Citizens Utility Company - Arizona Telephone Operations (Arizona Corporation Commission)
E-1032-95-473	Citizens Utility Co. - Northern Arizona Gas Division (Arizona CC)
E-1032-95-433	Citizens Utility Co. - Arizona Electric Division (Arizona CC)
	Collaborative Ratemaking Process Columbia Gas of Pennsylvania (Pennsylvania PUC)
GR-96-285	Missouri Gas Energy (Missouri PSC)
94-10-45	Southern New England Telephone Company (Connecticut PUC)
A.96-08-001 et al.	California Utilities' Applications to Identify Sunk Costs of Non-Nuclear Generation Assets, & Transition Costs for Electric Utility Restructuring, & Consolidated Proceedings (California PUC)
96-324	Bell Atlantic - Delaware, Inc. (Delaware PSC)
96-08-070, et al.	Pacific Gas & Electric Co., Southern California Edison Co. and San Diego Gas & Electric Company (California PUC)
97-05-12	Connecticut Light & Power (Connecticut PUC)
R-00973953	Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code (Pennsylvania PUC)
97-65	Application of Delmarva Power &Light Co. for Application of a Cost Accounting Manual and a Code of Conduct (Delaware PSC)
16705	Entergy Gulf States, Inc. (Cities Steering Committee)
E-1072-97-067	Southwestern Telephone Co. (Arizona Corporation Commission)
Non-Docketed Staff Investigation	Delaware - Estimate Impact of Universal Services Issues (Delaware PSC)
PU-314-97-12	US West Communications, Inc. Cost Studies (North Dakota PSC)
97-0351	Consumer Illinois Water Company (Illinois CC)
97-8001	Investigation of Issues to be Considered as a Result of Restructuring of Electric Industry (Nevada PSC)
U-0000-94-165	Generic Docket to Consider Competition in the Provision of Retail Electric Service (Arizona Corporation Commission)
98-05-006-Phase I	San Diego Gas & Electric Co., Section 386 costs (California PUC)
9355-U	Georgia Power Company Rate Case (Georgia PUC)
97-12-020 - Phase I	Pacific Gas & Electric Company (California PUC)
U-98-56, U-98-60, U-98-65, U-98-67	Investigation of 1998 Intrastate Access charge filings (Alaska PUC)
(U-99-66, U-99-65, U-99-56, U-99-52)	Investigation of 1999 Intrastate Access Charge filing (Alaska PUC)
Phase II of 97-SCCC-149-GIT	Southwestern Bell Telephone Company Cost Studies (Kansas CC)
PU-314-97-465	US West Universal Service Cost Model (North Dakota PSC)
Non-docketed Assistance	Bell Atlantic - Delaware, Inc., Review of New Telecomm. and Tariff Filings (Delaware PSC)
Contract Dispute	City of Zeeland, MI - Water Contract with the City of Holland, MI (Before an arbitration panel)
Non-docketed Project	City of Danville, IL - Valuation of Water System (Danville, IL)
Non-docketed Project	Village of University Park, IL - Valuation of Water and Sewer System (Village of University Park, Illinois)

E-1032-95-417	Citizens Utility Co., Maricopa Water/Wastewater Companies et al. (Arizona Corporation Commission)
T-1051B-99-0497	Proposed Merger of the Parent Corporation of Qwest Communications Corporation, LCI International Telecom Corp., and US West Communications, Inc. (Arizona CC)
T-01051B-99-0105	US West Communications, Inc. Rate Case (Arizona CC)
A00-07-043	Pacific Gas & Electric - 2001 Attrition (California PUC)
T-01051B-99-0499	US West/Quest Broadband Asset Transfer (Arizona CC)
99-419/420	US West, Inc. Toll and Access Rebalancing (North Dakota PSC)
PU314-99-119	US West, Inc. Residential Rate Increase and Cost Study Review (North Dakota PSC
98-0252	Ameritech - Illinois, Review of Alternative Regulation Plan (Illinois CUB)
00-108	Delmarva Billing System Investigation (Delaware PSC)
U-00-28	Matanuska Telephone Association (Alaska PUC)
Non-Docketed	Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation (California PUC)
00-11-038	Southern California Edison (California PUC)
00-11-056	Pacific Gas & Electric (California PUC)
00-10-028	The Utility Reform Network for Modification of Resolution E-3527 (California PUC)
98-479	Delmarva Power & Light Application for Approval of its Electric and Fuel Adjustments Costs (Delaware PSC)
99-457	Delaware Electric Cooperative Restructuring Filing (Delaware PSC)
99-582	Delmarva Power & Light dba Conectiv Power Delivery Analysis of Code of Conduct and Cost Accounting Manual (Delaware PSC)
99-03-04	United Illuminating Company Recovery of Stranded Costs (Connecticut OCC)
99-03-36	Connecticut Light & Power (Connecticut OCC)
Civil Action No. 98-1117	West Penn Power Company vs. PA PUC (Pennsylvania PSC)
Case No. 12604	Upper Peninsula Power Company (Michigan AG)
Case No. 12613	Wisconsin Public Service Commission (Michigan AG)
41651	Northern Indiana Public Service Co Overearnings investigation (Indiana UCC)
13605-U	Savannah Electric & Power Company – FCR (Georgia PSC)
14000-U	Georgia Power Company Rate Case/M&S Review (Georgia PSC)
13196-U	Savannah Electric & Power Company Natural Gas Procurement and Risk Management/Hedging Proposal, Docket No. 13196-U (Georgia PSC)
Non-Docketed	Georgia Power Company & Savannah Electric & Power FPR Company Fuel Procurement Audit (Georgia PSC)
Non-Docketed	Transition Costs of Nevada Vertically Integrated Utilities (US Department of Navy)
Application No. 99-01-016, Phase I	Post-Transition Ratemaking Mechanisms for the Electric Industry Restructuring (US Department of Navy)
99-02-05	Connecticut Light & Power (Connecticut OCC)
01-05-19-RE03	Yankee Gas Service Application for a Rate Increase, Phase I-2002-IERM (Connecticut OCC)
G-01551A-00-0309	Southwest Gas Corporation, Application to amend its rate Schedules (Arizona CC)
00-07-043	Pacific Gas & Electric Company Attrition & Application for a rate increase (California PUC)

97-12-020 Phase II	Pacific Gas & Electric Company Rate Case (California PUC)
01-10-10	United Illuminating Company (Connecticut OCC)
13711-U	Georgia Power FCR (Georgia PSC)
02-001	Verizon Delaware § 271(Delaware DPA)
02-BLVT-377-AUD	Blue Valley Telephone Company Audit/General Rate Investigation (Kansas CC)
02-S&TT-390-AUD	S&T Telephone Cooperative Audit/General Rate Investigation (Kansas CC)
01-SFLT-879-AUD	Sunflower Telephone Company Inc., Audit/General Rate Investigation (Kansas CC)
01-BSTT-878-AUD	Bluestem Telephone Company, Inc. Audit/General Rate Investigation (Kansas CC)
P404, 407, 520, 413 426, 427, 430, 421/ CI-00-712	Sherburne County Rural Telephone Company, dba as Connections, Etc. (Minnesota DOC)
U-01-85	ACS of Alaska, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-34	ACS of Anchorage, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-83	ACS of Fairbanks, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-87	ACS of the Northland, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
96-324, Phase II	Verizon Delaware, Inc. UNE Rate Filing (Delaware PSC)
03-WHST-503-AUD	Wheat State Telephone Company (Kansas CC)
04-GNBT-130-AUD	Golden Belt Telephone Association (Kansas CC)
Docket 6914	Shoreham Telephone Company, Inc. (Vermont BPU)
Docket No. E-01345A-06-009	Arizona Public Service Company (Arizona Corporation Commission)
Case No. 05-1278-E-PC-PW-42T	Appalachian Power Company and Wheeling Power Company both d/b/a American Electric Power (West Virginia PSC)
Docket No. 04-0113	Hawaiian Electric Company (Hawaii PUC)
Case No. U-14347	Consumers Energy Company (Michigan PSC)
Case No. 05-725-EL-UNC	Cincinnati Gas & Electric Company (PUC of Ohio)
Docket No. 21229-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 19142-U	Georgia Power Company (Georgia PSC)
Docket No. 03-07-01RE01	Connecticut Light & Power Company (CT DPUC)
Docket No. 19042-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 2004-178-E	South Carolina Electric & Gas Company (South Carolina PSC)
Docket No. 03-07-02	Connecticut Light & Power Company (CT DPUC)
Docket No. EX02060363, Phases I&II	Rockland Electric Company (NJ BPU)
Docket No. U-00-88	ENSTAR Natural Gas Company and Alaska Pipeline Company (Regulatory Commission of Alaska)
Phase 1-2002 IERM, Docket No. U-02-075	Interior Telephone Company, Inc. (Regulatory Commission of Alaska)
Docket No. 05-SCNT-1048-AUD	South Central Telephone Company (Kansas CC)
Docket No. 05-TRCT-607-KSF	Tri-County Telephone Company (Kansas CC)
Docket No. 05-KOKT-060-AUD	Kan Okla Telephone Company (Kansas CC)
Docket No. 2002-747	Northland Telephone Company of Maine (Maine PUC)
Docket No. 2003-34	Sidney Telephone Company (Maine PUC)

Docket No. 2003-35	Maine Telephone Company (Maine PUC)
Docket No. 2003-36	China Telephone Company (Maine PUC)
Docket No. 2003-37	Standish Telephone Company (Maine PUC)
Docket Nos. U-04-022, U-04-023	Anchorage Water and Wastewater Utility (Regulatory Commission of Alaska)
Case 05-116-U/06-055-U	Entergy Arkansas, Inc. EFC (Arkansas Public Service Commission)
Case 04-137-U	Southwest Power Pool RTO (Arkansas Public Service Commission)
Case No. 7109/7160	Vermont Gas Systems (Department of Public Service)
Case No. ER-2006-0315	Empire District Electric Company (Missouri PSC)
Case No. ER-2006-0314	Kansas City Power & Light Company (Missouri PSC)
Docket No. U-05-043,44	Golden Heart Utilities/College Park Utilities (Regulatory Commission of Alaska)
A-122250F5000	Equitable Resources, Inc. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
E-01345A-05-0816	Arizona Public Service Company (Arizona CC)
Docket No. 05-304	Delmarva Power & Light Company (Delaware PSC)
05-806-EL-UNC	Cincinnati Gas & Electric Company (Ohio PUC)
U-06-45	Anchorage Water Utility (Regulatory Commission of Alaska)
03-93-EL-ATA, 06-1068-EL-UNC	Duke Energy Ohio (Ohio PUC)
PUE-2006-00065	Appalachian Power Company (Virginia Corporation Commission)
G-04204A-06-0463 et. al	UNS Gas, Inc. (Arizona CC)
Docket No. 2006-0386	Hawaiian Electric Company, Inc (Hawaii PUC)
E-01933A-07-0402	Tucson Electric Power Company (Arizona CC)
G-01551A-07-0504	Southwest Gas Corporation (Arizona CC)
Docket No.UE-072300	Puget Sound Energy, Inc. (Washington UTC)
PUE-2008-00009	Virginia-American Water Company (Virginia SCC)
PUE-2008-00046	Appalachian Power Company (Virginia SCC)
E-01345A-08-0172	Arizona Public Service Company (Arizona CC)
A-2008-2063737	Babcock & Brown Infrastructure Fund North America, LP. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
08-1783-G-42T	Hope Gas, Inc., dba Dominion Hope (West Virginia PSC)
08-1761-G-PC	Hope Gas, Inc., dba Dominion Hope, Dominion Resources, Inc., and Peoples Hope Gas Companies (West Virginia PSC)
Docket No. 2008-0085	Hawaiian Electric Company, Inc. (Hawaii PUC)
Docket No. 2008-0266	Young Brothers, Limited (Hawaii PUC)
G-04024A-08-0571	UNS Gas, Inc. (Arizona CC)
Docket No. 09-29	Tidewater Utilities, Inc. (Delaware PSC)
Docket No. UE-090704	Puget Sound Energy, Inc. (Washington UTC)
09-0878-G-42T	Mountaineer Gas Company (West Virginia PSC)
2009-UA-0014	Mississippi Power Company (Mississippi PSC)
Docket No. 09-0319	Illinois-American Water Company (Illinois CC)
Docket No. 09-414	Delmarva Power & Light Company (Delaware PSC)
R-2009-2132019	Aqua Pennsylvania, Inc. (Pennsylvania PUC)
Docket Nos. U-09-069, U-09-070	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)
Docket Nos. U-04-023, U-04-024	Anchorage Water and Wastewater Utility - Remand (Regulatory Commission of Alaska)
W-01303A-09-0343 & SW-01303A-09-0343	Arizona-American Water Company (Arizona CC)
09-0872-EL-FAC	Financial Audits of the FAC of the Columbus Southern Power Company and the Ohio Power Company - Phase I (Ohio PUC)
2010-00036	Kentucky-American Water Company (Kentucky PSC)
E-04100A-09-0496	Southwest Transmission Cooperative, Inc. (Arizona CC)
E-01773A-09-0496	Arizona Electric Power Cooperative, Inc. (Arizona CC)
R-2010-2166208,	

R-2010-2166210, R-2010-2166212, & R-2010-2166214	Pennsylvania-American Water Company (Pennsylvania PUC)
PSC Docket No. 09-0602	Central Illinois Light Company D/B/A AmerenCILCO; Central Illinois Public Service Company D/B/A AmerenCIPS; Illinois Power Company D/B/A AmerenIP (Illinois CC)
10-0713-E-PC	Allegheny Power and FirstEnergy Corp. (West Virginia PSC)
Docket No. 31958	Georgia Power Company (Georgia PSC)
Docket No. 10-0467	Commonwealth Edison Company (Illinois CC)
PSC Docket No. 10-237	Delmarva Power & Light Company (Delaware PSC)
U-10-51	Cook Inlet Natural Gas Storage Alaska, LLC (Regulatory Commission of Alaska)
10-0699-E-42T	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
10-0920-W-42T	West Virginia-American Water Company (West Virginia PSC)

Southwest Gas Corporation
Docket No. G-01551A-10-0458
Attachment RCS-2
Staff Accounting Schedules
Accompanying the Direct Testimony of Ralph C. Smith

Schedule	Description	Pages
	Revenue Requirement Summary Schedules	
A	Calculation of Revenue Deficiency (Sufficiency)	1
A-1	Gross Revenue Conversion Factor	1
B	Adjusted Rate Base	1
B.1	Summary of Rate Base Adjustments	2
C	Adjusted Net Operating Income	1
C.1	Summary of Net Operating Income Adjustments	3
D	Capital Structure and Cost Rates	1
	Rate Base Adjustments	
B-1	Corrections to Completed Construction Not Classified	1
B-2	Yuma Manors Pipe Replacement	1
B-3	Cash Working Capital	1
B-4	Accumulated Deferred Income Taxes - Bonus Tax Depreciation on CCNC	1
B-5	Remove Corporate Aircraft Costs	1
B-6	Remove One-Half of Prepaid D&O Insurance	1
	Net Operating Income Adjustments	
C-1	CCNC Correction Depreciation and Property Tax Expense	2
C-2	Yuma Manors Depreciation and Property Tax Expense	2
C-3	Management Incentive Program	1
C-4	Restricted Stock/Unit Plan	1
C-5	Supplemental Executive Retirement Expense	1
C-6	American Gas Association Dues	3
C-7	Loss on Sale of Employee Homes for Relocation Expense	2
C-8	Test Year Rent Charged to Affiliate IntelliChoice Energy LLC	1
C-9	Gas Heat Pump Development Expenses	1
C-10	Interest Synchronization	1
C-11	Directors' and Officers' Liability Insurance	1
C-12	Self-Insurance Retention Expense	2
C-13	Leased Aircraft Operating Costs	1
C-14	COYL Leak Detection Survey	1
	Total Pages	37

Southwest Gas Corporation
Computation of Increase in Gross Revenue Requirement

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule A

Line No.	Description	Reference	SWG Proposed Original Cost (A)	SWG Proposed Fair Value (B)	Staff Proposed Original Cost (C)	Staff Proposed Fair Value (Alt. 1) (D1)	Staff Proposed Fair Value (Alt. 2) (D2)	Difference Fair Value (E) = D2 - B
1	Adjusted Rate Base	Sch. B	$ 1,073,700,633	$ 1,456,517,468	$ 1,070,115,558	$ 1,452,932,391	$ 1,452,932,391	$ (3,585,077)
2	Rate of Return	Sch. D	9.73%	7.50%	9.08%	6.69%	7.02%	
3	Operating Income Required		$ 104,483,741	$ 109,211,529	$ 97,138,991	$ 97,138,991	$ 101,924,201	$ (7,287,328)
4	Net Operating Income Available	Sch. C	$ 65,065,829	$ 65,065,829	$ 68,793,670	$ 68,793,670	$ 68,793,670	$ 3,727,841
5	Operating Income Excess/Deficiency		$ 39,417,912	$ 44,145,700	$ 28,345,321	$ 28,345,321	$ 33,130,531	$ (11,015,169)
6	Gross Revenue Conversion Factor	Sch. A-1	1.6579	1.6579	1.6579	1.6579	1.6579	1.6579
7	Overall Revenue Requirement		$ 65,350,956	$ 73,189,155	$ 46,993,708	$ 46,993,708	$ 54,927,107	$ (18,262,048)
8	Additional revenue requirement on Fair Value	Line 7		$ 7,838,200 (B - A)		$ - (D1 - C)	$ 7,933,399 (D2 - C)	

Notes and Source

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

SWG Schedule A-1 does not carry the Company's Original Cost calculations in its Schedule A-1, column c, through to a revenue requirement amount.

Southwest Gas Corporation
Computation of Gross Revenue Conversion Factor

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule A-1

Line No.	Description	Rate (A)	Company Proposed (B)	Staff Proposed (C)
1	Gross Revenue		1.0000000	1.0000000
2	Less: Uncollectible Revenue	0.2543%	0.0025428	0.0025428
3	State Taxable Income		0.9974572	0.9974572
4	Less: State Income Taxes	6.9680%	0.0695030	0.0695030
5	Federal Taxable Income		0.9279542	0.9279542
6	Federal Income Tax	35.0000%	0.3247840	0.3247840
7	Change in Net Operating Income		0.6031702	0.6031702
8	Gross Revenue Conversion Factor		1.6579	1.6579

Notes and Source

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

Components of Revenue Requirement Increase

		Amount	Percent
9	Net Income	$ 28,345,195	60.31700%
10	Federal and State Income Taxes	$ 18,529,008	39.42870%
11	Uncollectibles	$ 119,505	0.25430%
12	Total Revenue Increase	$ 46,993,708	100.00000%
13	Computation of State and Federal Income Tax Rate	L.10 / L.3	39.5292%
14	Per SWG Schedule C-3, page 3 of 3		39.5292%

Southwest Gas Corporation
Original Cost and RCND Adjusted Rate Base

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule B

Line No.	Description	Original Cost As Adjusted by SWG (A)	Original Cost Staff Adjustments (B)	Original Cost As Adjusted by Staff (C)	RCND As Adjusted by SWG (D)	RCND Staff Adjustments (E)	RCND As Adjusted by Staff (F)
	Gas Plant in Service						
1	Direct	$ 2,255,372,875	$ (335,852)	$ 2,255,037,023	$ 3,734,684,180	$ (335,852)	$ 3,734,348,328
2	System Allocable	$ 104,539,455	$ (1,512,324)	$ 103,027,131	$ 113,079,915	$ (1,512,324)	$ 111,567,591
3	Total Gross Plant	$ 2,359,912,330	$ (1,848,176)	$ 2,358,064,154	$ 3,847,764,095	$ (1,848,176)	$ 3,845,915,919
	Accumulated Depreciation and Amortization						
4	Direct	$ (886,327,699)	$ -	$ (886,327,699)	$ (1,483,912,048)	$ -	$ (1,483,912,048)
5	System Allocable	$ (68,873,041)	$ 197,292	$ (68,675,749)	$ (72,423,689)	$ 197,292	$ (72,226,397)
6	Total Accumulated Depreciation and Amortization	$ (955,200,740)	$ 197,292	$ (955,003,448)	$ (1,556,335,737)	$ 197,292	$ (1,556,138,445)
7	Net Gas Plant in Service	$ 1,404,711,591	$ (1,650,884)	$ 1,403,060,707	$ 2,291,428,358	$ (1,650,884)	$ 2,289,777,474
	Other Rate Base Items						
	Working Capital						
8	Cash Working Capital	$ (4,472,151)	$ (468,000)	$ (4,940,151)	$ (4,472,151)	$ (468,000)	$ (4,940,151)
9	Materials and Supplies	$ 9,920,409	$ -	$ 9,920,409	$ 9,920,409	$ -	$ 9,920,409
10	Prepayments	$ 4,744,133	$ (185,097)	$ 4,559,036	$ 4,744,133	$ (185,097)	$ 4,559,036
11	Customer Advances for Construction	$ (62,033,165)	$ -	$ (62,033,165)	$ (62,033,165)	$ -	$ (62,033,165)
12	Customer Deposits	$ (48,475,278)	$ -	$ (48,475,278)	$ (48,475,278)	$ -	$ (48,475,278)
13	Deferred Income Taxes	$ (230,694,907)	$ (1,281,095)	$ (231,976,002)	$ (351,778,007)	$ (1,281,095)	$ (353,059,102)
14	Other		$ -			$ -	
15	Total Other Rate Base Items	$ (331,010,958)	$ (1,934,192)	$ (332,945,149)	$ (452,094,058)	$ (1,934,192)	$ (454,028,249)
16	Total Rate Base	$ 1,073,700,633	$ (3,585,076)	$ 1,070,115,558	$ 1,839,334,300	$ (3,585,076)	$ 1,835,749,225

Notes and Source

Cols. A and D: SWG filing, Schedule B-1, Sheet 1 of 2

	Fair Value Calculation (Per Company)		
17	Original Cost	$ 1,073,700,633	
18	RCND	$ 1,839,334,300	
19	Total	$ 2,913,034,934	
20	Average (Fair Value)	$ 1,456,517,468	See Sch. A
	Fair Value Calculation (Per Staff)		
21	Original Cost	$ 1,070,115,558	
22	RCND	$ 1,835,749,225	
23	Total	$ 2,905,864,783	
24	Average (Fair Value)	$ 1,452,932,391	See Sch. A

Southwest Gas Corporation
Summary of Rate Base Adjustments
Original Cost
Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule B.1 (OCRB)

Line No.	Description	Staff Adjustments	Corrections to Completed Construction Not Classified	Yuma Manors Pipe Replacement	Cash Working Capital	Accumulated Deferred Income Taxes - Bonus Tax Depreciation on CCNC	Remove Corporate Aircraft Costs	Remove One-Half of Prepaid D&O Insurance
			B-1	B-2	B-3	B-4	B-5	B-6
	Gas Plant in Service							
1	Direct	$ (335,852)	$ (110,407)	$ (225,445)				
2	System Allocable	$ (1,512,324)	$ (956,250)				$ (556,074)	
3	Total Gross Plant	$ (1,848,176)	$ (1,066,657)	$ (225,445)	$ -	$ -	$ (556,074)	$ -
	Accumulated Depreciation and Amortization							
4	Direct	$ -						
5	System Allocable	$ 197,292					$ 197,292	
6	Total Accumulated Depreciation and Amortization	$ 197,292	$ -	$ -	$ -	$ -	$ 197,292	$ -
7	Net Gas Plant in Service	$ (1,650,884)	$ (1,066,657)	$ (225,445)	$ -	$ -	$ (358,782)	$ -
	Other Rate Base Items							
	Working Capital							
8	Cash Working Capital	$ (468,000)			$ (468,000)			
9	Materials and Supplies	$ -						
10	Prepayments	$ (185,097)						$ (185,097)
11	Customer Advances for Construction	$ -						
12	Customer Deposits	$ -						
13	Deferred Income Taxes	$ (1,281,095)				$ (1,286,985)	$ 5,890	
14	Other	$ -						
15	Total Other Rate Base Items	$ (1,934,192)	$ -	$ -	$ (468,000)	$ (1,286,985)	$ 5,890	$ (185,097)
16	Total Rate Base	$ (3,585,076)	$ (1,066,657)	$ (225,445)	$ (468,000)	$ (1,286,985)	$ (352,892)	$ (185,097)

Southwest Gas Corporation
Summary of Rate Base Adjustments
Reconstruction Cost New Depreciated
Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule B.1 (RCND)

Line No.	Description	Staff Adjustments	Corrections to Completed Construction Not Classified	Yuma Manors Pipe Replacement	Cash Working Capital	Accumulated Deferred Income Taxes - Bonus Tax	Remove Corporate Aircraft Costs	Remove One-Half of Prepaid D&O Insurance
			B-1	B-2	B-3	B-4	B-5	B-6
	Gas Plant in Service							
1	Direct	$ (335,852)	$ (110,407)	$ (225,445)				
2	System Allocable	$ (1,512,324)	$ (956,250)				$ (556,074)	
3	Total Gross Plant	$ (1,848,176)	$ (1,066,657)	$ (225,445)	$ -	$ -	$ (556,074)	$ -
	Accumulated Depreciation and Amortization							
4	Direct	$ -						
5	System Allocable	$ 197,292					$ 197,292	
6	Total Accumulated Depreciation and Amortization	$ 197,292	$ -	$ -	$ -	$ -	$ 197,292	$ -
7	Net Gas Plant in Service	$ (1,650,884)	$ (1,066,657)	$ (225,445)	$ -	$ -	$ (358,782)	$ -
	Other Rate Base Items							
	Working Capital							
8	Cash Working Capital	$ (468,000)			$ (468,000)			
9	Materials and Supplies	$ -						
10	Prepayments	$ (185,097)						$ (185,097)
11	Customer Advances for Construction	$ -						
12	Customer Deposits	$ -						
13	Deferred Income Taxes	$ (1,281,095)				$ (1,286,985)	$ 5,890	
14	Other	$ -						
15	Total Other Rate Base Items	$ (1,934,192)	$ -	$ -	$ (468,000)	$ (1,286,985)	$ 5,890	$ (185,097)
16	Total Rate Base	$ (3,585,076)	$ (1,066,657)	$ (225,445)	$ (468,000)	$ (1,286,985)	$ (352,892)	$ (185,097)

Southwest Gas Corporation
Adjusted Net Operating Income

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule C

Line No.	Description	As Adjusted by Company (A)	Staff Adjustments (B)	As Adjusted by Staff (C)
	Operating Revenues			
1	Revenues	$ 410,912,098	$ -	$ 410,912,098
2	Gas Cost		$ -	$ -
3	Total Margin	$ 410,912,098	$ -	$ 410,912,098
	Operating Expenses			
4	Other Gas Supply	$ 1,138,145	$ -	$ 1,138,145
5	Distribution	$ 100,579,868	$ 625,094	$ 101,204,963
6	Customer Accounts	$ 33,881,272	$ -	$ 33,881,272
7	Customer Information	$ 1,205,135	$ -	$ 1,205,135
8	Sales	$ -	$ -	$ -
	Administrative and General			
9	Direct	$ 6,339,402	$ (4,160,309)	$ 2,179,093
10	System Allocable	$ 58,786,097	$ (2,451,994)	$ 56,334,103
	Depreciation and Amortization			
11	Direct	$ 93,057,028	$ (17,099)	$ 93,039,929
12	System Allocable	$ 6,244,982	$ (115,257)	$ 6,129,725
13	Regulatory Amortizations	$ 284,581	$ -	$ 284,581
14	Other Taxes	$ 27,203,877	$ (138,360)	$ 27,065,517
15	Interest on Customer Deposits	$ 2,908,517	$ -	$ 2,908,517
16	Income Taxes	$ 14,217,365	$ 2,530,084	$ 16,747,449
17	Total Operating Expenses	$ 345,846,269	$ (3,727,841)	$ 342,118,428
18	Net Operating Income	$ 65,065,829	$ 3,727,841	$ 68,793,670

Notes and Source

Col. A: SWG filing, Schedule C-1, page 1 of 18, colume e
Col. B: Staff Schedule C.1

Southwest Gas Corporation
Summary of Net Operating Income Adjustments

Test Year Ended June 30, 2010

Line No.	Description	Staff Adjustments	CCNC Correction Depreciation and Property Tax Expense	Yuma Manors Depreciation and Property Tax Expense	Management Incentive Program	Restricted Stock/Unit Plan	Supplemental Executive Retirement Expense	American Gas Association Dues	Loss on Sale of Employee Homes for Relocation Expense
			C-1	C-2	C-3	C-4	C-5	C-6	C-7
	Operating Revenues								
1	Revenues	$ -							
2	Gas Cost	$ -							
3	Total Margin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Expenses								
4	Other Gas Supply	$ -							
5	Distribution	$ 625,094							$ (374,906)
6	Customer Accounts	$ -							
7	Customer Information	$ -							
8	Sales	$ -							
	Administrative and General								
9	Direct	$ (4,160,309)			$ (1,768,249)	$ (1,033,723)	$ (1,225,220)		
10	System Allocable	$ (2,451,994)					$ (500,619)	$ (90,898)	$ (128,714)
	Depreciation and Amortization								
11	Direct	$ (17,099)	$ (4,218)	$ (12,881)					
12	System Allocable	$ (115,257)	$ (95,625)						
13	Regulatory Amortizations	$ -							
14	Other Taxes	$ (138,360)	$ (2,236)	$ (4,566)	$ (131,558)				
15	Interest on Customer Deposits	$ -							
16	EXPENSES BEFORE INCOME TAXES	$ (6,257,925)	$ (102,079)	$ (17,447)	$ (1,899,807)	$ (1,033,723)	$ (1,725,839)	$ (90,898)	$ (503,620)
17	PRE-TAX OPERATING INCOME	$ 6,257,925	$ 102,079	$ 17,447	$ 1,899,807	$ 1,033,723	$ 1,725,839	$ 90,898	$ 503,620
18	Income Taxes	$ 2,530,084	$ 40,351	$ 6,897	$ 750,979	$ 408,622	$ 682,210	$ 35,931	$ 199,077
19	TOTAL OPERATING EXPENSES	$ (3,727,841)	$ (61,728)	$ (10,550)	$ (1,148,828)	$ (625,101)	$ (1,043,629)	$ (54,967)	$ (304,543)
20	OPERATING INCOME	$ 3,727,841	$ 61,728	$ 10,550	$ 1,148,828	$ 625,101	$ 1,043,629	$ 54,967	$ 304,543

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 June 30, 2010

Line No.	Description	Test Year Rent Charged to Affiliate IntelliChoice Energy LLC	Gas Heat Pump Development Expenses	Interest Synchronization	Directors' and Officers' Liability Insurance	Self-Insurance Retention Expense	Leased Aircraft Operating Costs	COYL Leak Detection Survey
		C-8	C-9	C-10	C-11	C-12	C-13	C-14
	Operating Revenues							
1	Revenues							
2	Gas Cost							
3	Total Margin	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Expenses							
4	Other Gas Supply							
5	Distribution							$ 1,000,000
6	Customer Accounts							
7	Customer Information							
8	Sales							
	Administrative and General							
9	Direct	$ (13,156)				$ (119,961)		
10	System Allocable		$ (711,287)		$ (386,402)	$ (459,813)	$ (174,261)	
	Depreciation and Amortization							
11	Direct							
12	System Allocable						$ (19,632)	
13	Regulatory Amortizations							
14	Other Taxes							
15	Interest on Customer Deposits							
16	EXPENSES BEFORE INCOME TAXES	$ (13,156)	$ (711,287)	$ -	$ (386,402)	$ (579,774)	$ (193,893)	$ 1,000,000
17	PRE-TAX OPERATING INCOME	$ 13,156	$ 711,287	$ -	$ 386,402	$ 579,774	$ 193,893	$ (1,000,000)
18	Income Taxes	$ 5,200	$ 281,166	$ 56,377	$ 152,742	$ 229,180	$ 76,644	$ (395,292)
19	TOTAL OPERATING EXPENSES	$ (7,956)	$ (430,121)	$ 56,377	$ (233,660)	$ (350,594)	$ (117,249)	$ 604,708
20	OPERATING INCOME	$ 7,956	$ 430,121	$ (56,377)	$ 233,660	$ 350,594	$ 117,249	$ (604,708)

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-10-0458
Schedule D

Test Year Ended June 30, 2010

Line No.	Capital Source	Capitalization Amount (A)	Capitalization Percent (B)	Cost Rate (C)	Weighted Avg. Cost of Capital (D)
	I. SWG Proposed				
	A. Weighted Average Cost of Capital for Original Cost Rate Base				
1	Long-Term Debt		47.70%	8.34%	3.98%
2	Common Equity		52.30%	11.00%	5.75%
3	Total		100.00%		9.73%
	B. Fair Value Rate of Return for Fair Value Rate Base				
4	Long-Term Debt		35.16%	8.34%	2.93%
5	Common Equity		38.55%	11.00%	4.24%
6	Appreciation Above OCRB		26.28%	1.24%	0.32%
7	Total		100.00%		7.50%
	II. Staff Proposed				
	A. Weighted Average Cost of Capital for Original Cost Rate Base [b]				
8	Long-Term Debt		47.70%	8.34%	3.98%
9	Common Equity		52.30%	9.75%	5.10%
10	Total		100.00%		9.08%
	B. Fair Value Rate of Return for Fair Value Rate Base - Alternative 1 [a]				
11	Long-Term Debt		35.13%	8.34%	2.93%
12	Common Equity		38.52%	9.75%	3.76%
13	Appreciation Above OCRB		26.35%	0.00% [a]	0.00%
14	Total		100.00%		6.69%
	B. Fair Value Rate of Return for Fair Value Rate Base - Alternative 2 [b]				
15	Long-Term Debt		35.13%	8.34%	2.93%
16	Common Equity		38.52%	9.75%	3.76%
17	Appreciation Above OCRB		26.35%	1.25% [b]	0.33%
18	Total		100.00%		7.02%

Notes and Source

Lines 1-7: SWG Schedule D-1

Lines 11-14, Col.A:

		Amount		Percent
19	Fair Value Rate Base	###########	Schedule A	
20	Original Cost Rate Base	###########	Schedule A	73.65%
21	Difference	$ 382,816,834		26.35%
				100.00%

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

22	Long-Term Debt	35.13%
23	Common Equity	38.52%
24	Appreciation Above OCRB	26.35%
25	Total	100.00%

[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, per Staff witness Parcell.

[b] Per Staff witness David Parcell

Southwest Gas Corporation
Corrections to Completed Construction Not Classified

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule B-1

Line No.	Description	Account	Amount (A)	Reference
	I. Southwest Gas Arizona Direct			
1	Company proposed adjustment		$ 2,806,169	SWG Filing, Adjustment 17
2	Amount corrected for plant in service at 6/30/2010		$ 2,695,762	Response to STF-6-7
3	Adjustment (decrease) to Company's requested rate base	376	$ (110,407)	
4	Percentage reduction		-3.93%	Line 3 / Line 1
5	Percentage relationship of corrected amount to Company's original amount		96.07%	Line 2 / Line 1
	II. Remove SCADA Project from System Allocable Account 303			
6	Adjustment (decrease) to Company's requested rate base		$ (1,700,000)	Response to STF-6-7(d)
7	Four-factor Allocation to Arizona Jurisdictional		56.25%	
8	Adjustment (decrease) to Company's requested rate base	303	$ (956,250)	
	III. Total Adjustment to ADIT for Tax Depreciation on CCNC			
9	Arizona Direct	376	$ (110,407)	Line 3
10	Corporate System Allocable	303	$ (956,250)	Line 8
11	Total Adjustment		$ (1,066,657)	

Notes and Source

	System Allocable CCNC:		
12	Per Southwest's Filing	$ 5,839,131	SWG Filing, Adjustment 17
13	As corrected to remove SCADA Project	$ 4,139,131	Response to STF-6-7(d)
14	Adjustment	$ (1,700,000)	Response to STF-6-7(d)

Southwest Gas Corporation
Yuma Manors Pipe Replacment

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule B-2

Line No.	Description	Account	Account 376 Mains Amount (A)	Account 380 Services Amount (B)	Total Amount (C)	Reference
	I. Staff Adjustment in SWG's Last Rate Case Adopted by the Commission					
	Staff Adjustment					
1	Adjustment to Test Year Plant in Service		$ (737,377)	$ (494,385)	$ (1,231,762)	Note A
2	Adjustment to Test Year Accumulated Depreciation		$ 116,703	$ 22,611	$ 139,314	Note A
3	Adjustment to Test Year Net Plant		$ (620,674)	$ (471,774)	$ (1,092,448)	
4	Adjustment adopted in Decision No. 70665 (50%)		$ (310,337)	$ (235,887)	$ (546,224)	Note B
5	Amount written off by Southwest Gas				$ 320,779	Note C
6	Amount remaining in SWG's rate base				$ 225,445	Note C; - (L4&L5)
	II. Remove Disallowance Amount from Last Rate Case that SWG Included in Current Case Rate Base					
7	Remove amount SWG included in rate base				$ (225,445)	Note C; - Line 6

Notes and Source

A Testimony of Staff Witness Ralph Smith in Docket No. G-01551A-07-0504, Attachment RCS-2, Schedule B-1
B Decision No. 70665 at page 8
C SWG witness Robert Mashas direct testimony, page 21

Allocation of remaining amount between mains and services for calculation of Depreciation Expense adjustment:

From Docket No. G-01551A-07-0504:	Amount (D)	Percent (E)	Allocation (F)	
Account 376, Mains	$ (310,337)	56.8150%	$ (128,087)	Note D
Account 380, Services	$ (235,887)	43.1850%	$ (97,358)	Note D
Total	$ (546,224)	100.0000%	$ (225,445)	Note D

D Also see SWG's response to data request STF-16-1, line 19

Southwest Gas Corporation

Cash Working Capital
Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule B-3

Line No.	Description	Per Company Cost (A)	Staff Adjustments (B)	Staff Adjusted (C)	Lag Days (D)	Dollar Days (E)
1	Cost of Gas	$ 379,159,715	$ -	$ 379,159,715	42.43	$ 16,087,746,707
2	Labor Cost	$ 130,360,854	$ (5,254,018)	$ 125,106,836	10.90	$ 1,363,664,509
3	Provision for Uncollected Accounts	$ 2,008,980	$ -	$ 2,008,980	120.00	$ 241,077,600
4	Other O & M Expenses	$ 68,719,020	$ (1,459,398)	$ 67,259,622	2.03	$ 136,537,033
5	Total O & M Expenses	$ 580,248,569	$ (6,713,416)	$ 573,535,153	30.73	$ 17,829,025,849
6	Interest	$ 42,713,744	$ (142,621)	$ 42,571,123	91.00	$ 3,873,972,193
7	Taxes Other Than Income Taxes	$ 27,203,877	$ (138,360)	$ 27,065,517	174.28	$ 4,716,978,303
8	Income Taxes-Current	$ 26,047,797	$ 2,530,084	$ 28,577,881	37.00	$ 1,057,381,597
9	Total Operating Expenses	$ 676,213,987	$ 2,391,724	$ 671,749,674	40.90	$ 27,477,357,942
10	Number of Days in Test Period	365		365		
11	Average Daily Operating Expense	$ 1,852,641		$ 1,840,410		
12	Lag in Receipt of Payment of Cash Expenses	40.64			40.90	
13	Lag in Receipt of Revenue	38.22			38.22	
14	Net Difference Revenue-Expense Lag	(2.41)		(2.68)		
	Cash Working Capital:					
14	Per Staff			$ (4,939,960)		
15	Per Company	$ (4,472,151)		$ (4,472,151)		
16	Staff Adjustment			$ (467,809)		
17	Staff Adjustment (rounded to thousands)			$ (468,000)		

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
Col.D: SWG Sch B-5, page 2 of 4
Col.E: Col. C x Col.D

Southwest Gas Corporation
Accumulated Deferred Income Taxes - Bonus Tax Depreciation on CCNC

Test Year Ended June 30, 2010

Line No.	Description	Account	Amount (A)	Reference
	I. Southwest Gas Arizona Direct			
1	Correction to Southwest's filing for ADIT on CCNC		$ (704,030)	Response to STF-6-7(d)
2	Relationship of CCNC corrected and original claimed CCNC		96.07%	Schedule B-1
3	Adjustment (decrease) to Company's requested rate base	282	$ (676,330)	
	II. Southwest Gas Corporate System Allocable			
4	Correction to Southwest's filing for ADIT on CCNC		$ (1,085,609)	Response to STF-6-7(d)
5	Relationship of CCNC corrected and original claimed CCNC		100%	Note A
6	Adjustment (decrease) to Company's requested rate base		$ (1,085,609)	
7	Four-factor Allocation to Arizona Jurisdictional		56.25%	Note B
8	Adjustment (decrease) to Company's requested rate base	282	$ (610,655)	
	III. Total Adjustment to ADIT for Tax Depreciation on CCNC			
9	Arizona Direct		$ (676,330)	Line 3
10	Corporate System Allocable		$ (610,655)	Line 8
11	Total Adjustment	282	$ (1,286,985)	

Notes and Source

A Per Southwest's response to STF-6-7(d):
"The Company is removing the $1,700,000 cost of the SCADA system originally included in Adjustment 17 in System Allocable Account 303. There was no deferred tax associated with this project included in this application, therefore, no adjustment to deferred taxes related to the removal of this project is required."

B SWG Schedule B-6, Sheet 3 of 3

Details of System Allocable Federal ADIT:

12	Account 282 - Federal ADIT Liability	$ 15,583,217	SWG Schedule B-6, Sheet 3
13	Correction to reflect ADIT on CCNC	$ 1,085,609	Response to STF-6-7(d)
14	Account 282 - Federal ADIT Liability, as corrected	$ 16,668,826	Response to STF-6-7(d)

Southwest Gas Corporation
Remove Corporate Aircraft Costs

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule B-5

Line No.	Description	Airplane Hanger (A)	Airplane Equipment (B)	Total Arizona Allocation (C)	Staff Adjustment (D)
1	Original Cost	$ 509,388	$ 46,686	$ 556,074	$ (556,074)
2	Accumulated Depreciation	$ (160,803)	$ (36,489)	$ (197,292)	$ 197,292
3	Accumulated Deferred Income Taxes	$ (2,321)	$ (3,569)	$ (5,890)	$ 5,890
4	Net Arizona Rate Base	$ 346,264	$ 6,628	$ 352,892	$ (352,892)

Notes and Source

SWG's response to data request STF-7-9

Southwest Gas Corporation
Remove One-Half of Prepaid D&O Insurance

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule B-6

Line No.	Description	Account	Prepaid D&O Insurance In AZ Jurisdictonal Rate Base (A)	Staff Allowance (One-Half) (B)	Staff Adjustment (C)
1	Prepayments	165	$ 370,193	$ 185,097	$ (185,097)

Notes and Source

SWG's response to data request STF-6-9

Southwest Gas Corporation
CCNC Correction Depreciation and Property Tax Expense

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule C-1

Line No.	Description	Account	Plant Amount (A)	Depreciation Rate (B)	Adjustment to Depreciation Expense (C)
1	Arizona Direct	376	$ (110,407)	3.82%	$ (4,218) [a]
2	Corporate System Allocable	303	$ (956,250)	10.00%	$ (95,625) [b]
3	Adjustment to Annualized Depreciation Expense		$ (1,066,657)		$ (99,843)

Notes and Source

Col.A: Schedule B-1
Col.B: SWG Depreciation and Annualization Expense Excel file workpaper
SWG wp 303, 10-year amortization applied for $1.7 million SCADA post test year adjustment
Col.C: Col. A x Col. B
[a] Also see, SWG's response to STF-16-3
[b] Also see, SWG's response to STF-16-2

FERC 403

Southwest Gas Corporation
CCNC Correction Depreciation and Property Tax Expense

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule C-1

Line No.	Description	Amount	Reference
	Adjustment to Property Tax Expense		
1	Adjustment to Net Plant in Service	$ (110,407)	Note A
2	Statutory Assessment Ratio	20.0%	Note C
3	Taxable Value	$ (22,081)	Note C
4	Property Tax Rate	10.13%	Notes C and B
5	Property Tax Expense Adjustment	$ (2,236)	Note C

Notes and Source

A Schedule B-1, line 3
B Also see Company's Schedule C-2, Adj. No. 14
C Also see, Company's response to STF 16-2 and STF 16-3

FERC 408.1

Southwest Gas Corporation
Yuma Manors Depreciation and Property Tax Expense

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule C-2

Line No.	Description	Plant Amount (A)	Depreciation Rate (B)	Adjustment to Depreciation Expense (C)
1	Account 376, Mains	$ (186,438)	3.82%	$ (7,122)
2	Account 380, Services	$ (108,664)	5.30%	$ (5,759)
3	Adjustment to Plant and Annualized Depreciation Expense	$ (295,102)		$ (12,881) [a]
4	Decision No. 70665, Adjustment to Accumulated Depreciation	$ 69,657		
5	Decision No. 70665, Adjustment to Net Plant	$ (225,445)		

Notes and Source

Col.A: Schedule B-2 and SWG's response to STF-16-1
Col.B: SWG Depreciation and Annualization Expense Excel file workpaper
Col.C: Col. A x Col. B
[a] Also see Company's response to STF-16-1

FERC 403

Southwest Gas Corporation
Yuma Manors Depreciation and Property Tax Expense

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule C-2

Line No.	Description	Amount	Reference
	Adjustment to Property Tax Expense		
1	Adjustment to Net Plant in Service	$ (225,445)	Note A
2	Statutory Assessment Ratio	20.0%	Note C
3	Taxable Value	$ (45,089)	Note C
4	Property Tax Rate	10.13%	Notes C and B
5	Property Tax Expense Adjustment	$ (4,566)	Note C

Notes and Source

A Schedule B-2
B Also see Company's Schedule C-2, Adj. No. 14
C Also see Company's response to STF-16-1
FERC 408.1

Southwest Gas Corporation
Management Incentive Program

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule C-3

Line No.	Description	Amount	Reference
1	Adjustment to Management Incentive Program Expense	$ (1,768,249)	A
2	Related Adjustment to Payroll Tax Expense	$ (131,558)	B
3	Total reduction to test year operating expenses	$ (1,899,807)	L1 and L2

Notes and Source

A	Adjustment to Management Incentive Program Expense		
	Amount below from SWG's responses to STF-1-83 and STF 17-2		
4	Test Year amount of Management Incentive Program Expense (Corporate)	$ 6,537,494	STF 17-2(a)
5	Allocation to Paiute (MMF)	$ (250,386)	3.83%
6	Net of Allocation to Paiute	$ 6,287,108	
7	Arizona Four Factor allocation rate per SWG Schedule C-1, sheet 17	56.25%	
8	Test Year amount of Management Incentive Program Expense (Arizona)	$ 3,536,498	
9	Shareholder allocation percentage	50%	
10	50% Allocation of MIP Expense to Shareholders	$ 1,768,249	FERC 920
B	Adjustment to Payroll Tax Expense		
11	Adjustment to Test Year MIP Expense	$ 1,768,249	Line 10
12	Payroll Tax Expense Rate	7.440%	C
13	Adjustment to Payroll Tax Expense	$ 131,558	

C Estimated based on SWG's annualized payroll tax expense per SWG Workpaper Supporting Adjustment No. 3, Annualized Fica And Medicare

Southwest Gas Corporation
Stock Based Compensation (Other Than MIP)

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule C-4

Line No.	Description	Amount	Reference
1	Adjustment to remove expense for Stock Based Compenation (other than MIP)	$ (1,033,723)	A

Notes and Source

A	Response to STF-6-5, amount is after allocation to Arizona	
	Compare, RSUP from SWG's response to STF-17-2	$ (1,033,831)

Account 920

Southwest Gas Corporation
Supplemental Executive Retirement Expense

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule C-5

Line No.	Description	Total Amount (A)	Arizona Amount (B)
1	Test Year Supplemental Executive Retirement Expense (Arizona)	$ (1,419,193)	$ (1,154,655)
2	Test Year Supplemental Executive Retirement Expense (Corporate Direct Arizona)	$ (70,565)	$ (70,565)
3	System Allocable Amount of SERP	$ (962,289)	$ (500,619)
4	Total	$ (2,452,046)	$ (1,725,839) [a]

Notes and Source

Col.A: SWG Workpaper Supporting Adjustment No. 3, Annualized Employee Benefits, Line 12, SERP
Col.B: SWG's response to STF 17-1
[a] Represents estimated amount of SERP expense in SWG's filing
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 June 30, 2010

Docket No. G-01551A-10-0458
Schedule C-6

Line No.	Description	Staff Adjustment (A)	Company Adjustment (B)	Net Staff Adjustment (C)	Reference
1	2009 AGA Dues per Filing	$ 495,541	$ 495,541		A
2	Recommended disallowance percentage	40%	6.09%		B
3	Recommended disallowance	$ (198,216)	$ (30,178)		L1 x L2
4	Less: Paiute & SGTC Allocation at 3.83%	$ 7,592	$ 1,156		C
5	Adjustment to AGA Dues Before Four-Factor	$ (190,624)	$ (29,022)		
6	Arizona Four-Factor Allocation	56.25%	56.25%		D
7	Adjustment to Arizona Related AGA Dues	$ (107,222)	$ (16,324)	$ (90,898)	

Notes and Source

A: SWG Filing, Schedule C-2, Adjustment No. 10, line 1
B: See testimony of Staff witness Ralph C. Smith and page 2 of this schedule
C: SWG Filing, Schedule C-2, Adjustment No. 10, line 4
D: SWG Filing, Schedule C-1, Sheet 17, Line 10(b)

FERC Account 930.2

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

Docket No. G-01551A-10-0458
Schedule C-6
Page 2 of 3

Line No.	NARUC Operating Expense Category	March 2005 NARUC Audit Report for Year Ended 12/31/02		AGA 2007 Budget			AGA 2008 Budget		
		% 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 from SWG's last rate case, Docket No. G-01551A-07-0504
Col.F: Southwest's Response to Staff data request STF-6-50(b) from SWG's last rate case, Docket No. G-01551A-07-0504

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

Docket No. G-01551A-10-0458
Schedule C-6
Page 3 of 3

Line No.	AGA Categories of Expenses	2001	2002	2003	2004	2005	2006	2007	2008	2009	Forecast 2010
	I. AGA Expenditures from STF-6-21										
1	Public Affairs	$ 5,703,920	$ 5,939,486	$ 6,336,326	$ 7,015,121	$ 5,726,187	$ 5,878,345	$ 5,563,947	$ 7,036,204	$ 6,087,552	$ 6,143,000
2	Policy, Planning & Regulatory Affairs	3,382,900	3,261,692	3,212,553	3,031,053	3,120,112	3,325,727	3,925,034	4,041,413	4,277,647	4,427,000
3	Market Development	1,196,791	349,589	-	-	-	-	-	-	-	-
4	Corporate Affairs	2,123,818	2,014,503	2,304,775	1,993,049	2,072,208	2,398,515	2,271,158	2,754,868	2,880,397	2,354,000
5	Operations & Engineering Management	3,664,863	3,729,829	4,302,428	4,262,228	5,154,993	5,116,637	5,693,934	5,119,289	5,474,235	5,085,000
6	Industry Finance & Administrative Programs	934,852	1,230,238	1,157,023	1,286,859	1,363,591	1,252,846	1,516,308	996,593	1,027,748	1,129,000
7	General Counsel	641,984	768,219	757,481	746,667	808,157	877,030	945,643	1,043,295	1,172,072	1,067,000
8	General and Administrative	4,273,134	3,894,457	4,124,675	5,034,491	4,322,358	4,676,721	4,932,418	5,275,571	5,569,647	5,535,000
9	**Total Expense Actuals**	$ 21,922,262	$ 21,188,013	$ 22,195,261	$ 23,369,468	$ 22,567,606	$ 23,525,821	$ 24,848,442	$ 26,267,233	$ 26,489,298	$ 25,740,000
	II. Percentage of Annual Totals by Category										
10	Public Affairs	26.02%	28.03%	28.55%	30.02%	25.37%	24.99%	22.39%	26.79%	22.98%	23.87%
11	Policy, Planning & Regulatory Affairs	15.43%	15.39%	14.47%	12.97%	13.83%	14.14%	15.80%	15.39%	16.15%	17.20%
12	Market Development	5.46%	1.65%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
13	Corporate Affairs	9.69%	9.51%	10.38%	8.53%	9.18%	10.20%	9.14%	10.49%	10.87%	9.15%
14	Operations & Engineering Management	16.72%	17.60%	19.38%	18.24%	22.84%	21.75%	22.91%	19.49%	20.67%	19.76%
15	Industry Finance & Administrative Programs	4.26%	5.81%	5.21%	5.51%	6.04%	5.33%	6.10%	3.79%	3.88%	4.39%
16	General Counsel	2.93%	3.63%	3.41%	3.20%	3.58%	3.73%	3.81%	3.97%	4.42%	4.15%
17	General and Administrative	19.49%	18.38%	18.58%	21.54%	19.15%	19.88%	19.85%	20.08%	21.03%	21.50%
18	Totals	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
19	Totals excluding General & Administrative	80.51%	81.62%	81.42%	78.46%	80.85%	80.12%	80.15%	79.92%	78.97%	78.50%
	III. Percentage of Totals With G&A Allocated										
20	Public Affairs	32.32%	34.35%	35.06%	38.26%	31.38%	31.19%	27.94%	33.52%	29.10%	30.40%
21	Policy, Planning & Regulatory Affairs	19.17%	18.86%	17.78%	16.53%	17.10%	17.64%	19.71%	19.25%	20.45%	21.91%
22	Market Development	6.78%	2.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
23	Corporate Affairs	12.03%	11.65%	12.75%	10.87%	11.36%	12.72%	11.40%	13.12%	13.77%	11.65%
24	Operations & Engineering Management	20.77%	21.57%	23.81%	23.25%	28.25%	27.15%	28.59%	24.39%	26.17%	25.17%
25	Industry Finance & Administrative Programs	5.30%	7.11%	6.40%	7.02%	7.47%	6.65%	7.61%	4.75%	4.91%	5.59%
26	General Counsel	3.64%	4.44%	4.19%	4.07%	4.43%	4.65%	4.75%	4.97%	5.60%	5.28%
27	General and Administrative										
28	Totals	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	IV. Calculated Disallowance Percentages										
29	Public Affairs	32.32%	34.35%	35.06%	38.26%	31.38%	31.19%	27.94%	33.52%	29.10%	30.40%
30	Policy, Planning & Regulatory Affairs										
31	Market Development										
32	Corporate Affairs	12.03%	11.65%	12.75%	10.87%	11.36%	12.72%	11.40%	13.12%	13.77%	11.65%
33	Operations & Engineering Management										
34	Industry Finance & Administrative Programs										
35	General Counsel	1.82%	2.22%	2.10%	2.04%	2.21%	2.33%	2.37%	2.49%	2.80%	2.64%
36	General and Administrative										
37	Totals	46.17%	48.22%	49.91%	51.17%	44.96%	46.24%	41.71%	49.13%	45.67%	44.69%

Notes and Source

Lines 1-9: Southwest Gas' response to data request STF-6-21

Southwest Gas Corporation
Loss on Sale of Employee Homes for Relocation Expense

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule C-7

Line No.	Description	Account	Company Recorded (A)	Staff Adjusted (B)	Staff Adjustment (C)
	I. Adjust to Normalized Level				
	Employee Relocation Expense And Losses Associated With Sales Of Employee Homes				
1	Arizona	88000001	$ 374,906	$ 199,331	$ (175,574)
2	Corporate Allocated	92100001	$ 237,939	$ 111,574	
3	Paiute & SGTC MMF		3.83%	3.83%	
4	Less: Paiute & SGTC Allocation		$ 9,113	$ 4,273	
5	Relocation Expenses Before 4-Factor		$ 228,826	$ 107,301	
6	Arizona 4-Factor Allocation		56.25%	56.25%	
7	Adjustment Allocated to Arizona	92100001	$ 128,714	$ 60,357	$ (68,357)
8	Total Arizona Relocation Costs		$ 503,620	$ 259,688	$ (243,931)
	II. Remove Remaining Expense from Test Year				
9	Arizona Direct				$ (199,331)
10	Corporate Allocated				$ (60,357)
11	Total				$ (259,688)
	II. Total Staff Adjustment to Remove Expense from Test Year				
12	Arizona Direct				$ (374,906)
13	Corporate Allocated				$ (128,714)
14	Total				$ (503,620)

Notes and Source

Col.A SWG's response to data request STF-6-29; also see page 2 of this schedule
Col.B Normalized Using a Five-Year Average. See page 2 of this schedule

Southwest Gas Corporation
2010 Arizona General Rate Case
Docket No. G-01551A-10-0458
Employee Relocation Expense And Losses Associated With Sales Of Employee Homes

Line No.	Description	2006 Loss	2006 Commission	2007 Loss	2007 Commission	2008 Loss	2008 Commission	2009 Loss	2009 Commission	2010 Loss	2010 Commission	Test Year July 2009 - June 2010 Loss	Test Year July 2009 - June 2010 Commission
	I. Annual Information Provided by Company												
1	Arizona - Account 88000001	$ -	$ -	$ 170,312	$ 33,144	$ 681,746	$ 62,220	$ 74,007	$ 14,400	$ 70,592	$ 34,338	$ 374,906	$ 62,520
2	Corporate - Account 92100001	$ 55,444	$ 23,940	$ 35,366	$ 16,440	$ 247,851	$ 49,830	$ 219,210	$ 20,700	$ -	$ -	$ 237,939	$ 50,100
3	Paiute & SGTC MMF	4.12%	4.12%	3.91%	3.91%	3.90%	3.90%	3.89%	3.89%	3.84%	3.84%	3.83%	3.83%
4	Less: Paiute & SGTC Allocation	$ 2,284	$ 986	$ 1,383	$ 643	$ 9,666	$ 1,943	$ 8,527	$ 805	$ -	$ -	$ 9,113	$ 1,919
5	Relocation Expenses Before 4-Factor	$ 53,160	$ 22,954	$ 33,983	$ 15,797	$ 238,184	$ 47,887	$ 210,683	$ 19,895	$ -	$ -	$ 228,826	$ 48,181
6	Arizona 4-Factor Allocation	56.81%	56.81%	56.81%	56.81%	56.54%	56.54%	56.42%	56.42%	56.05%	56.05%	56.25%	56.25%
7	Adjustment Allocated to Arizona	$ 30,200	$ 13,040	$ 19,306	$ 8,974	$ 134,669	$ 27,075	$ 118,867	$ 11,225	$ -	$ -	$ 128,715	$ 27,102
8	Total Arizona Relocation Costs	$ 30,200	$ 13,040	$ 189,617	$ 42,118	$ 816,416	$ 89,295	$ 192,874	$ 25,625	$ 70,592	$ 34,338	$ 503,620	$ 89,622

Notes and Source

SWG response to data request STF 6.29 (a), (b), (c) and (f)

Please note, for illustrative purposes, commissions were shown separately; however commissions are included in the loss amounts.

II. Summary of Loss on Sale of Employee Homes

	Year	Total AZ	AZ Direct Acct 921	Corporate Before Allocation Acct 880
9	2006	$ 30,200	$ -	$ 55,444
10	2007	$ 189,617	$ 170,312	$ 35,366
11	2008	$ 816,416	$ 681,746	$ 247,851
12	2009	$ 192,874	$ 74,007	$ 219,210
13	2010	$ 70,592	$ 70,592	$ -
14	**Average**	**$ 259,940**	**$ 199,331**	**$ 111,574**
15	**Test Year**	**$ 503,620**	**$ 374,906**	**$ 237,939**
16	TY Vs Avg $	$ 243,680	$ 175,574	$ 126,365
17	TY Vs Avg %	194%	188%	213%
	TY compared with:			
18	2009 $	$ 310,746	$ 300,899	$ 18,729
19	%	261.1%	506.6%	108.5%
20	2010 $	$ 433,028	$ 304,313	$ 237,939
21	%	713.4%	531.1%	N/A

Southwest Gas Corporation
Test Year Rent Charged to Affiliate IntelliChoice Energy LLC

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule C-8

Line No.	Description	FERC Account	Amount	Reference
	Test Year Rent that should have been reimbursed by affiliate ICE			
1		908	$ (1,760)	SWG Response to STF-11-1(n)
2		931	$ (11,396)	SWG Response to STF-11-1(n)
3	Total		$ (13,156)	

Notes and Source

Per SWG's response to data requeset STF-11-1(n), due to a billing error, ICE was not billed for its portion of rent and utilities during the test year. SWG identified the amount of rent that was not reimbursed in that response. Those amounts are removed from test year expense.

Southwest Gas Corporation
Gas Heat Pump Development Expenses

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule C-9

Line No.	Description	Account	Total EETD Amount (A)	Total GHP Development Amount (B)	Arizona EETD Amount (C)	Arizona as Percent of Total EETD (D)
	Remove Gas Heat Pump Development Expenses					
1		908	$ 1,679,741	$ (1,091,832)	$ 906,220	53.95%
2		920	$ 13,611	$ (8,847)	$ 13,853	101.78%
3		921	$ 8,477	$ (5,510)	$ 4,585	54.09%
4		930.2	$ 250,000	$ (162,500)		
5		931	$ 64,015	$ (41,609)	$ 34,629	54.10%
6	Total O&M Expense		$ 2,015,843	$ (1,310,298)	$ 959,287	
7	Account 930.2		$ 250,000		$ 135,000	54.00%
8	Total Arizona EETD				$ 1,094,287	
9	Portion of EETD related to GHP development				65%	
10	Adjustment to Test Year O&M Expense				$ (711,287)	

Notes and Source

Col.A: SWG response to STF-11-1(b) and STF-11-21; see page 2 of this Schedule
Col.B: 65% of EETD expenses are for Gas Heat Pump development per SWG's response to STF-11-1
Col A x 65%
Col.C: SWG response to STF-11-21 provided Arizona amounts for Accounts 908, 920, 921 and 931
Line 7: Arizona allocation estimated at 54 percent
Col.D: Col.C / Col.A

Southwest Gas Corporation
Gas Heat Pump Development Expenses

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule C-9

Line No.	Account/Description	2008	2009	2010	TME 6/30/2010
	(a)	(b)	(c)	(d)	(e)
1	182.3	$ -	$ 731,681	$ 550,532	$ 336,626
2	426.5	56,384	83,696	38,491	27,307
3	908	1,799,610	1,817,865	1,974,948	1,679,741 [a]
4	920	44,246	92,303	-	13,611 [a]
5	921	2,805	13,321	427	8,477 [a]
6	930.2	-	250,000	250,000	250,000 [a]
7	931	66,799	63,603	69,028	64,015 [a]
8	Total EETD	$ 1,969,844	$ 3,052,469	$ 2,883,426	$ 2,379,775
9	Est. GHP%	85%	65%	65%	65% [a]
10	Alloc to GHP	$ 1,674,368	$ 1,984,105	$ 1,874,227	$ 1,546,854
11	Cumulative GHP Cost	1,674,368	3,658,472	5,532,699	
12	Estimated Arizona allocation	54%	54%	54%	
13	Estimated Cumulative AZ GHP Cost	$ 904,159	$ 1,975,575	$ 2,987,657	

Source

Lines 1-10: SWG response to data request STF-11-1(b)

Line 12: See page 1 of this Schedule and SWG response to STF-11-21

[a] See page 1 of this Schedule for operating expense adjustment to remove GHP development costs

Southwest Gas Corporation
Interest Synchronization

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule C-10

Line No.	Description		Amount	Reference
1	Adjusted rate base	$	1,070,115,558	Schedule B
2	Weighted cost of debt		3.98%	Schedule D
3	Synchronized interest deduction	$	42,571,123	Line 1 x Line 2
4	Synchronized interest deduction per Company	$	42,713,744	Note A
5	Difference (decreased) increased interest deduction	$	(142,621)	Line 3 - Line 4
6	Combined federal and state income tax rates		39.529%	Schedule A-1
7	Increase (decrease) to income tax expense	$	56,377	

Notes and Source

A SWG Schedule C-3, Sheet 2 of 3

Southwest Gas Corporation
Directors' and Officers' Liability Insurance

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule C-11

Line No.	Description		Arizona Direct (A)	System Allocable Before FERC Allocation (B)	FERC Allocation 3.83% (C)	System Allocable (D)	System Allocable To Arizona 56.25% (E)	Total (F)
	I. Company Test Year Recorded							
1	Reserve for Self Insurance	Note A	$ -	$ 1,428,590	$ (54,715)	$ 1,373,875	$ 772,805 c	$ 772,805
	II. Staff Recommended (50/50 Shareholder/Ratepayer Sharing)							
2	Staff Recommended	Note B		$ 714,295	$ (27,357)	$ 686,938	$ 386,403	$ 386,403
3	Staff Adjustment to SWG Request	L2 - L1		$ (714,295)			$ (386,402)	$ (386,402)

Notes and Source

A SWG's response to data request STF-1-72

B Allowance reflects 50/50 Shareholder/Ratepayer sharing of the D&O Liability Insurance Expense

Southwest Gas Corporation
Reserve for Self Insurance

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule C-12

Line No.	Description		Arizona Direct (A)	System Allocable Before FERC Allocation (B)	FERC Allocation 3.83% (C)	System Allocable (D)	System Allocable To Arizona 56.25% (E)	Total (F)
	I. Company Test Year Recorded							
1	Reserve for Self Insurance	Note A	$ 537,500	$ 275,000	$ (10,533)	$ 264,467	$ 148,763 c	$ 686,263
	II. Company Requested							
2	Reserve for Self Insurance	Note A	$ 834,961	$ 1,000,000	$ (38,300)	$ 961,700	$ 540,956	$ 1,375,917
3	Company proposed adjustment	Note A	$ 297,461	$ 725,000				$ 689,654
4	Percent increase over test year recorded amount	Note B	55.3%	263.6%				100.5%
	III. Staff Recommended							
5	Staff Recommended	Note C	$ 715,000	$ 150,000	$ (5,745)	$ 144,255	$ 81,143	$ 796,143
6	**Staff Adjustment to SWG Request**	Note D	**$ (119,961)**				**$ (459,813)**	**$ (579,774)**
6a	Staff Adjustment to SWG Request			$ (850,000)				
	IV. Staff Recommended Compared with Test Year Recorded							
7	Staff Recommended versus Test Year Recorded	Note E and F	33.0% E	-45.5% E				16.0% E
8	Staff Recommended increase from Test Year Recorded							$ 109,880

Notes and Source

A Derived from SWG filing, Schedule C-2, Company Adjustment No. 9
B Line 3 / Line 1
C See page 2 of this schedule for details of Staff recommended normalized amount for self-insured expense.
D Line 5 - Line 2
E (Line 5 / Line 1) - 1
F Staff recommended compared with ten-year average excluding May 2005 extreme event

9	Ten Year Average	Page 2	$ 713,828	$ 57,450
10	(Line 5 / Line 9) - 1		0.16% F	161.10% F

Southwest Gas Corporation
Injuries and Damages, Account 925
Reserve for Self-Insurance Expense Normalization
Test Year Ended June 30, 2010

Line No.	Description	Year	Total Expense Recorded Arizona (A)	Total Expense Recorded Common (B)	Total Expense Recorded Without Extreme Expense from May 2005 Leaking Gas Line Fire Arizona (C)	Total Expense Recorded Without Extreme Expense from May 2005 Leaking Gas Line Fire Common (D)	Staff Proposed Arizona (E)	Staff Proposed Common (F)
	Reserve for Self-Insurance Expense							
1		2001	$ 426,955	$ 100,000	$ 426,955	$ 100,000		
2		2002	$ 350,000	$ 200,000	$ 350,000	$ 200,000		
3		2003	$ 1,941,509	$ (300,000)	$ 1,941,509	$ (300,000)		
4		2004	$ 2,154,000	$ 275,000	$ 2,154,000	$ 275,000		
5		2005	$ 1,360,224	$ 10,367,500 a	$ 1,360,224			
6		2006	$ (975,540)	$ 200,000	$ (975,540)	$ 200,000		
7		2007	$ 713,629	$ (25,500)	$ 713,629	$ (25,500)		
8		2008	$ 230,000	$ (300,000)	$ 230,000	$ (300,000)		
9		2009	$ 400,000	$ 275,000	$ 400,000	$ 275,000		
10		2010	$ 537,500	$ 150,000	$ 537,500	$ 150,000		
11	Total, 2001 through TYE 6/30/2010		$ 7,138,277	$ 10,942,000	$ 7,138,277	$ 574,500		
12	Ten Year Average		$ 713,828	$ 1,094,200	$ 713,828	$ 57,450	$ 715,000 b	$ 150,000 c
13	Pauite allocation	3.83%		$ (41,960)		$ (2,203)		$ (5,752)
14	Common before AZ allocation			$ 1,052,240		$ 55,247		$ 144,248
15	AZ allocation	56.25%		$ 591,885		$ 31,076		$ 81,140
16	AZ allocated and direct		$ 713,828	$ 591,885	$ 713,828	$ 31,076	$ 715,000	$ 81,140
	Adjustment to Southwest Proposed as Filed							
17	Southwest Gas proposed:							
	Page 1, line 2, Cols.A and E, respectively		$ 834,961	$ 540,956	$ 834,961	$ 540,956	$ 834,961	$ 540,956
18	Adjustment to SWG Proposed As Filed,							
	Based on Ten-Year Average		$ (121,133)	$ 50,929	$ (121,133)	$ (509,880)	$ (119,961)	$ (459,816)
19	Net adjustment to Arizona expense			$ (70,204)		$ (631,013)		$ (579,777)
				L.21, Col.A&B		L.21, Col.C&D		L.21, Col.E&F

Notes and Source

L 1-9: SWG's response to STF-6-12

L1-6: Also see, Staff Attachment RCS-2, Schedule C-12, from SWG's last rate case, Docket No. G-01551A-07-0504

L7-9: Also see, Company's response to STF-1-71, Reserve for Self Insurance, Account 92500001

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-6.12

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) from Docket No. G-01551A-07-0504

b Ten-Year Average, rounded up to nearest $5,000

c Calendar 2010 accrual used as reasonably representative; note this amount exceeds the 10-year average, excluding the impact of the abnormal and extreme payout relating to the May 2005 leaking gas line fire.

Southwest Gas Corporation
Leased Aircraft Operating Costs

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule C-13

Line No.	Description	Amount (A)	Reference
	Normalize Leased Aircraft Expense Allocated to Arizona		
1	Normalized expense	$ 298,000	See line 16, below
2	Test year expense	$ 472,261	Note A
3	Adjustment to test year expense	$ (174,261)	Line 2 - Line 1
4	Remove Depreciation Expense on Corporate Aircraft	$ (19,632)	Response to STF 7.9
5	Total Adjustment to Operating Expenses	$ (193,893)	

Notes and Source

A Prior year amounts are from SWG's response to STF-10-26 in Docket No. G-0551A-07-0504.

	Account	2004 (B)	2005 (C)	2006 (D)	2007 (E)	Average (F)	Test Year [Note A] (G)	Percent Increase (H)
4	908				$ 1,800	$ 450	$ 3,545	688%
5	920	$ 208,306	$ 220,273	$ 259,841	$ 231,208	$ 229,907	$ 300,159	31%
6	921	$ 181,231	$ 225,338	$ 216,448	$ 193,086	$ 204,026	$ 232,453	14%
7	925						$ 22,713	n/a
8	930.2	$ 28,500	$ 42,210	$ 53,300	$ 35,950	$ 39,990	$ 43,005	8%
9	931	$ 24,101	$ 27,026	$ 24,049	$ 25,134	$ 25,078	$ 271,180	981%
10	935	$ 679	$ 924	$ 4,297		$ 1,475		n/a
11	Totals	$ 442,817	$ 515,771	$ 557,935	$ 487,178	$ 500,926	$ 873,055	74%
12	Allocation to Paiute Pipeline				3.83%	$ (19,210)	$ (33,480)	
13	Aircraft Expense Net of PP/SGTC					$ 481,716	$ 839,575	74%
14	Arizona allocation factor and normalized leased aircraft expense				56.25%	$ 270,965	$ 472,261	74%
15	Limit increase to 10 percent					1.10		
16	Recommended normalized allowance, rounded to nearest $1,000					$ 298,000	$ 472,261	58%

A	Response to STF 7.9			
B	Compare: Normalized amount allowed from Docket No. G-0551A-07-0504 Testimony of Staff witness Ralph Smith, Attachment RCS-2, Schedule C-13	$ 272,533	$ 472,261	73%

Southwest Gas Corporation
COYL Leak Detection Survey

Test Year Ended June 30, 2010

Docket No. G-01551A-10-0458
Schedule C-14

Line No.	Description	Cost for COYL Leak Detection Survey	Reference
1	Estimate for COYL leak detection survey	$ 3,000,000	Note A
2	Period, in years	3	Interval between SWG Arizona rate cases
3	Annual allowance for COYL leak detection survey	$ 1,000,000	

Notes and Source

[A] See testimony of Staff witness Frye for the recommendation concerning the COYL leak detection survey
Estimate is from Southwest's response to data request STF-20-3

Southwest Gas Corporation
Docket No. G-01551A-10-0458
Attachment RCS-3
Copies of SWG's Responses to Data Requests
and Workpapers Referenced in the Direct Testimony and Schedules of
Ralph C. Smith

Data Request/ Workpaper No.	Subject	Confidential	No. of Pages	Page No.
ACC-STF-6-7	Completed Construction Not Classified - removal of SCADA system not placed into service (without Attachment b)	No	4	2 - 5
ACC-STF-1-26	ADIT - 50% Bonus Depreciation	No	2	6 - 7
ACC-STF-6-9	Removal of 50% of Directors and Officers' Liability Insurance	No	2	8 - 9
ACC-STF-6-1	Changes made to MIP	No	3	10 - 12
ACC-STF-11-10 (a)	Calculation of MIP for 2009-2001 (only Attachment A is included)	No	2	13 - 14
ACC-STF-1-50	Employee Benefits - Retirement and Incentive Programs	No	16	15 - 30
ACC-STF-1-92	Deviations from prior Commission Orders	No	1	31
ACC-STF-1-56	Pro Forma deviations from prior Commission orders	No	1	32
ACC-STF-1-57	Company affirmation of including MIP and SERP in filing contrary to Commission orders	No	1	33
ACC-STF-17-2	MIP and other incentive compensation - 2008-2010 jurisdictional amounts	No	2	34 - 35
ACC-STF-6-4	SERP expense and actuarial study	No	14	36 - 49
ACC-STF-6-2	Changes have not been made to SERP since last rate case	No	1	50
ACC-STF-6-21	AGA Dues - budget and financial information for 2008-2011	No	8	51 - 58
	Excerpts from NARUC-sponsered Audits of the Expenditures of the American Gas Association	No	10	59 - 68
	Excerpt from Florida PSC City Gas Company rate case, Docket No. 030569-GU on AGA Dues	No	3	69 - 71
ACC-STF-6-29	Relocation expense for losses associated with sale of employee homes	No	3	72 - 74
ACC-STF-11-21	Southwest Gas Energy Efficient Technology - Removal of GHP development cost from test year operating expenses	No	5	75 - 79
ACC-STF-1-98	Research and Development projects	No	28	80 - 107
ACC-STF-7-17	ICE charges and how they are treated for ratemaking purposes	No	3	108 - 110
ACC-STF-6-12	Computation of Injuries and Damages allowance	No	3	111 - 113
ACC-STF-20-3	Estimate of annual cost to conduct a leak survey of all COYLs	No	1	114
ACC-STF-16-7	COYL Replacement expense	No	2	115 - 116
ACC-STF-16-8	COYL Replacement - cost for years 2006-2010	No	1	117
ACC-STF-16-6 Corrected	COYL - SWG cost related to replacement of COYL for periods between June 30, 2010 and December 31, 2011	No	1	118
ACC-STF-7-13	Rate case filing cycle plans (without confidential attachment)	No	1	119
ACC-STF-1-5	SWG's last complete depreciation study (without voluminous attachments)	No	1	120
ACC-STF-16-1	Yuma Manors - calculation of plant, accumulated depreciation, property tax, and depreciation expense	No	2	121 - 122
ACC-STF-16-3	Completed Construction Not Classified correction to property tax and depreciation expense	No	1	123
ACC-STF-16-2	SCADA - removal affect on property tax and depreciation and amortization expense	No	1	124
ACC-STF-1-83	Service Planning Quality Award and Key Account Management Incentive Plan documents; 2008-2010 expenses for all incentive programs.	No	17	125 - 141
ACC-STF-17-1	Calculation of SERP allocation to Arizona	No	2	142 - 143
	SWG's response to STF-6-52 from Southwest Gas Docket No. G-01551A-07-0504 regarding AGA Dues	No	2	144 - 145
	SWG's response to STF-6-50(b) from Southwest Gas Docket No. G-01551A-07-0504 regarding AGA Dues	No	2	146 - 147
ACC-STF-1-72	Itemization of insurance expense included in test year	No	2	148 - 149
ACC-STF-1-71	Injuries and Damages expense for 2007-2010	No	2	150 - 151
	SWG's response to STF-10-26 from Southwest Gas Docket No. G-01551A-07-0504 regarding Leased Aircraft	No	2	152 - 153
ACC-STF-7-9	Leased aircraft and aviation equipment expense	No	3	154 - 156
	Total Pages Including this Page		156	

499-007

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-6
(ACC-STF-6-1 to ACC-STF-6-41)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 23, 2011

Request No. ACC-STF-6-7:

Refer to Adjustment 17, Completed Construction Not Classified ("CCNC").

a. Was the entire $2,806,169 in service as of June 30, 2010? If not, explain fully why not and identify all components and the related dollar amounts that were not in service as of that date.

b. Provide an itemization of the specific assets included in each of the following accounts:

   1) Computer Equipment, account 391.1

   2) Tools, Shop and Garage Equipment, account 394.0

c. Has all of the $2,806,169 been closed to Plant in Service by 12/31/2010? If not, explain fully why not and identify all components that have not been closed to plant in service by that date.

d. For purposes of computing 2009 bonus income tax depreciation, show in detail how the $2,806,169 CCNC was treated and reflected in SWG's rate filing. Include supporting workpapers.

Respondent: Revenue Requirements

"

"

"

"

Response:

A. The Company considers the facilities constructed through the work orders that make up Adjustment No. 17, reduced to $2,695,762 (please refer to response to Item C below), to be in-service and serving customers at the end of the test year June 2010. $2,525,939 (Workpaper B-2, Adj. 17, Sheet 1, Lines 4-9), or 90% of the adjustment relates to either pipe replacement or pressure reinforcement. The dollars recorded at June 2010 represents the cost of pipe that was delivering gas to customers at the end of the test year. Many of the work orders included in the CCNC adjustment were designed to accumulate the cost of replacing additional pipe which takes place after the test year. The attached schedule shows that the 38 work orders that the Company is now including in its CCNC adjustment were designed to receive $8,663,971 of charges. As of June 2010 these work orders were charged $2,695,762. The Company did not include these additional costs in Adjustment No. 17. The $160,124 of general plant included in Adjustment No. 17 represents plant that was acquired and serving the customer at the end of the test year, but were not closed on a timely basis. Please also refer to the response to item B.

B. Attached is the detail of the assets acquired as result of the two work orders included in Adjustment No. 17 Account 391.1 and the two workorders in Account 394.0. All assets were acquired as of June 2010.

C. Attached is a schedule that lists the in-service date of the work orders included in the CCNC adjustment. There are two work orders that have not closed and should be removed from the Company's original adjustment. The original $2,806,169 should be $2,695,762.

D. The Company's response to Staff Data Request No. ACC-STF-1-26 calculates the bonus depreciation January to August 2010 (50%) and September to December 2010 (100%) related to the $2,771,114. The deferred tax resulting from these plant additions was $704,030. In preparing this application, it was believed that the $704,030 was included in the $5,362,740 direct Arizona deferred tax adjustment to the Account 282, Accumulated Deferred Income Taxes. Schedule B-6, Sheet 3 of 3, Line 4, Col. (c) shows a balance of $210,794,189 which consists of the balance recorded at June 2010 of $205,431,448 and the $5,362,740 adjustment. In preparing the response to this data request, it came to the Company's attention that the $704,030 was not included. The Company's Schedule B-6, Sheet 3 of 3, Line 4, Col. (c) should be increased by $704,030 to $211,498,218. This correction is needed only if the Commission accepts the Company's adjusted proposed $2,771,114 CCNC Adjustment No. 17.

Schedule B-6, Sheet 3 of 3, Line 7 col. (c) shows $15,583,217 which is comprised of the balance per books of $14,936,004 and the $647,213 bonus depreciation adjustment shown in the attachments to Staff Data Request No. ACC-STF-1-26. This adjustment reflected the impact of bonus depreciation related to plant additions from January through June 2010. Not reflected was the impact of bonus depreciation on the Corporate CCNC reflected in Adjustment No. 17. Schedule B-6, Sheet 3 of 3, Line 7, Col. (c) should be increased by $1,085,609 to $16,668,826 which is an amount before allocation to Arizona. Again, this adjustment is only appropriate if the $4,139,131 adjusted CCNC Adjustment No. 17, is accepted by the Commission.

The Company is removing the $1,700,000 cost of the SCADA system originally included in Adjustment 17 in System Allocable Account 303. There was no deferred tax associated with this project included in this application, therefore, no adjustment to deferred taxes related to the removal of this project is required.

This response supplements the response to Staff Data Request No. ACC-STF-1-26, and a notice of correction of errors contemplated in Staff Data Request No. ACC-STF-1-54.

SOUTHWEST GAS CORPORATION
ARIZONA
COMPLETED CONSTRUCTION NOT CLASSIFIED TO PLANT IN-SERVICE
CWIP BALANCE AT JUNE 30, 2010
RESPONSE TO STAFF DATA REQUEST NO 6-7(A)

Line No.	Work Order Number [1]	FERC Account	BI No.	Work Order Description	Filed - Includes all Projects	Revised - Removed Two Projects	Original Estimate on Project	Transfer Date	In-Service Date at 3-31-2011
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	0036-C8526424	376	9604	FN: TWIN PEAKS JOINT TRENCH IN	$ 62,917	$ 62,917	$ 36,841	07/2010	7/16/2010
2	0036-C8527535	376	9604	FN: TWIN PEAKS & SANTA CRUZ RI	48,576	48,576	182,431	07/2010	7/15/2010
3	0036-W1166792	376	9604	FN:WRIGHTSTOWN AND HARRISON CU	81,631	81,631	66,204	07/2010	7/14/2010
4	0036-W1162974	376	9604	FN: MAGEE ROAD - ORACLE ROAD T	43,933	43,933	74,369	08/2010	9/17/2010
5	0042-W1027502	376	9604	FRE SCOT PIMA RD IMPROVEMENTS	60,023	60,023	123,975	07/2010	7/13/2010
6	0046-W0943131	376	9604	FRAN JESSE HAYES MAIN REPLACEM	78,677	78,677	79,224	07/2010	4/15/2010
7	**TOTAL BUDGET ITEM - 9604: Mains - Franchise Requirements**				$ 375,756	$ 375,756	$ 563,043		
8	0036-W1013692	376	9605	HDRP (2010) - ATLAS 0378 PHI	$ 66,611	$ 66,611	$ 452,900	10/2010	9/20/2010
9	0036-W1015125	376	9605	HDRP (2010) ATLAS 0316	181,067	181,067	685,305	01/2011	10/8/2010
10	0036-W1015362	376	9605	HDRP (2010) - ATLAS 0546	55,917	55,917	95,519	07/2010	6/30/2010
11	0036-W1015367	376	9605	HDRP (2010) - ATLAS 0324	43,027	43,027	698,068	01/2011	11/15/2010
12	0036-W1015372	376	9605	HDRP (2010) - ATLAS 0091	74,132	74,132	125,873	10/2010	5/11/2010
13	0036-W1033500	376	9605	HDRP (2010) - ATLAS 0314	24,132	24,132	220,863	10/2010	8/16/2010
14	0036-W1033502	376	9605	HDRP (2010) - ATLAS 0078	30,714	30,714	73,252	10/2010	7/22/2010
15	0036-W1036507	376	9605	SI - EL MORAGA MAIN REPLACEMEN	25,939	25,939	20,338	01/2011	1/14/2011
16	0036-W1084375	376	9605	HDRP (2010) - ATLAS 0378 PHII	26,378	26,378	676,989	10/2010	9/20/2010
17	0036-W1089739	376	9605	HDRP (RSRP) - ATLAS 0339	66,587	66,587	63,967	07/2010	7/19/2010
18	0036-W1122904	376	9605	IARP-ISOLATION AREA 123, 306,	35,055	-	-	-	-
19	0036-W1140931	376	9605	SI-MARYVALE MANOR STEEL REPLAC	37,720	37,720	264,108	07/2010	6/28/2010
20	0036-W1141832	376	9605	RPLC (2010) - ATLAS 0347 PHASE	101,783	101,783	98,700	07/2010	7/26/2010
21	0036-W1151150	376	9605	HDRP (RSRP) - ATLAS 0575 S&P E	25,584	25,584	30,182	07/2010	7/19/2010
22	0036-W1151915	376	9605	SI-GREEN VALLEY ABS REPLACEMEN	47,351	47,351	165,282	10/2010	10/11/2010
23	0036-W1169927	376	9605	HDRP (2010) - ATLAS 0113 PHII	67,397	67,397	442,774	10/2010	8/25/2010
24	0042-W1000572	376	9605	CITY SCAPE	63,337	63,337	53,761	07/2010	6/24/2010
25	0042-C7527275	376	9605	SPE-2010 PVC MAIN REPLACEMENT	162,788	162,788	1,059,478	12/2010	11/3/2010
26	0046-W1036763	376	9605	SI BOSTON ST. & HIGHLAND DR. S	58,056	58,056	94,591	07/2010	7/8/2010
27	**TOTAL BUDGET ITEM - 9605: Main Replacements**				$ 1,193,575	$ 1,158,520	$ 5,321,950		
28	0036-C8526474	376	9606	SI: I-10 CROSSING & TIFFANY LO	$ 87,498	$ 87,498	$ 98,767	07/2010	7/15/2010
29	0036-C8527415	376	9606	SI: LINDA VISTA & CMO DE MANAN	44,924	44,924	107,733	08/2010	8/5/2010
30	0042-C7524036	376	9606	PRASADA HIGH PRESSURE REINF	482,641	482,641	1,967,056	10/2010	9/16/2010
31	0042-W1067233	376	9606	SPE-HUNT HWY & ATTAWAY RD 6" M	108,591	108,591	84,575	07/2010	6/30/2010
32	**TOTAL BUDGET ITEM - 9606: Main - Pressure Reinforcement**				$ 723,653	$ 723,653	$ 2,258,130		
33	0042-C8524811	378	9607	PRASADA REGULATOR STATION	$ 36,874	$ 36,874	$ 69,775	10/2010	9/16/2010
34	0042-W1131431	378	9607	SPE-DR #424360 REPLACEMENT	31,796	31,796	116,504	10/2010	9/18/2010
35	**TOTAL BUDGET ITEM - 9607: Measuring and Regulating Station Equipment**				$ 68,669	$ 68,669	$ 186,279		
36	0046-W1150609	380	9609	RENEWAL OF CITY OF YUMA FRANCH	$ 51,437	$ 51,437	$ 51,437	07/2010	7/20/2010
37	**TOTAL BUDGET ITEM - 9609: Service Replacements**				$ 51,437	$ 51,437	$ 51,437		
38	0042-W1138058	376	9611	INSTALL RECTIFIER / SAE GROUND	$ 63,438	$ 63,438	$ 69,021	07/2010	5/7/2010
39	0042-W1155395	376	9611	REPLACE GROUNDBED - DEPLETED	60,889	60,889	43,180	07/2010	4/22/2010
40	0042-W1167888	376	9611	REPLACEGROUNDBED - DEPLETED RE	33,276	33,276	42,154	07/2010	5/21/2010
41	**TOTAL BUDGET ITEM - 9611: Mains - Cathodic Protection**				$ 157,602	$ 157,602	$ 154,355		
42	0042-W1001926	376	9635	SPW - TRANSMISSION MAIN VALVE	$ 75,353	$ -	$ -	-	-
43	**TOTAL BUDGET ITEM - 9635: High Pressure Distribution Mains**				$ 75,353	$ -	$ -		
44	0042-W1155080	394	9709	43RD OPS ABOVE GROUND HOIST	$ 50,199	$ 50,199	$ 50,199	07/2010	7/15/2010
45	0042-W1137825	394	9709	PURCHASE REGENT HYDRAULIC STEE	36,748	36,748	22,650	08/2010	8/16/2010
46	**TOTAL BUDGET ITEM - 9709: Tools, Shop and Garage Equipment**				$ 86,947	$ 86,947	$ 72,849		
47	0042-W0000306	391.1	9715	Line Matrix Printer Repic	$ 40,563	$ 40,563	$ 16,300	07/2010	7/26/2010
48	0042-W0000407	391.1	9715	Server Replacements - 6	32,614	32,614	39,627	08/2010	8/16/2010
49	**TOTAL BUDGET ITEM - 9715: Computer Equipment**				$ 73,177	$ 73,177	$ 55,927		
50	**TOTAL ARIZONA DOLLARS**				$ 2,806,169	$ 2,695,762	$ 8,663,971		
51	**TOTAL ARIZONA WORK ORDERS**				40	38	38		

491-026

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 to ACC-STF-1-107)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 11, 2011

Request No. ACC-STF-1-26:

Accumulated Deferred Income Taxes. Please show in detail how the Company reflected 50 percent bonus depreciation on all qualifying assets placed in to service from January 1 through June 30, 2010. If this was not reflected in the Company's filing, explain fully why not and provide calculations quantifying the adjustment necessary to reflect it.

Respondent: Corporate Tax

Response:

This adjustment is reflected in the Company's filing. Please refer to the attached spreadsheet for the detail of how the Company reflected the 50 percent bonus depreciation adjustment on all qualifying assets placed into service from January 1 through June 30, 2010 for both Arizona and Common.

ARIZONA CORPORATION COMMISSION
STAFF'S FIRST SET OF DATA REQUESTS TO SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-10-0458
RESPONSE TO STF 1.26

Arizona

Federal Tax Depreciation - 1/1/10-6/30/10		46,978,160
Accum Book Depreciation - 6/30/10	886,327,699	
Accum Book Depreciation - 12/31/09	851,193,683	
Book Reserve - 1/1/10-6/30/10		35,134,016
Book/Tax Difference - 1/1/10-6/30/10		11,844,144
Tax Rate		35%
2820 2105 Activity 1/1/10- 6/30/10 - Before So Ga		(4,145,450)
South Georgia Adjustment		(145,057)
2820 2105 Activity 1/1/10- 6/30/10		(4,290,507)
2820 2105 Balance at 12/31/09 - Per G/L		(206,503,681)
Adjusted 2820 2105 Balance at 6/30/10		(210,794,188)
2820 2105 Balance at 6/30/10 - Per G/L		(205,431,448)
2820 2105 Bonus Depreciation Adjustment at 6/30/10		(5,362,740)

Note 1: Schedule B-6, Sheet 3 of 3, Line 4 Col. (b)

Common

Federal Tax Depreciation - 1/1/10-6/30/10		3,754,017
Accum Book Depreciation - 6/30/10	122,445,201	
Accum Book Depreciation - 12/31/09	118,788,495	
Book Reserve - 1/1/10-6/30/10		3,656,706
Book/Tax Difference - 1/1/10-6/30/10		97,311
Tax Rate		35%
2820 2105 Activity 1/1/10- 6/30/10 - Before So Ga		(34,059)
South Georgia Adjustment		-
2820 2105 Activity 1/1/10- 6/30/10		(34,059)
2820 2105 Balance at 12/31/09 - Per G/L		(15,549,158)
Adjusted 2820 2105 Balance at 6/30/10		(15,583,217)
2820 2105 Balance at 6/30/10 - Per G/L		(14,936,004)
2820 2105 Bonus Depreciation Adjustment at 6/30/10		(647,213)

Note 1: Schedule B-6, Sheet 3 of 3, Line 7 Col. (b)

499-009

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-6
(ACC-STF-6-1 to ACC-STF-6-41)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 23, 2011

Request No. ACC-STF-6-9:

Directors and Officers' Liability Insurance expense.

a. Has Southwest included any prepaid Directors and Officers' Liability Insurance expense in its proposed operating expenses? If so, please identify the amount, by account.

b. Was 50% of Southwest's Directors and Officers' Liability Insurance expense disallowed in Southwest's most recent Nevada rate case, Docket No. 09-04003? If so, please explain fully Southwest's understanding of why that disallowance was made.

c. Has Southwest included any prepaid Directors and Officers' Liability Insurance cost in its proposed rate base? If so, please identify the amount, by account.

d. Was 50% of Southwest's Directors and Officers' Liability Insurance prepaid expense disallowed from rate base in Southwest's most recent Nevada rate case, Docket No. 09-04003? If so, please explain fully Southwest's understanding of why that disallowance was made.

Respondent: Revenue Requirements

Response:

a. Prepaid D&O expense is not included in operating expenses; it is included in prepayments and the 13-month average of the prepayment balance is a component of rate base. Prepaid D&O is charged to Account 165 when the insurance premiums are paid, and the prepaid balance is amortized monthly to Account 925. Please also refer to response to ACC-STF-1-72 for the amount of D&O expense included in Account 925 for the test year.

b. Yes, the Public Utilities Commission of Nevada (PUCN) allowed Southwest Gas to recover 50 percent of D&O insurance expenses. The D&O issue was addressed in the Order in Docket No. 09-04003, provided in response to ACC-STF-2-14, on pages 46-48. Southwest's understanding of the PUCN's rationale is limited to the wording contained in the Order.

c. Yes, prepaid D&O expenses are a component of rate base in Account 165. The amount included in the test year prior to allocation to Arizona is $658,144, and after 4-Factor the amount allocated to Arizona is $370,193.

d. Yes, the rate base related to the 13-month average of the D&O prepayment balance received the same ratemaking treatment from the PUCN as D&O expense.

499-001

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-6
(ACC-STF-6-1 to ACC-STF-6-41)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 23, 2011

Request No. ACC-STF-6-1:

Identify and fully explain all changes Southwest Gas has made to its Management Incentive Program (MIP) incentive compensation program since the test year utilized in SWG's last rate case, Docket No. G-01551A-07-0504.

Respondent: Human Resources

Response:

Please refer to the attached document.

ARIZONA GENERAL RATE CASE
DATA REQUEST NO. STF 6.1
MANAGEMENT INCENTIVE PLAN CHANGES

Southwest Gas Corporation (SWG) has made two modifications to the Management Incentive Plan (MIP) since the end of the test year (April 30, 2007) in the Company's last rate case affecting the performance measures and participant eligibility.

1. PERFORMANCE MEASURE CHANGES

The performance measures of the variable at-risk MIP were evaluated and modified in 2008, replacing five performance measures with four.

The MIP is variable compensation at-risk each year based on the performance relative to four measures that define the goals and benchmarks of the MIP, all designed to align the interests of customers, SWG management and shareholders. The measures are: (1) customer satisfaction; (2) customer-to-employee ratio; (3) return on equity; and (4) operating costs.

Customer Satisfaction

The customer satisfaction performance measure is a standard measure of performance in the utility industry and SWG is an industry leader in this area. SWG routinely performs in the low-to-mid 90's under this metric. Performance is currently measured monthly by an independent third-party, and the process is periodically audited by the SWG Internal Audit department. The target for this measure is set at 85 percent and is measured individually for each SWG operating division. This measure is a direct representation of the quality and efficiency of the service provided to SWG customers.

The customer satisfaction metric measures the quality, efficiency and reliability of service provided to SWG customers by capturing satisfaction levels of customers following recent contact with SWG. The goal of this metric is to maintain and enhance the customer experience by developing a solid service relationship upon which customers can depend. The information collected through the tracking program provides management with a tool to improve customer satisfaction and provides awareness of areas which may need attention while further solidifying an efficient and dependable customer service relationship.

Customer-to-Employee Ratio

The customer-to-employee ratio performance measure compares the actual prior year customer-to-employee ratio to an established benchmark. This is a standard productivity measure in the utility industry. Labor costs plus loadings represent nearly two-thirds of SWGs' total operations and maintenance expense. The SWG customer-to-employee ratio has shown consistent improvement during the past 10 years.

The customer-to-employee ratio illustrates a company's ability to operate efficiently. Therefore, a favorable customer-to-employee ratio indicates that a company is achieving increased efficiencies while at the same time controlling labor costs. The executive management team at SWG takes a hands-on approach to managing employee headcount, which includes reduction through attrition, detailed reviews of position requests and challenging employees to develop and embrace change (including technological advances) that yields higher productivity.

Return on Equity (ROE)

The ROE performance measure considers the authorized weighted average ROE of the returns utilized to establish rates in each of the regulatory jurisdictions in which SWG operates and is theoretically the ROE that SWG should be able to achieve on a company-wide basis. Over the last 10 years, SWG has experienced an actual average ROE of 6.9 percent, compared to an averaged authorized weighted average ROE of 10.8 percent for the same period. The target for this measure represents 80 percent of the company-wide authorized weighted-average ROE.

ROE is the total measure of SWG's performance and annually measures SWG's ability to manage costs. Indeed, SWG must judiciously manage costs in order to maximize earnings (ROE), which, in turn, benefits customers by minimizing rate increases.

Operating Costs

The operating costs performance measure quantifies management effectiveness in controlling operation and maintenance costs. The use of the rolling 10-year average used in prior years was replaced with a target that reflects estimated inflation and a growth factor. The inflation factor is determined by the Blue Chip Economic Indicators publication and the growth factor is based on customer growth.

As previously noted, the operating costs performance measure quantifies management effectiveness in controlling operating costs. The target for this measure is based on productivity efficiencies and is dependent upon management to act prudently to support cost containment, which, in turn, benefits customers by providing a reasonable cost of service.

2. TIER STRUCTURE CHANGES

The second modification to the MIP became effective in 2009 following approval by both SWG's Compensation Committee and Board of Directors. This change included increasing the eligibility threshold for the Non-Officer (30 percent) tier and creating a level for Technical Managers (10 percent tier).

The table below compares the previous and current MIP participant tier structure.

Position	Previous	Current [1]
CEO	115%	115%
President	100%	100%
Executive Officers	90%	90%
Sr Officers	75%	75%
Officers	50%	50%
Non-Officers [2]	30%	30%
Technical Managers [3]		10%

[1] Effective beginning in the 2009 plan year
[2] Eligibility threshold increased to positions with 775 Hay Points versus 700 Hay Points
[3] New tier added for Technical Managers, encompassing positions between 677 and 774 Hay Points

504-010

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-11
(ACC-STF-11-1 to ACC-STF-11-23)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: APRIL 8, 2011

Request No. ACC-STF-11-10:

Refer to the 11/15/2010 Compensation Committee meeting minutes, Exhibit A.

a. Please show in detail how each of the MIP figures for 2009, 2010 and 2011 listed there were derived. Include supporting calculations.

b. Are the 2009 and 2010 MIP criteria figures shown there based on actual results? If not, please provide MIP 2009 and 2010 actual results for each MIP performance measure and show in detail how such actual results were derived.

Respondent: Human Resources

Response:

a. Annually, the Compensation Committee* (Committee) of the Board of Directors reviews historical and forecasted data relevant to the four MIP performance measures (Return on Equity, Customer Satisfaction, Customer-to-Employee ratio and Operating Costs) and is responsible for setting the targets for each measure.

   As discussed in the Proxy Statements issued annually, the mix of performance measures and their respective targets are designed to address the interests of both customers and shareholders through the Company's financial performance, increased productivity and customer satisfaction.

   Please also refer to ACC-STF-11-10 Attachment A for supporting calculations.

b. Please refer to ACC-STF-11-10 Attachment B for supporting calculations of actual results for 2009 and 2010.

*The Board members who served on the Compensation Committee during 2009 and 2010 have never been an officer or employee of the Company or any of its subsidiaries. No member of the Compensation Committee had any relationship requiring disclosure under any paragraph of Item 404 of Regulation S-K of the Exchange Act.

SOUTHWEST GAS CORPORATION
ARIZONA
DATA REQUEST NO. STF 11.10 (a)
MIP PERFORMANCE TARGET CALCULATIONS

Line No.	Description	2011	2010	2009	Line No.
		(a)	(b)	(c)	
	Return-on-Equity (ROE)				
1	Companywide Authorized Weighted Average ROE	10.18%	10.33%	10.30%	1
2	*Threshold (70% of Target)*	*5.70%*	*5.78%*	*5.77%*	2
3	*Target (80% of Line 1, Cols (a), (b), (c), respectively)*	*8.14%*	*8.26%*	*8.24%*	3
4	*Maximum (140% of Target)*	*11.40%*	*11.56%*	*11.54%*	4
	Customer Satsifcation				
	According to the American Customer Satisfaction Index, the industry benchmark is 74%				
5	*Threshold*	*75%*	*75%*	*75%*	5
6	*Target*	*85%*	*85%*	*85%*	6
7	*Maximum*	*95%*	*95%*	*95%*	7
	Operating Costs				
	Blue Chip Economic Indicators *(estimated 2011, actual 2010 and 2009)*				
8	Minimum	2.1%	2.6%	3.4%	8
9	Average	1.5%	1.9%	2.5%	9
10	Maximum	1.0%	1.3%	1.7%	10
11	Growth *(actual 2010, 2009)*		1.35%	1.5%	11
12	High	1.2%			12
13	Average	0.8%			13
14	Low	0.4%			14
15	*Threshold*	*3.30%* [1]	*3.95%* [4]	*4.90%* [7]	15
16	*Target*	*2.30%* [2]	*3.25%* [5]	*4.00%* [8]	16
17	*Maximum*	*1.40%* [3]	*2.65%* [6]	*3.20%* [9]	17
	Customer-to-Employee Ratio				
18	*Threshold*	*782* [14]	*743* [13]	*743* [10]	18
19	*Target*	*790* [15]	*754* [13]	*754* [11]	19
20	*Maximum*	*802* [16]	*762* [13]	*762* [12]	20

[1] Line 8 Col (a) + Line 12 Col (a)
[2] Line 9 Col (a) + Line 13 Col (a)
[3] Line 10 Col (a) + Line 14 Col (a)
[4] Line 8 Col (b) + Line 11 Col (b)
[5] Line 9 Col (b) + Line 11 Col (b)
[6] Line 10 Col (b) + Line 11 Col (b)
[7] Line 8 Col (c) + Line 11 Col (c)
[8] Line 9 Col (c) + Line 11 Col (c)
[9] Line 10 Col (c) + Line 11 Col (c)
[10] Actual 2008 ratio of 743 customers per employee
[11] 1.5% improvement over the actual 2008 ratio of 743 customers per employee
[12] 2.5% increase over the actual 2008 ratio of 743 customers per employee
[13] Unchanged from 2009 due to the slow growth environment
[14] Actual 2010 ratio of 782 customers per employee
[15] 1.0% improvement over the actual 2010 ratio of 782 customers per employee
[16] 2.5% increase over the actual 2010 ratio of 782 customers per employee

491-050

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 to ACC-STF-1-107)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 11, 2011

Request No. ACC-STF-1-50:

Employee Benefits.

a. List and describe all retirement and incentive programs available to Company officers and employees and to affiliate officers and employees whose cost is charged to SWG.

b. Specifically identify the cost of any SERP or similar programs directly charged or allocated.

c. State the cost by program, of each retirement program directly charged or allocated.

d. Provide the incentive compensation program financial performance goals for 2008, 2009 and 2010.

e. For each incentive compensation program goal, for each year, show the actual results and how it compared with the target.

f. Provide the incentive compensation program in effect in each year, 2008, 2009 and 2010.

g. Show in detail how any special recognition awards recorded in the test year were determined.

Respondent: Human Resources

Response:

a. List and describe all retirement and incentive programs available to Company officers and employees and to affiliate officers and employees whose cost is charged to SWG.

Note: Affiliate officers and employees are not eligible for the programs described below.

Pension and Supplemental Retirement Plan

Southwest Gas' non-contributory, Defined Benefit Retirement Plan ("DBRP"), is available to all employees of the Company. Benefits are based on an employee's years of service, up to a maximum of 30 years, and the 12-month average of the employee's highest five consecutive years salaries, excluding bonuses, within the final ten years of service. The Internal Revenue Service ("IRS") does place a limit on the amount of annual compensation that can be considered in determining benefits under the DBRP. For 2010, the maximum annual compensation amount was $245,000. In future years, the maximum annual compensation will be adjusted to reflect changes in the cost of living as established by the IRS.

Executives also participate in the Company's Supplemental Executive Retirement Plan ("SERP"). Benefits from the plan, when added to the benefits received under the basic retirement plan, will equal 60 percent of annual compensation for senior executives, and 50 percent of annual compensation for all other officers. Annual compensation is defined as the 12-month average of the highest 36 months of salary. Generally, officers must be at least 55 years of age with 20 or more years of service to receive retirement benefits. Some reductions may apply, depending on an officer's age and years of service at the date of retirement.

The SERP is an unqualified plan and, as such, payments are not guaranteed (i.e., participants are general creditors of the Company). SERP benefits are common in the utility industry and are a current practice among the majority of the Company's peer group.

Executive Deferral Plan

Under the Executive Deferral Plan ("EDP"), executives at the vice president level and above may defer up to 100 percent of their annual compensation and 100 percent of the cash portion of their variable at-risk compensation. As a part of the EDP, the Company provides matching contributions that parallel the contributions made under the Company's 401(k) plan, which is available to all employees, equal to one-half the deferred amount up to 7 percent of their annual salary. Payouts under the EDP begin six months after the retirement date based on pre-selected time periods or at some other employment terminating event. Interest on EDP deferrals and the matching contributions is accrued annually at 150 percent of the Moodys Seasoned Corporate Bond Rate.

The EDP is an unqualified plan and, as such, participant balances are not guaranteed (i.e., participants are general creditors of the Company and their contributions to this account are at risk). A deferred compensation plan is common in the utility industry and is a current practice among the majority of the Company's peer group.

Employees Investment Plan/401(k)

The Southwest Gas Corporation Employees' Investment Plan ("EIP") is a qualified defined contribution plan that provides a retirement savings mechanism by allowing tax-deferred contributions and the tax-deferred growth of earnings. As part of the plan, the Company provides matching contributions equal to one-half the deferred amount up to 7 percent of their annual salary. Employees control how savings are invested by investing in any of the investment options the EIP offers. Officers of the Company may invest in the EIP, but they are not eligible to receive a Company match under this plan.

Variable At-Risk Pay

Management Incentive Plan

The Management Incentive Plan ("MIP") provides variable at-risk compensation to executives and upper-level management based on specific goals and performance objectives vital to the Company's short and long-term success. The MIP is at-risk each year based on performance relative to four measures: customer satisfaction, customer-to-employee ratio, return on equity ("ROE"), and operating costs. Forty percent of the total award earned under the MIP is paid in cash immediately following the financial close of the most recent calendar year. The remaining 60 percent is issued as performance shares and vest three years in the future. The longer-term performance shares act as a retention tool while aligning the interests of customers, Company management, and shareholders for continued financial and customer-oriented performance.

The MIP is measured as a percentage of base salary and varies by title, as follows:

Position	
CEO	115%
President	100%
Executive VP	90%
Senior VP	75%
VP	50%
Non-Officers	
Director/Senior Manager	30%
Key Management Employees	10%

Each measurement has a threshold, a target and a maximum, and, at target, contributes 25 percent toward the total award for the year. An award under a specific criterion may be given within a range from 70 percent, at threshold, to 140 percent, at maximum. Performance below the threshold results in no award under a specific criterion. There is no incremental value for performance over the maximum for any of the four criteria. In summary, an award can range from 0 percent to 140 percent of the stated MIP opportunity. In any year where the corporate dividend is reduced, there is no MIP distribution.

Restricted Stock/Unit Plan

The second component of variable at-risk pay is the Restricted Stock/Unit Plan ("RSUP"), which in May 2007 replaced the Company's Stock Incentive Plan. The RSUP is designed for the purpose of enhancing the competitive position of the total direct compensation and to further align customer, management, and shareholder interests, while sustaining a strong commitment to the long-term financial success of the Company and further encouraging management with ownership of Company stock.

The RSUP is available to officers and other key management employees. The RSUP is measured as a percentage of year-end base salary and varies by title, as follows:

Position	% of Base Salary	% Value Range Distribution
CEO	45	22.5 to 67.5
President	30	15.0 to 45.0
Executive VP	25	12.5 to 37.5
Senior VP	20	10.0 to 30.0
VP	15	7.5 to 22.5
Other Participants	10	5.0 to 15.0

As a measurement of long-term sustained performance, the average MIP award over the three-year period ending before the award date is the criteria used to calculate awards for officers and key employees. Amounts granted pursuant to the RSUP range from 50 to 150 percent of the target for each participant. The minimum three-year average MIP percent of target achieved required to receive a distribution under the RSUP is 90 percent. The dollar amount of the award distributed under the RSUP is converted to restricted share units using the market price on the date such awards are approved by the Company's Board of Directors. The units vest over a three-year period with 40 percent for the first year and 30 percent for the second and third years.

Aspire

The Aspire program ("Aspire") provides management with a tool with which to reward and recognize exempt (salaried) employees whose accomplishments demonstrate improved productivity, significant cost savings, or enhanced business processes. Only exempt employees who do not qualify for the MIP are eligible.

To qualify, an employee must be recommended in writing by an officer of the Company. The nomination must both quantify and qualify the contributions made to Southwest Gas during the calendar year. All nominations are approved by senior management and the Company's Board of Directors. Awards range from $2,500 to $7,500 and are granted to individuals who go significantly above and beyond their job responsibilities with substantial contributions toward the overall betterment of Southwest Gas, as well as demonstrate dedication to the goals and philosophy of the Company.

Going the Extra Mile

In 2009, the Company's perfect attendance program, Constant Flame, was replaced with the Going the Extra Mile ("GEM") program. GEM is a performance-based recognition program designed to recognize non-exempt employees for high-quality, sustained performance that provides a significant contribution to the Company. Employees nominated are evaluated on five measures: productivity, customer service, innovation, leadership, and character. The nomination must both quantify and qualify the contributions made to Southwest Gas during the calendar year. All nominations are approved by senior management and the Company's Board of Directors. All non-exempt employees who have completed twelve months of service, without disciplinary actions, preventable personal injuries or vehicle accidents are eligible each year. The number of employees who may be recognized each year is limited to one hundred non-exempt employees Companywide. The number of awards allocated to each jurisdiction is determined by the number of non-exempt employees in that jurisdiction as a percent of the total non-exempt employee population companywide.

b. Specifically identify the cost of any SERP or similar programs directly charged or allocated.

The amount of SERP requested for recovery in this proceeding allocated to Arizona is approximately $1.65 million.

c. State the cost by program, of each retirement program directly charged or allocated.

The amounts requested for recovery in this proceeding allocated to Arizona for the following retirement programs are approximately:

DBRP (Pension): $15.1 million

EDP: $1.55 million

401K: $2.08 million

d. Provide the incentive compensation program financial performance goals for 2008, 2009 and 2010.

Please refer to the attached Excel spreadsheet.

e. For each incentive compensation program goal, for each year, show the actual results and how it compared with the target.

Please refer to the attached Excel spreadsheet.

f. Provide the incentive compensation program in effect in each year, 2008, 2009 and 2010.

A copy of the MIP brochure has been provided in response to this item.

g. Show in detail how any special recognition awards recorded in the test year were determined.

Please refer to the paragraphs in item (a) above describing the Aspire and GEM programs.

SOUTHWEST GAS CORPORATION
ARIZONA
DATA REQUEST NO. STF 1.50 (d) (e)
MANAGEMENT INCENTIVE PLAN ("MIP")
PERFORMANCE GOALS AND ACTUAL RESULTS

Measurement	Plan Year 2008	2009	2010
Return on Equity			
Actual	0.0%	7.64%	8.23%
Target	8.06%	8.24%	8.26%
Earned	0.0%	92.7%	99.6%
x 25% weight	0.0%	23.18%	24.91%
Customer-to-Employee Ratio			
Actual	743	753	782
Target	735	754	754
Earned	121.32%	97.28%	140.0%
x 25% weight	30.33%	24.32%	35.0%
Customer Satisfaction			
Actual	96.0%	94.0%	92.5%
Target	85.0%	85.0%	85.0%
Earned	140.0%	136.0%	130.0%
x 25% weight	35.0%	34.0%	32.5%
Operating Cost Containment			
Actual	3.6%	2.09%	2.02%
Target	4.78%	4.00%	3.25%
Earned	140.0%	140.0%	140.0%
x 25% weight	35.0%	35.0%	35.0%
Total Percent of Target	100%	116%	127%

SOUTHWEST GAS

Management Incentive Plan

GENERAL REMARKS

This document has been created to explain the concepts of the Southwest Gas Corporation (SWG), Management Incentive Plan (MIP), adopted by the Board of Directors in 1993 and revised in 2009. It is intended for use by employees included in the MIP.

Every attempt has been made to ensure that the MIP conforms to the latest rules and regulations of the Securities and Exchange Commission (SEC) and Internal Revenue Service (IRS). This booklet, however, should not be considered an official legal document. The official plan document is available in Corporate Human Resources and may be consulted for further information.

MIP participants should periodically check with their personal tax, accounting, or legal counsel about changes in regulations governing incentive programs, created through legislative actions, new or amended SEC regulations, and IRS and Tax Code interpretations. For information about tax savings, or the ramifications of participation in the plan, you should consult your tax professional.

This document reflects current federal income tax treatment (which may be subject to change in the future) and does not include state or local ramifications.

PURPOSE OF THE PROGRAM

The Company's MIP provides variable incentive-based compensation to executives for the achievement of specific goals and benchmarks important to both the short-term and long-term success of the Company. The MIP strives to achieve the following:

- To focus SWG management on the achievement of specific performance objectives important to the Company's short-term and long-term success
- To ensure that there is a strong link between Company performance and financial rewards for management.
- To foster a common interest between SWG management, customers and shareholders.
- To encourage management ownership of SWG stock.

ELEMENTS OF THE PROGRAM

Annual Incentive Award: The dollar amount awarded to a plan participant on the basis of SWG performance during the annual performance period. A portion of the award is payable in cash as soon as practicable following the end of the performance period. The remaining portion is converted into performance shares and subject to a restriction period.

Performance Shares: A contingent right to receive shares of common stock in SWG which are not to be distributed to the participant until and unless certain restrictions have lapsed.

Dividend Credits: Additional dollar amounts convertible into Performance Shares (during the restriction period) as determined by the cumulative quarterly dividends declared on Company common stock during the restriction period.

Note: Normally, annual incentive awards will be calculated and paid during the first quarter following the end of the plan year.

ELIGIBILITY AND SELECTION

Positions qualifying for participation in the MIP will be determined by SWG senior management and approved by the Compensation Committee of SWG's Board of Directors, hereafter referred to as the "Committee."

Generally speaking, award potential and/or guidelines will be determined separately for each eligible tier of SWG management. The tiers, their composition, and the guideline awards for each tier are subject to change from time to time.

Selection for participation in one year does not guarantee selection in succeeding years.

INCENTIVE AWARD OPPORTUNITIES

Individuals selected for participation in the MIP will be assigned incentive award opportunities, which are expressed as a percentage of their base salaries.

The incentive award opportunities include a targeted incentive award and a range around the target that corresponds to various levels of performance measured on a number of dimensions. Meeting the individual measurement goal at the expected target pays 100 percent of that measurement. The range for each individual measurement equals 70 percent at threshold and increases to 140 percent at maximum. Performance below threshold results in zero payout for the specific measure.

Target, threshold, or maximum incentive award opportunities for any tier are subject to change at the discretion of the Committee. The following table depicts the current targeted incentive award opportunity as a percentage of base salary, by tier of participant:

INCENTIVE AWARD OPPORTUNITY					
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1	CEO	0%	81%	115%	161%
2	President	0%	70%	100%	140%
3	Executive Officers	0%	63%	90%	126%
4	Senior Officers	0%	53%	75%	105%
5	Officers	0%	35%	50%	70%
6	Non-Officers	0%	21%	30%	42%
7	Other Key Employees	0%	7%	10%	14%

FREQUENCY

Incentive awards will be granted on an annual basis consistent with SWG's compensation philosophy and strategy, and taking into account the Company's overall competitive posture on all aspects of direct compensation.

ANNUAL INCENTIVE AWARD

Annual incentive awards will be provided to eligible participants in the plan each year if Company performance measures are achieved.

ANNUAL PERFORMANCE MEASURES

Each measurement has a threshold, target and maximum, and, at target, contributes 25 percent toward the total award for the year. An award under a specific criterion may be given within a range from 70 percent, at threshold, to 140 percent, at maximum. Performance below the threshold results in no award under the specific criteria. There is no incremental value for

performance over the maximum for any of the four criteria. An award can range from zero percent to 140 percent of the stated MIP opportunity. In any year where the corporate dividend is reduced, there is no MIP award given. For the purposes of determining the actual awards under the MIP, performance will be evaluated on several dimensions.

The annual performance measures, which are equally weighted, are as follows:

- Return on equity (ROE)
- Customer-to-employee ratio
- Customer service satisfaction (independently determined)
- Operating cost increases

Note: Individual performance will be measured annually. If a participant fails to meet established goals or performance expectations, an adjustment may be made to the individual award.

AWARD CALCULATIONS SCHEDULES

Targets – The measurement target will be established annually. Current measurements, which are weighted equally, are reflected in the following tables.

PERFORMANCE MEASURES AND WEIGHTS					
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	SOURCE FOR MEASUREMENT
ROE	5.77%	8.24%	11.54%	25%	Company-wide authorized weighted average ROE
Customer-to-Employee Ratio	743	754	762	25%	Target = prior year actual ratio adjusted upward by 1.5%
Customer Service Satisfaction	75%	85%	95%	25%	Monthly surveys
Operating Cost Increases	4.9%	4.0%	3.2%	25%	Inflation (1.7% to 3.4%) plus customer growth of 1.5%
POTENTIAL	**70%**	**100%**	**140%**	**100%**	**TOTAL**

Note: No annual incentive awards will be payable unless the Company's dividends equal or exceed the prior year's dividends.

Award Payout – Following the calculation and Committee approval of the annual incentive award, it is divided into short- and long-term components. The short-term component, which is 40 percent of the total award, is paid in cash to the participant. The long-term component, which is the remaining 60 percent of the award, is converted into performance shares that will be subject to a three-year restriction period.

Award Form – The short-term component of the annual award each year will be paid in cash. The long-term component award is paid in Company stock following successful completion of the three-year restriction period.

Withholding Taxes – The Company will deduct all applicable federal, state, and local taxes of any kind required by law to be withheld upon the payment of the annual incentive award.

PERFORMANCE SHARES

The long-term component of the MIP is reflected through the use of the performance shares, which are paid in shares of Company common stock following successful completion of the restriction period.

Award Term – Awards of performance shares will be made each year (contingent on a payout from the annual incentive plan), and will be subject to a three-year restriction period.

Number of Shares Granted – The number of performance shares granted to an individual is determined by two factors: the amount of the award earned under the long-term component of the annual incentive plan, and the price of SWG common stock at the date of the conversion into performance shares.

The amount of the annual incentive award to be converted into performance shares is divided by the average of the fair market value of SWG stock on the first five trading days of January to determine the number of performance shares that a participant receives.

Restriction Period – All performance shares will be restricted for a period of three years, during which time the plan participants will not have ownership of, or be able to sell, the stock, or rights to the stock which underlie the award. During the restriction period, SWG will maintain performance share accounts for each participant, which may increase in size as dividends are declared on SWG common stock and are reinvested. At the end of the restriction period (or earlier if circumstances warrant), each participant's performance share account will be closed by calculating a final number of shares and paying the participant in whole shares of SWG common stock, either before or after taxes are withheld.

DIVIDENDS

The dividend rate paid on SWG common stock during the restriction period will be used to determine the amount credited to the participant's performance share account.

Dividends will be credited to the participant's performance share account in an equivalent number of performance shares on a quarterly basis.

ANNUAL INCENTIVE AWARD – ROE COMPONENT

The target is set at 80% of the authorized weighted-average ROE. The minimum is set at 70% of the target, with the maximum set at 140% of the target. The range of performance and possible payouts are as follows:

	Minimum	Target	Authorized ROE	Maximum
Performance	5.77%	8.24%	10.30%	11.54%
Payout	70%	100%	125%	140%
Weighting	17.50%	25%	31.25%	35%

ANNUAL INCENTIVE AWARD – C/E RATIO COMPONENT

The target is set at a 1.5% improvement over the actual prior year customer to employee ratio. The minimum is set at zero percent improvement, with the maximum set at a 2.5% improvement over the previous year. The range of performance and possible payouts are as follows:

	Minimum	Target	Maximum
Performance	743	754	762
Payout	70%	100%	140%
Weighting	17.50%	25%	35%

ANNUAL INCENTIVE AWARD – CUSTOMER SATISFACTION COMPONENT

The target is set at an 85% customer satisfaction rating. The minimum is set at 75%, with the maximum set at a 95% customer satisfaction rating. The range of performance and possible payouts are as follows:

	Minimum	Target	Maximum
Performance	75%	85%	95%
Payout	70%	100%	140%
Weighting	17.50%	25%	35%

ANNUAL INCENTIVE AWARD – OPERATING COST COMPONENT

The threshold, target, and maximum are comprised of inflation (ranges from 1.7% to 3.4%) plus customer growth factor of 1.5%. The target is set at 4.0%, based on inflation of 2.5% and a 1.5% customer growth factor. The minimum is set at 4.9%, which is calculated using an inflationary factor of 3.4% and a 1.5% customer growth factor. The maximum is set at 3.2%, which is calculated using an inflationary factor of 1.7% with 1.5% customer growth factor. The range of performance and possible payouts are as follows:

	Minimum	Target	Maximum
Performance	4.9%	4.0%	3.2%
Payout	70%	100%	140%
Weighting	17.50%	25%	35%

SAMPLE AWARD PAYOUT

The following is a sample of a payout for an officer (with a 50% of salary award opportunity), based on 2009 targets and ***hypothetical actual results*** for 2009:

[illegible]	[illegible]
ROE	5.60%
target	8.24%
% target award earned	0
x 25% weight	0
Customer/Employee Ratio	762
target	754
% target award earned	140.0%
x 25% weight	35
Customer/Service Satisfaction	95.0%
target	85.0%
% target award earned	140.0%
x 25% weight	35
Operating Costs	4.0%
target	4.0%
% target award earned	100.0%
x 25% weight	25
TOTAL EARNED (as percentage of target)	95

Based upon the above, the payout, expressed as a percent of your salary, would be as follows:

Total Incentive Award	47.5%
Short-term (40%)	19.0%
Long-term (60%)	28.5%

491-092

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 to ACC-STF-1-107)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 11, 2011

Request No. ACC-STF-1-92:

Precedent. Are there any aspects of the Company's accounting adjustments and revenue requirement claim which represents a conscious deviation from the principles and policies established in prior Commission Orders? If so, identify each area of deviation, and for each deviation explain the Company's perception of the principle established in the prior Commission orders, how the Company's proposed treatment in this rate case deviates from the principles established in the prior Commission orders, and the dollar impact resulting from such deviation. Show which accounts are affected and the dollar impact on each account for each such deviation.

Respondent: Revenue Requirements

Response:

Please refer to the response of Southwest Gas to ACC-STF-1-56 and ACC-STF-1-57.

491-056

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 to ACC-STF-1-107)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 11, 2011

Request No. ACC-STF-1-56:

Filing Information. Do any of the Company's proposed pro forma adjustments represent a conscious deviation from the treatment of similar items in the Commission's order in the Company's last rate case? If so, please identify, quantify and explain each such item for which the Company has not followed the same treatment applied in the Commission's order in its last rate case.

Respondent: Revenue Requirements

Response:

No. Southwest Gas calculated each proposed proforma adjustment based on a reasonable analysis of the facts and circumstances in this rate case.

491-057

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 to ACC-STF-1-107)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 11, 2011

Request No. ACC-STF-1-57:

Filing Information. Has the Company knowingly failed to reflect in its filing any adjustments that were ordered of similar items in the Commission's order in the Company's last rate case? If so, please identify, quantify and explain each such item for which the Company has not followed the same treatment applied in the Commission's order in its last rate case.

Respondent: Revenue Requirements

Response:

Yes. Southwest Gas is requesting full recovery of its Management Incentive Plan and Supplemental Executive Retirement Plan. Please also refer to the prefiled direct testimony by Sandra Gaffin for further explanation of the Company's justification for inclusion of these costs in rates; and the supporting documents included with the Company's filing for information supporting the amount requested.

513-002

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-17
(ACC-STF-17-1 to ACC-STF-17-2)

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: APRIL 21, 2011

Request No. ACC-STF-17-2:

MIP and other incentive comp. Refer to the response to STF-1-83, which lists various incentive compensation amounts for 2008, 2009 and 2010 before allocation to Arizona.

a. Provide the Arizona jurisdictional amount for the MIP amount requested by Southwest, and show in detail how that was derived. Include supporting calculations.

b. Provide the Arizona jurisdictional amount for the MIP amount for each of the annual MIP amounts listed in response to STF 1-83. For each year, show in detail how the Arizona jurisdictional amount was derived. Include supporting calculations.

c. For each non-MIP item of incentive comp, listed in the response to STF 1-83, for each year, show the corresponding Arizona jurisdictional amount and show in detail how the Arizona jurisdictional amount was derived. Include supporting calculations.

d. For each non-MIP item of incentive comp, listed in the response to STF 1-83, for the test year, show the corresponding Arizona jurisdictional test year amount and show in detail how the Arizona jurisdictional test year amount was derived. Include supporting calculations.

Respondent: Revenue Requirements

Response:

Please refer to the attached spreadsheet.

SOUTHWEST GAS CORPORATION
MIP and OTHER INCENTIVE COMPENSATION EXPENSES
TEST YEAR JULY 2009 to JUNE 2010
RESPONSE TO DATA REQUEST NO. STF-17-2 (a) and (d)

	MIP 920	Aspire Award 920	GEM 920	RSUP 920	SP Quality Award 903	KAM Incentive Plan 903
Test Year July 2009 to June 2010						
Corporate Costs	$ 6,537,494	$ 73,500	$ 196,000	$ 1,911,117	$ -	$ -
Paiute & SGTC MMF	3.83%	3.83%	3.83%	3.83%		
Less: Paiute & SGTC Allocation	$ 250,386	$ 2,815	$ 7,507	$ 73,196	$ -	$ -
Incentive Compensation Expenses Before 4-Factor	6,287,108	70,685	188,493	1,837,921	-	-
Arizona 4-Factor Allocation	56.25%	56.25%	56.25%	56.25%		
Incentive Compensation Allocated to Arizona	$ 3,536,498	$ 39,760	$ 106,027	$ 1,033,831	$ -	$ -
Arizona Direct Costs	$ -	$ -	$ -	$ -	$ 231,974	$ 69,184
Total Arizona Incentive Compensation Costs	$ 3,536,498	$ 39,760	$ 106,027	$ 1,033,831	$ 231,974	$ 69,184

499-004

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-6
(ACC-STF-6-1 to ACC-STF-6-41)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 23, 2011

Request No. ACC-STF-6-4:

Provide a breakout of the amount of test year SERP expense by participant. Include supporting calculations.

Respondent: Revenue Requirements

Response:

Test year SERP expense is based on the most recent actuarial study, which is attached. SERP expense is a total company amount that is allocated to each ratemaking jurisdiction, based on charged labor, using the labor loading process. Test year SERP expense by participant is not information that is used by the Company, and is not readily available to the Company.

Hewitt

Actuarial Report

Southwest Gas Corporation
Supplemental Retirement Plan
2010 Pension Cost and 2009 Year-end Disclosure

To protect the confidential and proprietary information included in this material, it may not be disclosed or provided to any third parties without the approval of Hewitt Associates LLC.

Preparation of this Actuarial Valuation

Supplemental Retirement Plan for Southwest Gas Corporation

This report has been prepared as of December 31, 2009 for the Supplemental Retirement Plan. The primary purpose of this report is to present to management the accounting and reporting requirements for the 2009 and 2010 fiscal years for pension benefits as set forth in Accounting Standards Codification (ASC) section 715 (FASB Statement of Financial Accounting Standard No. 87 as amended ("SFAS No. 87") and No. 88 as amended ("SFAS No. 88")—including the provisions of SFAS No. 132(R) and SFAS No. 158. Determinations for purposes other than financial accounting requirements may be significantly different from the results reported herein. Thus, the use of this report for purposes other than those expressed here may not be appropriate.

In conducting the valuation, we have relied on personnel, plan design, and asset information supplied by the plan sponsor. While we cannot verify the accuracy of all this information, the supplied information was reviewed for consistency and reasonability. As a result of this review, we have no reason to doubt the substantial accuracy of the information and believe that it has produced appropriate results. This information, along with any adjustments or modifications, is summarized in various sections of this report.

This valuation has been conducted in accordance with generally accepted actuarial principles and practices, including the applicable Actuarial Standards of Practice as issued by the Actuarial Standards Board. In addition, the valuation results are based on our understanding of the requirements of SFAS No. 87 and SFAS No. 88. The information in this report is not intended to supersede or supplant the advice and interpretations of the Company's auditors.

The actuarial assumptions and methods used in this valuation are described in the Actuarial Assumptions section of this report. The plan sponsor selected the economic assumptions and prescribed them for use for purposes of compliance with SFAS No. 87 and SFAS No. 88. While the demographic assumptions were also prescribed by the plan sponsor, Hewitt Associates provided guidance with respect to these assumptions and it is our belief that they represent reasonable expectations of anticipated plan experience.

The undersigned is familiar with the near-term and long-term aspects of pension valuations and meets the Qualification Standards of the American Academy of Actuaries necessary to render the actuarial opinions herein. All of the sections of this report are considered an integral part of the actuarial opinions.

Preparation of this Actuarial Valuation (continued)

To our knowledge, no associate of Hewitt Associates providing services to Southwest Gas Corporation has any direct financial interest or indirect material interest in Southwest Gas Corporation. Thus, we believe there is no relationship existing that might affect our capacity to prepare and certify this actuarial report for Southwest Gas Corporation.

Hewitt Associates LLC

Steven R. Camferdam
Fellow of the Society of Actuaries
Enrolled Actuary

John S. Nelson
Associate of the Society of Actuaries

February 2010

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Determination of Net Periodic Pension Cost

Net Periodic Pension Cost

	2009	2010
Current service cost	$ 194,718	$ 371,829
Interest cost	2,064,530	2,045,330
Expected asset return	0	0
Amortization of:		
Unrecognized transition obligation/(asset)	0	0
Unrecognized prior service cost	0	0
Unrecognized net loss/(gain)	909,451	1,154,628
Net periodic pension cost	$ 3,168,699	$ 3,571,787
Expected benefit payments	$ 2,400,000	$ 2,500,000
Expected contributions	$ 2,400,000	$ 2,500,000
Key assumptions:		
Discount rate	6.75%	6.00%
Expected rate of return on plan assets	8.00%	8.00%
Amortization period for unrecognized net gain/(loss)	6.89	7.61

Year-end Disclosure

	2008	2009
Change in Projected Benefit Obligation (PBO)		
Benefit obligation at beginning of year	$ 32,605,426	$ 31,785,623
Service cost	97,167	194,718
Interest cost	2,041,353	2,064,530
Plan amendments	0	0
Special termination benefits	0	0
Curtailment gain	0	0
Actuarial (gain)/loss	(594,843)	3,785,371
Benefits paid	(2,363,480)	(2,491,402)
Benefit obligation at end of year	$ 31,785,623	$ 35,338,840
Accumulated Benefit Obligation, End of Year	$ 28,426,550	$ 31,517,460
Change in Plan Assets		
Fair value of plan assets at beginning of year	$ 0	$ 0
Actual return on plan assets	0	0
Company contributions	2,363,480	2,491,402
Benefits paid	(2,363,480)	(2,491,402)
Fair value of plan assets at end of year	$ 0	$ 0
Funded Status	$ (31,785,623)	$ (35,338,840)
Amounts Recognized in the Statement of Financial Position		
Noncurrent assets	$ 0	$ 0
Current liabilities	(2,500,000)	(2,500,000)
Noncurrent liabilities	(29,285,623)	(32,838,840)
Net pension asset/(liability) at year-end	$ (31,785,623)	$ (35,338,840)
Amounts Recognized in Accumulated Other Comprehensive Income (OCI)		
Net actuarial loss/(gain)	$ 9,444,680	$ 12,320,600
Prior service cost/(credit)	0	0
Net transition obligation/(asset)	0	0
	$ 9,444,680	$ 12,320,600
Weighted-Average Assumptions as of December 31		
Discount rate	6.75%	6.00%
Rate of compensation increase	3.75%	3.25%

Year-end Disclosure (continued)

	2008	2009
Components of Net Periodic Pension Cost		
Service cost	$ 97,167	$ 194,718
Interest cost	2,041,353	2,064,530
Expected return on plan assets	0	0
Amortization of:		
Unrecognized net (gain)/loss	996,909	909,451
Unrecognized prior service cost	0	0
Unrecognized net (asset)/obligation	0	0
Net periodic pension cost	$ 3,135,429	$ 3,168,699
Special termination benefits	0	0
Curtailment (gain)/charge	0	0
Total net periodic pension cost	$ 3,135,429	$ 3,168,699
Other Changes in Plan Assets and PBO Recognized in OCI		
Net actuarial loss/(gain)	$ (594,843)	$ 3,785,371
Amortization of net actuarial (loss)/gain	(996,909)	(909,451)
Prior service cost/(credit)	0	0
Amortization of prior service cost	0	0
Amortization of net transition obligation	0	0
Total recognized in OCI	$ (1,591,752)	$ 2,875,920
Total recognized in net periodic pension cost and OCI	$ 1,543,677	$ 6,044,619

The estimated net loss, prior service cost and transition obligation that will be amortized from accumulated other comprehensive income into net periodic benefit cost during fiscal 2010 are $1.1 million, $0 and $0, respectively.

Weighted-Average Assumptions Used to Determine Net Periodic Pension Cost for Year Ended December 31		
Discount rate (pension cost)	6.50%	6.75%
Expected rate of return on plan assets	8.00%	8.00%
Rate of compensation increase	4.00%	3.75%

Estimated Future Benefit Payments	Pension Benefits
2010	$ 2,500,000
2011	$ 2,500,000
2012	$ 2,500,000
2013	$ 2,500,000
2014	$ 2,500,000
Years 2015-2019	$ 12,100,000

Personnel Information

This section begins with summary information concerning the various types of participants included in this actuarial valuation—active participants, retired participants, beneficiaries, and terminated participants with deferred vested benefits.

The January 1, 2010 actuarial valuation was based on personnel information from Company records as of August 1, 2009. The following table shows the number of participants by category.

Personnel Summary

	August 1, 2008	August 1, 2009
Actives	17	20
Terminated vesteds	1	1
Retirees and beneficiaries	29	31
Total participants	47	52

Personnel Information (continued)

Following are the characteristics of the participants included in the valuation.

	August 1, 2008	August 1, 2009
Active Participants		
Number	17	20
Average present age	54.3	53.5
Average years of service	24.2	23.0
Average compensation[1]	$ 240,802	$ 255,494
Retirees and Beneficiaries		
Number	29	31
Average age	72.2	72.4
Average annual benefit	$ 80,180	$ 74,215
Term Vested Participants		
Number	1	1
Average present age	61.0	62.0
Average annual benefit	$ 1,012	$ 1,012

[1] Includes EDP deferrals.

Plan Provisions

Effective Date	Restated effective March 2, 1993.
Plan Participation	Officers and participants in the Executive Deferral Plan participate in the SERP.
Retirement Benefits	
Eligibility	Eligibility for benefit amount described in (a) below: All participants are eligible at age 55 and 20 years of service; senior executives are also eligible at age 65 and 10 years of service. (Senior officers who became participants prior to March 5, 1991 are eligible at age 55 and 10 years of service.) Eligibility for benefit amount described in (b) below: Participants who do not meet the above eligibility requirements but who are vested in their basic plan benefit.
Benefit Amount	Benefit amounts are described below: (a) 50% (60% for senior officers) times average earnings less benefits under the basic plan. The benefit is reduced in the same manner as the basic plan for retirement before age 60. (b) Basic plan benefit without IRS limits calculated as if EDP deferrals were included in pensionable earnings less the actual basic plan benefit.
Preretirement Death Benefits	
Eligibility	Eligibility for retirement benefits with an eligible spouse.
Benefit Amount	50% of the benefit amount determined as if the participant had retired and begun receiving a benefit on the first of the month before the date of death.
Postretirement Death Benefit	
Eligibility	Receiving retirement benefits with an eligible spouse.
Benefit Amount	50% of the benefit the participant was receiving. The benefit at retirement is not reduced for this coverage.

Plan Provisions (continued)

Disability Benefits	
Eligibility	Total disability before age 65.
Benefit Amount	50% (60% for senior officer) times Average Earnings less any salary continuance, long-term disability or Basic Plan benefits. The benefit begins at disability and continues for life or until recovery.
Average Earnings	Average earnings for the highest consecutive 36-month period with the Company (highest 12 months for participants prior to March 5, 1991).
Earnings	Includes Effective Earnings as defined in the Basic Plan plus any EDP deferrals, but generally excludes amounts received or deferred from any company incentive or bonus plan.
Basic Plan	The defined benefit plans of Southwest Gas.
Senior Officer	Officers with the title "Senior Vice President" or above.
Eligible Spouse	The spouse to whom the participant has been legally married at least one year at the time of death or time of benefit commencement, if earlier.

Actuarial Assumptions

Measurement Date December 31, 2009.

Actuarial Method Projected unit credit.

Market Related Value of Assets The plan is considered unfunded for SFAS 87 purposes.

Discount Rate 6.00% at December 31, 2009.

Salary Increases 2.75% base pay increases plus merit increases. Sample merit increases are shown below:

Age	Rate
30	4.0%
40	2.0%
50	0.5%
60	0.0%

Mortality Rates RP2000 Combined Healthy Mortality Table projected to 2010.

Termination Rates None assumed.

Disability Rates None assumed.

Retirement Age Rates of retirement as shown below:

	Rate by Service			Rate by Service	
Age	Under 20	20+	Age	Under 20	20+
55	3%	15%	62	20%	20%
56	3%	10%	63	25%	25%
57	3%	10%	64	40%	40%
58	3%	10%	65	67%	67%
59	10%	15%	66	67%	67%
60	12%	12%	67	100%	100%
61	16%	16%			

Marital Status 100% assumed to be married with wives two years younger than husbands.

Maximum Qualified Plan Benefit As described in IRC Section 415 ($195,000 for 2009) projected 3.25% per year.

Actuarial Assumptions (continued)

Maximum Qualified Plan Pensionable Pay	$245,000 in 2009 with 3.25% per year increases.
EDP Deferrals	Future deferrals assumed to continue at current rates.

499-002

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-6
(ACC-STF-6-1 to ACC-STF-6-41)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 23, 2011

Request No. ACC-STF-6-2:

Identify and fully explain all changes Southwest Gas has made to its Supplemental Executive Retirement Program (SERP) since the test year utilized in SWG's last rate case, Docket No. G-01551A-07-0504.

Respondent: Human Resources

Response:

No changes have been made to the Supplemental Executive Retirement Plan since SWG's last rate case, Docket No. G-01551A-07-0504.

499-021

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-6
(ACC-STF-6-1 to ACC-STF-6-41)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 23, 2011

Request No. ACC-STF-6-21:

AGA dues. Request No. ACC-STF-1-41(b) asked Southwest to Provide all budget and financial information the Company possess for the AGA for years 2008, 2009 and 2010 and/or budgeted for 2011.

a. Why did Southwest's response to ACC-STF-1-41 not include any of the information requested in ACC-STF-1-41(b)?

b. Provide all information in Southwest's possession that is responsive to ACC-STF-1-41(b).

c. Has Southwest requested any budget or financial information from the AGA for any of the years, 2008, 2009 and 2010 and/or budgeted for 2011? If not, explain fully why not. If so, provide a copy of Southwest's request and identify and provide a copy of the documents received.

Respondent: Revenue Requirements

Response:

The response to ACC-STF-1-41(b) was inadvertently omitted. Southwest Gas requested 2009 and 2010 information from AGA for the preparation of this rate case since those are the two years that covered the test year. The attached documents include a copy of the information request made by Southwest Gas to AGA for purposes of preparing its proforma adjustment to AGA dues, along with information provided by the AGA that is responsive to part (b) of this request.

Randi Aldridge - RE: AGA Financial Information

From: "Allen, Doug" <DAllen@aga.org>
To: "Randi Aldridge" <Randi.Aldridge@swgas.com>, "Martin, Joe" <JMartin@aga.org>
Date: 8/19/2010 11:19 AM
Subject: RE: AGA Financial Information
Attachments: Lobbying Percentages 2003_2009.pdf; 2009 Actuals v2.pdf

Hello, Randi. I believe the attached files contain all the information you requested. Please let me know if you need anything else.

Thanks.

Doug Allen

From: Randi Aldridge [mailto:Randi.Aldridge@swgas.com]
Sent: Tuesday, August 17, 2010 8:05 PM
To: Martin, Joe
Cc: Allen, Doug
Subject: RE: AGA Financial Information

Thanks Joe. If I could get the information from you or Doug by the 25th that would be great, if not please let me know. Thanks for your help, Randi

Randi

Randi L. Aldridge, CMA
Manager/Revenue Requirements | Southwest Gas Corporation
p.702.876.7184 f.702.222.1475

PLEASE CONSIDER THE ENVIRONMENT BEFORE PRINTING THIS EMAIL.

>>> "Martin, Joe" <JMartin@aga.org> 8/17/2010 5:03 PM >>>

Hi Randi,

Sorry I didn't get back to you sooner. I'm out of town until Thursday. I've copied Doug Allen on this message who can get you the information you need.

Joe

From: Randi Aldridge [mailto:Randi.Aldridge@swgas.com]
Sent: Monday, August 16, 2010 8:28 PM
To: Martin, Joe
Subject: RE: AGA Financial Information

Hi Joe, Southwest Gas is beginning preparations for an Arizona rate case. I was wondering if you could provide the below numbers for 2009, and if you have any budgeted amounts for 2010. If you have .pdf documents to support the amounts that would be suitable to use as exhibits or workpapers in our filing, that would be helpful.

Thank you! Randi

Randi

Randi L. Aldridge, CMA
Manager/Revenue Requirements | Southwest Gas Corporation
p.702.876.7184 f.702.222.1475

PLEASE CONSIDER THE ENVIRONMENT BEFORE PRINTING THIS EMAIL.

>>> "Martin, Joe" <JMartin@aga.org> 8/18/2009 4:17 AM >>>

Randi,

Here are the 2008 actual final numbers for the Association. I'm not sure where the $300,000 for advertising comes from. We do advertising but it's all advocacy and is included in the lobbying numbers. Many years ago we use to do advertising that was more marketing in nature that many state commissions would disallow. That program was terminated about 10 years ago.

Public affairs	7,036,204
Policy, Planning and Regulatory Affairs	4,041,413
Corporate affairs and International	2,754,868
Operating and engineering	5,119,289
Industry Finance and Admin. Programs	996,593
General counsel	1,043,295
Political Action Committee	190,595
General & Administration	5,275,571

Lobbying percentages:

2003	2.10%
2004	1.55%
2005	2.35%
2006	2.30%
2007	2.13%
2008	4.38%

Joe

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AMERICAN GAS ASSOCIATION
2003 - 2009 LOBBYING PERCENTAGES

Listed below are the percentages of AGA dues related to lobbying activities for the years 2003 through 2009. AGA uses lobbying expenses as defined under IRC Section 162.

Year	Lobbying %
2003	2.10%
2004	1.55%
2005	2.35%
2006	2.30%
2007	2.13%
2008	4.38%
2009	6.09%

08/19/2010

AMERICAN GAS ASSOCIATION
2008 BUDGET

	$ 2008 ALLOCATION	% 2008 ALLOCATION
Advertising	$300,000	1.18%
Corporate Affairs	$2,317,000	9.14%
General & Administrative	$5,127,000	20.22%
General Counsel	$1,056,000	4.17%
Industry Finance & Administrative Programs	$852,000	3.36%
Operations & Engineering Management	$5,505,000	21.71%
Policy, Planning & Regulatory Affairs	$4,000,000	15.78%
Public Affairs	$6,195,000	24.44%
Total Budget	$25,352,000	100.00%

Note
AGA estimates that lobbying expenses, as defined under IRC Section 162, will account for 4% of member dues in 2008.

AMERICAN GAS ASSOCIATION
2009 BUDGET

	$ 2009 ALLOCATION	% 2009 ALLOCATION
Advertising	$250,000	0.90%
Corporate Affairs	$2,979,000	10.77%
General & Administrative	$5,267,000	19.05%
General Counsel	$1,148,000	4.15%
Industry Finance & Administrative Programs	$1,204,000	4.35%
Operations & Engineering Management	$5,929,000	21.44%
Policy, Planning & Regulatory Affairs	$4,329,000	15.65%
Public Affairs	$6,547,000	23.68%
Total Budget	$27,653,000	100.00%

Note
AGA estimates that lobbying expenses, as defined under IRC Section 162, will account for 5% of member dues in 2009.

AMERICAN GAS ASSOCIATION
2009 Non Dues Revenue Actuals

AGA Program Categories	2009
Public Affairs	$623,783
Policy, Planning & Regulatory Affairs	$148,436
Market Development	$0
Corporate Affairs	$617,396
Operations & Engineering Management	$2,227,420
Industry Finance & Administrative Programs	$760,640
General Counsel	$195,570
General and Administrative	$223,995
Total Non Dues Revenue Actuals	$4,797,240

AGA Categories of Expenses	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010 (forecast)
Public Affairs	$ 5,703,920	$ 5,939,486	$ 6,336,326	$ 7,015,121	$ 5,726,187	$ 5,878,345	$ 5,563,947	$ 7,036,204	$ 6,087,552	$ 6,143,000
Policy, Planning & Regulatory Affairs	3,382,900	3,261,692	3,212,553	3,031,053	3,120,112	3,325,727	3,925,034	4,041,413	4,277,647	4,427,000
Market Development	1,196,791	349,589	-	-	-	-	-	-	-	-
Corporate Affairs	2,123,818	2,014,503	2,304,775	1,993,049	2,072,208	2,398,515	2,271,158	2,754,868	2,880,397	2,354,000
Operations & Engineering Management	3,664,863	3,729,829	4,302,428	4,262,228	5,154,993	5,116,637	5,693,934	5,119,289	5,474,235	5,085,000
Industry Finance & Administrative Programs	934,852	1,230,238	1,157,023	1,286,859	1,363,591	1,252,846	1,516,308	996,593	1,027,748	1,129,000
General Counsel	641,984	768,219	757,481	746,667	808,157	877,030	945,643	1,043,295	1,172,072	1,067,000
General and Administrative	4,273,134	3,894,457	4,124,675	5,034,491	4,322,358	4,676,721	4,932,418	5,275,571	5,569,647	5,535,000
Total Expense Actuals	$ 21,922,262	$ 21,188,013	$ 22,195,261	$ 23,369,468	$ 22,567,606	$ 23,525,821	$ 24,848,442	$ 26,267,233	$ 26,489,298	$ 25,740,000

Provided By: American Gas Association
October 2010

AUDIT REPORT ON THE EXPENDITURES

OF THE

AMERICAN GAS ASSOCIATION

(For the 12 month period ended December 31,1999)

JUNE 2001

COMMITTEE ON
UTILITY ASSOCIATION OVERSIGHT

National Association of
Regulatory Utility Commissioners
1101 Vermont Avenue; Suite 200
Washington, D.C. 20005

Telephone No. (202) 1898-2200

AMERICAN GAS ASSOCIATION
SUMMARY OF EXPENSES
FOR THE YEAR ENDED DECEMBER **31,1999**

EXPENSE CATEGORY	PERCENTAGE
Public Affairs	15.43%
Communications	11.64%
Media Communications:	
Commercial Equipment	4.47%
Environmental	0.74 %
Promotional	0.74%
Residential Equipment	2.96%
Corporate Affairs & International	11.30%
General Counsel & Corporate Secretary	4.02%
Regulatory Affairs	11.20%
Marketing Services	15.02%
Operating & Engineering Services	14.70%
Policy & Analysis	12.07%
Industry Finance & Admin. Programs	2.94 %
General & Administrative Expense	0.00%
TOTAL	107.23% *

* Expense in excess of 100% not funded by dues.

Note: The table above was prepared by the Staff Subcommittee on Utility Association Oversight and should be read in conjunction with the audited financial statements and schedules contained within this report. The expense categories listed above relate to audit definitions found on page III-3 herein.

American Gas Association
Expenditures Funded by Member Dues
For the Year Ended December 31, 1999

Group Number	Group Name	Net Expense		Adjustments	G&A Allocation (5)	Adjusted Net Expense	% of Dues
03	Public Affairs	4,147,682	3, 4	(1,690,669)	455,752	2,912,765	15.43%
03	Communications		4	1,698,695	498,479	2,197,174	11.64%
08	Media Communications						
	Commercial Equipment	759,932	1,2	61,868	21,400	843,200	4.47%
	Environmental	126,708	1,2	10,316	3,568	140,592	0.74%
	Promotional	126,708	1,2	10,316	3,568	140,592	0.74%
	Residential Equipment	503,934	1,2	41,027	14,191	559,152	2.96%
06. 16	Corporate Affairs and International	1,483,688	3	(5,217)	655,144	2,133,615	11.30%
05	General Counsel & Corp. Secretary	588,436	3		170,907	759,343	4.02%
09	Regulatory Affairs	1,492,676	3	194,393	427,268	2,114,337	11.20%
08	Marketing Services	4,654,503	1, 2	(2,302,920)	484,237	2,835,820	15.02%
14	Operating & Engineering Services	1,949,534			826,051	2,775.585	14.70%
07	Policy & Analysis	1,374,743	1	277.704	626,659	2,279,106	12.07%
12	Industry Finance & Admin. Programs	498,349			56,969	555,318	2.94%
01.10.11	General & Administrative Expense	4,247,002	3	(2,809)	(4,244,193)		0.00%
	Grand Total	21,953,895		$ (1,707,296)	$ -	$ 20,246,599	107.23%

Adjustments as a result of A.G.A./NARUC Oversight Committee Staff agreement.

1 Allocation of Group Vice President's salaries.
2 Media Communications portion of division expenses.
3 Expenses transferred to Government Relations.
4 Breakout of communications portion of division expenses
5 G&A allocated on basis of equivalent full-time employees during 1999.

AMERICAN GAS ASSOCIATION

Definitions of Functional Cost Centers
For the Year Ended December 31, 1999

COST CENTER	DESCRIPTION
03	Communications develops informational materials for member companies and consumers and coordinates all media activity.
	Public affairs provides members with information on legislative developments: prepares testimony, comments, and filings regarding legislative activities; lobbies on behalf of the industry.
08	Media Communications manages the development and placement of consumer information advertisements in national print and electronic media.
	Commercial Equipment - explains the use of specific models of commercial/institutional equipment, emphasizing cost savings energy efficiency and the other additional benefits of natural gas.
	Environmental - describes the environmental benefits of natural gas to advocate its increased use to replace other fuels.
	Industrial Equipment - explains cost-savings, energy-savings and other benefits provided by the industrial applicationsof specific equipment.
	Institutional - to enhance the image of the natural gas industry as a business entity.
	Power Generation Natural Gas Equipment - explains cost-savings. energy-savings and other benefits provided by specific equipment for generating power.
	Promotional - promotes the efficient use of natural gas by emphasizing the resource efficiency, cost and other inherent qualities of natural gas.
	Residential Equipment - explains cost-savings, energy-savings, and other related benefits to the customer/user provided by certain models of residential natural gas appliances such as boiler, furnaces, ranges and water heaters.
12	Finance & Administration develops and implements programs in such areas as accounting, human resources and risk management for member companies.

05 General Counsel & Corporate Secretaw provides legal counsel to the Association

06 Corporate Affairs provides opportun'ities for interaction between member companies and the financial community. The focus is to promote interest in the investment opportunities in the industry.

09 Regulatory Affairs provides members with information on FERC and state regulatory developments; prepares testimony, comments, and filings regarding regulatory activities.

08 Market Development assists members in their efforts to encourage the most efficient utilization of gas energy by exchanging information about marketing trends, conducting utilization efficiency programs and exploring market opportunities.

14 Operating & Engineering develops and implements programs and practices to meet the operational, safety and engineering needs of the industry.

07 Policy & Analysis identifies the need for and conducts energy analyses and modeling efforts in the areas of gas supply and demand, economics and the environment.

General & Administrative includes:

01 Office of the President provides senior management guidance for all A.G.A. activities.

10 Human Resources develops and administers employee programs and provides general office and personnel services.

11 Finance and Administration develops and administers financial accounting and treasury services and maintains computers services capability.

* Pipeline Research: develops, manages and evaluates pipeline research projects that provide advances in technology.

* Reserve: Extraordinary adjustments are recorded as reserve charges. Major adjustments are identified in the audited financial statements.

* Not funded by current year General Fund Dues.

Damaisron

AUDIT REPORT ON THE EXPENDITURES

OF THE

AMERICAN GAS ASSOCIATION

(For the 12 month period ended December 31, 1998)

JANUARY 2000

COMMITTEE ON
UTILITY ASSOCIATION OVERSIGHT

National Association of
Regulatory Utility Commissioners
1101 Vermont Avenue, N.W., Suite 200
Washington, D.C. 20005

Telephone No. (202) 898-2200

AMERICAN GAS ASSOCIATION
SUMMARY OF EXPENSES
FOR THE YEAR ENDED DECEMBER 31, 1998

EXPENSE CATEGORY	PERCENTAGE
Communications	10.27%
MEDIA COMMUNICATIONS:	
Commercial Equipment	5.96%
Environmental	3.37%
Industrial Equipment	1.36%
Promotional	1.46%
Residential Equipment	8.40%
Finance & Administration Services	12.17%
General Counsel & Corporate Secretary	5.54%
Government Relations	23.86%
Marketing Services	16.20%
Meeting Services	-0.18%
Operating & Engineering Services	4.90%
Planning & Analysis	9.51%
General & Administrative Expense	0.00%
TOTAL	102.82% *

* Expense in excess of 100% not funded by dues.

Note: The table above was prepared by the Staff Subcommittee on Utility Association Oversight and should be read in conjunction with the audited financial statements and schedules contained within this report. The expense categories listed above relate to audit definitions found on page III-3 herein.

American Gas Association
Expenditures Funded by Member Dues
For the Year Ended December 31, 1998

Group Number	Group Name	Net Expense		Adjustments	G&A Allocation (4)	Adjusted Net Expense	% of Dues
03	Communications	1,561,612	2	(2,679)	430,782	1,989,715	10.27%
13	Media Communications						
	Commercial Equipment	1,105,739	1,2	31,943	17,848	1,155,530	5.96%
	Environmental	625,598	1,2	18,072	10,098	653,768	3.37%
	Industrial Equipment	252,954	1,2	7,307	4,083	264,344	1.36%
	Promotional	270,820	1,2	7,823	4,372	283,015	1.46%
	Residential Equipment	1,557,378	1,2	44,990	25,139	1,627,507	8.40%
06	Finance & Administration Services	1,797,937	3	(13,893)	574,377	2,358,420	12.17%
05	General Counsel & Corp. Secretary	938,797	3	(8,566)	143,594	1,073,825	5.54%
09	Government Relations	3,802,555	3	22,459	800,025	4,625,039	23.86%
08	Marketing Services	2,693,462	1	(107,456)	553,863	3,139,869	16.20%
04	Meeting Services	(34,155)		-	-	(34,155)	-0.18%
14	Operating & Engineering Services	661,825		-	287,188	949,013	4.90%
07	Policy & Analysis	1,392,718		-	451,296	1,844,014	9.51%
01,10,11	General & Administrative Expense	3,302,665		- -	(3,302,665)	0	0.00%
	Grand Total	19,929,905		$ 0	$ 0	$ 19,929,905	102.84%

Adjustments as a result of A.G.A./NARUC Oversight Committee Staff agreement.

1 Allocation of Group Vice President's salaries.
2 Media Communications portion of division expenses.
3 Expenses transferred to Government Relations.
4 G&A allocated on basis of equivalent full-time employees during 1997.

AMERICAN GAS ASSOCIATION

Definitions of Functional Cost Centers
For the Year Ended December 31, 1998

COST CENTER	DESCRIPTION
03	Communications develops informational materials for member companies and consumers and coordinates all media activity.
13	Media Communications manages the development and placement of consumer information advertisements in national print and electronic media.
	Commercial Equipment - explains the use of specific models of commercial/institutional equipment, emphasizing cost savings energy efficiency and the other additional benefits of natural gas.
	Environmental - describes the environmental benefits of natural gas to advocate its increased use to replace other fuels.
	Industrial Equipment - explains cost-savings, energy-savings and other benefits provided by the industrial applications of specific equipment.
	Promotional - promotes the efficient use of natural gas by emphasizing the resource efficiency, cost and other inherent qualities of natural gas.
	Residential Equipment - explains cost-savings, energy-savings, and other related benefits to the customer/user provided by certain models of residential natural gas appliances such as boiler, furnaces, ranges and water heaters.
06/ 16	Finance & Administration develops and implements programs in such areas as accounting, human resources and risk management for member companies.
05	General Counsel & Corporate Secretary provides legal counsel to the Association.
09	Government Relations provides members with information on legislative and regulatory developments; prepares testimony, comments, and filings regarding legislative and regulatory activities; lobbies on behalf of the industry.
08	Marketing assists members in their efforts to encourage the most efficient utilization of gas energy by exchanging information about marketing trends, conducting utilization efficiency programs and exploring market opportunities.

04 Meeting Services and Membership Services provides support services for committee meetings and conferences. In addition, coordinates services provided to members.

14 Operating & Engineering develops and implements programs and practices to meet the operational, safety and engineering needs of the industry.

07 Policy & Analysis identifies the need for and conducts energy analyses and modeling efforts in the areas of gas supply and demand, economics and the environment.

General & Administrative includes:

01 Office of the President provides senior management guidance for all A.G.A. activities.

10 Human Resources develops and administers employee programs and provides general office and personnel services.

11 Finance and Administration develops and administers financial accounting and treasury services and maintains computers services capability.

* Pipeline Research: develops, manages and evaluates pipeline research projects that provide advances in technology.

* Reserve: Extraordinary adjustments are recorded as reserve charges. Major adjustments are identified in the audited financial statements.

* Not funded by current year General Fund Dues.

State of Florida

Public Service Commission

CAPITAL CIRCLE OFFICE CENTER • 2540 SHUMARD OAK BOULEVARD
TALLAHASSEE, FLORIDA 32399-0850

-M-E-M-O-R-A-N-D-U-M-

DATE: DECEMBER 23, 2003

TO: DIRECTOR, DIVISION OF THE COMMISSION CLERK & ADMINISTRATIVE SERVICES (BAYÓ)

FROM: DIVISION OF ECONOMIC REGULATION (BRINKLEY, BAXTER, DRAPER, GARDNER, HEWITT, KAPROTH, KENNY, LESTER, LINGO, C. ROMIG, SPRINGER, STALLCUP, WHEELER, WINTERS)
DIVISION OF COMPETITIVE SERVICES (MAKIN)
OFFICE OF THE GENERAL COUNSEL (JAEGER)

RE: DOCKET NO. 030569-GU - APPLICATION FOR RATE INCREASE BY CITY GAS COMPANY OF FLORIDA.

AGENDA: 01/06/04 - REGULAR AGENDA - PROPOSED AGENCY ACTION - INTERESTED PERSONS MAY PARTICIPATE

CRITICAL DATES: 5-MONTH EFFECTIVE DATE: JANUARY 15, 2004 (PAA RATE CASE)

SPECIAL INSTRUCTIONS: NONE

FILE NAME AND LOCATION: S:\PSC\ECR\WP\City Gas 030569-GU\
Final.RCM
Final Attachments 1-5.123
Final Attachments 6A-7P.123
Final Attachment 8.xls

ISSUE 39: Is City Gas's $(2,847) adjustment to Account 921, Office Supplies and Expenses, for American Gas Association membership dues appropriate?

RECOMMENDATION: No. Account 921, Office Supplies and Expenses, should be reduced by an additional $13,178 for American Gas Association membership dues related to charitable contributions and advertising that is not informational or educational in nature. (C. ROMIG)

STAFF ANALYSIS: On MFR Schedule G-2, Page 17 of 34, the Company included $1,966,495 in its Account 921, Office Supplies and Expense for the 2003 interim year. Included in this amount is $39,277 related to American Gas Association (AGA) membership dues. This was inflated for customer growth and general inflation of 1.0232 to $40,188. On MFR G-2, Page 2 of 34, it removed $2,847 that was labeled as "attributable to lobbying." This represents an adjustment of 7.08%.

In City Gas's last rate case, In re: Request for rate increase by City Gas Company of Florida, Docket No. 000768-GU, Order No. PSC-01-0316-PAA-GU, issued February 5, 2001, the Company removed $4,045 for AGA dues for lobbying. The Commission removed an additional combined amount of $4,970 for memberships, dues and contributions. In re: Application for a rate increase by City Gas Company of Florida, Docket No. 940276-GU, Order No. PSC-94-0957-FOF-GU, issued August 9, 1994, for interim purposes, the Commission disallowed 40% of AGA dues. This order stated that the percentage was based on the 1993 National Association of Regulatory Commission's (NARUC) Audit Report on the Expenditures of the American Gas Association (Audit Report). Order No. PSC-94-0957-FOF-GU further stated that this reduction was consistent with adjustments made in rate cases involving other gas companies. In the final order in Docket No. 940276-GU, Order No. PSC-94-1570-FOF-GU, issued December 19, 1994, the Commission removed 40.48% of AGA dues "which were related to lobbying and advertising that did not meet the criteria of being informational or educational in nature." In re: Request for rate increase by Florida Division of Chesapeake Utilities Corporation, Docket No. 000108-GU, Order No. PSC-00-2263-FOF-GU, issued November 28, 2000, the Commission removed 45.10% of AGA dues.

The latest NARUC Audit Report on AGA expenditures that Staff was able to locate is dated June, 2001, for the twelve-month period ended December 31, 1999. By a review of the Summary of Expenses, it appears that 41.65% of 1999 AGA expenditures are for lobbying and advertising. Staff has not been able to locate a more recent

NARUC Audit Report of the AGA expenditures. However, because approximately 40% appears to have been consistent over a number of years, Staff believes it is not unreasonable to assume that 40% is representative of 2003 and 2004 expenditures and recommends that 40% of AGA dues be disallowed in this proceeding.

From information supplied by the Company, AGA dues were $39,277 in 2003. According to recommendations in Issue 44 and 45, Account 921 should be trended on inflation only at 2.0% for 2004. On that basis the 2004 amount is $40,063 ($39,277 x 1.02). Disallowing 40% would result in disallowing $16,025 for 2004. The Company's $2,847 adjustment reduces Staff's adjustment to $13,178 ($16,025 - $2,847) for 2004. This position follows past Commission practice of placing charitable contributions and advertising that is not informational or educational in nature below the line.

Based on the above analysis, Account 921, Office Supplies and Expenses, should be reduced by an additional $13,178 for AGA membership dues related to charitable contributions and advertising that is not informational or educational in nature.

The Company is in agreement with this adjustment.

499-029

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-6
(ACC-STF-6-1 to ACC-STF-6-41)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 23, 2011

Request No. ACC-STF-6-29:

Relocation expense and losses associated with sales of employee homes.

a. Please identify, by account, all expense in the test year related to gains or losses associated with sales of employee homes.

b. Please identify, by account, all expense in the test year related to sales commissions on the purchase or sale of employee homes.

c. Please provide comparative information for each calendar year, 2006 through 2010.

d. Please identify, by account, all rate base amounts in the test year related to Company ownership of employee homes.

e. As of June 30, 2010, identify, by account, the Company's equity in employee homes.

f. For all amounts identified in response to parts a through e, above, please also provide the Arizona jurisdictional amount.

Respondent: Revenue Requirements

Response:

Please refer to the attached spreadsheets for answers to ACC-STF-6-29 (a), (b), (c), (e) and (f). Please note, for illustrative purposes, commissions were shown separately from the loss amounts; however, commissions are included in the loss amounts.

With regard to ACC-STF-6-29 (d), no amounts related to Company ownership of employee homes were included in rate base.

SOUTHWEST GAS CORPORATION
2010 ARIZONA GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
EMPLOYEE RELOCATION EXPENSE AND LOSSES ASSOCIATED WITH SALES OF EMPLOYEE HOMES
DATA REQUEST STF 6.29 (a), (b), (c) and (f)

	2006		2007		2008		2009		2010		Test Year July 2009 - June 2010	
	Loss	Commission	Loss	Commission	Loss	Commission	Loss	Commission	Loss	Commission	Loss	Commission
Arizona - Account 88000001	$ -	$ -	$ 170,312	$ 33,144	$ 681,746	$ 62,220	$ 74,007	$ 14,400	$ 70,592	$ 34,338	$ 374,906	$ 62,520
Corporate - Account 92100001	$ 55,444	$ 23,940	$ 35,366	$ 16,440	$ 247,851	$ 49,830	$ 219,210	$ 20,700	$ -	$ -	$ 237,939	$ 50,100
Paiute & SGTC MMF	4.12%	4.12%	3.91%	3.91%	3.90%	3.90%	3.89%	3.89%	3.84%	3.84%	3.83%	3.83%
Less: Paiute & SGTC Allocation	$ 2,284	$ 986	$ 1,383	$ 643	$ 9,666	$ 1,943	$ 8,527	$ 805	$ -	$ -	$ 9,113	$ 1,919
Relocation Expenses Before 4-Factor	$ 53,160	$ 22,954	$ 33,983	$ 15,797	$ 238,184	$ 47,887	$ 210,683	$ 19,895	$ -	$ -	$ 228,826	$ 48,181
Arizona 4-Factor Allocation	56.81%	56.81%	56.81%	56.81%	56.54%	56.54%	56.42%	56.42%	56.05%	56.05%	56.25%	56.25%
Adjustment Allocated to Arizona	$ 30,200	$ 13,040	$ 19,306	$ 8,974	$ 134,669	$ 27,075	$ 118,867	$ 11,225	$ -	$ -	$ 128,715	$ 27,102
Total Arizona Relocation Costs	$ 30,200	$ 13,040	$ 189,617	$ 42,118	$ 816,416	$ 89,295	$ 192,874	$ 25,625	$ 70,592	$ 34,338	$ 503,620	$ 89,622

Please note, for illustrative purposes, commissions were shown separately; however commissions are included in the loss amounts.

SOUTHWEST GAS CORPORATION
2010 ARIZONA GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
EQUITY IN EMPLOYEE HOMES AS OF JUNE 30, 2010
DATA REQUEST STF 6.29 (e) and (f)

		Balance as of June 30, 2010
Total Company - Account 17401150	$	1,634,654.55
Arizona 4-Factor Allocation		56.25%
Arizona Portion of Equity in Employee Homes	$	919,493

504-021

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-11
(ACC-STF-11-1 to ACC-STF-11-23)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: APRIL 8, 2011

Request No. ACC-STF-11-21:

Southwest Gas Energy Efficient Technology (EET).

a. Please identify all costs included in the test year related to the Southwest Gas Energy Efficient Technology department or unit.

b. Please provide a breakout for the test year, and, for comparison purposes, for calendar years 2009 and 2010, of the EET time and costs related to (1) gas heat pump research and development and (2) other energy efficiency projects.

c. Please identify and explain each other energy efficiency project in 2009 and 2010 in which EET was engaged, other than the gas heat pump research and development.

d. Are there any other departments in the Westwood facility other than EET and Intellichoice Energy LLC? If not, explain why not. If so, please identify the other Southwest departments at that location.

e. What was the total cost of the Westwood facility for the test year and for calendar 2009 and 2010? Show in total and also show the Arizona jurisdictional amounts for each period.

Respondent: Revenue Requirements / Energy Efficient Technology Department

Response:

a. Total costs included in Arizona for EETD during the test year are $336,626 charged to Account 182.3 and recovered through the Arizona R&D surcharge; $1,679,741 to Account 908 of which $906,220 was allocated to Arizona; $25,609 to Account 920 of which $13,853 was allocated to Arizona; $8,477 to Account 921 of

which $4,585 was allocated to Arizona; and $64,014 to Account 931 of which $34,629 was allocated to Arizona.

b. Please refer to the attached spreadsheet of test year EETD charges requested in base rates in Arizona compared to calendar years 2009 and 2010. Amounts shown are after allocation to Arizona. While costs are not tracked by project, the EETD estimates that 65 percent of its time was related to gas heat pump research, and the remaining 35 percent is related to other energy efficiency projects.

c. Please refer to the attached document.

d. No. The Westwood facility does not have suitable available space for other Southwest departments to utilize.

e. The total costs of the Westwood facility, before and after allocation to Arizona, are included in the attached spreadsheet.

SOUTHWEST GAS CORPORATION
ARIZONA
ENERGY EFFICIENT TECHNOLOGY DEPARTMENT
COSTS REQUESTED FOR RECOVERY IN BASE RATES
CALENDAR YEARS 2009 AND 2010, AND TWELVE MONTHS ENDED JUNE 30, 2010

Line No.	Description (a)	Test Year (b)	2009 (c)	2010 (d)	Line No.
1	Account 908	$ 906,220	$ 980,738	$ 1,065,485	1
2	Account 920	13,853	49,932	-	2
3	Account 921	4,585	7,206	231	3
4	Account 931	34,629	34,406	37,341	4
5	Total	$ 959,287	$ 1,072,282	$ 1,103,057	5

SOUTHWEST GAS CORPORATION
ARIZONA
ENERGY EFFICIENT TECHNOLOGY DEPARTMENT
WESTWOOD FACILITY COSTS
CALENDAR YEARS 2009 AND 2010, AND TWELVE MONTHS ENDED JUNE 30, 2010

Line No.	Description (a)	Test Year (b)	2009 (c)	2010 (d)	Line No.
1	Rent	$ 64,015	$ 63,603	$ 69,028	1
2	Gas	12,942	12,689	7,905	2
3	Electric	17,268	19,950	15,581	3
4	Water	290	230	303	4
5	Sewer	595	549	438	5
6	Trash	4,648	7,513	3,040	6
7	Janitorial, Alarm Monitoring, Pest Control	6,828	6,828	6,828	7
8	Total	$ 106,585	$ 111,362	$ 103,122	8
9	4-Factor Allocation	56.25%	56.25%	56.25%	9
10	Amount Allocated to Arizona	$ 59,954	$ 62,641	$ 58,006	10

2009-2010 Energy Efficiency Projects

1. Arizona Corporation Commission - Solar Thermal / Demonstration (Tempe, AZ)
   - System Installation/Operations
   - Data Monitoring Installation / Review
   - ACC Final reports / presentation
2. Arizona Corporation Commission - Solar Thermal / Water & Space Heating Demonstration (Tucson, AZ) Pepper Viner Home
   - System Installation/Operations
   - Data Monitoring Installation / Review
   - ACC Final reports / presentation
3. Arizona Corporation Commission - Gas Engine Driven Water Heating (GEDWH), Phase II and III
   - Final report (Phase II)
   - Scope of Work (Phase III)
   - Design & Fabrication (Phase III)
4. Operations Technology Development (OTD) Board Involvement
   - OTD Administration and Individual Project Oversight
   - NYSEARCH Administration and Individual Project Oversight
5. Utilization Technology Development (UTD)Program
   - Nevada Filing for Rate Recovery of Dues
   - UTD Administration and Individual Project Oversight
   - UTD Board Involvement
6. Energy Solutions Center (ESC)
   - ESC Administration and Project Oversight
   - Quarterly Technology and Marketing Assessment Forum (TMAF) meetings
7. Natural Gas Vehicles (NGV) Initiative
   - Co-Lead of NGV Workgroup
   - American Gas Association (AGA)/ America's Natural Gas Alliance (ANGA) – Participate in review of marketing analysis
   - Clean American Transportation Alliance (CATA)
8. SWG Biogas Task Group
9. Desert Research Institute (DRI)
   - DRI Engine Testing
   - DRI Maintain Relationship
10. Codes, Standards, Guidelines Support
    - American Gas Association (AGA) Building Energy Codes Standards (BECS) Committee
    - American Society of Heating, Ventilation, Air-conditioning and Refrigeration Engineers (ASHRAE) Standards – 90.1, 189.1
    - United States Green Building Council (USGBC) – Leadership in Energy and Environmental Design (LEED) Guidelines
    - National Association of Home Builders (NAHB) – Green Homes
    - Energy Star
    - Nevada Solar Thermal Regulations
    - Consortium for Energy Efficiency

491-098

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 to ACC-STF-1-107)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 11, 2011

Request No. ACC-STF-1-98:

Research and Development.

a. Does the Company undertake R&D projects for only those studies which will most beneficially impact its operations?

b. How does the Company determine which R&D studies will be most cost beneficial to it?

c. List each research and development project for which the Company is incurring cost, or for which costs are being allocated to the Company, during the test year. For each, show the accounts and amounts in which such cost is being recorded.

d. Provide a copy of any and all cost/benefit analyses for each research and development project for which the Company is incurring cost, or for which costs are being allocated to the Company, during the test year.

e. Provide the amount of R&D expense recorded in each year, 2005 through calendar year 2010 and identify the accounts charged.

Respondent: Revenue Requirements / Energy Efficient Technology Department

Response:

a. The Company does undertake projects that are anticipated to benefit its operations, but also undertakes projects that will benefit customers, the community and the natural gas distribution industry. In Decision No. 68487 (D.68487), pp. 60-61, the Commission directed Southwest Gas to fund R&D projects, subject to oversight by the Commission. The funds for such projects are collected from customers through a surcharge, and held and disbursed through a balancing account.

b. While some R&D projects have potential cost benefits, most natural gas R&D pursued by the Company is difficult to analyze from a traditional cost-benefit analysis perspective. Rather the Company considers potential benefits such as enhanced pipeline safety or integrity, streamlined operation and maintenance activities, improved end-use energy efficiency, and improved processes to address environmental challenges.

The Company has established an internal research committee comprised of representatives from engineering, operations, construction, environmental, and energy efficiency groups. This committee reviews research proposals taking into consideration the potential benefits discussed above, and recommends projects to fund. An internal steering committee has also been established, which reviews and approves recommendations brought forward by the research committee.

In addition to the Company committees, the projects are reviewed by the ACC Staff every year as ordered in D.68487. The Company is required to file a list of projects to be funded every year. Before the official filing, the Company hosts a conference call with the ACC Staff to discuss the projects. Once Southwest makes its official filing, typically around April, the Commission has 30 days to provide the Company input on the projects funded for the given year.

c. Please refer to the attached worksheet for the list of R&D projects undertaken by Southwest Gas in accordance with D.68487. In addition, Southwest Gas has pursued energy efficient technology projects, specifically a gas engine driven air conditioner or what is termed the "GEDAC" project. This has been a part of Southwest Gas' efforts to utilize energy efficient technologies to help reduce electric peak demand, assist in the transition to a more environmentally-friendly and carbon neutral society, and more efficiently and effectively use natural gas in desert climates. This project was undertaken with the knowledge and encouragement of the Commission Staff and Commissioners. This project was also sponsored and co-funded by the U.S. Department of Energy. Amounts allocated to Arizona for this project during the test year in Account 908 totaled $337,959.

d. The Company does not conduct a traditional cost-benefit analysis for each R&D project. The Company does, however, evaluate potential benefits for every project and these benefits are noted in each project description in the attached worksheet.

e. Please refer to the table below and attached worksheet.

Year	Amount	Account	General Description
2005	$55,000	92100001	Gen. Studies (AGF), Pipeline Integrity and Keyhole (GTI), Yield Strength (ASME)
2006	$20,000	92100001	Keyhole (GTI)
2006-2010	See attached worksheet	18236403	See attached worksheet

Southwest Gas Arizona Research
Summary Report
February 25, 2011

Ref. Number	Organization/Project Name	Research Performer	Project Description	*Potential* Benefits to AZ Customers	Apr '06 - Mar. '07 Funding	Apr. '07 - Mar. '08 Funding	Apr. '08 - Mar. '09 Funding	Apr. '09 - Mar. '10 Funding	Apr. '10 - Mar. '11 Funding
	Operations Technology Development (OTD) Program								
	Dues (Project Allocation and Administrative Costs)				***$430,000***	***$430,000***	***$430,000***	***$430,000***	***$216,108***
	Carry over from previous year					$268,500	$91,360	$115,082	$233,892
	Refunds/Royalties								$3,084
	Total Available for Allocation					***$698,500***	***$521,360***	***$545,082***	***$453,084***
OTD-0	OTD Administrative Costs	GTI			$21,500	$21,500	$22,399	$32,250	$33,750
OTD-1	**(1.6.h) Complete** Project Development and Field Testing of the Digital Leak Detector	GTI	The objective of this project is to develop and commercialize a leak detection and pinpointing digital leak detector (DLD) that is proven in multi-utility applications. The DLD detects the acoustic signal created by the gas or fluid escaping the pressurized pipe.	Improved accuracy in pinpointing hard to find leaks. In addition, reduced costs in pinpointing leaks.	$40,000	$18,120	$7,550		
OTD-2	**(1.7.a) Complete -** Universal Utility Locator	GTI	The objective of this project is to develop a prototype locating system that is able to locate plastic and other non-metallic pipes in a variety of soil conditions. The prototype will also be able to provide information about depth, diameter and material composition of the pipe.	Reduced costs in locating non-metallic pipe.		$20,000	($11,365)		
OTD-3	**(1.7.b) CANCELED** Low-Cost, Nano-Methane Sensor	GTI				$0			
OTD-4	(1.8.g) Acoustic Sewer Lateral Locator	GTI	Trenchless pipe installation techniques greatly reduce natural gas pipe installation costs and minimize impact to the environment and general public. Unfortunately, there have been occasions where a gas plastic pipe has been unintentionally installed through a sewer lateral and the operator is unaware of this situation. The intent of this project is to develop acoustic tools/processes. The key challenges to address include:1) operations in all types of soil under various operating conditions, 2) cost effectiveness of the device, and 3) ease of operation by field crews.	Enhanced safety through a more accurate method of locating sewer laterals. In addition, reduced costs in locating sewer laterals.			$15,000	$14,368	

Southwest Gas Arizona Research
Summary Report
February 25, 2011

Ref. Number	Organization/Project Name	Research Performer	Project Description	*Potential* Benefits to AZ Customers	Apr '06 - Mar. '07 Funding	Apr. '07 - Mar. '08 Funding	Apr. '08 - Mar. '09 Funding	Apr. '09 - Mar. '10 Funding	Apr. '10 - Mar. '11 Funding
OTD-5	(1.h) Hand-held Acoustic Pipe Detector (Phase II & III)	GTI	The objective of this project is to design, build and test a commercial-grade (Phase III), handheld pulse-echo sonic detector capable of detecting and locating small diameter metallic and nonmetalic pipe in all soil types.	Reduced costs in locating non-metallic pipe.	$15,000	$11,893		$10,902	$3,624
	(1.10.a) Ethane Only Detector	GTI	Natural gas typically contains 1-5% ethane. When situations require the identification of natural gas is crtitical (ex., distinguishing between sewer gas or pipeline natural gas), detection of ethane can help verify natural gas is present. This project will develop a handheld instrument which can be utilized rapidly and easily in the field to resolve the absence or presence of ethane as a fingerprint for natural gas whenever the origin of a methane signal is questionable. Optical technology will be utilized.	Reduced costs in distinguishing natural gas vs. other sources of methane.					$5,000
OTD-6	(2.7.b) Qualification of Saddle and Electrofusion Joint Designs and Test Methods to Validate Safe Long Term Performance	GTI	The objective of this project is to develop a novel approach to ensure the safe and long-term performance of various types of lateral connections including: saddle heat fusion joints, electrofusion joints, and mechanical joining.	Improved joining procedures and/or joint evaluation, to ensure long term joint integrity.		$25,000	$12,500	$15,000	$15,000
OTD-7	(2.7.d) Cold Adhesive Repair (CAR) and Joining of Polyethylene Pipes with Minimal Surface Preparation	GTI	The primary objective of this project is to develop and commercialize an economical, reliable, and safe technology to quickly and effectively repair damaged and leaky PE gas pipes using modern structural cold adhesives, optimized for low-surface-energy-materials such as PE, that: require little surface preparation, cure at typical field temperatures, cure within short periods not exceeding 90 minutes, and do not require any tools, heating, pressure or significant training.	Reduced costs in repairing damages to plastic pipe.		$10,000	$9,268		

Southwest Gas Arizona Research
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OTD-8	(2.7.e) External Repair Tool for PE Pipe	GTI	The overall objective of this project is to continue the research that Timberline has already conducted to: optimize the design of the repair patch and repair patch material, optimize the design of the mechanical tool to apply the repair patch, and perform appropriate testing and address regulatory codes for the repair patch to be accepted as a repair method for PE pipe.	Reduced costs in repairing damages to plastic pipe. Enhanced safety by allowing the repair of damaged plastic pipe from above ground (i.e not in the ditch)		$45,000	$32,936		$10,000
OTD-9	(2.7.g) Composite Pipeline Repair Systems - Analysis of Adhesive Degradation - Permanence of Repair	GTI	This project will include the evaluation of the adhesives used in commercially available composite repair techniques to establish if their performance dictates a "permanent" or "temporary" repair classification for the overall repair system. Composite system repairs depend heavily on the adhesives used to transfer the load from the repaired pipe to the repair system. In order to fully assess the suitability of such repairs (as permanent or temporary solutions), the possibility of degradation of the adhesive over time must be investigated.	Enhanced integrity and possible reduced costs in repairing steel pipe.		$25,000	$15,018	$12,922	
OTD-10	**(2.7.h) Complete - Investigate a Mitigation Strategy for Elemental Sulfur Deposits in Gas Pipelines (SWG Initiated Project)**	GTI	A review and evaluation of the cause of elemental sulfur powder deposit in gas pipeline equipment.	Enhanced safety and reliability by better understanding root cause of sulfur deposits. In addition, possible reduced costs in addressing/resolving deposits.		$44,000	($15,719)		

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OTD-11	(2.8.c) Electrofusion Coupling Guidelines	GTI	Extensive work has been done to develop the electrofusion (EF) joining process and to investigate both the short and long term performance of coupling joint. However, a great deal of dimensional variation can exist with the fit of the coupling onto the pipe due to differences in EF coupling tolerances, tooling, and installer practices. Current industry standards for EF couplings place no limitations on the coupling I.D. tolerances, scrapping limits, or the annular gap. The objective of this project is to develop guidelines to address these issues.	Improved joining procedures and/or joint evaluation, to ensure long term joint integrity.			$5,000	$0	
OTD-12	(2.9.e) HP stopping equipment	GTI	To develop "high pressure" inflatable stoppers as an alternative to currently employed stopping equipment for routine and emergency stopping operations on pipe materials such as steel, cast iron, PE, and PVC. New line stopping equipment can address challenging by-pass or pipe shut-off situations. In addition, inflatable stoppers could save significant time and money during day to day operations.	Reduced costs in emergency stopping operations.				$15,000	$10,128
OTD-13	(4.5.d) Complete - Monitor Internal Corrosion Using Fluidized Sensors	GTI	The objective of this project is to develop sensors and delivery package that can be introduced into the gas stream and identify likely locations of internal corrosion as they flow through the pipeline. This type of information would reduce the total number of required excavations for internal corrosion assessment or eliminate the need to excavate the pipe altogether.	Reduced costs in detecting internal corrosion areas.	$25,000	$4,997		($1,903)	
OTD-14	(4.6.a) Repair Techniques for Low Stress Pipelines	GTI	Testing and assessment of various repair techniques will be conducted to help provide justification for their use as long term repair methods on low stress pipelines allowed by CFR 49 Part 192. Results may help reduce the cost of repairing the steel pipelines by minimizing the need to cut full sections of pipe to make repairs.	Enhanced integrity and possible reduced costs in repairing steel pipe.	$25,000	$10,714	$22,551	$0	

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OTD-15	**(4.6.b) Complete** - Risk-Based DIMP Procedure for Plastic Gas Pipelines	GTI	The primary objective of this project is to develop a risk-based distribution integrity management procedure and software for companies to manage their plastic distribution pipelines.	Improved process for assessing plastic pipe risks.	$25,000	$13,500	$12,790		
OTD-16	**(4.7.a) Complete.** In-Field Corrosion Rate Measurement for IMP	GTI	The purpose of this project is to provide a systematic and simple method to measure the general corrosion rate of steel or cast iron materials in the field and to collect and measure key soil and environmental parameters responsible for pitting/localized corrosion for a pipeline region/system. These sets of data (with select pre-assessment data) will be entered into a simple computer program/spreadsheet that combines the measured and collected data with historical/statistical data and provides a realistic corrosion growth rate to calculate reassessment intervals.	More efficient method for determining corrosion rates.		$30,000	$36,923		
OTD-17	**(4.7.f)** Internal inspection sensor and platform for Explorer II (robot for 6"/8") (NYSEARCH)	NYSEARCH	See description under 4.3 below. This is the same effort but was funded under a separate OTD line item. Efforts under this funding is complete.	Application of a new technology to help meet PHMSA's integrity management regulations. In addition, possible reduced assessment costs for steel transmission pipe.		$25,000			
OTD-18	**(4.7.g)** Yield Strength Determination using pipe coupons	GTI	Federal safety regulations establish a minimum yield strength of steel pipe at 25,000 psi if the specifications of the steel pipe are unknown. Current methods to determine actual yield strength are cumbersome in that a pipe section is removed, which typically requires the pipeline to be taken out of service. This project is evaluating the determination of yield strength from small pipe coupons that do not require the pipeline to be taken out of service. If successful, the process developed will provide SWG a more economic option to determine yield strength which would allow SWG to more appropriately address the risks posed by the pipeline.	Reduced costs in determining actual yield strength of in-service pipe.		$17,000	$15,941	$10,000	$8,458

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OTD-19	(4.8.a) Guided Wave Validation as Hydro Equivalent	GTI	Guided wave technology is being used to assess steel transmission pipe in casings as a result of federal transmission pipeline integrity regulations. Federal regulators however, are uncertain of the effectiveness and limitations of the technology. The purpose of this project is to compare the defects identified by guided wave technology to those identified in a pressure test (typically conducted as a hydro/water test). Pressure testing is currently accepted by federal regulators as an assessment technology.	Enhanced safety and integrity of transmission facilities covered under PHMSA's integrity management regulation through the appropriate use of guided wave technology. In addition, possible reduced costs to meeting regulations.			$25,000	$19,036	
OTD-20	(4.8.g) GTI/NYSEARCH North American Casing Program (GTI Project)	GTI	All steel pipe in casings that fall within the scope of federal transmission pipeline integrity management regulations, have to be assessed by December 2012. Pipelines in casing are challenging to assess because they are often un-piggable, can not be taken out of service to conduct a pressure test, and have limited external corrosion direct assessment tools that are applicable. The intent of this program is to identify and conduct research projects through the collaboration of all stakeholders that include pipeline operators, federal and state regulators, research organizations, and manufacturers and service providers.	Enhanced safety and integrity of transmission facilities covered under PHMSA's integrity management regulation through the appropriate use of casing assessment methodologies. In addition, possible reduced costs to meeting regulations.			$15,000		
OTD-21	(4.8.i) Extended Reassessment Interval Validation Through Dielectric Wax Casing Fill	GTI/Profile	To develop in-situ corrosion monitoring techniques and validation testing associated with the use of dielectric wax used to fill a casing. Monitoring techniques will be used for determining corrosion growth rate and for ensuring the quality and long-term performance of the wax fill. The results of the monitoring techniques could be used to help justify an extend re-assessment intervals for confirmatory direct assessment under integrity management regulations.	Improved understanding of affects of wax fills on corrosion rates. Possible reduced costs to meeting PHMSA integrity management regulations.			$10,000	$9,333	$7,033

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OTD-22	(4.9.a) Increase Trmn. Boundary 20 -> 30% SMYS	GTI	This project attempts to verify that a lower boundary of 20% SMYS for transmission classification is overly conservative. The work in this project will involve an international incident review and mathematical modeling (if necessary) to demonstrate that a lower boundary of 30% SMYS is more representative of actual leak vs rupture failures. The overall objective of the project will be to provide regulators and operators with information based on sound engineering principles that allows the selection of the most appropriate integrity management process.	Better understanding of risks and consequences of failures on lower stressed transmission pipelines. Results could provide a basis to reduce PHMSA integrity management requirements, thus reducing costs, without sacrificing safety.				$19,000	$13,963
OTD-23	(4.9.b) 2" Camera for Live Gas Internal Inspection	TBD	To identify, develop, and/or demonstrate the use of a camera for the internal inspection of 2-inch gas mains without having to shut off the flow of gas and segment the pipe. This will be done by identifying a capable camera and then, working with the manufacturer, making modifications (if necessary) for live gas use. Fittings will also be reviewed and developed if necessary. The device and fittings will be capable of inspecting 2-inch and larger PE, PVC, steel, or cast iron mains.	Reduced costs for inspecting 2" gas mains.				$15,000	$29,219
OTD-24	(4.10.a) 4" MFL Tethered Inspection Tool for Unpiggable Pipe	GTI	A tethered 4" MFL tool capable of entering transmission pipe in live conditions has been developed but not fully demonstrated. In addition, no efforts have been pursued for a similar tool for larger pipe sizes (6" - 12"). If this technology is effective, then it could help utilities inspect transmission pipe in casings that fall under the PHMSA integrity management rules. This particular effort includes the demonstration of the 4" tool.	Application of a new technology to help meet PHMSA's integrity management regulations. In addition, possible reduced assessment costs for steel transmission pipe.					$25,183

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OTD-25	(4.e) Inspection Platforms for Unpiggable Pipelines (NYSEARCH)	NYSEARCH	This is a NYSEARCH effort that is being funded with OTD funds. There are 2 NYSEARCH robotics inspection tools for un-piggable pipe, included in these efforts. One is the development of an Explorer II robot that utilizes an Remote Field Eddy Current (RFEC) sensor for 6" - 8" pipe. The other is for the TIGRE robot that is for 22" - 24" pipe and utilizes MFL technology. Both efforts were initiated due to transmission integrity management regulations promulgated by PHMSA. Distributions companies like SWG operate transmission pipelines that can not accommodate traditional in-line inspection tools (i.e. smart pigs).	Application of a new technology to help meet PHMSA's integrity management regulations. In addition, possible reduced assessment costs for steel transmission pipe.		$105,000		$11,484	$86,923
OTD-26	(5.6.c) Complete - Field Collection of Mapping and GIS Information Using GPS Coordinates: Phase 2	GTI	The objective of this project is to develop a system that automatically collects digital mapping and GIS data during routine operations (locates, leak survey, corrosion monitoring, meter reading). This will be accomplished by implementing methodologies and software to attach GPS coordinates to field data. The field data will be collected using an "electronic work ticket" that geo-codes the data with no additional operator effort.	Evaluation of processes that may help reduce costs in updating mapping systems.		$1,000			
OTD-27	(5.6.e) Complete. Portable Propane Air Residential Temporary Gas Supply	GTI	The purpose of this project is to research, design, prototype, test, and commercialize a portable Propane-Air system for use as a temporary gas supply on residential applications.	New device that can keep customers in-service during maintenance to gas facilities.	$10,000	$8,404			
OTD-28	(5.7.a) Re-Coating with Minimal or No Surface Preparation for Vaults and Other High Moisture Environments (SWG Initiated Project)	GTI	The project will research/develop a coating system that can be applied over gas piping with little or no surface preparation that will prevent atmospheric corrosion.	Reduced costs by reducing the amount of work required to re-coat pipe.		$45,000	$40,645		

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OTD-29	**Complete - (5.7.c)** Guidelines for Use of Copper Clad Steel Tracer Wire	GTI	The objective of this project is to test and evaluate Copper Clad Steel (CCS) tracer wire under laboratory and field conditions, examine the properties of the wire to develop installation methods, develop an installed wire comparison to copper wire, and to provide guidelines for the use of copper clad steel tracer.	Reduced costs by utilizing an alternative material to copper.		$25,000	$18,421		
OTD-30	(5.7.f) Automated Meter Shut-Off Device (AMS)	GTI	This project will develop an automated meter shut-off (AMS) device that would fit over the current meter shut-off valve (existing meter inlet valve) without the need to interrupt gas supply to the customer. Upon remote actuation of the battery powered device releasing the rotary actuator (via itron type device or drive by vehicle), the AMS will close the gas meter inlet valve, stopping the flow of gas through the meter.	Reduced costs in installing a remote shut off device.		$5,000	$4,519		
OTD-31	**(5.7.l) Complete -** Integrating Radio Frequency Identification (RFID) into Daily Gas Operations	GTI	The overall project objective is to demonstrate that the use of direct burial RFID can save considerable time and effort in daily utility operations for a very modest cost.	Reduced costs in data collection processes.		$5,000			
OTD-32	**(5.6.q) Complete -** EFV testing	GTI	Starting in June of 2008, all natural gas service lines to certain types of services will be required to have an excess flow valve (EFV) installed. This is a result of a new federal pipeline safety regulation issued in 2007. The purpose of this project is to conduct independent testing and analysis of various EFVs to help operators determine the most appropriate EFVs to utilize in their distribution systems.	Enhanced safety through the selection of appropriate EFV types.		$30,000	$26,933		

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OTD-33	(5.7.p) GPS Consortium (GTI Project)	GTI	The objective of the GPS Consortium Program is to facilitate technology transfer regarding the use of GPS technology for utility operations. The program activities include demonstrations, identification of research needs, workshops, pilot projects, best practices/standards development and general information sharing. A key focus is to establish standards or best practices for GPS data collection and GIS integration processes.	Reduced costs in implementing new GPS and GIS systems or devices.		$15,000		$15,000	
OTD-34	**(5.8.b) Complete** - Study of Anode Life Effectiveness (SWG Initiated Project)	GTI	The intent of this project is to identify the various factors affecting the life of one pound anodes utilized in isolated steel services in AZ.	Enhanced safety through the appropriate specification and application of anodes.			$30,000		
OTD-35	(5.8.e) Development of Standardized Algorithms and Identifiers for Enhanced Material Tracking and Traceability	GTI	The purpose of this project is to develop a series of protocols that can be used effectively by gas distribution companies to more accurately track their underground facilities. The protocols will be developed from standardized algorithms and identifiers to characterize the various components within the gas distribution network (pipe, fittings, and appurtenances). These are then to be integrated within a utility's procurement, design, build, and construction process. Material traceability is important, particularly in the event that products are identified with defects that may affect the integrity of the system.	Standardized traceability among major gas carrying component manufacturers. This could help reduce costs associated with establishing internal tracking processes.			$15,000	$10,798	$8,333
OTD-36	**(5.8.n) Complete** - Quality Assurance Remote Management (QARM) - GPS Cameras for Joint Inspection	GTI	The objective of this program is to identify and develop procedures and tools to allow inspectors and management to monitor the quality of field operations remotely. This program will identify key elements to consider if implementing the use of cameras to photograph plastic joining operations as a means of recording visual inspections.	Enhanced inspection reporting.			$10,000		

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OTD-37	(5.9.c) Mitigating Electrical Interference on CP Systems	GTI	To identify or develop practices that mitigate the effects of electrical interference on cathodic protection (CP) and telemetry systems. In addition to steady state AC interference, transient conditions such as power line faults and lightning strikes will be examined. The evidence for corrosion or damage that is caused by AC interference will also be examined. This project will focus on particular areas evident to LDCs, such as those related to light-rail systems or underground high voltage electric lines.	Enhanced safety by mitigating interference on CP systems. Also, possible reduced costs in mitigating interference.				$20,000	$19,980
OTD-38	(5.9.j) Gas Distribution Model (GTI Project)	GTI	The objective of this program is to develop an industry data model and standards for natural gas distribution operators to reduce the cost of software implementation, increase interoperability, and improve data collection efforts. The Gas Distribution Model (GDM) and standards will specify the data structure for operations, assets, field data collection, and regulatory compliance without requiring operators to restructure their existing data model.	Standardized approach in creating distribution risk models. This could help reduce costs in establishing or implementing various types of risk models.				$5,000	$5,000
OTD-39	(5.10.g) Indoor Air Quality and Safety Issues	GTI	This effort is to gather historical information and research on indoor air quality and safety issue. This will provide a readily available resource for natural gas operators to help address codes, standards, and guidelines that attempt to dis-allow or discourage gas appliances.	Will help ensure natural gas appliances are treated fairly in codes, standards, and guidelines.					$20,000
OTD-40	(6.6.a) Keyhole Project	GTI	Keyhole technology provides access to buried pipelines through a hole approximately 18" in diameter. This small size has many advantages including, lower excavation costs and required resources and minimal impact and restoration to pavement. This program evaluates and demonstrates new applications for keyhole technology.	Reduced excavation and restoration costs.		$20,000		$20,000	$0

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OTD-41	**(6.8.a) GTI Carbon Management Initiative (GTI Project)**	GTI	The CMIC is intended to serve as a clearinghouse for relevant carbon management information and to develop, where necessary, credible information products and functional tools to meet the needs of investors and their customers. Some deliverable for 2008 include a public-access and members-only website containing technical reports and information on products and a database of energy use profiles of gas, oil and electric end-use technologies for residential and commercial markets	Better understanding of the role natural gas end-use equipment has in reducing overall energy use and in reducing green house gas emissions (i.e. CO2).			$25,000	$25,000	$30,000
OTD-41	**(6.8.c) Complete** - Study on Direct Use of Nat. Gas to Reduce CO2 (GTI Project)	GTI	The goal of the program is to provide credible, defensible technical information on the benefits and costs of direct use of natural gas in residential, commercial, and industrial markets to reduce greenhouse gas emissions. The approach to achieve that goal in this program is to perform scenario analyses using the National Energy Modeling System (NEMS), the economy-wide, integrated energy model used by the Energy Information Administration to provide energy market and infrastructure projections to 2030.	Better understanding of the role natural gas end-use equipment has in reducing overall energy use and in reducing green house gas emissions (i.e. CO2).			$5,000		
OTD-42	**(7.7.b) Complete** - Evaluating Distribution Greenhouse Gas Sources, including Field Measurement Program	Other	This project to be completed by Innovative Environmental Solutions, Inc. (IES), will improve high priority greenhouse gas (GHG) emissions factors (EFs) for estimation of GHGs from measurement and regulation facilities. The emission factors investigated will be determined based on input from project investors and the results of an AGA collaborative project with INGAA and API that prioritized GHG emission factors for natural gas systems.	Enhanced standardized GHG emissions reporting. Also, possible reduction in costs associated with tabulating GHG emissions from distribution systems.		$15,000	$14,448		

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OTD-43	(7.7.d) Complete Biogas: Guidance for Dairy Waste (GTI Project)	GTI	Biogas from dairy cow waste can be processed and utilized as a renewable energy. The objective of this project is to help develop a basis for a national standard on the quality of biogas for acceptance into natural gas pipeline systems. This project will assess and document available domestic and international information to develop a broader knowledge base related to biogas production, gas treatment, gas quality standards, and gas quality test protocols. In addition, it will develop and execute a laboratory-testing program to evaluate raw (before cleanup) and post-cleanup biogas in order to assess quality, safety, and compatibility with existing supplies, pipeline delivery infrastructure, and customer end use equipment.	Reduction in overall green house gas emissions through the use of renewable gas. Also, local supply of gas may help reduce gas costs to customers.		$20,000		$3,000	
OTD-42	(7.8.a) (GTI) Biogas: Guidance for Landfill and Water Treatment Facilities	GTI	This project is primarily being funded by the U.S. Department of Transportation's Pipeline and Hazardous Material Safety Administration (DOT/PHMSA). This project attempts to develop guidance on requirements on accepting biogas from landfills and waste water treatment facilities into natural gas pipelines. This project will include a sample collection and data analysis program to include up to a total of 90 samples (40 raw/20 clean landfill gas, 10 raw/10 clean wastewater treatment biogas and 10 natural gas samples).	Reduction in overall green house gas emissions through the use of renewable gas. Also, local supply of gas may help reduce gas costs to customers.				$15,000	
OTD-43	(7.9.c) Biogas: Siloxane Concentrations, Phase I (GTI Project)	GTI	The objective of this project is to initiate the assessment and documentation to help prepare guidance material on acceptable levels of siloxane in biogas, mainly from landfills and wastewater treatment plants. This project is aimed at developing a detailed test program for determining acceptable siloxane levels.	Reduction in overall green house gas emissions through the use of renewable gas. Also, local supply of gas may help reduce gas costs to customers.				$0	$10,000

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OTD-44	(7.9.d) Improving Methane Emission Estimates for LDCs - Phase I	GTI/Heath	This is in relation to OTD project 7.7.b which addressed pipeline measurement and regulation equipment. This 7.9.d project address emissions from pipelines. Current estimation methodologies for quantifying fugitive and vented methane emissions are broad based and may over or under estimate actual emissions based on an operators pipeline system characteristics. The resulting emission methodologies should ultimately be integrated with existing gas distribution software and system tools to allow for convenient implementation and reasonable methane emissions management practices.	Enhanced standardized GHG emissions reporting. Also, possible reduction in costs associated with tabulating GHG emissions from distribution systems.				$15,000	$2,292
OTD-47	(7.9.e) Biogas: Portable Package for On-site Analysis	GTI	The objective of this project is to develop a cost-effective portable (skid-mounted or smaller) analytical package (instrumentation or surrogate analytical techniques) for biomethane.					$0	
OTD-45	(7.10.a) Trace Constituents Phase I (GTI Project)	GTI	The purpose of the overall study (Phase I and Phase II) is to more fully understand the trace constituent profile in natural gas, so that more accurate comparison of renewable natural gas with existing natural gas supplies may be facilitated. The natural gas industry will benefit from this study because an updated analytical profile of trace constituents will be amassed, through a sampling and analysis program of natural gas samples collected throughout various regions in the US.	Reduction in overall green house gas emissions through the use of renewable gas. Also, local supply of gas may help reduce gas costs to customers.					$5,000
OTD-46	(7.10.b) Odor Fade Guidelines (GTI Project)	GTI	The goal of the project will be to provide a "Practical Pipeline Operator Guide" to manage odor fade issues associated with typical gas system operating conditions and materials of construction.. This will include a tested methodology to validate additional combinations of Gas, System, and Material scenarios.	Enhanced safety through the appropriate specification and procedures for ensuring sufficient odorant in distribution systems.					$12,940

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OTD-47	(7.10.c) Improving Methane Emissions Estimate for LDCs Phase II	GTI	This is a continuation of 7.9.d and will entail field testing using the procedure developed from Phase 1. Field measurements will be compared to previous estimates.	Enhanced standardized GHG emissions reporting. Also, possible reduction in costs associated with tabulating GHG emissions from distribution systems.					$20,000
OTD-48	Other - UTD MIT Study Support on Direct Use of Gas	GTI	The MIT study is being conducted on behalf of DOE. Initially, this study did not consider direct use of natural gas as means of reducing overall energy consumption and a reduction in green house gases. This funding will help MIT expand the scope of their work to address direct use of natural gas.						$5,000
					$161,500	*$616,128*	*$420,758*	*$311,190*	*$386,826*
				Credits		*$8,988*	*$14,480*		
				OTD Balance	*$268,500*	*$91,360*	*$115,082*	*$233,892*	*$66,258*

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	NYSEARCH								
	NYSEARCH Membership Dues				***$37,500***	***$12,400***	***$67,150***	***$40,000***	***$40,000***
NYS-1	**Complete** - Effect of Gas Quality Changes on Pipeline Components	GTI	Natural gas received as LNG import gas, has different gas quality characteristics as compared to the natural gas historically received from North American supplies (US and Canada). Import LNG is typically "drier" and hotter than domestic supplies. This dry gas has been identified as a potential cause of leaks in mechanical fittings due to the drying of the elastomers. This study will evaluate various compositions of "dry" natural gas to elastomers used in various types of mechanical fittings.	Enhanced safety through the use of appropriate interchangeability standards/guidelines for new sources of natural gas.	$41,560				
NYS-2	**Complete** - Demonstration of Long Range Ultrasonic tool at NYSEARCH test bed	NYSEARCH	The purpose of this effort is to test and evaluate a specific guided wave ultrasonic tool utilized by SWG. At the time of this evaluation, PHMSA did not establish rigorous guidelines for the use of such tools.	Enhanced safety and integrity of transmission facilities covered under PHMSA's integrity management regulation through the appropriate use of guided wave technology. In addition, possible reduced costs to meeting regulations.	$27,600				
NYS-3	Rock Impingement resistance of PE pipe	Hessel Labs	The objective of this project is to determine resistance of polyethylene pipe to rock impingement. New grades of plastic pipe have appeared to more resistant to rock impingement but no thorough evaluations have been conducted.	Enhanced safety and integrity of PE pipe through improved pipe installation procedures (if required)	*$12,140*				

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Ref. Number	Organization/Project Name	Research Performer	Project Description	*Potential* Benefits to AZ Customers	Apr '06 - Mar. '07 Funding	Apr. '07 - Mar. '08 Funding	Apr. '08 - Mar. '09 Funding	Apr. '09 - Mar. '10 Funding	Apr. '10 - Mar. '11 Funding
NYS-4	Butt Fusion Joint Integrity Program	GTI	This work is being done in conjunction with project OTD-6 (2.7.b) related to lateral joint integrity. A controlled butt heat fusion process will be developed on the basis of comprehensive testing and evaluation using novel test methodologies in order to validate the safe long term performance of PE butt fusion joints over their intended design life. The process will take into account actual in-service stress states through comprehensive computer modeling and empirical testing. Criteria will then be developed to identify suspect joint via short and long term testing. Finally, key criteria for existing and future NDE technologies will be identified.	Improved joining procedures and/or joint evaluation, to ensure long term joint integrity.	$13,450			$26,485	
NYS-5	**Complete** - Casing assessment technologies		To develop & share information about the performance of inspection technologies on cased pipe in five field applications. Five service providers using 2 types of guided wave technologies will evaluate similar pipe segments.	Enhanced safety and integrity of transmission facilities covered under PHMSA's integrity management regulation through the appropriate use of casing assessment methodologies. In addition, possible reduced costs to meeting regulations.		$33,955			
NYS-6	Gas Quality Impact on Residential Appliances	Environ/GTI	Natural gas received as LNG import gas, has different gas quality characteristics as compared to the *natural gas historically received from* North American supplies (US and Canada). Import LNG is typically "drier" and hotter than domestic supplies. The impact of the changes in gas quality to residential appliances has been known to cause some safety issues because gas burners are adjusted for a certain range of gas quality specifications. The intent of this project is to help identify the effects of varying gas quality in residential appliances.	Enhanced safety through the use of appropriate interchangeability standards/guidelines for new sources of natural gas.			$35,425		

Ref. Number	Organization/Project Name	Research Performer	Project Description	*Potential* Benefits to AZ Customers	Apr '06 - Mar. '07 Funding	Apr. '07 - Mar. '08 Funding	Apr. '08 - Mar. '09 Funding	Apr. '09 - Mar. '10 Funding	Apr. '10 - Mar. '11 Funding
NYS-7	Complete - 3rd Party Detection and Damage	Magal	This effort will evaluate technologies that can be applied to third party monitoring that were developed by Magal Senstar Inc. The applications are: 1) PipeGuard – consist of sensing units that consist of geophones buried 3 feet below grade to sense third party intrusions, 2) Dreambox – a video analytics platform that uses cameras to detect and alarm when it recognizes images of excavating equipment. The intent is to determine if these technologies are effective and practical to apply to pipeline monitoring to help prevent 3rd party damage.	Enhanced safety through the identification of 3rd party threats to pipelines.		$9,360			
NYS-8	Casing risk assessment methodology (M2001-003-B, Phase III)	Maibauer	Integrity management regulations require that transmission pipeline in casings in high consequence areas be assessed. The challenge with casings for distribution companies, is that ECDA and ILI tools are not feasible to utilize. The objectives of the proposed project are to: 1) develop a simple tool for making data validated decisions on assessment or monitoring of cased pipes in HCAs, and, 2) allow a streamlined and formal approach for prioritizing casings inspection activities that can be integrated with other benchmarking and technology developments for this purpose.	Standardized approach to assessing risk of casings. Possible reduced costs in conducting risk analysis of casings.				$4,440	$17,000
NYS-9	Explorer Demonstration in AZ (robotics demo)	Invondane	The objective of this effort is to field demonstrate the Explorer II in-line inspection robot in a SWG 8" transmission pipeline facility in Phoenix. This is one of the tools we are funding under OTD-17 and OTD-25 above. The approximate length of the demonstration would include about 3,000 feet of pipe. The sensor technology is a Remote Field Eddy Current (RFEC) which is not commercially used in the industry (i.e. standard is MFL).	Application of a new technology to help meet PHMSA's integrity management regulations. In addition, possible reduced assessment costs.				$0	*$60,000*

Southwest Gas Arizona Research
Summary Report
February 25, 2011

Ref. Number	Organization/Project Name	Research Performer	Project Description	*Potential* Benefits to AZ Customers	Apr '06 - Mar. '07 Funding	Apr. '07 - Mar. '08 Funding	Apr. '08 - Mar. '09 Funding	Apr. '09 - Mar. '10 Funding	Apr. '10 - Mar. '11 Funding
NYS-10	NDE inspection technology for PE fusions joints	TWI	The key objective of this effort are to determine the detection capabilities of TWI's existing NDE equipment for 4" and 8" PE butt fusions. In addition, this effort intends to determine critical flaw sizes that impact long term integrity of butt fusion joints. Finally, this effort will include the manufacturing of a new prototype system(s) that will be demonstrated at various utilities.	Enhanced safety and integrity through detection of defective fusion joints.					*$0*
					$132,250	*$55,715*	*$102,575*	*$70,925*	*$117,000*

Southwest Gas Arizona Research
Summary Report
February 25, 2011

Ref. Number	Organization/Project Name	Research Performer	Project Description	*Potential* Benefits to AZ Customers	Apr '06 - Mar. '07 Funding	Apr. '07 - Mar. '08 Funding	Apr. '08 - Mar. '09 Funding	Apr. '09 - Mar. '10 Funding	Apr. '10 - Mar. '11 Funding
	American Gas Foundation (AGF)								
AGF-1	**Complete** - Study on Research and Development in Natural Gas Transmission and Distribution	GOIA	This effort will consist of a comprehensive review of past and current RD&D funding and programs for the natural gas transmission and distribution pipelines.	Better understanding of RD&D organizations and efforts which will help SWG in managing AZ customer RD&D dollars.	$15,000	$0			
AGF-2	Bldg. Energy Codes and Stds. Research	Misc.	Natural gas safety standards and guidelines that apply to facilities downstream of the meter, are critical in helping ensure that natural gas is used safely in buildings and residences. This effort helps provide technical research to support changes to codes and standards.	Enhanced safety in the utilization and application of natural gas equipment.	$25,000	$0			
					$40,000	*$0*	*$0*	*$0*	*$0*
	Managed by EETD								
EETD-1	Gas Engine Driven Heat Pump Water Heater		A natural gas engine driven heat pump can be utilized for hot water heating which would increase the total energy efficiency as compared to current natural gas or electric water heaters. This development would be a multiple year project including phases for research, bread boards, prototyping site verification and installation.	Such a product would provide an opportunity to replace existing inefficient water heaters and provide a better energy alternative for new construction buildings.	$46,737	$100,000		$1,242	
EETD-2	Solar Air Conditioning with Natural Gas back-up		This solar demonstration project will illustrate the value of utilizing solar energy to cool homes, supermarkets, office buildings, factories, etc. Solar will be the primary energy source with natural gas as the back-up. Solar energy would be utilized during daylight hours and natural gas at night or on cloudy days. The purpose of this solar air conditioning demonstration is to show the significant environmental benefits and consumer energy savings potential of the technology.	A possible more efficient, effective and environmentally friendly way to air condition buildings.	*$28,017*	$85,000		$126,187	$3,000

Southwest Gas Arizona Research
Summary Report
February 25, 2011

Ref. Number	Organization/Project Name	Research Performer	Project Description	*Potential* Benefits to AZ Customers	Apr '06 - Mar. '07 Funding	Apr. '07 - Mar. '08 Funding	Apr. '08 - Mar. '09 Funding	Apr. '09 - Mar. '10 Funding	Apr. '10 - Mar. '11 Funding
EETD-3	CO_2 sensor for industrial natural gas boilers		A small number of larger boilers with output >10 million BTUs, use oxygen and carbon monoxide (CO) sensors to calculate hydrocarbon and CO2 levels, to optimize combustion. The recent advent of a novel gas sensor technology platform capable of producing low cost sensors that can measure directly flue hydrocarbon and CO2 levels, offers an alternate and better method for maximizing combustion efficiency for gas burners. The purpose of this project would be to determine the applicability and feasibility of utilizing this new sensor for existing boilers, to improve the overall efficiency.			$0			
EETD-4	Solar Thermal Domestic Water Heating and Hydronic Space Heating with Natural Gas Backup		The solar thermal domestic water heating and hydronic space heating project will demonstrate the efficient use of solar energy and natural gas to meet the day to day hot water and space heating demands of single family homes. The solar thermal energy will be used as the primary energy source and natural gas will be used as the backup or secondary energy source.	Demonstrates the potential natural gas savings from the use of solar thermal systems.				$4,228	$3,000
EETD-5	Gas Engine Driven Heat Pump - Generator Addition for Plug-in Hybrid		Natural gas engine drive heat pumps are currently being commercialized in AZ. The engine utilized in these heat pumps can be utilized to drive an electric generator, which could then be utilized to help charge a plug-in hybrid. Some effort has already been initiated in this regard, and this funding would help further evaluate appropriate generators and plug-in vehicle charging requirements.	Demonstrates the potential for further development of commercial gas heat pumps providing plug-in vehicle charging. This would help SWG AZ customers with plug-in vehicles reduce their overall electric grid requirements to charge their vehicles.				$0	

Southwest Gas Arizona Research
Summary Report
February 25, 2011

Ref. Number	Organization/Project Name	Research Performer	Project Description	*Potential* Benefits to AZ Customers	Apr '06 - Mar. '07 Funding	Apr. '07 - Mar. '08 Funding	Apr. '08 - Mar. '09 Funding	Apr. '09 - Mar. '10 Funding	Apr. '10 - Mar. '11 Funding
EETD-6	GHP Prototype w/Stirling Engine combined with EHP (Deluge and 10-ton EHP 13 SEER)		The objective of this project is to evaluate whether additional efficiencies can be gained from overall GHP performance utilizing a stirling engine. A prototype unit will be developed using a sterling engine and an off the shelf 13 SEER electric heat pump. The sterling engine will utilize natural gas as a fuel source.	While this is a proof of concept effort, if proven feasible, such a product would provide additional efficiencies for gas cooling applications.				$35,700	$50,000
EETD-7	Solar Thermal System Equipment Demo		An additional system will be installed for a commercial or residential application to further evaluate actual operations and energy usage from solar thermal systems. While manufacturers have published data on potential energy savings of solar thermal systems, actual savings varies significantly depending on application and use by customers. Evaluation of more systems are required to provide SWG customers a better estimate of potential savings. The location of the installation is yet to be determined.	Demonstrates the potential natural gas savings from the use of solar thermal systems.				$8,256	$15,000
EETD-8	GHP Demonstration Project in AZ		The objective of this effort is to further demonstrate the energy savings of GHP applications. This project would include the purchase and installation of GHPs at a SWG customer facility. Data monitoring equipment would be added.	Demonstrates potential overall building energy savings by the use of gas heat pumps.					$200,000
					$74,754	***$185,000***	***$149,830***	***$175,613***	***$271,000***

Southwest Gas Arizona Research
Summary Report
February 25, 2011

Ref. Number	Organization/Project Name	Research Performer	Project Description	*Potential* Benefits to AZ Customers	Apr '06 - Mar. '07 Funding	Apr. '07 - Mar. '08 Funding	Apr. '08 - Mar. '09 Funding	Apr. '09 - Mar. '10 Funding	Apr. '10 - Mar. '11 Funding
	ASME Pipeline Research								
ASME-1	**Complete.** Application Guide for *Determining Yield Strength* of In-Service Pipe Using Hardness Testing (Previously paid $10K under O&M)		Federal safety regulations establish a minimum yield strength of steel pipe at 25,000 psi if the specifications of the steel pipe are unknown. Current methods to determine actual yield strength are cumbersome in that a pipe section is removed, which typically requires the pipeline to be taken out of service. This project evaluates the use of hardness testing which does not require a cut out of pipe sections, to correlate to the pipes yield strength. A significant portion of this effort will be to develop a field guide on how to use hardness testing to correlate to yield strength.	Reduced costs in determining actual yield strength of in-service pipe.	$10,000	$0			
	Other								
OTH-1	Research consultant - help manage projects, develop proposals	Campbell	SWG will utilize this outside consultant to help manage and/or stay abreast of projects funded. Consultant will also help SWG prepare research proposals, specific to SWG's needs, to present to various research organizations.	Helps provide input on projects funded by SWG to help ensure they are to the benefit of AZ customers.	$1,000	$18,000	*$11,116*	$4,691	$10,000
OTH-2	Safety Vest Evaluation/Testing	SWG	The objective of this project is to help identify appropriate safety vests for field use during natural gas emergencies. Safety vests require reflective coatings, however vests utilized by SWG have experienced color degradation as well as static charges. GTI will evaluate phenomenon behind issues and tests various vests on the market.	Enhanced safety through the application of appropriate safety vests.					$25,000
OTH-3	SWG Application of ASME Hardness Testing Procedure	SWG	This project will design and familiarize Southwest Gas technical staff and field inspectors with the capabilities and limitations of the methodology described in ASME CRTD-91 "Applications Guide for Determining the Yield Strength of In-Service Pipe by Hardness Evaluation".	Reduced costs in determining actual yield strength of in-service pipe.					*$15,000*
					$1,000	*$18,000*	*$11,116*	*$4,691*	*$50,000*

Southwest Gas Arizona Research
Summary Report
February 25, 2011

Ref. Number	Organization/Project Name	Research Performer	Project Description	*Potential* Benefits to AZ Customers	Apr '06 - Mar. '07 Funding	Apr. '07 - Mar. '08 Funding	Apr. '08 - Mar. '09 Funding	Apr. '09 - Mar. '10 Funding	Apr. '10 - Mar. '11 Funding

Allocation Summary

Apr '06 - Mar. '07 Funding	Apr. '07 - Mar. '08 Funding	Apr. '08 - Mar. '09 Funding	Apr. '09 - Mar. '10 Funding	Apr. '10 - Mar. '11 Funding
$688,004	$688,715	$693,521	$681,229	$654,108
$688,712	$688,712	$688,712	$683,903	$688,712
$708	-$3	*-$4,809*	*$2,674*	*$34,604*

General Notes:

1	**Total authorized collection in Final Order is $688,712 per year. Funding is collected in a deferred balancing account (18236403)**
2	**Proposed projects reflected in current or proposed funding year may change. Some projects may terminate pending progress or proposed projects may not materialize due to lack of support. In addition, research organizations meet and discuss new and existing projects at**
3	**Actual allocation amount may change due to changes in projects described in 2 above or due to number of companies that ultimately**

	April 2009 - March 2010	April 2010 - March 2011
Total Available	$688,712.00	$688,712.00
EETD Allocation		
Operations Allocation		$256,108.00
EETD Balance	$62,607.44	
Operations Balance	$70,129.83	
Total Balance	***$132,737.27***	***$432,604.00***

500-017

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-7
(ACC-STF-7-1 to ACC-STF-7-23)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 31, 2011

Request No. ACC-STF-7-17:

Intellichoice Energy LLC.

a. Identify and explain all charges from Intellichoice Energy LLC to Southwest Gas during the test year, by account.

b. For each charge from Intellichoice Energy LLC to Southwest Gas identified in response to part a, describe how Southwest Gas has treated the charge for ratemaking purposes in the current rate case.

c. Identify and explain all services and products that are being purchased by Southwest Gas from Intellichoice Energy LLC.

d. Identify which of the services and products identified in response to part c were the subject of competitive bid or request for proposal (RFP) process.

Respondent: Revenue Requirements / Energy Efficient Technology Department

Response:

Per Staff Data Request ACC-STF-11-1(a), this response is being supplemented with information for the pre-Intellichoice Energy (ICE) period, including costs from all entities associated with Tommis Young that were involved in GHP technology, which include Team Consulting, All Air Systems, Blue Mountain Energy, Summit Energy Efficiency Resources, Sundance Energy Holdings, Governet, and Precision Sheet Metal. Blue Mountain Energy and Governet are owned by Paula Young.

a. Please refer to the attached file for the requested information. There were no test year charges for Summit Energy Efficiency Resources, Sundance Energy Holdings, Governet, or Precision Sheet Metal.

b. The ratemaking treatment of the charges included in the attached file are as follows. Charges to Account 107 are included in rate base in the Southern Nevada ratemaking jurisdiction and do not impact Arizona rates. Charges to Account 182.3 are recovered through the Arizona R&D Surcharge, and not in base rates. Charges to Accounts 886 are charged to Arizona operating expenses, and charges to Account 893 are charged to Southern Nevada operating expenses. Charges to Account 426.5 are considered "below-the-line" and are not recovered in rates in any ratemaking jurisdiction. Charges to Account 143 were related to the formation of ICE and not recovered in rates in any ratemaking jurisdiction. Charges to Account 908 are allocated to each state ratemaking jurisdiction based on the 4-Factor.

c. Description of products and/or services purchased by Southwest: ICE: consulting, engineering and testing services and reimbursement for materials. Blue Mountain Energy: project management and administrative services and reimbursement for materials. All Air Systems Inc: maintenance of AISIN units located in Bullhead City district office. Team Consulting: consulting, engineering, and testing services, and reimbursement for materials.

d. These vendors were considered sole source providers during the test year. None of the services and/or products identified in part c to this response were subject to a competitive bid or RFP process.

SOUTHWEST GAS CORPORATION
CHARGES FROM ICE AND OTHER TOMMIS YOUNG-RELATED ENTITIES
FOR THE TWELVE MONTHS ENDED JUNE 30, 2010
IN RESPONSE TO DATA REQUEST NO. STF-7-17

Line No.	Description (a)	Ratemaking Treatment (b)	Amount (c)	Line No.
	Intellichoice Energy, LLC (ICE)			
1	182.3	AZ R&D Surcharge	$ 62,210	1
2	426.5	Below-the-line, not recovered in rates	53,865	2
3	908	4-Factor Allocation	235,441	3
4	Total		$ 351,516	4
	Team Consulting			
5	143	Not recovered in rates	$ 408,570	5
6	182.3	AZ R&D Surcharge	71,345	6
7	908	4-Factor Allocation	365,956	7
8	Total		$ 845,871	8
	All Air Systems			
9	107	Southern Nevada Rate Base	$ 86,714	9
10	886	Arizona Operating Expenses	3,696	10
11	893	Southern NV Operating Expenses	57,546	11
12	Total		$ 147,956	12
	Blue Mountain Energy			
13	182.3	AZ R&D Surcharge	$ 641	13
14	908	4-Factor Allocation	131,001	14
15	Total		$ 131,642	15

499-012

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-6
(ACC-STF-6-1 to ACC-STF-6-41)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 23, 2011

Request No. ACC-STF-6-12:

Injuries and Damages. Refer to Decision No. 70665, at pages 13-15. Please provide all information needed to compute the allowance for Injuries and Damages in the current SWG rate case to be computed similarly to how that allowance was determined in SWG's last Arizona rate case, Docket No. G-01551A-07-0504.

Respondent: Revenue Requirements

Response:

Please refer to the attached schedule that calculates the self-insured component of injuries and damages expense in a manner consistent with Staff's and ultimately the Commission's adoption of Staff's calculation in the last rate case proceeding. Simply put, the Staff in the last rate case calculated the ten-year average of Arizona direct self-insured amounts up to and including $1 million for each claim. The Staff in the last rate case removed the only claim that was for an amount greater than $1 million up to $5 million, otherwise referred to by the Company as the self-insured aggregate. The Staff also included the four-factor allocation of liability insurance which covers the cost of claims above the $5 million aggregate self-insurance amount. Finally, the Staff also included the cost of Arizona direct self-insured workers compensation expense along wtih miscellaneous legal expense associated with injuries and damages. The Company's proposal in this proceeding mirrors Staff's calculation in the last rate case except for one item. The Company's proposal includes a normalized cost for the category of self-insurance not included in the Staff calculation. The Company uses the ten-year average of the two Arizona claims that exceed the $1 million self-insured retention, but limited each incident to the current $5 million maximum. The aggregate for the two incidents totaled $10 million, which when divided by ten years averages out to $1 million per year. The Company then four-factors this amount to Arizona. The self-insured aggregate has the effect of reducing system allocable liability insurance premiums, therefore, allocating these costs to all jurisdictions appears reasonable.

SOUTHWEST GAS CORPORATION
INJURIES AND DAMAGES, ACCOUNT 925
IN RESPONSE TO STF 6.12
RESERVE FOR SELF-INSURANCE EXPENSE NORMALIZATION
TEST YEAR ENDED JUNE 30, 2010

Line No.	Description		Company Test Year As Recorded (a)	Company Requested As Filed (b)	Staff Proposed (c)	Staff Adjustment (d) Col (c)-(b)
	Arizona Direct					
1	Legal and Other Costs		$ 718,799	$ 718,799	$ 718,799	$ -
2	Reserve for Self Insurance		$ 537,500	$ 834,961	$ 720,000 b	$ (114,961)
3	Workmen's Comp Expense		$ 308,201	$ 308,201	$ 308,201	$ -
4	Self-Insured Workmen's Self-insured		$ -	$ -	$ -	$ -
5	Total Arizona Direct		$ 1,564,500	$ 1,861,961	$ 1,747,000	$ (114,961)
	Common Before Allocation to Arizona					
6	Legal and Other Costs		$ 269,748	$ 269,748	$ 269,748	$ -
7	Reserve for Self Insurance		$ 275,000	$ 1,000,000	$ 275,000 b	$ (725,000)
8	Self-Insured Workmen's Comp		$ -	$ -	$ -	$ -
9	Insurance		$ 9,927,437	$ 9,927,437	$ 9,927,437	$ -
10	Subtotal before Paiute Allocation		$ 10,472,185	$ 11,197,185	$ 10,472,185	$ (725,000)
11	Paiute Allocation	3.83%	$ (401,591) a	$ (429,393) a	$ (401,591) a	$ 27,803
12	Subtotal after Paiute Allocation		$ 10,070,594	$ 10,767,792	$ 10,070,594	$ (697,197)
	Arizona Allocation of Common					
13	Legal and Other Costs	56.25%	$ 151,728	$ 151,728	$ 151,728	$ 0
14	Reserve for Self Insurance	56.25%	$ 154,682	$ 562,481	$ 154,682	$ (407,799)
15	Self-Insured Workmen's Comp	56.25%	$ -	$ -	$ -	$ -
16	Insurance	56.25%	$ 5,583,990	$ 5,583,990	$ 5,583,990	$ 0
17	Paiute Allocation	56.25%	$ (225,887)	$ (241,525)	$ (225,887)	$ 15,638
18	Total Common Allocated to Arizona		$ 5,664,513	$ 6,056,673	$ 5,664,513	$ (392,160)
19	Total Arizona Direct and Allocated		$ 7,229,013	$ 7,918,634	$ 7,411,513	$ (507,121)
20	Company's proposed adjustments to Account 925 in its filing			$ 689,621	$ (507,121)	
				Col.B - Col.A		
	Components of Company's proposed adjustments to Account 925, I&J Expense:					
21						
22	SWG Adjustment 9, Self Insured Retention Normalization			$ 661,818 b	$ (479,319)	
23	SWG Adjustment 10, A&G Expenses, Annualized Paiute Allocation			$ 27,803	$ (27,803)	
24	Total Company-proposed adjustments to Account 925 expense			$ 689,621	$ (507,121)	
25	Percentage increase over test year recorded amount			10%	-7%	
26	Staff proposed adjustment to SWG as-filed pro forma expense for Account 925					$ (507,121)

Notes and Source

a Line 10 multiplied by Paiute Allocation
b See page 2 of this schedule for replica of Staff Analysis of ten years of recorded expense

SOUTHWEST GAS CORPORATION
INJURIES AND DAMAGES, ACCOUNT 925
IN RESPONSE TO STF 6.12
RESERVE FOR SELF-INSURANCE EXPENSE NORMALIZATION
TEST YEAR ENDED JUNE 30, 2010

Line No.	Description	Year	Total Expense Recorded Arizona (A)	Total Expense Recorded Common (B)	Total Expense Recorded Without Extreme Expense from May 2005 Leaking Gas Line Fire Arizona (C)	Total Expense Recorded Without Extreme Expense from May 2005 Leaking Gas Line Fire Common (D)	Staff Proposed Arizona (E)	Staff Proposed Common (F)
	Reserve for Self-Insurance Expense							
1		2001	$ 426,955	$ 100,000	$ 426,955	$ 100,000		
2		2002	$ 350,000	$ 200,000	$ 350,000	$ 200,000		
3		2003	$ 1,941,509	$ (300,000)	$ 1,941,509	$ (300,000)		
4		2004	$ 2,154,000	$ 275,000	$ 2,154,000	$ 275,000		
5		2005	$ 1,360,224	$ 10,367,500 a	$ 1,360,224	$ 367,500 a		
6		2006	$ (975,540)	$ 200,000	$ (975,540)	$ 200,000		
7		2007	$ 713,629	$ (25,500)	$ 713,629	$ (25,500)		
8		2008	$ 230,000	$ (300,000)	$ 230,000	$ (300,000)		
9		2009	$ 400,000	$ 275,000	$ 400,000	$ 275,000		
10		2010	$ 537,500	$ 150,000	$ 537,500	$ 150,000		
11	Total		$ 7,138,277	$ 10,942,000	$ 7,138,277	$ 942,000		
12	Ten Year Average		$ 713,828	$ 1,094,200	$ 713,828	$ 94,200	$ 720,000 b	$ 275,000 c
13	Pauite allocation	3.83%		$ (41,961)		$ (3,612)		$ (10,546)
14	Common before AZ allocation			$ 1,052,239		$ 90,588		$ 264,454
15	AZ allocation	56.7%		$ 596,620		$ 51,363		$ 149,946
16	AZ allocated and direct		$ 713,828	$ 596,620	$ 713,828	$ 51,363	$ 720,000	$ 149,946
	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	$ 1,272,593	$ (1,745,235)	$ 1,272,593	$ (2,290,492)	$ 1,278,765	$ (2,191,909)
19	Net adjustment to Arizona expense		$ (472,642)		$ (1,017,899)		$ (913,144)	
			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	$ 1,572,593	$ (2,255,404)	$ 1,572,593	$ (2,800,661)	$ 1,578,765	$ (2,702,078)
22	Net adjustment to Arizona expense		$ (682,811)		$ (1,228,068)		$ (1,123,313)	
			L.21, Col.A&B		L.21, Col.C&D		L.21, Col.E&F	

Notes and Source

a May 2005 leaking gas line fire excluded.
b Ten-Year Average, rounded upward to nearest $10,000
c Whole year before test period.

518-003

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-20
(ACC-STF-20-1 to ACC-STF-20-3)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: APRIL 29, 2011

Request No. ACC-STF-20-3:

Regarding the customer-owned yard lines (COYLs), what would be the cost, timeline, and feasibility of doing a leak survey of all COYLs? Could this survey be completed in two years or in three years? Please provide a detailed cost estimate.

Respondent: Engineering

Response:

Southwest Gas is not responsible nor has any obligation for the maintenance (including the leak survey) of COYLs; thus the cost, timeline, and feasibility of such an activity is difficult to estimate due the lack of historical knowledge of and experience with the COYLs themselves. The COYLs are not mapped nor is information on their location usually available from the homeowners. The location of the underground COYLs, from the custody transfer point located at the outlet of Southwest Gas' meter to a customer's house, building or gas utilization equipment may not be obvious. The COYLs could also have one or more branch connections with extensions that do not surface above ground. The actual location of each underground COYL would be difficult and in many cases impossible to know with certainty unless the COYL was completely exposed. Additionally, the homeowners must grant Southwest Gas permission to access private property. Denial of such access would prevent Southwest Gas from performing the leak survey. Southwest Gas therefore does not believe it would be feasible to leak survey all COYLs.

Because Southwest Gas is not responsible for maintaining and servicing COYLs, it can only provide an estimate of the cost and timeline based upon experience and knowledge of leak surveying Company owned and mapped services. To leak survey a total of 102,570 services, which is the approximate number of COYLs in Southwest Gas' Arizona system, would cost an estimated $3,000,000 over a minimum three year timeframe. Additional costs and time would be realized when leaks are found on COYLs to properly secure the situation and turn off the service. When necessary, these actions also include evacuating the premises and ~~to~~ aerating any residual natural gas. Customers would also be notified of their financial responsibility to repair or replace the COYL prior to Southwest Gas reactivating their service.

512-007

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-16
ACC-STF-16-1 to ACC-STF-16-14)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: APRIL 20, 2011

Request No. ACC-STF-16-7:

COYL.

a. Please provide the Company's estimates total number of COYLs on Southwest's system if different from the 108,000 mentioned at page 9 of Mr. Schmitz's direct testimony.

b. Provide the actual (or if actual is not available, estimated) numbers of COYLs on Southwest's Arizona system for Central Arizona and Southern Arizona and, also, if available the numbers of COYLs located in each city, town, or district.

c. Please provide estimates of the COYL locations (city, town or district) that Southwest would propose to replace for $10 million in its pilot program.

d. Please provide Southwest's best estimate of the total cost of replacing all COYLs on its Arizona system.

e. Please provide Southwest's best estimate of the time frame it would take to replace all COYLs on its Arizona system assuming replacements were to occur at a rate of 5,000 every two years.

Respondent: Division Operations/Revenue Requirements

Response:

a. Southwest Gas' estimate of COYLs in Arizona has been further refined, based on feedback received as a result of customer mailings. Southwest Gas' current estimate of COYLs on its system in Arizona is 102,574.

b. The estimated number of COYLs on Southwest's Arizona system by district is as follows:

Eastern District:	1,944
Mountain District:	2,840
Southeast District:	2,489
Tucson District:	70,406
Valley District:	9,345
Yuma District:	846
Phoenix District:	12,919
Wickenburg District	348
Bullhead District:	1,437
	========
Total:	102,574

c. To maximize the available dollars for the pilot, a sampling strategy would be utilized to perform the replacements based on a representative sample of the population in Southwest Gas' Arizona service territory. Because the majority of COYLs are located in the Tucson district, it is expected that a representatively large portion of the pilot project would be conducted in that district.

d. Southwest Gas estimates that it can replace COYLs at an average cost of $2,000 per service, excluding those residences where there are significant physical obstacles. At 102,574 COYLs, Southwest Gas' best estimate of the total cost to replace COYLs on its system in Arizona is $205 million at current costs.

e. Given Southwest Gas' estimate of 102,574 COYLs, and assuming that all customers would want their COYL facilities replaced by utility-owned and operated facilities, at a rate of 5,000 replacements every two years as posed in this question, it would take approximately 41 years to replace all COYLs. Southwest Gas proposed the instant pilot program to gain experience with actual replacement costs and customer receptiveness to the program, and, pending Commission approval, would review its experience with the pilot program prior to proposing any further expansion of the COYL replacements to the Commission.

512-008

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-16
ACC-STF-16-1 to ACC-STF-16-14)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: APRIL 20, 2011

Request No. ACC-STF-16-8:

COYL. Please identify the number of COYLs that Southwest Gas has replaced in Arizona in each year, 2006 through 2010, and what the total cost was for each year.

Respondent: Division Operations/Revenue Requirements

Response:

The replacement of COYL is predominantly performed in Southwest Gas' Tucson district. The number and cost of COYLs replaced by year is as follows:

2006	498	$454,536
2007	432	412,406
2008	306	293,778
2009	322	331,278
2010	272	282,304

512-006

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-16
ACC-STF-16-1 to ACC-STF-16-14)
* * *
DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: APRIL 20, 2011

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: APRIL 20, 2011

Request No. ACC-STF-16-6:

COYL. Please identify all costs related to Southwest's installation of Southwest Gas facilities to replace customer owned yard lines for each of the following periods:

1. June 30, 2010 through December 31, 2010.
2. December 31, 2010 through March 31, 2011.
3. Projected/budgeted for March 31, 2011 through December 31, 2011.
4. Projected/budgeted for Calendar 2011.

Respondent: Revenue Requirements/Engineering

Response:

Consistent with Arizona Tariff Rule No. 6, section E(6)(b), Southwest Gas performs the replacement of customer owned yard lines (COYL) at the expense of the customer. Customer contributions for the installation of Southwest Gas facilities to replace COYLs are as follows:

June 30, 2010 through December 31, 2010: $159,730
December 31, 2010 through March 31, 2011: $173,966
Projected/budgeted for March 31, 2011 through December 31, 2011: $276,034
Total amount Projected/budgeted for Calendar 2011: $450,000

500-013

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-7
(ACC-STF-7-1 to ACC-STF-7-23)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 31, 2011

Request No. ACC-STF-7-13:

Rate case.

a. Please identify and provide Southwest's rate case filing plans.

b. Please describe how the plans identified in response to part a have affected the period selected by Southwest for the normalization of rate case cost for its current Arizona rate case.

Respondent: Revenue Requirements

Response:

a. Attached is Southwest Gas' most recent anticipated rate case preparation and processing work schedule, which covers 2011-2013.

b. Southwest Gas anticipates a four year rate case cycle in Arizona. Therefore, Southwest Gas proposed to amortize rate case expense over four years.

491-005

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 to ACC-STF-1-107)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 11, 2011

Request No. ACC-STF-1-5:

Please provide a complete copy (both in electronic and paper) of SWG's last complete depreciation study.

Respondent: Revenue Requirements

Response:

For corporate (i.e. system allocable) plant, a portion of which is allocated to Arizona, the last approved depreciation study was filed in Nevada during 2007 using a period ended date of December 31, 2006. The system allocable rates approved in Nevada are used in all of Southwest's ratemaking jurisdictions so the appropriate amounts of corporate plant are recovered in rates from Southwest's Arizona, Nevada, and California customers.

At the time of the last depreciation study in Arizona, Arizona had two separate rate jurisdictions: Southern Arizona and Central Arizona. In 1996, the two Arizona rate jurisdictions were combined into one rate jurisdiction and the depreciation rate for the combined jurisdiction was a blended average of the existing rates for the Southern Arizona and Central Arizona jurisdictions. This combined rate is the currently approved rate used in the Arizona rate jurisdiction.

The complete studies are attached in electronic format only since the studies are voluminous.

512-001

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-16
ACC-STF-16-1 to ACC-STF-16-14)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: APRIL 20, 2011

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: APRIL 20, 2011

Request No. ACC-STF-16-1:

Yuma Manors.

a. Provide a breakout of the $225,445 rate base amount mentioned on page 21 of Mr. Mashas' testimony between (1) Plant and (2) Accumulated Depreciation.

b. Identify the property tax expense included in jurisdictional operating expenses by Southwest related to the $225,445 rate base amount for Yuma Manors. Include supporting calculations.

c. Identify the Depreciation expense included in jurisdictional operating expenses by Southwest related to the $225,445 rate base amount for Yuma Manors. Include supporting calculations.

Respondent: Revenue Requirements

Response:

Please refer to the attached calculations.

SOUTHWEST GAS CORPORATION
2010 ARIZONA GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
YUMA MANORS PIPE REPLACEMENT
DATA REQUEST STF 16.1

Line No.	Description	Account	Account 376 Mains Amount (A)	Account 380 Services Amount (B)	Total Amount (C)	Line No.
	I. Costs Recorded by Company Through End of Test Year Ended April 30, 2007					
	A. For New Plant Replacing the Original Plant					
1	Costs incurred prior to and during the test year	101	$ 368,689	$ 247,193	$ 615,881	1
2	Accumulated Depreciation	108	(550)	(603)	(1,153)	2
3	Net Plant in Service - replacement plant		$ 368,139	$ 246,590	$ 614,729	3
	B. For the Original Cost of Plant Installed 1954-1958					
	1. Plant in Service					
4	Gas Plant in Service	101	$ 75,770	$ 13,731	$ 89,501	4
5	Gas Plant Retired	101	(75,770)	(13,731)	(89,501)	5
6	Gas Plant in Service After Retirement	101	$ -	$ -	$ -	6
	2. Accumulated Depreciation					
7	Accumulated Depreciation recorded at April 2007	108	$ (135,640)	$ (28,599)	$ (164,239)	7
8	Gas Plant Retired	108	75,770	13,731	89,501	8
9	Removal costs incurred prior to and during the test year	108	2,069	4,166	6,234	9
10	Impact on Accumulated Depreciation	108	$ (57,802)	$ (10,703)	$ (68,505)	10
11	Impact on Net Plant		$ 57,802	$ 10,703	$ 68,505	11
	II. Staff Adjustment					
12	Remove impact on test year of replacement plant		$ (368,139)	$ (246,590)	$ (614,729)	12
13	Remove impact on test year of original plant retired		57,802	10,703	68,505	13
14	Adjustment to Test Year Net Plant		$ (310,337)	$ (235,887)	$ (546,224)	14
15	Adjustment to Test Year Plant in Service		$ (368,689)	$ (247,193)	$ (615,881)	15
16	Adjustment to Test Year Accumulated Depreciation		58,352	11,306	69,657	16
17	Adjustment to Test Year Net Plant		$ (310,337)	$ (235,887)	$ (546,224)	17
18	Decision No. 70665 Page 8 Line12		$ (182,250)	$ (138,529)	$ (320,779)	18
19	Decision No. 70665 Page 8 Line13		$ (128,087)	$ (97,358)	$ (225,445)	19
	Property Tax Expense					
20	Adjusted Net Plant In-Service				$ (225,445)	20
21	Assessment Ratio				20%	21
22	Assessed Property				$ (45,089)	22
23	Property Tax Rate				10.1263%	23
24	Property Tax Expense				$ (4,566)	24

	Depreciation Expense	Account 376 Mains Amount	Account 380 Services Amount	Total Amount	
25	Gross Depreciable Plant	$ (368,689)	$ (247,193)	$ (615,881)	25
26	Commission Adjustment	(182,250)	(138,529)	(320,779)	26
27	Adjusted Depreciable Plant	$ (186,438)	$ (108,664)	$ (295,102)	27
28	Depreciation Rate	3.82%	5.30%		28
29	Depreciation Expense	$ (7,122)	$ (5,759)	$ (12,881)	29

512-003

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-16
ACC-STF-16-1 to ACC-STF-16-14)

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: APRIL 20, 2011

Request No. ACC-STF-16-3:

Completed Construction Not Classified (CCNC) correction. In response to Staff discovery, including STF-6-7(a) and (c), the Company indicated that two work orders have not closed and should be removed from the Company's original adjustment, which should be reduced to $2,695,762. The reduction is $110,407.

a. Identify the amount of property tax expense included in jurisdictional operating expenses by Southwest related to the $110,407 correction for CCNC. Include supporting calculations.

b. Identify the amount of Depreciation expense included in jurisdictional operating expenses by Southwest related to the $110,407 correction for CCNC. Include supporting calculations.

Respondent: Revenue Requirements

Response:

The effects of removing work order 0036W1122904 for $35,055 and work order 0042W1001926 for $75,353 on property tax expense and depreciation expense are as follows:

Decrease in Net Plant in Service	$ 110,407
2011 Assessment Rate	20%
Subtotal	22,081
Property Tax Rate	10.1263%
Decrease in Property Taxes	$ 2,236

Decrease in Net Plant in Service	$ 110,407
Mains - Account 376 Depreciation Rate	3.82%
Decrease in AZ Direct Depreciation Expense	$ 4,218

512-002

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-16
ACC-STF-16-1 to ACC-STF-16-14)

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: APRIL 20, 2011

Request No. ACC-STF-16-2:

SCADA. The Company's response to data request STF-6-7(d) stated that: The Company is removing the $1,700,000 cost of the SCADA system originally included in Adjustment 17 in System Allocable Account 303. The Company's response to data request STF-6-19(a) states that: The ... SCADA System, has not yet been placed into service; therefore, the Company is no longer requesting that this item be included in rate base or amortization expense in this proceeding, reducing the plant in service increase to $4,139,131.

a. Identify the amount of property tax expense included in jurisdictional operating expenses by Southwest related to $1.7 million SCADA system that is being removed from plant because it was not in service by June 30, 2010. Include supporting calculations.

b. Identify the amount of Depreciation expense included in jurisdictional operating expenses by Southwest related to $1.7 million SCADA system. Include supporting calculations.

Respondent: Revenue Requirements

Response:

a.) Corporate System Allocable Plant located in the state of Nevada, is not subject to Arizona Property Taxes; therefore, the removal of $1,700,000 for the SCADA project had zero effect on property taxes.

b.) The removal of the SCADA project had the following effect on Depreciation and Amortization Expense:

Per Workpapers C-2, Adjustment No. 13, Sheet 8, Ln 40(k), the annual amortization was $170,000, based on a 10-year amortization period. After the 4-Factor percentage of 56.25%, the allocation to Arizona was $95,625.

491-083

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 to ACC-STF-1-107)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 11, 2011

Request No. ACC-STF-1-83:

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 2008, 2009 and calendar year 2010. Identify the accounts charged. Identify all incentive and bonus program expense charged or allocated to the Company from affiliates in 2008, 2009 and calendar year 2010.

Respondent: Human Resources

Response:

The Aspire, Constant Flame, GEM, and Management Incentive Plan ("MIP") programs are discussed in the Company's response to ACC-STF-1-50. Please refer to Attachment A for the current document related to the Service Planning Quality Award and Attachment B for the current document related to the Key Account Management ("KAM") Incentive Plan. Constant Flame (charged to Account 926) was replaced by GEM (charged to Account 920) in 2010.

Expenses incurred in 2008, 2009 and 2010 for each program are reflected on the attached spreadsheet. Please note the amounts shown for each program other than the Service Planning Quality Award are before allocation to Arizona.

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

SOUTHWEST GAS®

SERVICE PLANNING QUALITY INCENTIVE AWARD

2009/2010

Service Planning Quality Award for 2009/2010
Table of Contents

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Service Planning Quality Award – 2009/2010 4

1. Administrative Information

A. The effects of the Service Planning Quality Award on employee benefits are summarized below:

1. Salary Continuation Program

   Coverage is provided at no cost to the employee. Payments are based on the hourly rate computed from an individual's September 1 base salary and the previous four quarters total Quality Award compensation.

2. Retirement

   Quality Award compensation is included in the average effective earnings of the five highest calendar years of continuous service during the ten years immediately prior to termination.

3. EIP

   EIP contributions are deducted from Quality Award payments, when paid, at the rate specified by the individual. Contributions are matched $.50 on each $1.00 contributed up to seven percent (7%) of total annual earnings, subject to any IRS limitations.

4. Life Insurance

   a) Basic

      Salary utilized in the computation of life insurance entitlement is comprised of the individual's September 1 base salary and the previous four quarters total Quality Award compensation.

   b) Employee Custom Life Insurance

      Amounts available for purchase are factored off the earnings amount indicated in Basic Life Insurance above (employee paid).

c) Spouse Custom Life

Amounts available for purchase are factored off the earnings amount indicated in Basic Life Insurance above (employee paid).

5. Accidental Death and Dismemberment Insurance

a) Basic

Salary utilized in the computation of life insurance entitlement is comprised of the individual's September 1 base salary and the previous four quarters total Quality Award compensation.

b) Additional

Amounts available for purchase are set for all employees (employee paid).

c) Business Travel Accidental Insurance

Coverage is equal to the individual's September 1 base salary and the previous four quarters total Quality Award compensation. The premium is entirely Company paid.

6. Basic Long-term Disability

Coverage is provided at no cost to the employee. Payout is 66⅔ percent of the individual's September 1 base salary and the monthly average of the previous four quarters total Quality Award compensation.

B. Termination of or adjustments to this Quality Award program could occur at any time at the discretion of the Company, as determined by executive management.

Service Planning Quality Award

PROCESSING SCHEDULE
2009

QUARTER	DUE TO ENERGY SERVICES	DUE TO PAYROLL	PAYDATE
4TH 2008*	01/19/09	01/22/09	01/29/09
1ST 2009	04/15/09	04/20/09	04/24/09
2ND 2009	07/15/09	07/20/09	07/27/09
3RD 2009	10/16/09	10/21/09	10/28/09

Service Planning Quality Award

PROCESSING SCHEDULE
2010

QUARTER	DUE TO ENERGY SERVICES	DUE TO PAYROLL	PAYDATE
4TH 2009*	01/20/10	01/22/10	01/29/10
1ST 2010	04/19/10	04/21/10	04/28/10
2ND 2010	07/20/10	07/22/10	07/29/10
3RD 2010	10/19/10	10/21/10	10/27/10

Service Planning Quality Award 2009/2010

The Service Planning Quality Award was effective as of January 1, 2006.

The Service Planning Quality Award is based on the employee's outstanding achievement and performance for that quarter based on defined production criteria including, but not limited to, customer satisfaction, leadership, innovation and working within the allowable budget. The Quality Award value will be justified based on the defined criteria for the individual employee based on their service territory and submitted to the Division Vice President. Once approved by the Division Vice President, the values will be forwarded to the Energy Services Department for compilation and totaling with all divisions and forwarded to Payroll for processing.

The Service Planning Quality Award value will be up to a maximum of $2500.00 per quarter per Service Planner or Senior Service Planner, up to a maximum of $10,000 annually. A percentage of the award may be earned based on the measured results of the defined criteria.

The Service Planning Quality Award value will be up to a maximum of $3000.00 per quarter per Supervisor, up to a maximum of $12,000 annually. A percentage of the award may be earned based on the measured results of the defined criteria.

The Service Planning Quality Award value will be up to a maximum of $3000.00 per quarter per Manager, up to a maximum of $12,000 annually. A percentage of the award may be earned based on the measured results of the defined criteria. This plan for Service Planning Managers varies from the Service Planner, Senior Service Planner and Service Planning Supervisor in that the award is not included in the retirement calculation. The award, up to $3000 per quarter, is considered a bonus and therefore does not qualify to be included in the retirement calculation.

The Service Planning Quality Award will be paid quarterly.

SOUTHWEST GAS

KEY ACCOUNT MANAGEMENT

2010 PERFORMANCE INITIATIVE AWARD PLAN (PIA)

MANAGER, SUPERVISOR AND INDUSTRIAL GAS ENGINEER

Effective January 1, 2010

Revised: 10/29/09

2010 PIA Schedule - Key Account Management

Quarter	*Due to KAM*	*Due to Payroll*	*Pay date*
1st – 2010	4-12-10	4-21-10	4-28-10
2nd – 2010	7-12-10	7-22-10	7-29-10
3rd – 2010	10-8-10	10-21-10	10-27-10
4th – 2010	1-10-11	1-??-11	??

*These dates may change according to Payroll's schedule for the new year.

KAM PERFORMANCE INITIATIVE AWARD PLAN
IMPACT ON EMPLOYEE BENEFITS
SUPERVISOR AND INDUSTRIAL GAS ENGINEER

SALARY CONTINUATION PROGRAM

Coverage is provided at no cost to the employee. Payments are based on the hourly rate computed from an individual's September 1 base salary and the previous four quarters total PIA compensation.

RETIREMENT

For supervisors and Industrial Gas Engineers, PIA compensation is included in the average effective earnings of the five highest calendar years of continuous service during the ten years immediately prior to termination. This does not apply to managers and above.

EIP

EIP contributions are deducted from PIA payments, when paid, at the rate specified by the individual. Contributions are matched $.50 on each $1.00 contributed up to 7% of total annual earnings, subject to any IRS limitations.

LIFE INSURANCE

Basic

Salary utilized in the computation of Life Insurance entitlement is comprised of the individual's September 1 base salary and the previous four quarters total PIA compensation.

Employee Custom Life Insurance

Amounts available for purchase are factored off the earnings amount indicated in Basic Life Insurance above (employee paid).

Spouse Custom Life Insurance

Amounts available for purchase are factored off the earnings amount indicated in Basic Life Insurance above (employee paid).

Children's Life Insurance

$10,000 per child available (employee paid).

IMPACT ON EMPLOYEE BENEFITS

SUPERVISOR AND INDUSTRIAL GAS ENGINEER

ACCIDENTAL DEATH AND DISMEMBERMENT INSURANCE

Basic

Salary utilized in the computation of Life Insurance entitlement is comprised of the individual September 1 base salary and the previous four quarters total PIA compensation.

Additional

Amounts available for purchase are set for all employees (employee paid).

Business Travel Accident Insurance

Coverage is equal to the individual's September 1 base salary and the previous four quarters total PIA compensation. The premium is entirely Company paid.

LONG TERM DISABILITY

Coverage is provided at no cost to employee. Payout is 66-2/3% of the individual's September 1 base salary and the monthly average of the previous four quarters total PIA compensation.

KAM PERFORMANCE INITIATIVE AWARD PLAN
GUIDELINES AND CALCULATIONS
KAM MANAGER

Program Objective: To incent the KAM Manager to achieve exceptional performance in the areas of customer service, project development/management and contract negotiations related to maintaining or improving the Company's margin. These activities seek to maximize the use of the Company's distribution system which benefits and protects captive customers (residential) by spreading fixed cost recovery over a greater number of customers/volumes.

Program Goals:

- Maintain and increase margin from qualified new and existing KAM customers through installations of new, additional or incrementally larger natural gas equipment.
- Ensure that Southwest Gas facility investments meet required criteria and that security/risk concerns are appropriately addressed.
- Maximize annual margin collection from customers that can demonstrate the ability to use an alternate energy source.

General Guidelines:

- Incentive payment will occur within the following two months of each quarter.
- The Manager will receive 10% of the aggregate amount of incentives earned by the IGE's and Supervisors.
- The Manager may earn a one-time $1,000 incentive payment for each special project successfully negotiated. Special projects are those that require significant negotiating time, investment and involvement of different Corporate departments.
- Termination of or adjustments to this program may occur due to changes in the overall economic condition of the Company.

KAM PERFORMANCE INITIATIVE AWARD PLAN
GUIDELINES AND CALCULATIONS
SUPERVISOR AND INDUSTRIAL GAS ENGINEER

Program Objective: To incent the IGE/Supervisor to achieve exceptional performance in the areas of customer service, project development/management and contract negotiations related to maintaining or improving the Company's margin. These activities seek to maximize the use of the Company's distribution system which benefits and protects captive customers (residential) by spreading fixed cost recovery over a greater number of customers/volumes.

Program Goals:

- Maintain and increase margin from qualified new and existing KAM customers through installations of new, additional or incrementally larger natural gas equipment.
- Ensure that Southwest Gas facility investments meet required criteria and that security/risk concerns are appropriately addressed.
- Maximize annual margin collection from customers that can demonstrate the ability to use an alternate energy source.

General Guidelines:

- At its discretion, management will review the IGE/Supervisor's salary in accordance with the Employee Salary Administration program. The KAM Performance Initiative Award Plan and Employee Salary Administration programs are independent.
- The PIA Plan document will be reviewed annually by KAM management. Continuation of the PIA Plan and incentive programs within the Plan can change at management's discretion from year to year.
- PIA payments generally occur within two months after the end of each quarter. The specific dates are determined by the Payroll Department.
- PIA payments will be based on increasing the company's margin and/or negotiating contracts with KAM qualified accounts (as defined in SP 910.0).
- Termination of, or adjustments to, this program may occur at any time at the discretion of management.
- Under special circumstances compensation under the PIA may be shared by a KAM team where more than one IGE/Supervisor was involved in the project.
- Project costs shall include all facility related costs attributed to serving the customer minus non-refundable Contributions in Aid of Construction (CIAC). Project costs include, but are not limited to the following: Cost of any required taps or tap upgrades, approach mains, onsite mains, reg stations, services and meters.
- All natural gas equipment installed by a Customer and claimed under the PIA must be recorded and verified by the IGE/Supervisor. Each quarter, projects may be audited at

random to verify installation of claimed equipment.

- Compensation under the PIA can only be earned on new or existing KAM qualified accounts. However, at management's discretion, a project that does not qualify as a KAM account on its own may be eligible for a PIA as long as the project is managed by an IGE/Supervisor.
- Caps noted in the Plan apply to an overall project. If the project is broken into phases, an incentive may be requested on each phase if either: 1) the phases could be considered discrete projects so that the cap would be applied to each phase; or 2) it takes multiple phases to reach the incentive cap amount for the project. When a project is organized into phases, the IGE, Supervisor, and KAM manager or designate must determine how the Plan will be applied.
- For purposes of this plan, Alternate Fuel Customers are defined as a class of customer who have historically shown a tendency to switch between energy sources. Examples include irrigation customers and asphalt plants. Also included are any customers who have installed or can easily change to facilities capable of using alternate fuels.
- The use of the Incremental Cost Method (ICM) or multiples of margin to calculate allowable investment in this Plan shall conform to the applicable tariff provisions at the time the award is requested. The multiples noted in the Plan are for illustrative purposes and may change from time to time as the tariff is updated.
- If any provision of this Plan shall be deemed to be prohibited or invalid under applicable law or tariff, such provision shall be ineffective only to the extent of such prohibition or invalidity.

Additional Margin:

Compensation under the PIA can be requested for projects that increase the Company's margin through the installation of new, additional or incrementally larger natural gas equipment or converting existing equipment from an alternate fuel to natural gas. When new equipment is displacing existing gas fired equipment, the net incremental margin will be used as the basis for calculating the award.

Projects for Alternate Fuel Customers without a minimum volume or margin commitment.

A project is eligible for a PIA at the end of the first anniversary date of the equipment being converted and/or the establishment of natural gas service. In addition,

- Project would only be eligible for a PIA if the account has been inactive for at least a one (1) year period.
- IGE/Supervisor must submit an Informational Notification Form describing the project during the quarter the equipment has been installed, is operational and any facility upgrades required by Southwest are complete.
- The customer must remain active for a minimum period of one year.
- A PIA in the amount of 20% of actual margin will be paid at the end of the first

anniversary date, subject to an overall project cap of $2,500.

- A PIA can only be requested once every four years for each account.
- In Arizona, projects must be evaluated using the Incremental Contribution Method (ICM). The project must still meet or exceed the minimum required rate of return with the PIA included. If the return is not acceptable with the PIA included, the award can be reduced accordingly.
- In Nevada, project costs must not exceed four (4) years of calculated annual margin.
- In California, project costs must not exceed 6.2 years of calculated annual margin.

Projects (other than for Alternate Fuel Customers) without a minimum volume or margin commitment.

A project is eligible for a PIA when the equipment has been installed; is operational and any facility upgrades required by Southwest are complete.

- IGE/Supervisor may be compensated up to 20% of the first year's incremental margin subject to a project cap of $2,500.
- In Arizona, projects must be evaluated using the Incremental Contribution Method (ICM). The project must still meet or exceed the minimum required rate of return with the PIA included. If the return is not acceptable with the PIA included, the award can be reduced accordingly.
- In Nevada, project costs must not exceed four (4) years of calculated annual margin.
- In California, project costs must not exceed 6.2 years of calculated annual margin.

Projects (including Alternate Fuel Customers) with a minimum volume or margin commitment.

A project is eligible for a PIA when the Minimum Annual Volume/Margin requirements begin.

- IGE/Supervisor may be compensated up to 20% of the project's incremental margin subject to a project cap of $3,000.
- All projects qualifying for this performance incentive must have a contract containing a minimum volume or minimum margin obligation from the customer.
- The primary term of such contract must be at least two years. Contracts with primary terms less than two years will be treated like projects without a minimum volume or margin obligation.
- The incentive calculation will be based on the lesser of the total contract margin or the margin from the first five years of the contract's primary term.
- In Arizona, project must be evaluated using the Incremental Contribution Method (ICM). The project must still meet or exceed the minimum required rate of return with the PIA included. If the return is not acceptable with the PIA included, the award can be reduced accordingly.
- In Nevada, project costs must not exceed four (4) years of calculated annual margin.

- In California, project costs must not exceed 6.2 years of calculated annual margin.

Contract Negotiation related to Margin Retention:

A performance incentive can be requested for contracts negotiated with Optional Fuel and Bypass capable customers when the contracted margin rate exceeds the required floor margin rate. The successful negotiation is eligible for a PIA when the term of the agreement begins. The following conditions/requirements apply:

- A PIA will be calculated as: 20% x (negotiated margin– floor margin).
- The PIA is subject to a cap of $2,500 per contract.
- A contract must be executed that includes; a minimum annual volume or margin obligation from the customer: financial disincentive to the customer for early contract termination, or; management approved equivalents.
- The floor margin rate will be calculated by the Pricing Department.
- The primary term of the contract must be greater than two years.
- The incentive calculation will be based on the lesser of the total contract margin or the margin from the first five years of the contract's primary term.

Special Incentive:

From time to time, KAM management may offer special incentives related to Company initiatives. These incentives will generally be short-term and will not be a permanent part of the Plan.

SOUTHWEST GAS CORPORATION
INCENTIVE COMPENSATION EXPENSES
CALENDAR YEARS 2008-2010
IN RESPONSE TO DATA REQUEST NO. STF-1-83

	MIP [1]	Aspire Award [1]	Constant Flame/ GEM [1], [2]	RSUP [1]	SP Quality Award	KAM Incentive Plan [1]
2008	$ 5,953,219	$ 133,500	$ 182,500	$ 1,327,123	$ 279,550	$ 123,650
2009	5,953,364	174,500	210,000	2,103,149	244,300	132,436
2010	6,946,420	73,500	196,000	1,835,028	214,025	124,789
Account	920	920	926/920	920	903	903

[1] Amounts are before allocation to Arizona.
[2] The Constant Flame Program (Acct 926) was replaced by the GEM Award (Acct 920) in 2010.

513-001

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-17
ACC-STF-17-1 to ACC-STF-17-2)

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: APRIL 21, 2011

Request No. ACC-STF-17-1:

SERP.

a. The response to STF-1-50(b) states that The amount of SERP requested for recovery in this proceeding allocated to Arizona is approximately $1.65 million. Please show in detail how the $1.65 million was derived and reconcile that amount to SWG's workpapers.

b. SWG Workpaper Supporting Adjustment No. 3, Annualized Employee Benefits, Line 12, show the following amounts for SERP:

Test Year Supplemental Executive Retirement Expense (Arizona)	$ (1,419,193)
Test Year Supplemental Executive Retirement Expense (Corporate Direct Arizona)	$ (70,565)
System Allocable Amount of SERP	$ (962,289)
Total	$ (2,452,046)

Please confirm that the test year amount for SERP in SWG's filing is $2,452,046. If not, show in detail what the Arizona jurisdictional amount is and how it was derived.

Respondent: Revenue Requirements

Response:

The amount of SERP requested for the Arizona jurisdiction in the filing is not $2,452,046. The $962,289 system allocable amount of SERP shown on WP C-2Adjustment No. 3, Sheet 5, Ln 12 is prior to allocation to Arizona. The attached schedule shows the approximate amount of SERP included in the filing, and includes references to workpapers supporting the calculations. The precise amount of SERP requested for recovery is impacted by numerous calculations within the cost of service model, including cash working capital and the labor loading allocations. The attached spreadsheet, which does not reproduce every calculation within Southwest Gas' cost of service model, but shows the largest components, shows an impact of approximately $1.73 million. Any changes to the allocation methods, charged labor amounts, or cash working capital components will impact the exact amount of SERP requested for recovery in Arizona.

SOUTHWEST GAS CORPORATION
SUPPLEMENTAL RETIREMENT PLAN
IN RESPONSE TO DATA REQUEST NO. STF-17-1

Line No.	Description	Arizona	Corporate Direct Arizona	System Allocable	Reference	Line No.
	(a)	(b)	(c)	(d)	(e)	
1	SERP	$ 1,419,193	$ 70,565	$ 962,289	WP C-2, Adj. No. 3, Sh 5, Ln 12	1
2	% O&M to Total - Arizona	81.36%			WP C-2, Adj. No. 3, Sh 18, Ln 11	2
3	% O&M to Total - Corporate		100%	96.17%	WP C-2, Adj. No. 3, Sh 20, Ln 9	3
4	% SERP to O&M	$ 1,154,655	$ 70,565	$ 925,433		4
5	Paiute and SGTC MMF Allocation			3.83%	Schedule C-1, Sh 18, Ln 8(h)+(i)	5
6	SERP Net of Paiute and SGTC			$ 889,989		6
7	Arizona 4-Factor Allocation			56.25% [1]	Schedule C-1, Sh 17, Ln 10(b)	7
8	System Allocable SERP to AZ			$ 500,619		8
9	Total SERP (Approximate)			$ 1,725,839	Ln 4(b) + Ln 4(c) + Ln 8(d)	9

[1] The majority of system allocable dollars are allocated to Arizona based on the 4-Factor, as shown on WP C-2, Adj No. 3, Sheets 21-22, Col (i)

254-052

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-6-52:

Please refer to Ms. Aldridge's direct testimony, page 24. Please show in detail how the Company identified the portion of AGA costs that relate to marketing and lobbying activities. Include a copy of any and all source documents used to identify those percentages.

Respondent: Revenue Requirements

Response:

The portion of advertising and lobbying costs was provided to Southwest by the AGA in the attached document.

AMERICAN GAS ASSOCIATION
2007 BUDGET

	$ 2007 ALLOCATION	% 2007 ALLOCATION
Advertising	$345,000	1.39%
Corporate Affairs	$2,099,000	8.44%
General & Administrative	$4,665,000	18.77%
General Counsel	$1,016,000	4.09%
Industry Finance & Administrative Programs	$1,283,000	5.16%
Operations & Engineering Management	$5,993,000	24.11%
Policy, Planning & Regulatory Affairs	$3,669,000	14.76%
Public Affairs	$5,790,000	23.29%
Total Budget	$24,860,000	100.00%

Note:
AGA estimates that lobbying expenses, as defined under IRC Section 162, will account for 2% of member dues in 2007.

254-050

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-6-50:

Please refer to Ms. Aldridge's direct testimony, Exhibit RLA-2.

a. Please provide a complete copy of the March 2005 Annual Audit report and show the percentages of AGA cost for each NARUC-designated functional category of AGA activities.

b. Does Southwest Gas or AGA have more current information on the percentage of AGA costs in each NARUC-designated functional category of AGA activities? If so, please provide the most current information.

Respondent: Revenue Requirements

Response:

a. Attached is the copy of the Annual Audit Report on the Expenditures of the American Gas Association (AGA) for the 12 month period ended December 31, 2002, dated March 2005. This report is the most recent audit report submitted to NARUC. According to the AGA, NARUC no longer requests that the AGA provide annual audit reports. The lobbying percentage is found on the page preceding the table of contents. The other percentages are found on page III-2.

b. Attached is the updated budget information for 2008 provided by the AGA to Southwest.

AMERICAN GAS ASSOCIATION
2008 BUDGET

	$ 2008 ALLOCATION	% 2008 ALLOCATION
Advertising	$300,000	1.18%
Corporate Affairs	$2,317,000	9.14%
General & Administrative	$5,127,000	20.22%
General Counsel	$1,056,000	4.17%
Industry Finance & Administrative Programs	$852,000	3.36%
Operations & Engineering Management	$5,505,000	21.71%
Policy, Planning & Regulatory Affairs	$4,000,000	15.78%
Public Affairs	$6,195,000	24.44%
Total Budget	$25,352,000	100.00%

Note
AGA estimates that lobbying expenses, as defined under IRC Section 162, will account for 4% of member dues in 2008.

491-072

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 to ACC-STF-1-107)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 11, 2011

Request No. ACC-STF-1-72:

Insurance Expense. Itemize each component of insurance expense included in the test year, and provide comparative information for calendar 2007, 2008, 2009 and 2010. Indicate the accounts and amounts in which each item of insurance expense is recorded.

Respondent: Revenue Requirements

Response:

Please see the attached schedule listing the recorded insurance expenses for the test year and calendar years 2007, 2008, 2009, and 2010.

SOUTHWEST GAS CORPORATION
ARIZONA
DATA REQUEST NO. STF-1-72
INSURANCE EXPENSE
2007-2009 AND TEST YEAR ENDING JUNE 30, 2010

Line No.	Description	Calendar Year 2007	Calendar Year 2008	Calendar Year 2009	Calendar Year 2010	Test Year TME June 2010	Line No.
	Account 924.0 0001						
1	Property	$ 472,664	$ 475,201	$ 513,300	$ 533,446	$ 555,425	1
	Account 925.0 0001						
2	Aviation Liability	$ 31,000	$ 27,595	$ 23,600	$ 21,350	$ 22,710	2
3	Commercial Crime	12,600	12,600	10,892	8,500	8,842	3
4	Commercial General Liability	7,520,456	7,653,674	7,593,283	7,668,278	7,713,146	4
5	D & O Liability	1,583,246	1,362,984	1,391,214	1,431,467	1,428,590	5
6	Employee Benefits	171,600	172,150	178,198	177,796	178,188	6
7	Workmen's Compensation	149,015	153,506	155,929	162,132	159,454	7

491-071

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-1
(ACC-STF-1-1 to ACC-STF-1-107)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 11, 2011

Request No. ACC-STF-1-71:

Injuries and Damages. State the amount of injuries and damages expense for each of the last three years, and for the test year, by account.

Respondent: Revenue Requirements

Response:

Attached is a schedule that shows the injuries and damages expense for the twelve month periods ending December 2007 through 2009 and the test year ending June 30, 2010. The expenses are grouped into four categories: 1) legal and other expense; 2) reserve for the self-insurance; 3) self-insured worker's compensation; and 4) insurance.

Also, refer to workpapers to Schedule C-2, Adjustment No. 9, Sheet 1.

SOUTHWEST GAS CORPORATION
ACCOUNT 925 - INJURIES AND DAMAGES
2007-2009 AND TEST YEAR ENDING JUNE 30, 2010

Description	Account Number	Rate Jurisdiction	2007	2008	2009	June 2010
Legal and Other Costs	92500001	Tot. AZ	$ 280,762	$ 322,110	$ 507,803	$ 718,799
Reserve for Self-Insurance	92500001		713,629	230,000	400,000	537,500
Self-Insured Wk Cmp	92501832		293,006	199,472	356,049	308,201
			$ 1,287,397	$ 751,581	$ 1,263,852	$ 1,564,501
Legal and Other Costs	92500001	No. CA	$ 0	$ 2,559	$ 0	$ 0
Reserve for Self-Insurance	92500001		0	0	0	0
Self-Insured Wk Cmp	92501832		3,720	5,157	6,738	7,955
			$ 3,720	$ 7,716	$ 6,738	$ 7,955
Legal and Other Costs	92500001	So. CA	$ 68,011	$ 70,198	$ 46,057	$ 6,469
Reserve for Self-Insurance	92500001		0	400,000	(32,021)	125,000
Self-Insured Wk Cmp	92501832		126,864	182,734	96,440	106,237
			$ 194,876	$ 652,933	$ 110,476	$ 237,706
Legal and Other Costs	92500001	SLT	$	$ 0	$ 0	$ 0
Reserve for Self-Insurance	92500001			175,000	225,000	125,000
Self-Insured Wk Cmp	92501832			0	0	0
			$ 0	$ 175,000	$ 225,000	$ 125,000
Legal and Other Costs	92500001	No. NV	$ 6,813	$ 13,156	$ 72,042	$ 82,506
Reserve for Self-Insurance	92500001		0	0	0	0
Self-Insured Wk Cmp	92501832		126,500	46,084	55,562	16,256
			$ 133,313	$ 59,240	$ 127,603	$ 98,762
Legal and Other Costs	92500001	So. NV	$ 90,121	$ 63,286	$ 53,510	$ 63,000
Reserve for Self-Insurance	92500001		786,405	444,596	9,278	75,000
Self-Insured Wk Cmp	92501832		93,819	88,116	114,439	227,907
			$ 970,345	$ 595,998	$ 177,227	$ 365,907
Legal and Other Costs	92500001	Common	$ 637,558	$ 646,078	$ 243,891	$ 269,748
Reserve for Self-Insurance	92500001		(25,500)	(300,000)	275,000	275,000
Self-Insured Wk Cmp	92501832		11,468	1,908	(63,728)	3,556
Insurance	92501831		9,883,857	9,771,350	9,754,271	9,927,437
Allocation - Paiute	92501900		(430,803)	(391,618)	(394,084)	(403,853)
			$ 10,076,580	$ 9,727,718	$ 9,815,350	$ 10,071,888
Total Account 925			$ 12,666,231	$ 11,795,186	$ 11,501,247	$ 12,346,719

295-026

SOUTHWEST GAS CORPORATION
2007 GENERAL RATE CASE
DOCKET NO. G-01551A-07-0504
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-10
(ACC-STF-10-1 THROUGH ACC-STF-10-26)

DOCKET NO.: G-01551A-07-0504
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 29, 2008

Request No. ACC-STF-10-26: ✓

Aircraft and aviation operations. (a) Please identify the investment cost and operating cost of all owned and leased aircraft in the test year, and provide comparable information for calendar 2004, 2005, 2006 and 2007. (b) Please identify all costs and expenses, by account, for all owned and/or leased aircraft and aviation operations for the test year that were charged to Arizona utility operations.

Respondent: Revenue Requirements

Response:

Please find the attached schedule listing the operating costs associated with the leased aircraft used by Southwest for business operations. Southwest does not own any aircraft. The amounts are listed by account, from 2004 through 2007, as well as the test year, and the portion allocated to Arizona is shown. Any amounts that were directly charged to non-Arizona jurisdictions or below-the-line (Account 426.5) were excluded from this schedule.

SOUTHWEST GAS CORPORATION
SYSTEM ALLOCABLE
DATA REQUEST NO. STF-10-26
LEASED AIRCRAFT OPERATING COSTS

Line No.	Account	2004	2005	2006	2007	Test Year TME 4/30/2007	Line No.
1	908.0	$ -	$ -	$ -	$ 1,500	$ -	1
2	920.0	206,306	220,273	259,841	231,208	263,810	2
3	921.0	181,231	225,338	216,448	193,086	222,344	3
4	930.2	28,500	42,210	53,300	35,950	50,300	4
5	931.0	24,101	27,026	24,049	25,134	24,049	5
6	935.0	679	924	4,297	-	233	6
7	Total	$ 442,816	$ 515,771	$ 557,935	$ 486,878	$ 560,736	7
	Description						
8	Allocation to Paiute Pipeline (PP)/SGTC	4.91%	4.91%	4.11%	4.12%	3.96%	8
9	Aircraft Expense Allocated to PP/SGTC	$ 21,742	$ 25,324	$ 22,931	$ 20,059	$ 22,205	9
10	Aircraft Expense Net of PP/SGTC	$ 421,074	$ 490,447	$ 535,003	$ 466,819	$ 538,531	10
11	AZ Allocation Factor	57.66%	57.10%	56.81%	56.78%	56.70%	11
12	Aircraft Expense Allocated to AZ	$ 242,791	$ 280,045	$ 303,935	$ 265,060	$ 305,347	12

500-009

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-7
(ACC-STF-7-1 to ACC-STF-7-23)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MARCH 31, 2011

Request No. ACC-STF-7-9:

Aircraft and aviation. Has Southwest included any amounts in rate base or operating expense related to owned or leased aircraft or aviation equipment? If so, please identity all such amounts by account.

Respondent: Revenue Requirements

Response:

Please refer to the attached spreadsheets. The first illustrates the amount Southwest Gas included for aircraft-related operating expenses during the test year, by account and after allocation to Arizona. The other spreadsheet calculates the rate base associated with the company-operated airplane hangar and collision avoidance equipment after allocation to Arizona.

SOUTHWEST GAS CORPORATION
2010 ARIZONA GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
AIRCRAFT-RELATED EXPENSES
DATA REQUEST STF 7.9

Accounts		Total
90800001	$	3,545
92000001		300,159
92100001		232,453
92501831		22,713
93020001		43,005
93100001		271,180
Total	$	873,055
Paiute and SGTC MMF		3.83%
Less: Paiute and SGTC Allocation	$	33,480
Aircraft Expense Before 4-Factor	$	839,575
Arizona 4-Factor Allocation		56.25%
Arizona Related Operating Expense	$	472,261
Depreciation Expense	$	34,902
Arizona 4-Factor Allocation		56.25%
Arizona Related Depreciation Expense	$	19,632
Total Arizona Aircraft-Related Expenses	$	491,893

SOUTHWEST GAS CORPORATION
2010 ARIZONA GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
AIRCRAFT-RELATED RATE BASE
DATA REQUEST STF 7.9

Line No.	Description	Airplane Hangar	Airplane Equipment	Paiute & SGTC Alloc 3.83%	Net of Paiute & SGTC Alloc	Arizona Allocation 56.25%	Line No.
	(a)	(b)	(c)	(d)	(e)	(f)	
1	Original Cost	$ 941,644		$ 36,065	$ 905,579	$ 509,388	1
2	Accumulated Depreciation	(297,257)		(11,385)	(285,872)	(160,803)	2
3	Accumulated Deferred Income Taxes	(4,291)		(164)	(4,127)	(2,321)	3
4	Original Cost		$ 86,303	3,305	82,998	46,686	4
5	Accumulated Depreciation		(67,452)	(2,583)	(64,869)	(36,489)	5
6	Accumulated Deferred Income Taxes		(6,598)	(253)	(6,345)	(3,569)	6
7	Total Rate Base	$ 640,096	$ 12,253	$ 24,985	$ 627,364	$ 352,892	7

Explanation:
To determine the rate base associated with the company operated airplane hangar and collision avoidance equipment.

ATTACHMENT RCS-4
REDACTED

Southwest Gas Corporation
Docket No. G-01551A-10-0458
Attachment RCS-5
Copies of Regulatory Commission Order Excerpts Addressing Sharing of Directors & Officers Liability Insurance Cost Between Shareholders and Ratepayers

Jurisdiction	Docket No.	Order Date	Utility	No. of Pages	Page No.
Florida	090079-EI; 090144-EI; 090145-EI	March 5, 2010	Progress Energy Florida, Inc.	4	2 - 5
Connecticut	08-07-04	February 4, 2009	United Illuminating Company	3	6 - 8
Connecticut	07-07-01	January 28, 2008	Connecticut Light and Power Company	3	9 - 11
Connecticut	05-06-04	January 27, 2006	United Illuminating Company	3	12 - 14
Connecticut	03-07-02	December 17, 2003	Connecticut Light and Power Company	3	15 - 17
Connecticut	98-1-02	February 5, 1999	Connecticut Light and Power Company	2	18 - 19
Connecticut	99-09-03	May 25, 2000	Connecticut Natural Gas Corporation	3	20 - 22
Arkansas	06-101-U	June 15, 2007	Entergy Arkansas, Inc.	3	23 - 25
Arkansas	04-121-U	September 19, 2005	Centerpoint Energy Resources Corp	3	26 - 28
Arkansas	04-176-U	October 31, 2005	Arkansas Western Gas Company	3	29 - 31
			Total Pages Including this Page	31	

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for increase in rates by Progress Energy Florida, Inc.	DOCKET NO. 090079-EI
In re: Petition for limited proceeding to include Bartow repowering project in base rates, by Progress Energy Florida, Inc.	DOCKET NO. 090144-EI
In re: Petition for expedited approval of the deferral of pension expenses, authorization to charge storm hardening expenses to the storm damage reserve, and variance from or waiver of Rule 25-6.0143(1)(c), (d), and (f), F.A.C., by Progress Energy Florida, Inc.	DOCKET NO. 090145-EI ORDER NO. PSC-10-0131-FOF-EI ISSUED: March 5, 2010

The following Commissioners participated in the disposition of this matter:

NANCY ARGENZIANO, Chairman
LISA POLAK EDGAR
NATHAN A. SKOP
DAVID E. KLEMENT
BEN A. "STEVE" STEVENS III

APPEARANCES:

R. ALEXANDER GLENN, JOHN T. BURNETT, ESQUIRES, Progress Energy Service Company, LLC, P.O. Box 14042, St. Petersburg, Florida 33733-4042; JAMES MICHAEL WALLS, DIANNE M. TRIPLETT, and MATTHEW BERNIER, ESQUIRES, Carlton Fields, P.A., Post Office Box 3239, Tampa, Florida 33601-3239; RICHARD D. MELSON, ESQUIRE, 705 Piedmont Drive, Tallahassee, Florida 32312
On behalf of Progress Energy Florida, Inc. (PEF).

CHARLES REHWINKEL, Associate Public Counsel, CHARLIE BECK, Deputy Public Counsel, and PATRICIA A. CHRISTENSEN, Associate Public Counsel, ESQUIRES, Office of the Public Counsel, c/o the Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400
On behalf of the Citizens of the State of Florida (OPC).

STEPHANIE ALEXANDER, ESQUIRE, 200 West 200 West College Avenue, Suite 216, Tallahassee, Florida 32301
On behalf of the Florida Association for Fairness in Rate Making (AFFIRM).

costs have been removed. Accordingly, we find that PEF has made the appropriate adjustments to remove aviation cost for the test year.

H. Advertising Expenses

PEF removed promotional advertising costs in the amount of $3,388,000, as reflected in MFR Schedule C-2. The jurisdictional amount, net of tax, is $2,081,000. The explanation given by PEF is to exclude the cost of promotional advertising in order to comply with our guidelines.

We note an excerpt from the procedures followed by our auditors for the 2008 base year:

> We reviewed additional samples of utility advertising expenses, industry dues, economic development expenses, outside services, sales expenses, customer service expenses and administrative and general service expenses to ensure that amounts supporting non-utility operations were removed.

The Company's advertising expense is one of the areas specifically examined by our auditors. There were no findings with respect to this issue. Therefore, we find that PEF has made the appropriate adjustments to remove advertising expenses for the test year.

I. Directors and Officers (D&O) Liability Insurance

PEF argued that OPC witness Schultz is incorrect in his assertion that D&O liability insurance does not benefit ratepayers, and thus should be disallowed. PEF cited to the most recent TECO case in which this Commission decided that D&O liability insurance is a necessary and reasonable business expense and is appropriately included in customers' rates.[40] PEF asserted that we have already rejected the argument that Mr. Schultz raises in other cases and there is no valid reason for us to depart from its previous findings in this case.

OPC witness Schultz questioned whether the cost of D&O liability insurance is a necessary and appropriate expense to pass on to ratepayers. He stated that the expense protects shareholders from the decisions they made when they hired the Company's Board of Directors and the Board of Directors in turn hired the officers of the Company. He noted that the Company included $2.2 million in Account 925 for D&O liability insurance, but he believes the correct amount to be $2,750,650 for $300,000,000 in coverage. He disagreed with our recent Peoples Gas case in which the expense was allowed as a legitimate business expense.[41] The witness testified that the pertinent issue is whether the cost is beneficial to ratepayers, not whether it is a legitimate business expense. He stated that we have disallowed the cost in the past.

OPC witness Schultz testified that other jurisdictions have disallowed the expense. He stated, for example, that a Connecticut decision limited recovery by Connecticut Light and

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[40] Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company, p. 64.

[41] Order No. PSC-09-0411-FOF-GU, issued June 9, 2009, in Docket No. 080318-GU, In re: Petition for rate increase by Peoples Gas System, p. 37-38.

Power to thirty percent, because ratepayers should not be required to protect shareholders from the decisions they make in electing the Board of Directors. He added that Consolidated Edison was not allowed to recover the full amount in a New York case. He explained that the disallowance was due to excessive coverage in part, and that a portion of the amount found to be reasonable was also disallowed. He stated the reason for the additional disallowance was that D&O Liability insurance provides protection to shareholders from matters in which the customers have no influence.

OPC witness Schultz recommended disallowance of the total cost of D&O liability insurance of $2,750,650 ($2,412,100 jurisdictional) because the purpose of the insurance is to protect shareholders, not ratepayers. He stated that he does not take the position that the Company should not have the insurance, but that it should be paid for by those who benefit from the insurance; that is, the shareholders.

OPC argued that PEF did not offer any testimony in rebuttal to OPC witness Schultz that the D&O liability insurance should be disallowed. OPC stated that, in each of the cases cited by witness Schultz in his testimony, the Company argued that D&O liability insurance is a necessary and prudent cost required to attract and retain competent directors and officers, yet a disallowance was made. OPC challenged the cost for $300,000,000 of coverage as being excessive, and questioned whether the cost for that level of coverage is appropriate to pass on to ratepayers.

OPC noted in particular a Consolidated Edison Company Case. OPC stated that in the final decision, the New York Commission (NYC) ruled that $300,000,000 of coverage was excessive based on the comparisons to similar companies and disallowed the premium associated with $100,000,000 excess, and then disallowed 50 percent of the premium associated with the $200,000,000 that was determined to be reasonable. OPC stated that, in the discussion, the NYC noted that D&O insurance provides substantial protection to shareholders who elect directors and have influence over whether competent directors and officers are in place, while customers have no influence. OPC noted that the NYC further stated at page 91 of its order that:

> We find no particularly good way to distinguish and quantify the benefits of D&O insurance to ratepayers from the benefits to shareholders, especially taking into account the advantage that shareholders have in control over directors and officers. We believe the fairest and most reasonable way to apportion the cost of D&O insurance therefore is to share it equally between ratepayers and shareholders.

FIPUG argued that the amount should be disallowed, because the expense directly benefits only PEF's shareholders.

We agree with OPC witness Schultz that this Commission has disallowed D&O insurance in water and wastewater cases in the past.[42] We do not agree with OPC that the ratepayers do not

[42] See Order Nos. PSC-09-0385-FOF-WS, issued May 29, 2009, in Docket No. 080121-WS, In re: Application for increase in water and wastewater rates in Alachua, Brevard, DeSoto, Highlands, Lake, Lee, Marion, Orange, Palm

benefit from D&O liability insurance. We believe that D&O liability insurance has become a necessary part of conducting business for any company or organization and it would be difficult for companies to attract and retain competent directors and officers with out it. We also believe that ratepayers receive benefits from being part of a large public company, such as easier access to capital which may result in lower rates. As stated in the TECO order:

> We find that [D&O liability] insurance is a part of doing business for a publicly-owned Company. It is necessary to attract and retain competent directors and officers. Corporate surveys indicate that virtually all public entities maintain [D&O liability] insurance, including investor-owned electric utilities. . . . We do not agree with OPC that the ratepayers do not benefit from [D&O liability] insurance. It is not realistic to expect a large public company to operate effectively without [D&O liability] insurance.[43]

We agree with PEF that the amount of the D&O liability insurance provided in discovery responses is $2.2 million, not $2.75 million as adjusted by OPC witness Schultz. However, we note that the amount of the premium for the test year is projected to be higher than the premium for 2008-2009, but lower than the previous three years, even though the amount of coverage was increased from $280 million to $300 million.

In summary, we believe that D&O liability insurance has become a necessary part of conducting business for any publicly owned company and it would be difficult for companies to attract and retain competent directors and officers without it. We also believe that ratepayers receive benefits from being part of a large public company including, among other things, easier access to capital. Because D&O liability insurance benefits both the ratepayer and the shareholder, it should be a shared cost. Thus, we find that O&M expense shall be reduced by $964,913 jurisdictional to reflect the sharing of costs between the ratepayers and the shareholders.

J. Injuries and Damages Expense

PEF stated that FERC Account 925 on MFR Schedule C-4, p. 44 of 48, reflects an expense of $8,882,000 for injuries and expenses. PEF stated that the numbers were audited by our auditors who reconciled the amounts on the MFRs for 2008 expenses to the Company's actual book and records. PEF stated that it based its 2010 budget for injuries and damages expense on the Company's actual historical 2008 expenses. PEF argued that it is, therefore, entitled to recover this expense.

Beach, Pasco, Polk, Putnam, Seminole, Sumter, Volusia, and Washington Counties by Aqua Utilities Florida, Inc., p. 81; PSC-07-0505-SC-WS, issued June 13, 2007, in Docket No. 060253-WS, In re: Application for increase in water and wastewater rates in Marion, Orange, Pasco, Pinellas, and Seminole Counties by Utilities, Inc. of Florida, p.44; PSC-03-1440-FOF-WS, issued December 22, 2003, in Docket No. 020071-WS, In re: Application for rate increase in Marion, Orange, Pasco, Pinellas, and Seminole Counties by Utilities, Inc. of Florida, p. 84; and PSC-99-1912-FOF-SU, issued September 27, 1999, in Docket No. 971065-SU, In re: Application for rate increase in Pinellas County by Mid-County Services, Inc., p. 20-22.

[43] Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company, p. 64.

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 08-07-04 APPLICATION OF THE UNITED ILLUMINATING COMPANY TO INCREASE ITS RATES AND CHARGES

February 4, 2009

By the following Commissioners:

John W. Betkoski, III
Donald W. Downes
Anthony J. Palermino

DECISION

TABLE P/R - 5

CORRECTED TABLE

(in $000s)

Compensation Expense	2009	2010
Proposed Base Payroll	$56,627	$59,115
Department Adjustment	($3,880)	($4,565)
Allowed Base Payroll	$52,747	$54,550
Overtime and Premium Pay	$6,754	$7,024
Department Adjustment	($1,672)	($1,942)
Allowed O/T and Premium Pay	$5,082	$5,082
Capitalized Overhead Pay	($4,083)	($4,207)
Department Adjustment	$80	$63
Allowed Cap. O/H	($4,003)	($4,144)
Incentive Compensation	$7,665	$7,791
Department Adjustment	($3,671)	($3,797)
Allowed Incent. Comp.	$3,994	$3,994
Total Compensation Proposed	**$66,963**	**$69,723**
Total Dept. Adjustments	**($9,143)**	**($10,241)**
Total Allowed Compensation	**$57,820**	**$59,482**
Allocated Incentive Comp.	**$1,154**	**$1,146**
Total Department Adjustments	**($553)**	**($559)**
Allowed Alloc. Inc. Comp.	**$601**	**$587**
Total Compensation Adjustments	**($9,696)**	**($10,800)**

To address the public's concern that customers are paying 100% of the compensation paid to the top officers of the Company, the Department offers that, for example, the adjustments made in this Decision reduce the amount of compensation paid to the Company President and Chief Operating Officer, that are actually included in rates and paid by customers, by approximately 33% and 31%, respectively.

2. Directors and Officers Liability Insurance

In its Application UI requested the Department authorize $844 thousand for 2009 and 2010 Directors and Officers Liability Insurance (DOL) ($852 thousand less $8 thousand allocated to non-regulated entities). Schedule WP C-3.31 A&B. The Company's position is that DOL is a business expense of having a public corporation, and the customers pay for all of the ordinary business expenses that a company would incur. Tr. 10/14/08, pp 62 and 63.

The OCC stated that in the past two rate decisions involving UI, the Department has determined that a portion of UI's DOL insurance costs should be funded by ratepayers. Despite this fact, UI is proposing to recover 100% of its DOL insurance

costs in this proceeding. The OCC cited its previous arguments that corporate scandals have increased costs dramatically, that ratepayers do not elect the Board of Directors (BOD) and officers of the Company, and that shareholders, who are protected by the insurance, should not be subsidized by ratepayers for DOL insurance costs that are designed to protect shareholders from their own decisions. The facts and circumstances regarding the DOL insurance have not changed since UI's last rate case. The OCC recommends that the DOL insurance be reduced by 75% with only 25% being passed on to customers, but stated that its absolute preference would be to disallow the cost completely. OCC Brief, pp. 79 and 80.

The AG indicates that the amount requested is roughly six times the amount that the Department approved in the 2006 Decision. In the 2006 Decision, the Department specifically agreed with both the AG and OCC that "DOL insurance protects only shareholders from the actions of management that they selected." Although the Department allowed UI to collect one-quarter of its requested amount in the 2006 Decision, the Company requested the entire amount be funded by ratepayers. The AG stated that this bold act of indifference to the Department's clear precedent and to the financial stresses facing its customers should be firmly rejected. At the very most, the Department should authorize only the levels for DOL insurance that it approved in the 2006 Decision. AG Brief, p. 18.

In the 2006 Decision, the Department noted the OCC's and AG's positions, as well as the position of the Company who stated that if there was no insurance and there was a huge claim, it could put the Company in financial peril, which would potentially impair its ability to serve. Therefore, the Department allocated 75% of DOL costs to the shareholders, with the residual 25% to be funded by ratepayers. 2006 Decision, pp. 46 and 47. The Department rejects the Company's current proposal that ratepayers fund 100% of DOL insurance costs, and reconfirms the precedent afforded by the 2006 Decision. Accordingly, the Department allows $211 thousand of DOL insurance costs to be funded by ratepayers in years 2009 and 2010 ($844 thousand times 25%). This results in DOL insurance expense decreases of $633 thousand in each of years 2009 and 2010.

3. Fringe Benefits

a. Compensation Adjustment to Fringe Benefits

In Section III.1.f., the Department made adjustments to compensation of $12.033 million and $13.655 million in 2009 and 2010, respectively. This also results in an adjustment to fringe benefits that accompany compensation. The Company indicates that its composite fringe benefit rate for 2009 and 2010 is 45%. Responses to Interrogatories EL-30-2; EL-31-2; and EL 33-1.

In its Written Exceptions, the Company argues, against its own filed and sworn record evidence of a 45% fringe benefit expense related to compensation, that the "correct compensation-driven benefits loader from an expense standpoint" is 20.6% and attempts to justify that amount by listing greatly reduced expense amounts for certain "Compensation Driven Employee-Related Benefits Loader." UI Exceptions, pp. 29 and 30. The Department notes that the Company's Response to Interrogatory EL-33 that

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 07-07-01 APPLICATION OF THE CONNECTICUT LIGHT AND POWER COMPANY TO AMEND RATE SCHEDULES

January 28, 2008

By the following Commissioners:

Anthony J. Palermino
Anne C. George
John W. Betkoski, III

DECISION

expenses by $2.232 million to remove the non payroll projected costs in excess of the original budget.

2. Insurance Expense

The test year expense for insurance expense was $6.817 million. The Company proposed a rate year increase of $.65 million or a rate year expense of $7.467 million. Application, Schedule C-3.10. CL&P revised the request and reduced the insurance expense by $17,000. The revision was a result of recent premium information. The change is a combination of increases and decreases in different types of insurance. Response to Interrogatory EL-80-SP01.

The Department accepts the Company's revisions except for the Directors and Officers insurance expense and capital allocation as discussed in detail below.

a. Director and Officer Insurance Expense

The test year expense for Director and Officer (D&O) insurance expense was $1.423 million. The Company proposed a rate year increase of $0.164 million or a rate year expense of $1.587 million. Application, WP C-3.10. As indicated above, CL&P revised its rate year insurance expense and decreased the rate year D&O insurance expense amount by $.270 million to $1.317 million. Response to Interrogatory EL-80-SP01 and Late Filed Exhibit No. 112SP-01.

CL&P claims that D&O insurance is a legitimate and customary operating expense and that no director or officer with the necessary knowledge and experience would take the risks associated with serving CL&P without this type of protection. CL&P states that the Sarbanes-Oxley Act requires that certain skill-sets be reflected in the Board of Directors (BOD), and in order to attract and retain individuals that meet these requirements CL&P must offer D&O coverage to its BOD. CL&P indicated that the Department has already confirmed that D&O is a necessary operating expense that is recoverable. CL&P Brief, p. 39.

The AG argues for the removal of the entire $1.587 million. The AG states that it is inappropriate to force customers to fund a plan that benefits only shareholders. D&O insurance protects shareholders from their own decisions and is intended to protect directors and officers from lawsuits brought by shareholders. AG Brief, p. 20.

The OCC states that premiums for insurance excluding D&O insurance decreased from $9.4 million to $8.41 million while D&O insurance is estimated to increase 11.5% from $1.423 million to $1.587 million. Further, the OCC believes that the D&O insurance requested amount is excessive, ignores the Department's prior rulings, and ratepayers should not be required to protect shareholders from the decisions they make in electing the BOD. The OCC argues that Sarbanes-Oxley merely requires officers & directors who have a fiduciary duty to acknowledge responsibility by signing their names. It was not the implementation of Sarbanes-Oxley that caused an increase in premiums, it's the claims filed that caused the increase. The OCC adds that D&O insurance has drastically increased from 5.67% of the aggregate insurance amount in 2002 to 13.15% in 2006 and projected to cost 15.87% in the rate

year. The OCC recommends a D&O insurance reduction of $1.202 million to $0.385 million. The OCC calculated this amount by using the 2002 test year amount increased by inflation. OCC Brief, p. 44.

In Docket No. 03-07-02, CL&P requested a rate year amount of $1.043 million and was allowed the test year amount of $.330 million. 03-07-02 Decision, pp. 48-49. This allowed 33% of the requested amount. In that decision, the Department indicated that it does allow some level of D&O insurance expense in rates to assure some level of ratepayer protection from lawsuits. In the UI Decision, the Department allowed 25% of the D&O insurance expense to be allocated to customers. In the Decision dated February 5, 1999, n Docket No. 98-01-02, DPUC Review of the Connecticut Light and Power Company's Rates and Charges – Phase II, the Department took the OCC approach and calculated the 1999 expense by inflating the 1996 level. This allowed 46.7% of the requested amount. In the Decision dated May 25, 2000, in Docket No. 99-09-03, Application of Connecticut Natural Gas Corporation for a Rate Increase, the Department allowed 20% of the premium amount.

The Department agrees in part with the OCC that ratepayers should not be required to protect shareholders from the decisions they make in electing the BOD. However, the Department historically has allocated a percentage to ratepayers to protect from catastrophic lawsuits. Accordingly, the Department finds it appropriate to allocate 30% to ratepayers and 70% to shareholders. This allocation is fair and consistent with the level allowed in Docket No. 03-07-02. Therefore, the Department allows $.395 million ($1.317 million x 30%) and disallows $.922 million to be collected in rates.

b. Insurance Expense - Capital Allocation

CL&P originally proposed a rate year capitalization factor of 25.3%. Application, Schedule WPC-3.10. The Company revised this amount to 26.6% in order to reflect updates based on recent invoices. Response to EL-80-SP01 and Late Filed Exhibit No. 112. The test year before pro forma adjustment was 35.6%. Application, Schedule WPC-3.10. A majority of the pro forma adjustment was to remove a non-recurring charge for the public liability reserve. This adjustment was based on an independent study performed by Mercer, Inc. The remaining pro forma adjustment included the addition of $284,000 that was for a non-recurring credit or refund received from USICO, a mutual property insurance company. Response to Interrogatory EL-43.

The OCC claims that CL&P has included a significant increase in the percent of costs being charged to expense as opposed to capital. Specifically, the Company's proposed reduction of more than 10% to the capital allocation is significant considering CL&P's focus on system improvements. The OCC argues that the Company did not present any evidence to justify an allocation change. OCC Brief, p. 41. The OCC recommends using the test year capitalization factor of 35.6%. That capitalized amount reduces the aggregate insurance expense to $5.802 million for a total disallowance of $1.665 million. OCC Brief, pp. 43-44.

As indicated below, the Company's insurance capitalization percents have ranged from a low of 25.6% to a high of 40.5% in the years 2002 through 2006.

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 05-06-04 APPLICATION OF THE UNITED ILLUMINATING COMPANY TO INCREASE ITS RATES AND CHARGES

January 27, 2006

By the following Commissioners:

John W. Betkoski, III
Donald W. Downes
Jack R. Goldberg
Anne C. George
Anthony J. Palermino

DECISION

Description	2006	2007	2008	2009
Benchmarking studies	$ 72,000	$ 72,000	$ 73,000	$ 74,000
BPL	$ 98,000	$ 98,000	$ 98,000	$ 98,000
Regulatory consulting	$ 131,000	$ 138,000	$ 145,000	$ 152,000
Client services support	$ 275,000	$ 296,000	$ 311,000	$ 329,000
Total professional services expense disallowed	$ 576,000	$ 604,000	$ 627,000	$ 653,000

8. Outside Services - Audit and Accounting Expense

UI originally projected $533,000, $552,000, $573,000 and $594,000 for audit and accounting expense for rate years 2006 through 2009, respectively. Schedule C-3.16 A–D. UI later increased the projected expenses by $149,000, $164,000, $177,000 and $194,000 for rate years 2006 through 2009, respectively, citing the Company's response to Interrogatory EL-159. Late Filed Exhibit No. 1, Revised.

However, the response to Interrogatory EL-159 only identified a potential increase of $100,000 for 2006. The Company's response to Interrogatory EL-159 and the testimony on 10/14/05 state that the original projection was strictly an estimate and that UI is in negotiations with Pricewaterhouse Coopers for a new contract. UI is seeking to enter into a long term fixed price contract for SEC reporting audit services to mitigate the potential increase. UI testified that the Company is still negotiating and trying to get the price increase down, but, the increase could be greater than the original estimate. Response to Interrogatory EL-159; Tr. 10/14/05, pp. 174 and 175. UI later testified that they negotiated a new contract and the increases in Late Filed Exhibit No. 1 are based on the cost of the new contract. Tr. 11/9/05, p. 2394.

The OCC believes that the response to Interrogatory EL-159 does not support the amount of increase apparently requested by UI in Late Filed Exhibit No. 1 and leaves unanswered questions regarding the certainty of the projected increases. Therefore, the OCC has removed the increases identified in Late Filed Exhibit No. 1. OCC Brief, pp. 63 and 64, Exhibit 5.

The Department takes into account the entire record evidence on a given expense in determining if it is proper for the rate year. Therefore, based on the testimony given during the late filed exhibit hearing, the Department approves the increase to accounting and audit expense as shown in Late Filed Exhibit No. 1, Revised.

9. Directors and Officers Liability Insurance

The Company proposes expenses for Directors and Officers Liability Insurance (DOL) of $533,879 for 2006, and $559,612 for each of the years 2007 through 2009. Response to Interrogatory OCC-104. UI contends that it could not attract a director if it didn't have DOL. It is a cost of doing business. Tr. 10/12/05, p. 868. Further, the Company asserts that, taken to the extreme, "if there was no insurance and there was a huge claim, it could put the company in financial peril, which would potentially impair its ability to serve." Tr. 10/11/05, p. 801.

The OCC indicates that "the numerous corporate scandals since 2001 has caused the cost of the DOL insurance to skyrocket." Schultz and DeRonne PFT, p. 48. Further, "DOL insurance provides shareholders protection from their decision. Ratepayers in general do not elect the Board of Directors and do not appoint officers to run the Company. Shareholders are protected by this insurance against their own decision in the selection of management. Ratepayers should not pay for the cost of insurance designed to protect shareholders from their own decisions." OCC Brief, p. 93; Tr. 10/12/05, pp. 867 and 868. Therefore, the OCC recommends that all of the DOL amounts during the rate period be excluded from rates and be covered completely by shareholders, not ratepayers.

The AG agrees with the OCC's reasoning that DOL insurance protects only shareholders from the actions of management that they selected. Thus, DOL insurance expense should be eliminated from UI's rates entirely. AG Brief, pp. 24 and 25.

The Department partially agrees with the OCC, the AG and the Company. In the 03-07-02 Decision, the Department allowed a portion of that company's proposed expense and stated that "the Department has historically allowed some level of expense for D&O Insurance in rates to assure some level of ratepayer protection from catastrophic lawsuits." 03-07-02 Decision, p. 49. The Department also notes that the annual gross DOL premium (before credits and allocations) was $134, 430 in years 2001 and 2002, increasing to $1,029,516 in years 2007 through 2009, lending credence to the OCC's assertion regarding corporate scandals, above. The Department agrees with the OCC that the shareholders should bear the weight of their decisions in appointing directors (who appoint the officers of the Company). Accordingly, the Department allows $140,000 of DOL expense, or approximately ¼ of the total company expense, to be collected in rates as the customers' responsibility.

The Department, therefore, disallows DOL expenses of $393,879 in 2006, and $419,612 in each of 2007, 2008 and 2009.

10. Postage Expense

UI projected postage expense in the amounts of $1,475,000, $1,479,000, $1,485,000, and $1,491,000 for rate years 2006 though 2009, respectively. UI increased the test year expense of $1,361,000 by $74,000 for an anticipated 5.4% increase from the USPS and $31,000 for volume and usage increase. Schedule C-3.20 A – D.

The Governors of the U.S. Postal Service have accepted the recommendation to increase most postal rates and fees by 5.4% effective January 8, 2006, including an increase in the rate for first-class mail from 37 cents to 39 cents. See http://www.usps.com/ratecase/welcome.htm.

UI states that the volume and usage increase is due to items such as increase in collection letters due to higher disconnect for nonpayment activity, new program mailings and increased economic development activity. Response to Interrogatory EL-220.

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 03-07-02 APPLICATION OF THE CONNECTICUT LIGHT AND POWER COMPANY TO AMEND ITS RATE SCHEDULES

December 17, 2003

By the following Commissioners:

Donald W. Downes
Jack R. Goldberg
John W. Betkoski, III
Linda J. Kelly
Anne C. George

DECISION

The Department, therefore, accepts the Company's revision to computer and other expenses as indicated in the Response to Interrogatory OCC-93. Accordingly, the Department reduces computer expenses by $.348 million ($10.119 million less $9.771 million) and other O&M expenses related to the test year processing and storage balance of $.596 million, for a total O&M adjustment for these items of $.944 million ($.348 million plus $.596 million).

2. Insurance Expense

a. Directors and Officers Liability Insurance

The Company requested Directors & Officers Liability Insurance Expense (D&O Insurance) of $1.043 million in the rate year. This included a test year pro forma adjustment of $.029 million and a rate year adjustment of $.684 million above the test year actual amount of $.330 million based on the actual renewal premiums for the policy period 4/23/03 to 4/23/04. Schedule WP C-3.12; Response to Interrogatory OCC-101.

The OCC argues for the removal of the entire $1.043 million of D&O Insurance expense. The OCC states:

> Ratepayers should not be forced to pay a cost that protects shareholders from the shareholders' own decisions. Shareholders determine who the Board of Directors are and the Board of Directors are responsible for appointing officers of the Company. The officers are highly compensated to provide quality leadership with the utmost integrity. Ratepayers are responsible for paying for the directors and officers services. The shareholders, not ratepayers, determine who the directors and officers are. Therefore, the shareholder should assume the risk associated with their decision regarding the management of the Company. The cost to obtain insurance to protect the shareholders investment from their choice of management should be the responsibility of the shareholders.

OCC Brief, p. 64

The OCC also cites that the escalation in D&O Insurance rates stem from the insurers' need to continue to reserve for litigation and settlement expenses in connection with an influx of claims arising from such entities as Worldcom, Enron, Kmart, etc. Response to Interrogatory OCC-101. The increases in D&O Insurance and the related costs are due to the failures of directors and officers to ensure the Company operated prudently and reasonably. An alternative to total disallowance of cost would be to allow the test year cost of $.330 million. OCC Brief, p. 65.

The Department is sympathetic with OCC's arguments and generally agrees that the increased premiums are, at least in part, caused by Officer/Director mismanagement or misconduct in major corporations. Further, the Department notes that CL&P's recent claims experience includes settlement of eight federal and state shareholder class action lawsuits that stemmed from the Nuclear Regulatory Commission's Watch List of problems at its Millstone Nuclear Plant in 1996 that resulted

in a $20.050 million settlement by its insurer. Further, a $33 million settlement was reached with the non-NU joint owners of Millstone 3 related to the Company's operation of that plant. Late Filed Exhibit 73 and 73-SP01. However, the Department has historically allowed some level of expense for D&O Insurance in rates to assure some level of ratepayer protection from catastrophic lawsuits. Therefore, the Department will allow the test year cost of $.330 million and reduce the Company's D&O Insurance expense by $.713 million ($1.043 million less $.330 million).

b. Public Liability Expense

The Company requested Public Liability Expense of $2.591 million in the rate year in Account 925.02. This Account includes the cost of the reserve accrual to protect the utility against injuries and damages claims of employees or others, losses of such character not covered by insurance, and expenses incurred in settlement of injuries and damages claims. It also includes the cost of labor and related supplies and expenses incurred in injuries and damages activities. Uniform System of Accounts prescribed for Electric Utilities, Public Utilities Control Authority State of Connecticut, 1/1/63, p. 177 (USOC). In its calculation of this expense, CL&P removed $1.497 million of test year expense that was capitalized, thus reducing the overall test year expense of $2.591 million to $1.094 million. Schedule WP C-3.12.

In response to an OCC data request, the OCC questioned why CL&P should no longer treat the public liability expense as an overhead cost, subject to capitalization. In the Company's response it indicated "[u]pon further review it was determined that public liability insurance is an appropriate cost to be capitalized under the FERC Electric Plant instructions." CL&P determined that the payroll overhead rate is the best vehicle for capitalizing these costs and changed the overhead rate for the remainder of 2003 to include these costs. Response to Interrogatory OCC-99. Accordingly, the OCC recommends that $1.497 million of public liability expense be capitalized, thereby reducing CL&P's proposed expense.

The Department agrees with the OCC and the Company that a portion of public liability expense, particularly as it relates to construction projects, is properly capitalizable. The USOC provides, for example, that the cost of injuries and damages or reserve accruals capitalized shall be charged to construction directly or by transfer to construction work orders from this account. USOC, p. 177. The Department also notes that it has been CL&P's consistent practice to capitalize a portion of public liability expense. Response to Interrogatory OCC-100. The Company provided a revised schedule that calculated the capitalized portion of Public Liability Expense using a capitalization rate of 38.5% that resulted in a capitalization amount of $.998 million. Schedule WP C-3.12 Revised. The Department notes that the capitalization percentage is consistent with other payroll-related capitalizations. Schedule WP C-3.28a. The Department, therefore, reduces public liability expense by $.998 million to reflect such capitalization.

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 98-01-02 DPUC REVIEW OF THE CONNECTICUT LIGHT AND POWER COMPANY'S RATES AND CHARGES - PHASE II

February 5, 1999

By the following Commissioners:

Glenn Arthur
Jack R. Goldberg
Linda Kelly Arnold
Donald W. Downes
John W. Betkoski, III

DECISION

amount. OCC analyzed the storm expense data and found that there is no relationship between total storm expense and inflation. For example, storm expenses were higher in 1992 and 1993 compared to 1994 and expenses in 1995 and 1996 were higher compared to 1997. Therefore, OCC also believes that there is no justification for an escalation factor in the storm budget. PRO Brief, pp. 9 and 10; OCC Brief, pp. IV-52 and 53.

The Department often uses a historical average, excluding the highest and lowest years' costs, to calculate a rate year expense and believes that is the appropriate method for storm expense. The Department agrees with OCC's analysis on the escalation factor. The Department calculates 1999 storm expense to be $8.483 million by averaging storm costs for 1992 - 1997, excluding the lowest and highest costs in 1994 and 1996. Therefore, the Department reduces expenses by $3.169 million ($11.652 million - $8.483 million).

27. Directors' and Officers' Insurance

CL&P has requested $1.391 million in directors' and officers' (D&O) liability insurance premiums for the rate year. Response to Interrogatory OCC-70. D&O insurance expenses for the years 1994 - 1997 were $497,000, $456,000, $630,000 and $1,022,000, respectively. Expenses increased due to claims paid and higher liability limits. CL&P projects 1999 expenses will be higher for the same reasons. Responses to Interrogatories OCC-312 and PRO-6; Late Filed Exhibit No. 5, AR-DPUC-14. The Company indicated that the two reasons were actually one and the same. As claims are paid, the insurance available in the future is reduced by that amount. Because of the claims already paid and potential claims, the Company purchased higher limits to restore its liability coverage to previous amounts. This would give the Company enough coverage for potential future claims. Tr. 10/20/98, pp. 4005 and 4006; Late Filed Exhibit No. 162. A Company witness testified that all of the shareholder lawsuits are well known to CL&P and the Department and any damage claims would be borne by shareholders. Tr. 9/10/98, pp. 430-432.

PRO, AG and OCC argue that D&O costs have increased from 1995 to 1997 as a direct result of management imprudence and the nuclear outages. The claims paid and pending relate to the nuclear outages. OCC and PRO believe the expense should be reduced to the 1996 level. Even though the outages occurred during 1996, PRO believes this would allow for some increase due to inflation. OCC Brief, p. IV-39; PRO Brief, p. 12; AG Brief, p. 15.

Ratepayers should not have to fund higher liability limits for directors and officers when it is those directors and officers who failed to ensure that the Company operated prudently and reasonably. The Department reduces D&O liability insurance premiums to a level that does not reflect the nuclear outages. The Department agrees that the 1999 expense should be based on the 1996 level. However, the Department also believes that this is an expense that is typically influenced by inflation and sets the 1999 allowed expense at $.65 million, which is the 1996 actual expense adjusted for inflation. Therefore, 1999 expenses are reduced by $.741 million ($1.391 million - $.65 million).

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 99-09-03 APPLICATION OF CONNECTICUT NATURAL GAS CORPORATION FOR A RATE INCREASE

May 25, 2000

By the following Commissioners:

Glenn Arthur
Jack R. Goldberg
Linda Kelly Arnold

DECISION

tax rate of 8.3% in the rate year. Tr. 2/16/00, p. 1775. Accordingly, the Department will reduce payroll taxes by an additional $42,746 ($515,017 x 8.3%).

In Version B, CNG made a vacancy adjustment of $160,493. However, the Company failed to make a corresponding adjustment for payroll taxes and the O&M allocation factor of 83.6%. Schedule WPC-3.28. Accordingly, the Department will further reduce this expense by $13,321 ($160,493 x 8.3%). The Department's total reduction to payroll taxes is $255,260 ($199,193 + $42,746 + $13,321).

c. Gross Receipts Tax

Gas distribution companies are subject to the Connecticut gross receipts tax (GRT). GRT rates of 4% and 5% apply to residential customers and commercial/industrial customers, respectively. CNG's initial application projected a pro forma GRT expense of $10,599,786 for pro forma taxes at present rates. Schedule WPC-3.41. The Company's request for a $15,738,284 increase in its revenue requirement added $675,684 for a total pro forma GRT of $11,275,470. Schedule C1/C2. Subsequently, the Company increased its pro forma revenues by $8,010,815. Late Filed Exhibit No. 4, Version B. This increased pro forma GRT by $343,924. Together, the changes increased pro forma GRT by $709,958 to $11,619,394.

The Company calculated a 4.29% blended GRT rate by combining the calculated taxes on residential revenues and commercial revenues. Schedule WPC-3.41. CNG's calculation of its blended GRT rate properly excluded taxes on non-taxable interruptible service revenues. Tr. 1/11/00, p. 137.

In Section II.C, above, the Department adjusted CNG's revenues for firm transportation by $58,700, and for an additional customer by $109,000. The Department will make an adjustment to GRT at the rate of 4.29%. Therefore, the Department will increase CNG's GRT by $7,194 ([$58,700 + $109,000] x 4.29%).

d. Summary of Other Tax Adjustments

The Department's total adjustment for other taxes is $(1,055,804), $(255,260) for payroll tax, $(807,738) for property tax, and $7,194 for gross receipts tax.

9. *Insurance*

a. Directors and Officers Liability

CNG has included the cost of D&O liability policies in pro forma insurance expense. The D&O insurance provides the Company with coverage for certain types of wrongful acts by directors or officers of the corporation. Its intent is to safeguard the assets of the corporation so that the Company can continue to provide service to its customers and earn a fair return for its shareholders. The Company has two such policies. The first provides regular coverage and has a $84,100 annual premium. The Company included $70,308 of that premium (83.6%) in its pro forma expense. The second policy provides excess coverage and has a $87,900 annual premium. The

Company included $73,397 of that premium in its pro forma expense for a total pro forma D&O insurance cost of $143,705 ($70,308 + $73,397). Schedule WPC-3.32.

OCC recommends that CNG's adjusted expenses be reduced by $81,807 to reflect the allocation of 20% of regular D&O liability insurance and 100% of the excess D&O liability insurance to shareholders. OCC would prefer that the cost be split equally between ratepayers and shareholders. Not withstanding that action, the OCC believes it appropriate to remain consistent with the Previous Rate Decision where 20% of the regulated premium was disallowed. OCC Brief, pp. 11, 37. Based on CNG testimony, PRO recommends a $7,031 reduction to this expense. PRO Brief, p. 11.

In the Previous Rate Decision, the Department found that the Company needed D&O insurance to attract and keep qualified directors and officers. However, because shareholders could also initiate suits against the directors and officers, the Department disallowed 20% of the premium of regular coverage. Additionally, the Department found that the Company had not justified allowance of premiums of excess D&O coverage in rates. Decision, p. 33.

The Company has not presented any evidence in the instant docket to warrant dissimilar treatment. Accordingly, the Department again disallows the cost of the excess coverage policy premium in its entirety and 20% of the regular policy. Accordingly, the Department will reduce this expense by $14,062 (20% x $70,308) to eliminate costs attributable to shareholders. The resultant allowed premium of $56,246 requires an adjustment of $14,062. Adding that to the disallowed excess coverage premium of $73,397 produces a total reduction to D&O insurance expense of $87,459.

b. Weather Stabilization Insurance

CNG seeks to recover $993,063 in premiums for a weather stabilization insurance (WSI) policy covering the 2000/2001 heating season. Schedule C-3.32. This approximates the cost of the policy for the 1999/2000 season but is more than the cost of the policy in the 1998/1999 season. The witness stated that the Company obtained this insurance coverage to mitigate large swings in the Company's earnings in periods of extremely warm weather. CNG also proposed to set up a deferred account to allow true-ups of insurance premium costs in future rate proceedings. Bolduc PFT, pp. 7, 10.

AG proposes that the Department reject CNG's proposal to recover any costs associated with WSI because it is not a cost that ratepayers should bear. Additionally, AG points out that shareholders have already been compensated for weather in the allowed ROE. Furthermore, the Company has failed to show that the WSI provides any real benefits to ratepayers. Brief, p. 6.

OCC opposes the inclusion of WSI premiums above the line. Brief, p. 44. OCC agrees with AG that weather related risks are reflected in a company's ROE, and further states that eliminating that risk would require a fundamental reassessment of the cost of doing business. Cotton PFT, p. 12.

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ARKANSAS PUBLIC SERVICE COMMISSION

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IN THE MATTER OF THE APPLICATION OF)	
ENTERGY ARKANSAS, INC. FOR APPROVAL)	DOCKET NO. 06-101-U
OF CHANGES IN RATES FOR RETAIL)	ORDER NO. 10
ELECTRIC SERVICE)	

ORDER

Summary

On August 15, 2006, Entergy Arkansas, Inc. ("EAI") filed in this Docket its Application seeking an increase in the rates it charges its Arkansas retail electric customers. As later amended, EAI seeks a retail revenue requirement increase of $106,534,000 or approximately 11.79% above its current authorized retail revenue requirement. However, based upon the evidence presented in this Docket, the Commission finds that EAI's retail revenue requirement is excessive and should be reduced by approximately $5.67 million effective as of June 15, 2007. Among other adjustments the Commission denied EAI's request for an 11.25% return on equity. Instead, the Commission set EAI's return on equity at 9.9%.

The Commission also denied EAI's request to recover a number of expenses from its ratepayers, including reducing the level of incentive pay and stock options requested by EAI by over $21 million, and by rejecting EAI's request for its ratepayers to pay for entertainment expenses which included tickets to sporting events and concerts, golf balls and golf tournament expenses, and dinners and alcohol to entertain political figures.

Further, the Commission approved EAI's request to recover costs relating to projects and organizations that promote new technologies and research and

Having found no direct or measurable benefit to ratepayers of these types of incentives, the Commission directs that these costs not be included in rates.

As to Mr. Marcus' recommendation to disallow certain perquisites provided EAI's Chief Executive Officer and the five top executives at Entergy Corp. which include club dues, financial counseling, the corporate airplane, and a tax "gross-up", the Commission finds no substantial evidence to support the recovery of such expenditures from EAI's ratepayers. The Commission finds that, as noted by Mr. Marcus, these types of expenditures are unreasonable in light of the salaries paid Entergy's top executives. The Commission therefore disallows these perquisites.

Director and Officer Liability Insurance

EAI's application included $191,580[38] in expenses for Director and Officer Liability ("D&O") Insurance. Staff witness Plunkett recommends a 50% sharing of these costs, pursuant to past Commission practice and based on the benefits that D&O insurance provides for both stockholders and ratepayers. (T. 1472) Ms. Plunkett further testifies that her recommendation does not presuppose that this expenditure is unreasonable nor does it imply it is not useful in shielding officers and directors from shareholder litigation. Rather, she continues, her recommendation recognizes that the protection afforded officers and directors is primarily a benefit to shareholders, with EAI providing little evidence of benefits to ratepayers. (T. 1505)

AG witness Marcus, noting similar Commission findings in other dockets, also recommends that these costs be shared equally between shareholders and ratepayers,

[38]Ms. Plunkett removed $95,790 in D&O Insurance from EAI per book, representing 50% of actual expenses. Actual per book expenses would be twice that amount or $191,580.

testifying that the shareholders are the beneficiaries of such policies when mismanagement is the subject of litigation by shareholders. (T. 702, 767)

Mr. McDonald recommends that the Commission reject the Staff's and the AG's proposed adjustment, arguing that the cost is "a reasonable and legitimate cost...to encourage qualified individuals to serve as a member of the board of directors." Mr. McDonald also testifies that the positions taken by Staff and the AG, on this and other similar recommendations would, if carried to every EAI cost, result in leaving EAI without "its legal right to recover the reasonable costs it incurs to provide electric service to its customers." (T. 155)

The Commission agrees that ratepayers, as well as shareholders, benefit from good utility management, which D&O Insurance helps secure. However, as found in prior dockets, the direct monetary benefits of D&O Insurance flow to shareholders as recipients of any payment made under these policies. That monetary protection is not enjoyed by ratepayers. The Commission therefore finds that, because shareholders materially benefit from this insurance, the costs of D&O Insurance should be equally shared between shareholder and ratepayer.[39]

Civic Dues, Donations, and Club Memberships

Both Staff witness Plunkett and AG witness Marcus recommend disallowance of all costs related to civic club dues, club memberships, donations, and other costs such as "institutional advertising, lobbying, and donations, including support and sponsorship of local community organizations and local events." (T. 695.697, 1471) Ms. Plunkett notes that both FERC, which requires these items be listed as non-utility expenses, and

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ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF AN APPLICATION FOR A GENERAL CHANGE OR MODIFICATION IN CENTERPOINT ENERGY ARKLA, A DIVISION OF CENTERPOINT ENERGY RESOURCES CORP'S RATES, CHARGES, AND TARIFFS	)))))	DOCKET NO. 04-121-U ORDER NO. 16

ORDER

On November 24, 2004, CenterPoint Energy Arkla ("Arkla" or the "Company") filed an Application for approval of a general change or modification in its rates and tariffs.[1] Arkla's initial Application reflects that it was seeking a non-gas rate increase of $33,996,382 based on an overall non-gas revenue requirement of $182,525,265. Order No. 4, entered on December 16, 2004, suspended Arkla's proposed rates, charges, and tariffs pending further investigation by the Commission.

The parties to this proceeding are Arkla, the General Staff of the Arkansas Public Service Commission ("Staff"), the Attorney General of Arkansas ("AG"), Arkansas Gas Consumers ("AGC"), and the Commercial Energy Users Group ("CEUG").

Arkla filed the written testimonies of Jeffrey A. Bish, Charles J. Harder, F. Jay Cummings, Samuel C. Hadaway, Alan D. Henry, Michael TheBerge, Gerald W. Tucker, Steve Malkey, Michael J. Adams, Walter L. Fitzgerald, Michael Hamilton, and John J. Spanos. The Staff filed the written testimonies of Robert Booth, Alice D. Wright, Alisa Williams[2], Don E. Martin, Gail P. Fritchman, Don Malone, L.A. Richmond, Gayle Frier, Johnny Brown, Robert H. Swaim, and Adrienne R.W. Bradley. The AG filed the written testimony of William B. Marcus.

[1] Arkla filed additional revisions to its Application on December 27, 2004, January 10, 2005, and January 13, 2005.
[2] On August 3, 2005, the Staff filed Notice that Jeff Hilton, Manager of Staff's Audit Section, was adopting the pre-filed testimony of Staff witness Alisa Williams.

adjustments were calculated by applying the contribution rate to each party's respective payroll adjustments.

The Commission finds that the employee savings plan contribution rate should be applied to the amount determined for regular salaries and wages, overtime, and incentive pay consistent with the Commission's decision on these issues. The Commission accepted Arkla's position on regular salaries and wages, and overtime, and the Staff's position on incentive pay. (Adjustment No. IS-20).

Director's and Officer's Insurance ("D&O")

The purpose of D&O insurance is to protect officers and directors of a corporation from liability in the event of a claim or lawsuit against them asserting wrongdoing in connection with the Company's business. AG witness Marcus has two concerns with Arkla's treatment of this expense: (1) Arkla's revised allocation methodology from an asset-based to an O&M-based allocation has doubled Arkla's costs; and (2) the costs should be split on a 50-50 basis to recognize that shareholders are the major beneficiaries of policy payouts when something goes wrong. (T. 1376-1377) Arkla Witness Harder testified that the use of an O&M allocation factor is appropriate for an expense that bears no relation to the level of plant. He contended that this is a necessary business expense which enables the Company to attract and retain qualified management. (T. 152-153) Mr. Marcus disagreed, stating that the expense is not related to O&M expense either, the allocation shifts the cost to Arkla away from Arkla's electric affiliate, and utility profits are asset-based. Also, since shareholders receive the benefit of insurance payouts, they should bear a portion of the cost of buying the insurance. (T. 1465-1466) Mr.

Harder responded, contending that: (1) the AG cites no evidence to show shareholders are the primary beneficiaries of these insurance proceeds; (2) litigation often involves past stockholders, in which instance they are no different than other individuals filing tort claims; and (3) when current shareholders are involved, payments are made to the corporation in which case customers are the ultimate beneficiaries. (T. 1227-1229)

The Commission finds that Arkla has not justified its change in allocation factors nor has it justified why this expense should not be split equally between stockholders and ratepayers. Arkla did not adequately explain why, at this time, it changed from a asset-based to an O&M expense-based allocation factor. Arkla's explanation that it is an expense to attract qualified management does not establish a justifiable relationship between the cost and the cost expense allocation factor the Company used. Mr. Marcus testified that D&O insurance costs are part of general corporate overhead to protect Company profits which are largely asset-based for a utility. (T. 167-169) Mr. Marcus' testimony that this insurance protects corporate profits also lends support for sharing the insurance costs between shareholders and ratepayers. The news (T. 1040) is replete with stories about companies experiencing lawsuits by shareholders. The Commission agrees with the AG that more often than not it is the current shareholders who sue management and who receive a large portion of the proceeds from the D&O insurance payouts. Accordingly, the Commission finds that Arkla's existing asset-based allocation for D&O insurance should be maintained and that the expense for D&O insurance should be shared on a 50-50 basis between shareholders and ratepayes.

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ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ARKANSAS WESTERN GAS COMPANY FOR APPROVAL OF A GENERAL CHANGE IN RATES AND TARIFFS	))))	DOCKET NO. 04-176-U ORDER NO. 6

ORDER

PROCEDURAL HISTORY

On December 29, 2004, Arkansas Western Gas Company ("AWG" or the "Company") filed an application for approval of a general change or modification in its rates and tariffs. AWG requested that its rates be increased by $9,739,459 annually. Order No. 2, entered January 10, 2005, suspended AWG's proposed rates, charges, and tariffs pending further investigation by the Commission. Order No. 2 also established a procedural schedule for the purposes of investigating AWG's application.

The parties to this proceeding are AWG, the General Staff of the Arkansas Public Service Commission ("Staff"), the Attorney General of Arkansas ("AG"), Northwest Arkansas Gas Consumers ("NWAGC"), and the Commercial Energy Users Group ("CEUG").

On December 29, 2004, AWG filed the Direct Testimony and Exhibits of Alan N. Stewart, Executive Vice-President of AWG, Donna R. Campbell, Manager, Rates and Regulation Department of AWG, Ricky A. Gunter, Vice President of Rates and Regulation for AWG, Glenn M. Morgan, Controller and Treasurer for AWG, and Dr. Roger A. Morin,[1] Principal, Utility Research International, in support of its application.

[1]Professor of Finance, Georgia State University and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry at Georgia State University, Atlanta, Georgia.

3. **Payroll Taxes**:

Differences between Staff's and the Company's calculation of payroll taxes and that of the AG relate entirely to the differences between the parties regarding the appropriate level of payroll to include in revenue requirement.

In view of the foregoing findings on payroll, the Commission finds that Staff's adjustments for FICA and other payroll taxes is appropriate and should be adopted.

C. Fringe Benefits

As with payroll taxes, any differences among the parties for fringe benefits, including worker's compensation, medical insurance, pension expense, and employee savings plan/life insurance relate to the level of proposed payroll. Therefore, as with payroll taxes, in view of the foregoing findings on payroll, the Commission finds that Staff's adjustments for any fringe benefits should be adopted.

D. Directors and Officers Insurance ("D & O")

The AG and AWG also disagree about inclusion in revenue requirement of 100% of the liability insurance provided by AWG and SWN for its directors and officers. Mr. Marcus argues that the major beneficiaries of this type of insurance will be the stockholders and its issuance provides no assurances of better management or decision making by officers and directors for the benefit of ratepayers. He also testifies that, in AWG's last rate case, Docket No. 02-227-U, the Commission approved a sharing of the cost between ratepayers and stockholders and he recommends that the Commission require equal sharing here. (Tr. at 72-73) Mr. Morgan disputes the AG's view of the benefits provided by this expense, noting that this type of insurance is essential

to the operation of AWG, without which it could not attract the necessary management personnel to operate the Company. (Tr. at 350)

As it has held in previous rate cases, most notably in AWG's last rate case in Docket No. 02-227-U, the Commission finds that D&O insurance benefits both stockholders and ratepayers. Therefore, as recommended by AG witness Marcus this expense should be split 50/50 between stockholders and ratepayers.

E. Uncollectible Accounts Expense

Uncollectible accounts expense has been calculated by the parties, each using a percent of uncollectible accounts to revenues applied to pro forma operating revenues as explained by Staff witness Williams. (Tr. at 1442) As discussed in the following section on the revenue conversion factor, the calculation of that percent remains in dispute. The Commission has found in its discussion of the revenue conversion factor that Staff's calculated factor for uncollectible accounts expense is appropriate. In view of that finding, the Commission, therefore, also approves Staff's calculated level of uncollectible accounts expense.

F. Revenue Conversion Factor

Revenue conversion factor issues still in contention among the parties include: the term over which uncollectible accounts as a percent of revenues are averaged in order to estimate a normal level; a proposal to incorporate late payment charge revenues in the conversion factor as a percent of revenues; and a proposal to calculate and apply separate conversion factors by class to recognize each class's distinctive level of uncollectible accounts.

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
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 ITS PROPERTIES THROUGHOUT ARIZONA.	)	DOCKET NO. G-01551A-10-0458

PUBLIC

DIRECT

TESTIMONY

OF

DAVID E. DISMUKES, PH.D.

CONSULTING ECONOMIST

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 24, 2011

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David E. Dismukes, Ph.D. Resume ..... ATTACHMENT 1

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EXECUTIVE SUMMARY
SOUTHWEST GAS CORPORATION
DOCKET NO. G-01551A-10-0458

I present testimony on three subjects regarding the Southwest Gas Corporation's ("Company") proposed: revenue decoupling mechanism, its proposed class cost of service study ("CCOSS"), and its proposed rate design. Staff recommends that the Arizona Corporation Commission ("Commission") reject the Company's proposed revenue decoupling mechanism. As an alternative, Staff recommends a lost fixed cost recovery ("LFCR") mechanism that is performance-based and would actively incent the Company to meet the Commission's energy efficiency goals, while holding the Company harmless for the revenue losses associated with meeting these energy efficiency goals. Staff recommends that the Commission modify several of the Company's CCOSS allocation factors particularly those associated with the allocation of plant investments. Staff also recommends that the Commission retain the existing level of customer charges for all customer classes and implement rates that adhere to generally-accepted rate design principles used in utility regulation.

INTRODUCTION

Q. Would you please state your name and business address?

A. My name is David E. Dismukes. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana.

Q. Would you please state your occupation and current place of employment?

A. I am a Consulting Economist with the Acadian Consulting Group, LLC ("ACG"), a research and consulting firm that specializes in the analysis of regulatory, economic, financial, accounting, statistical, and public policy issues associated with regulated and energy industries. ACG is a Louisiana-registered partnership, formed in 1995, and is located in Baton Rouge, Louisiana, with additional staff in Los Angeles, California, and Fallon, Nevada.

Q. Do you hold any academic positions?

A. Yes. I am also a Full Professor, Associate Executive Director, and Director of Policy Analysis at the Center for Energy Studies, Louisiana State University ("LSU"). I also hold an appointment as an Adjunct Professor in the E.J. Ourso College of Business Administration (Department of Economics), I am a co-director of the Coastal Marine Institute in the School of the Coast and the Environment, and I am a member of the graduate research faculty at LSU.

Q. Have you prepared any attachments to your testimony outlining your qualifications in energy and regulated industries?

A. Yes. Attachment 1 to my testimony provides my academic vita that includes a full listing of my publications, presentations, pre-filed expert witness testimony, expert reports, expert legislative testimony, and affidavits.

Q. Have you prepared any exhibits to support your testimony?

A. Yes. I have prepared 22 exhibits in support of my testimony.

Q. What is the purpose of your testimony?

A. I have been retained by the Arizona Corporation Commission ("ACC" or "Commission"), Utilities Division ("Staff") to provide an expert opinion on several policy and rate design proposals included in the rate filing made by Southwest Gas Corporation ("Southwest" or "Company"), before the Commission. My testimony will address the Company's revenue decoupling proposal, Class Cost of Service Study, and rate design proposals and tariff modifications.

Q. How is the remainder of your testimony organized?

A. My testimony is organized into the following sections:

- Summary of Recommendations
- Decoupling
- Class Cost of Service Study
- Rate Design
- Conclusions

SUMMARY OF RECOMMENDATIONS

Q. Would you please summarize your recommendations and conclusions regarding the Company's proposed revenue decoupling mechanism?

A. Yes. Staff recommends that the Commission should reject the Company's proposed revenue decoupling mechanism since:

- The proposed efficiency enabling provision ("EEP") mechanism would shift revenue recovery risk associated with changes in the economy, price, and other factors away from the Company and its shareholders and onto ratepayers. Such a shifting of risk, without any corresponding mitigation or ratepayer protection measures will result in rates that are not fair, just, and reasonable.

- The inclusion of a weather component in the proposed EEP provides the Company with virtually free weather-related sales insurance without any corresponding benefit to ratepayers. Even if revenue decoupling is adopted, this aspect of the Company's EEP proposal should be rejected, without a showing of some corresponding benefit to ratepayers.

- The EEP mechanism has been offered on a permanent basis and has no review or analysis period to assess its effectiveness or the emergence of any unanticipated consequences.

- The EEP mechanism is not accompanied or tied to any verifiable, performance-based energy efficiency goals and outcomes.

- The EEP mechanism is likely to make the Company whole for changes in sales that have nothing to do with its energy efficiency efforts.

Q. Would you please describe Staff's alternative proposal?

A. Yes. Should the Commission accept the need for decoupling, Staff recommends that the Commission approve the lost fixed recovery ("LFCR") performance-based mechanism that would actively incent the Company to meet the Commission's energy efficiency

goals, while holding the Company harmless for the revenue losses associated with its energy efficiency efforts if it meets the Commission's goals. If the Company is correct that cost-effective energy efficiency programs result in stranding its fixed costs (and capacity), then the only time in which this fixed cost recovery problem should arise is when the Company has met real, meaningful, and measurable energy efficiency goals. Under Staff's proposal, the Company would attain greater amounts of fixed cost recovery as it meets its Commission-defined energy efficiency goals.

Q. If the Commission adopts the Company's proposed revenue decoupling mechanism, what conditions should the Commission apply to the mechanism?

A. Staff recommends the Commission adopt the following ratepayer protection mechanisms if the Company's decoupling mechanism is approved.

- Adoption of an annual earnings review and a refund of all dollars in excess of the Company's authorized return to ratepayers during the period in which full revenue decoupling is in place.

- Adoption of a three year review period for energy efficiency performance and any lost revenue mechanism adopted by the Commission. The Company's performance should be judged against energy efficiency performance goals including new, incremental energy efficiency programs that are implemented after the decoupling mechanism is initiated. This review should include a regulatory presumption that any lost revenue recovery mechanism will be discontinued in three years unless the Company has clearly demonstrated that its disincentives for the promotion of energy efficiency have been eliminated.

- A three year review process that includes: (1) an energy efficiency review; (2) a revenue deferrals and collections review if full decoupling is adopted by the Commission; (3) a customer usage analysis; and (4) other review criteria addressing internal changes in the Company's energy efficiency culture and philosophy and the financial market perceptions of its revenue decoupling mechanism and related earnings impacts.

- Annual reporting requirements that include both the Company's proposal to reconcile actual-to-allowed revenue, an annual earnings surveillance report, and a reconciliation of the forecasted to actual per measure/per customer class total energy efficiency savings and participation levels in the prior year relative to forecasted level.

- The three year review should be conducted by a consultant selected by Staff and funded by the Company at a level of not more than $100,000 per review.

Q. If the Commission adopts Staff's alternative mechanism, what conditions should the Commission apply to the mechanism?

A. Staff recommends the Commission adopt the following ratepayer protection mechanisms if the Staff's proposed LCFR is approved:

- Adoption of an annual review period for energy efficiency performance and any lost revenue mechanism adopted by the Commission. The Company's performance should be judged against energy efficiency performance goals including new, incremental energy efficiency programs that are implemented after the LCFR mechanism is initiated.

- An annual review process that includes: (1) an energy efficiency review; (2) a customer usage analysis; and (3) other review criteria addressing internal changes in the Company's energy efficiency culture and philosophy and the financial market perceptions of its revenue decoupling mechanism and related earnings impacts.

- Annual reporting requirements that include both a reconciliation of the LFCR mechanism and identification of per measure/per customer class total energy efficiency savings and participation levels in the prior year relative to forecasted level.

- The annual review should be conducted by a consultant selected by Staff and funded by the Company at a level of not more than $50,000 annually.

Q. Does Staff have any other recommendations regardless of whether the Commission adopts a full decoupling mechanism or the LFCR recommended by the Staff?

A. Yes. The Commission should evaluate changes in usage pre- and post-policy adoption regardless of whether or not a revenue decoupling mechanism is adopted. Some of the customer usage statistics that should be included in this review include:

- An analysis of usage differences between new and existing customers.
- A comparison of the differences between new and existing customer UPC.
- An analysis of overall customer usage, UPC, and customer growth per class on a pre- and post-decoupling basis.
- An analysis of customer migration during the three-year review period.
- An analysis of Company activities in supporting new customer growth including the encouragement of new and economic uses of natural gas.

- A survey of customer perception, understanding, and acceptance of the decoupling mechanism and its intent.

Q. Would you please summarize Staff's Class Cost of Service Study recommendations?

A. Yes. Staff recommends that the Commission adopt the following alternative CCOSS allocation factors:

- Distribution mains should be allocated on a 50-50 basis with 50 percent of those investments being allocated to customers and the other 50 percent allocated on non-customer factors. This differs from the Company's proposal to allocate mains investment on a 50 percent demand/50 percent customer allocation basis.

- The non-customer component of the mains investment allocator should be divided on a 50-50 commodity-demand basis.

- Measuring and regulating equipment should be allocated on a 50 percent demand and 50 percent commodity basis, instead of the 50 percent customer and 50 percent demand allocation proposed by the Company.

- Maintenance of mains should be allocated on the basis of 50 percent customers, 25 percent demand, and 25 percent commodity, consistent with the plant account associated with these maintenance activities.

- Measuring and regulating equipment – industrial should be allocated to industrial customers only, as opposed to the Company's method which allocated these costs to all customers.

- The Commission should order the Company to include the special procurement gas customers served under Schedule G-30 in the CCOSS submitted in its next rate case.

- The Commission should order the Company to develop an accounting process that explicitly identifies customer class-specific Contributions in Aid of Construction ("CIAC") in such a manner that CIAC can be appropriately assigned to the classes that paid the CIAC.

- All CCOSS errors identified by the Company in response to Staff's discovery should be corrected including those associated with the allocation of services, meters, and customer installation expenses.

Q. Would you please summarize Staff's rate design recommendations?

A. Yes. Staff's rate design recommendations can be summarized as follows:

- Revenue responsibilities for developing rates should be allocated on a methodology that constrains any one class from receiving a rate increase greater than 1.25 times the system average and distribute any of the remaining revenue deficiency across classes earning less than three times the proposed system average increase.

- Existing customer charges should be held at their current levels.

- The Company's existing uniform volumetric rate structure should be continued.

- Volumetric rates should be increased according to the results of Staff's alternative class cost of service model and the Staff's recommended revenue requirement.

- Staff recommends the Commission reject the Company's low income class rate design proposal and continue the existing 20 percent discount on the first 150 therms of winter usage.

- For the Company's Special Residential Gas Service for Air Conditioning rate, Staff recommends a gradual move towards a uniform volumetric rate for this class until such time that the Company can support a declining block rate with class-specific cost information.

- Staff agrees with the Company proposal to separate the Large General Service class. However, the Commission should reject the Company's customer and delivery charge proposals for the Large-1 and Large-2 General Service classes. Instead, Staff recommends that the Commission decrease the customer charge of the Large-1 General Service class to $120 per month and examine further decreases in the Company's next rate case. Staff also recommends the Commission increase the customer charge of the Large 2 General Service class to $240 per month.

- Staff recommends that the Commission order the Company to close the Small Essential Agriculture tariff to all new customers.

- Staff has expressed a strong interest to investigate alternative rate designs that may send better price signals to customers about the opportunity cost of their natural

gas consumption decisions. Staff recommends the Commission order the Company to evaluate alternative rate designs, including an inclining block rate structure for residential and commercial customers, in the next rate case. Each alternative rate design proposal offered by the Company should include documentable cost support and other details indicating how the alternative rate design promotes and supports energy efficiency.

- Staff recommends the Commission adopt the Company's proposed change for Rate Schedule No. B-1.

- Staff recommends that the Commission order the Company to either (a) discontinue collecting advances and CIAC that result in a return on equity that is more than 50 basis points above the allowed return, or (b) demonstrate that the Incremental Cost Model filed in this case, and used to estimate these advances, are not representative of the final advances and CIAC collected from customers.

DECOUPLING

A. Introduction

Q. What are Staff's general recommendations regarding the Company's proposed revenue decoupling mechanism?

A. Staff recommends that the Commission reject the Company's proposed revenue decoupling mechanism.

Q. What was the rationale for the Company's proposal?

A. The Company effectively bases its proposal on the assertion that regulation is ineffective in balancing the risks and rewards associated with energy efficiency investments.[1] According to the Company, traditional regulation has a number of inherent flaws that challenge its ability to promote energy efficiency and recover its revenue requirement.[2]

Q. How does revenue decoupling deviate from common regulatory principles?

A. Utility regulation is based upon a principle, developed over the past century, commonly referred to as the "regulatory compact," that defines the relationship and expectations between regulated companies and their regulators. This relationship gives regulated utilities a specific service territory and an opportunity, but not a guarantee, to earn a reasonable rate of return on, and recovery of, their prudently-incurred investments. In return, regulated utilities are obligated to provide safe, reliable, and economic service to their ratepayers at rates that are fair, just, and reasonable. Full decoupling, like Southwest's proposal, however, differs from this principle by creating an almost guaranteed revenue requirement for the Company with little to no market incentives or discipline for efficient service, and without mitigation or ratepayer protection measures.

Q. Does Staff agree with the Company's argument that its proposed EEP will better align its incentives with those of its customers?

A. No, particularly since this argument tends to overstate the financial impacts that are claimed to arise from the promotion of utility-sponsored energy efficiency. Lost base revenues associated with energy efficiency are only one of several factors that can

[1] Direct Testimony of Edward B. Gieseking, p. 5.
[2] Direct Testimony of Edward B. Gieseking, p. 7.

influence total sales revenues. Other factors include, but are not entirely limited to price, weather, and income. As a result, full revenue decoupling, as proposed by Southwest, can lead to bill surcharges for revenue changes that have nothing to do with utility-sponsored energy efficiency programs.

B. Revenue decoupling mechanisms and the proposed EEP

Q. Has the ACC issued a policy statement supportive of revenue decoupling?

A. Yes. This Policy Statement[3] is the outcome of several rounds of comments and workshops held throughout 2010. The investigation itself was the result of issues raised during the course of setting energy efficiency standards for electric utilities (December 19, 2009) and jurisdictional gas utilities (August 2010) during roughly the same period of time.

Q. What was the outcome of this workshop process?

A. The Commission issued a Policy Statement and Report at the conclusion of this process. The Report, which precedes the Policy Statement, summarizes the workshop process, identifies the parties participating in the workshop, and highlights various parties' positions. The Policy Statement itself consists of three pages and 13 specific policy bullet points.

Q. Did the ACC recognize that specific revenue decoupling guidelines were best determined in a general rate case?

A. Yes. While the ACC Policy Statement generally supports some type of revenue decoupling, the Commission also recognizes, as did most parties at the ACC's workshops,

[3] ACC Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures. Docket Nos. E-00000J-08-0314 and G-00000C-08-0314. December 29, 2010.

that specific policies and proposals, as well as potential alternatives, can and should be considered within the context of a specific rate case proceeding. The Workshop Summary explicitly notes that:

> In response to a question as to whether Arizona should engage in a broad approval of decoupling, utilities responded that a rulemaking would provide a framework and parameters but the expectation was that utilities would more fully address issues within a specific rate case proceeding.

Later, the ACC, in the Workshop Summary noted:

> The Commission believes that adoption of decoupling should occur in rate cases, with evaluation and review occurring after an initial three year period.

In the formal Policy Statement itself, the Commission notes that utilities may file a proposal for decoupling or an alternative mechanism for addressing disincentives, in its next general rate case.[4] The ACC did not adopt, require, nor mandate revenue decoupling, leaving the ultimate decision regarding revenue decoupling, and the merits of specific decoupling proposals, to be addressed in utility-specific rate cases.

Q. Did the Policy Statement recognize that alternatives to revenue decoupling could also be examined?

A. Yes. While the ACC Policy Statement offers a number of positive assertions about the use of revenue decoupling as a policy mechanism to address perceived utility disincentives to energy efficiency, it also clearly recognizes that decoupling is not the only

[4] ACC Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures. Docket Nos. E-00000J-08-0314 and G-00000C-08-0314. December 29, 2010, p. 32.

policy option available to regulators. For instance, in Policy Statement Number 3, the ACC explicitly notes that it:

> ...could also consider alternative methods for addressing utility financial disincentives. Some form of decoupling, or alternative for addressing financial disincentives must be adopted in order to encourage and enable aggressive use of demand side management programs and the achievement of Arizona's [energy efficiency goals].

In Policy Statement Number 5, the ACC notes:

> Adoption of decoupling (or any other alternative mechanisms that addresses utility disincentives to promoting energy efficiency) should not occur as a pilot, as this insufficiently supports demand side management efforts.

In Policy Statement Number 7, the ACC notes:

> Utilities are encouraged to develop customer rate designs that support energy efficiency and work well in tandem with decoupling (or alternative mechanisms).

Thus, the ACC Policy Statement clearly recognizes that common revenue decoupling is not the only mechanism that can support utility efforts in promoting energy efficiency and that it was open to the consideration of "alternative mechanisms."

C. Overview of the Company's EEP Proposal

Q. How would the Company's decoupling mechanism work?

A. Southwest proposes to implement revenue decoupling on a revenue per customer ("RPC") basis. An RPC-based mechanism is a common form of revenue decoupling that starts with the determination of an allowed RPC, typically derived from the outcome of a concurrent rate proceeding. The allowed (test year) revenue requirement, divided by the

total number of test year customers is then utilized as the allowed RPC for future revenue decoupling reconciliation purposes. Future decoupling reconciliations compare actual RPC (actual revenues collected per the actual number of customers in the same reconciliation period) to allowed RPC to determine a per customer revenue deficiency or surplus. This per customer difference is then multiplied by the number of actual customers in the reconciliation period to arrive at a total revenue deficiency or surplus. This deficiency or surplus is divided by reconciliation period sales to develop a per therm surcharge or credit that will be applied to the upcoming twelve-month recovery period.

Q. Would ratepayers be subject to a single or a multiple decoupling reconciliation process under the Company's EEP?

A. Ratepayers would be subjected to multiple reconciliations.[5] For instance, the first set of decoupling reconciliations would be done on a monthly basis, and assess a surcharge or credit for weather-related deviations in heating season usage. The second set of decoupling reconciliations would be conducted at the end of the year, would true up the difference between actual and allowed revenues discussed earlier, and assess this difference on monthly bills for the upcoming 12 months.

Q. Would the Company be made whole for changes in sales created by the weather?

A. Yes. The second component of the Company's revenue decoupling mechanism includes a true-up for weather-related differences in usage during its heating season months.[6] Ratepayers would be assessed a charge (or credit) if the prior month's weather was warmer (or colder) than normal. Here, "normal" weather is defined as the rolling ten year

[5] Direct Testimony of Edward B. Gieseking, p. 3.
[6] Direct Testimony of Edward B. Gieseking, p. 3.

average of the observed heating degree days ("HDDs").[7] Weather normalized usage for each customer is estimated as the difference in HDDs (actual to normal) times the statistically-estimated average response that customers tend to exhibit when HDDs are varied. The Company estimates this average weather response, or weather sensitivity, for single family residential customers as being 0.16. In other words, a one HDD deviation from average weather tends to result in a 0.16 therm increase in usage, holding other factors constant.[8]

Q. Has the Company included any customer protection mechanisms in its proposed EEP?

A. None that are comparable to those included in the revenue decoupling mechanisms of other states. The Company is not proposing to subject its revenue decoupling mechanisms to a future review and evaluation; its mechanism is not tied to successfully meeting the Commission's energy efficiency goals; and the proposal sets a rate cap at a relatively high percentage.

Q. Has the Company provided any "back-casts" that show the impact that revenue decoupling would have on customer bills had it been previously adopted?

A. Yes. The Company provided calculations showing the impact of decoupling as if it had been in place from 2007 through 2010 in response to Staff Data Request 3-32. This information revealed that for the residential classes, the Company would have collected additional revenue ranging from $7.6 million in 2007 to $29.3 million in 2009. In total,

[7] A heating degree day ("HDD") is a measure that relates temperature to energy demand. One HDD is defined as the difference in average daily temperatures to a reference temperature of 65 degrees. If the average temperature is equal to or greater than 65 degrees, there are no HDDs for that day. If the average temperature is lower than 65 degrees, then each degree lower is counted as an HDD. See National Oceanic and Atmospheric Administration, National Weather Service, Internet website: http://nws.noaa.gov/glossary/.

[8] Response to Staff Data Request ACC-STF-3-6

for the four years, Southwest would have collected an additional $62.0 million from residential customers if its rates had been decoupled. The average annual decoupling collections would have amounted to six percent of residential test year revenue. Further, for residential customers, the Company estimates surcharges in each of the four years, dispelling any notion that the rate impacts from revenue decoupling would have been symmetrical.

Q. What were the estimated impacts for the other customer classes?

A. Smaller impacts are indicated from the general service classes. If decoupling had been in place over the past four years, the Company would have collected an additional $3.9 million from customers with an annual average surcharge of close to $1 million, or one percent of test year revenue. Although the Company estimates that there would have been a total revenue increase for the entire general service class, the small and medium general service customers would have witnessed rate decreases with decoupling.

D. Rationale for Decoupling

Q. What are the purported disincentives to utilities to promote energy efficiency?

A. Some energy efficiency advocates, as well as many (but not all) utilities, argue that current regulatory pricing practices discourage utility-sponsored energy efficiency programs. These supporters note that energy efficiency reduces sales thereby reducing a utility's ability to recover its fixed costs. One of the primary reasons for the Company's revenue decoupling proposal is to address its claims that there is a mismatch between the financial interests of its customers and its shareholders regarding energy efficiency.[9]

[9] Direct Testimony of Edward B. Gieseking, p. 5.

Q. How does revenue decoupling address this claimed disincentive?

A. The general premise behind revenue decoupling is that it removes the relationship between the collection of a utility's revenue requirement and its sales, thereby removing the disincentives to pursue end user efficiency programs. For instance, under the Company's revenue decoupling approach, changes in sales revenues would be compared with benchmark revenue amounts.

Q. Are sales decreases due to energy efficiency the only source of differences between test year (allowed) and actual revenues?

A. No. There are a variety of other reasons why retail sales and revenues in any given year can differ from the test year amount. These impacts are usually much larger than sales losses created by energy efficiency programs. Consider that test year retail sales and revenues in a rate case are usually based upon a "typical" year and as such, are based upon typical factors such as the weather, the economy, and prices, among other things. In any given year, the actual performance of the economy may differ from the test year. Weather may be colder or warmer than the historical normal weather trends included in the test year, and other factors may occur in any given year that impact sales differently than what was anticipated in the test year determination. The differences in sales created by weather, the economy, commodity prices, and other factors usually account for greater changes in revenue than those resulting from utility-sponsored energy efficiency programs.

Q. What factors have motivated renewed interest in revenue decoupling?

A. Revenue decoupling attained a new level of interest around 2004 to 2005 due to (1) past increases in natural gas prices which have impacted overall usage and (2) the significant acceleration of state-driven energy efficiency ("EE") goals and targets. Exhibit DED-1

presents a map that shows EE goals that many states have recently adopted hoping to attain demand reduction levels by as much as 15 to 20 percent by 2015.

Q. Are natural gas and electric utilities facing similar usage trends?

A. No. Natural gas utilities, including Southwest in this proceeding, have suggested an additional motivation for promoting revenue decoupling associated with decreasing residential usage per customer ("UPC") over the past several years.[10] Electric utilities have not been facing similar decreasing UPC trends. In fact, electric utilities have seen UPC trends that generally move in opposite directions from those seen in the natural gas industry. The chart in Exhibit DED-2 compares overall U.S. electric and natural gas UPC trends over the past 19 years. While electric UPC has been generally increasing over this same period, natural gas UPC has been generally decreasing.

Q. What level of lost base revenue can be expected for Southwest as a result of meeting the Commission's energy efficiency goals?

A. Exhibit DED-3 shows the Company's historic and forecasted annual lost base revenues that are created by the Commission's annual energy efficiency goals. These lost base revenues do not exceed 0.7 percent of forecasted base revenues in any given year.

Q. What factors are influencing UPC if energy efficiency savings are not significantly impacting utility revenues?

A. A number of factors influence sales including weather, income, commodity prices, as well as structural usage changes created by new and more efficient appliance standards. More recently, the recession and its consequences of unemployment and belt tightening have

[10] Direct Testimony of Robert A. Mashas, pp. 4, 6-7; Direct Testimony of James L. Cattanach, p. 10.

contributed to a reduction in usage by customers. As noted earlier, natural gas commodity prices have changed dramatically over the past eight years starting during the winter of 2000-2001 and particularly in the aftermath of Hurricanes Katrina and Rita in 2005. These collective changes have had considerable impacts on recent changes in total residential UPC.

Q. How does the promotion of market transformation programs impact sales?

A. Market transformation is commonly associated with informational and educational programs designed to change consumer perceptions about energy use and efficiency. Education, however, is a long-term proposition and the results of these market transformation programs will likely be embedded (and difficult to separate) from the trend in usage per customer.

E. Revenue Decoupling and Weather Normalization

Q. Why has the Company's revenue decoupling mechanism included an adjustment for weather?

A. The Company's request appears to be based upon the fact that a weather adjustment opportunity was discussed, and eligible for future consideration, in the Commission's prior Policy Statement.[11] The Company suggests that the weather normalization adjustment ("WNA") component of its revenue decoupling mechanism is designed to provide immediate relief to customers from extreme weather events.[12] However, a close examination of past weather trends shows that the Company and its shareholders would have attained greater relief from this mechanism than ratepayers.

[11] Arizona Corporation Commission, "ACC Policy Statement Regarding Utility Disincentives to Energy Efficiency and Decoupled Rate Structures," p. 32
[12] Response to Data Request RUCO-2-10.

Q. What are the common arguments that utilities have offered for WNA mechanisms?

A. Utility justifications for WNAs typically rest upon two premises. The first is that the regulatory process is deficient and unable to set rates correctly since actual sales and revenues are almost certain to never coincide. The second is that changes in sales are inherently risky, and the Company should be insulated from this risk by a true-up mechanism that allows it a level of revenues that is unaffected by weather.

Q. Does Staff agree with the premise that weather risk is symmetrical?

A. No. On some occasions, utilities, in making WNA proposals, will make the claim that weather risk is symmetrical and that WNA mechanisms can serve as a balancing mechanism between customers and utilities. That is not the case in this proceeding as the Company has not attempted to make this claim. The typical utility argument justifying the implementation of a WNA mechanism is that these mechanisms will effectively "institutionalize" long run weather trends: in some periods, rates will be increased due to warmer-than-normal temperatures and in other periods, rates will decrease to reflect colder-than-normal temperatures. Under this logic, in the long run, the colder-than-normal cycles will offset the warmer-than-normal cycles, resulting, on average, in a zero gain to either party (e.g., utility, ratepayers).

Q. Do these mechanisms tend to be symmetric?

A. Usually not and the degree of asymmetry inherent in the mechanism will in large part be a function of how the mechanism is constructed, the time period between rate cases, and the weather cycles under which the mechanisms are evaluated. It is quite possible that these mechanisms can be pure risk-shifting mechanisms placing greater weather-related sales risk on customers and away from utilities and their shareholders.

Q. Have any regulatory commissions revised their approval of a WNA because of this risk asymmetry?

A. Yes. The Connecticut DPUC noted that WNA clauses are not symmetrical in the benefits shared between the utility and ratepayer. In a recent Southern Connecticut Gas Company ("Southern") decoupling proceeding, the utility noted that it has received significantly greater benefits than ratepayers over a 15 year period. The DPUC noted that "Southern received a total of $43.6 million in net WNA revenue" over a 15 year period and that the utility's "ROE has benefitted significantly."[13] Exhibit DED-4 provides a table, based upon data developed by Southern, that was cited by the DPUC as providing evidence regarding asymmetric WNA benefits accruing to the utility.

Q. Did the Connecticut DPUC draw any conclusions from this analysis?

A. Yes. The DPUC noted:

> The WNA has not performed as the Department had believed it would when its continuation was allowed in the 2000 Decision. To date, the WNA has been <u>one-sided in favor of the Company</u>. As stated earlier, the Department was of the belief that the ROE would be reduced in future years and that the <u>revenue flows would average out over the 30-year normal weather period</u>. The WNA is now half-way through the 30-year averaging period and <u>neither has happened</u>. The 85 basis point average bonus to the ROE has now increased to 93 basis points and the Company is nearly $44 million better off with the WNA than without. Further, what was deemed an "accident of history" by the Department in the 2000 Decision has actually continued on a trend of warmer than normal weather in 12 of the 15 years since the WNA was established. Unless the weather pattern turns colder than normal for the majority of the remaining years of the 30-year cycle, the revenue flows will have little or no opportunity to average-out, and the benefit between ratepayers and the Company will not equalize as expected. Because there is no guarantee that the current weather

[13] Application of the Southern Connecticut Gas Company for a Rate Increase. Connecticut Department of Public Utility Control. Docket No. 08-12-07. Order Dated July 17, 2009, emphasis added.

> trend will reverse itself, the Department finds that continuing the WNA would not be in the public interest.
>
> Consequently, the Department hereby abolishes Southern's WNA. Effective with new rates, Southern is directed to cease applying the WNA to customer bills. The Department reserves for a future proceeding any determination regarding the historic operation and financial impact on the company and ratepayers of the WNA.[14]

Q. Does Staff think weather-related risk is symmetrical under the Company's proposal?

A. No, based on to the information included in the Company's application and testimony. Under the status quo, the Company would continue to deal with the risk of any potential losses (or gains) in sales associated with changes in weather. The Company itself has repeatedly noted that this is a risk that somehow compromises its ability to earn its revenue requirement and represents a fundamental shortcoming in its interpretation of traditional regulation.[15] Thus, approval of the Company's proposal would be a net shifting of risk away from itself and onto customers.

Q. Are the historic weather trends symmetrical in the Company's service territory?

A. No. Exhibit DED-5 shows that the difference between actual heating degree days and normal heating degree days ("normals") for the residential rate class (G-5) has been consistently skewed against ratepayers in samples based upon 3, 5, 7, and 10-year periods ending January 2011.

[14] Application of the Southern Connecticut Gas Company for a Rate Increase. Connecticut Department of Public Utility Control. Docket No. 08-12-07. Order Dated July 17, 2009, emphasis added.
[15] Direct Testimony of Theodore K. Wood, p. 7.

Q. Is the historic usage change resulting from these biased differences significant?

A. Yes. Exhibit DED-6 shows that the usage from these warmer-than-normal biases was relatively significant over the 3, 5, 7, and 10-year sample periods.

Q. Is a WNA component required as part of a decoupling mechanism?

A. No, and a number of states that have adopted revenue decoupling mechanisms, such as Colorado, Idaho, Michigan, Minnesota and Washington, have explicitly done so without a weather adjustment component.

Q. Would Staff recommend approval of a WNA if these weather trends were exactly symmetrical?

A. No, since there would be no need for a WNA. A symmetrical WNA would balance revenue losses with gains over the long run, rendering the need for a WNA moot.

F. Washington Utilities and Transportation Commission's ("WUTC") Evaluation of Decoupling

Q. What mechanisms did the WUTC define as being appropriate and associated with the "direct" actions of utility energy efficiency efforts?

A. The WUTC states that it will only consider a "limited decoupling mechanism," in the context of a general rate case, and conditioned any consideration of a limited decoupling proposal entirely upon a utility's level of energy efficiency achievement:

> The Commission remains receptive to recovery of lost margin attributable to company-sponsored conservation programs and company-sponsored education and information programs. The Commission generally will not consider approving mechanisms that permit recovery of lost margin not attributable to a company's conservation efforts, such as conservation not supported by a utility's above–stated conservation efforts, customer-

initiated fuel substitution and other responses to price elasticity, or increased stringency of energy or building codes and standards.[16]

G. Staff's Alternative Recommendations

Q. Can Staff please explain its alternative recommendation?

A. Yes. One of the problems with true revenue decoupling is that by decoupling revenues and costs from sales, revenue decoupling can also decouple a primary determinant of performance from rates. If left unchecked, rates may start to reflect accumulated inefficiencies and potentially over-capitalization. There are alternative methods, however, that can preserve the traditional performance/rate relationship by tying any lost fixed cost recovery amounts to energy efficiency savings.

Q. Can you explain how this lost fixed cost recovery ("LFCR") mechanism would work?

A. Yes. A LFCR mechanism would tie the Company's performance in its energy efficiency efforts to potential lost base revenue recovery. If Southwest is correct, that the deployment of cost-effective energy efficiency results in stranding its fixed costs (and capacity), then the only time in which this fixed cost recovery problem should arise is when the Company has met real, meaningful, and measurable energy efficiency goals.[17] Under Staff's proposal, the Company would attain greater amounts of fixed cost recovery as it meets its Commission-defined energy efficiency goals.

[16] In the Matter of the Washington Utilities and Transportation Commission's Investigation into Energy Conservation Incentives. Washington State Utilities and Transportation Commission. Docket-100522. Report and Policy Statement on Regulatory Mechanisms, Including Decoupling, to Encourage Utilities to Meet or Exceed their Conservation Targets. November 4, 2010.
[17] Direct Testimony of Edward B. Gieseking, p. 7

Q. How would the LFCR be collected from customers?

A. The LFCR would be a separate surcharge included on each customer's bill, much like a gas adjustment surcharge.

Q. How would this mechanism work?

A. The mechanism would effectively allow the Company to recover its first year lost base revenues that could arise as if 100 percent of its first year energy efficiency goals were achieved. Using the Staff recommended rates and the Company's 2011 energy efficiency saving goal of 2,281,000 therms, Staff estimates 2011 lost base revenues to be approximately $1,313,481. Dividing this amount by applicable 2010 therms of 615,748,565 yields a 2011 surcharge of $0.00213 per therm.

Q. How would the next reconciliation work?

A. The Company would be allowed to recover, through a per unit surcharge, the total amount of the anticipated 2012 lost base revenues assuming it achieves 100 percent of its 2011 energy efficiency savings. This amount would be trued-up to actual lost base revenue in the April 2013 reconciliation process. If the Company does not meet 100 percent of its 2012 energy savings goals, the difference between the 100 percent it was allowed to collect and the actual lost revenue would be refunded to ratepayers during the 2013 reconciliation process. In addition, if Southwest does not meet its 2012 savings goals, it will not be allowed to recover its estimated lost base revenue for 2013. The Company will only be allowed to recover upcoming estimated lost revenue if it meets or exceeds the prior year's energy savings goals.

Q. How would adjustments be made?

A. Each year, the Commission would undertake a reconciliation process, much like the one proposed under the Company's decoupling mechanisms. However, under Staff's alternative, the Company's actual energy efficiency savings would be compared to the Commission's current efficiency goals. If the Company attains 100 percent of its required energy efficiency goals at the time of the reconciliation, it would be allowed to increase its surcharge amount to a level comparable to the lost base revenues anticipated for the next year's energy efficiency activities. If the Company fails to reach those goals, there would be no surcharge allowed for the upcoming year's lost base revenues.

Q. What would happen if the Company exceeds its energy efficiency goals in any reconciliation period?

A. The Company would only be allowed to recover 100 percent of the upcoming year lost base revenues. However, the Company would be permitted to recover, through the surcharge, in the following year the difference between 100 percent collected from customers and the actual amount of lost base revenues associated with attaining energy saving greater than 100 percent of the year's goal, as limited by yearly targets in the energy efficiency rules.

Q. Would usage changes related to weather be included in Staff's alternative proposal?

A. No, since changes in usage that were created by the weather are not related to the Company's energy efficiency performance.

Q. How would the reconciliation process work?

A. The reconciliation period would begin April 1 of each year with the filing of the Company's DSM report as currently required for the preceding year. In this filing, the

Company would file its energy efficiency savings and lost revenue information along with all supporting calculations and documentation for the calendar year. This filing would also include the surcharge calculation for the upcoming year. For example, the Company's 2012 filing would be based upon calendar year 2011 energy efficiency savings. Staff would review the LFCR filing within 60 days. If Staff finds problems with the filing, those problems would be taken to the Commission for further resolution. If there are no problems with the Company's filing, the surcharge would take effect June 1.

Q. Should an independent audit and evaluation be performed in order to confirm compliance with the Commission's Gas Energy Efficiency rules and/or or adjust the savings reported in the Company's annual DSM progress report, as filed each April 1st?

A. Yes. Staff has proposed an adjustor mechanism to permit recovery of lost revenue to recover possible stranded fixed costs due to the Company's efforts to meet the Commission's gas energy efficiency standards. An independent audit/evaluation would ensure that recovery through this mechanism is based on the most accurate possible determination of the energy savings achieved. Such an audit/evaluation will also be useful for ensuring that the savings achieved by the Energy Efficient and Renewable Energy Resource Technology Portfolio ("EE and RET Portfolio") are commensurate with the level of ratepayer funding.

Q. How should the independent audit and evaluation be performed?

A. The audit/evaluation should be performed by an independent consultant selected by Staff, at a time to be determined by Staff, and may include, but not be limited to, the following elements:

- Verifying the correct installation of a sampling of DSM and RET measures;
- Verifying the therm, or therm equivalent, savings per measure in a sampling of DSM and RET measures;
- Verifying the therm, or therm equivalent, savings in a sampling of DSM or RET programs;
- Reviewing calculations relating to the portfolio or energy efficiency savings for accuracy;
- Determining whether any baselines utilized for determining energy savings should be reset due to changes in appliance or building standards;
- Determining whether participation levels are reported accurately;
- Evaluating any education or assessment programs to determine whether they are leading to energy savings due to an increased awareness about energy use and opportunities for saving energy; and
- Evaluating Southwest's claims of savings related to changes in building and appliance standards to verify savings from those changes, and to verify that Southwest's efforts to support the adoption and implementation of the new standards have been adequately demonstrated and documented.

Q. How should the independent audit and evaluation be funded?

A. Staff would select an independent consultant using the Request for Proposal process and would oversee the audit/evaluation, but Southwest would be responsible for funding the audit/evaluation for up to $50,000.

Q. What does Staff see as the benefit of its proposal relative to the Company's requested decoupling mechanism?

A. Staff believes that its LFCR proposal offers a number of advantages over the Company's full revenue decoupling mechanism. The LFCR will:

- Re-couple performance, cost, and revenue recovery in a fashion consistent with the best practices and traditions of utility regulation.

- Preserve traditional risk relationships in utility regulation with the Company bearing risks associated with both its costs and the overall business environment in which it operates.

- Remove disincentives for energy efficiency by creating positive (not neutral) incentives.

- Remove the increasingly-recognized deficiency created by full revenue decoupling that could allow utilities to collect revenue deficiencies that far exceed their energy efficiency efforts.

H. Ratepayer Protection Mechanisms

Q. Are ratepayer protection mechanisms commonly adopted with revenue decoupling?

A. Yes, and Staff has surveyed some of these provisions for utilities that have approved revenue decoupling plans in Exhibit DED-7. Various states have used one or a combination of the following protections in the development of their respective revenue decoupling mechanisms:

- Recovery Structures: This type of protection mechanism typically limits the range of revenue recovery for a utility under decoupling. One example of this is Colorado's approach that only allows revenue recovery in instances where UPC falls by more than 50 percent of the five year average decrease. Another would be Washington's approach that caps total recoveries to 45 percent of all revenue deferrals and conditions recovery of that 45 percent on the utility's energy efficiency performance.

- Recovery Limitations: This type of protection restricts the amount of revenue that can be collected in any period by some fixed amount. Examples include Oregon's original approach that limits revenue recovery to only 90 percent of the difference between actual and allowed margins, and Indiana's provisions for its gas utilities that restricts revenue recovery to only 85 percent of the difference between allowed and actual margins.

- Caps on Accruals: This approach is common among approved decoupling mechanisms and caps the amount of overall accrual to some pre-defined percent of total revenues or some other measure. An example would be Utah's limitation on recovery balances of one percent of total revenues or Wisconsin's 100 basis point limitation.

- DSM Targets or Goals: Many programs either require DSM targets or goals to be a companion of the adoption of revenue decoupling. Some commissions, like the WUTC, actually tie revenue decoupling recoveries to EE achievement. The purpose of these types of protections is to ensure that the benefits created by utility

energy efficiency programs are balanced against the cost of potential revenue decoupling surcharges.

- Annual Filings and Periodic Reviews: Many programs require utilities to file information on balances and true ups periodically and many limit the adoption of revenue decoupling programs to a fixed period for a review on potential unanticipated consequences.

Q. Should the Commission adopt ratepayer protection mechanisms?

A. Yes. The Commission should adopt ratepayer protection mechanisms under either the Company's full decoupling approach or under the Staff's proposed LFCR. Staff will first present the ratepayer protection mechanisms for a full revenue decoupling approach like the one proposed by the Company and then its LFCR.

Q. Should the Commission adopt a rate cap under the Company's decoupling proposal?

A. Yes. If the Commission accepts the Company's proposal, it should cap deferrals to one percent of total revenues. This level is consistent with many other state revenue cap provisions for revenue decoupling.

Q. What about a hard earnings cap?

A. Yes. If the Commission approves the Company's revenue decoupling mechanism, Staff recommends that the Commission require an annual earnings review. The Company should be required to refund all dollars in excess of the Company's authorized return to ratepayers during the period in which full revenue decoupling is in place.

Q. Does Staff recommend any other ratepayer protections?

A. Yes. The Company's energy efficiency performance, under full revenue decoupling, should be examined after a three-year period. The regulatory review at the end of the fixed period should be clearly defined and should be based upon a regulatory presumption that the Company's proposed revenue decoupling mechanism will be discontinued unless the Company can clearly demonstrate that its disincentives for the promotion of energy efficiency have been eliminated and the mechanism served its intended purposes.

A three-year review period is similar to the time periods that have been accepted in other states approving revenue decoupling proposals. Three years seems to be a long enough period to evaluate meaningful changes in the Company's promotion of energy efficiency, but not so long as to allow unanticipated consequences of revenue decoupling from becoming unmanageable.

Q. What review criteria should the Commission include in this process?

A. The Commission should consider adopting several criteria in its evaluation process that are similar to those adopted in other states. Review criteria could fit into four general categories that would include: (1) an energy efficiency review; (2) a revenue deferrals and collections review; (3) a customer usage analysis; and (4) other review criteria that are defined by the Commission, the Company and other stakeholders.

Q. What should be included in the energy efficiency part of the review?

A. A review of the Company's energy efficiency activities is important in understanding the role that revenue decoupling mechanisms play in removing the purported disincentive to promoting energy efficiency. Some of the potential areas of review should include, but not be limited to:

- A comparison of pre- and post-review period energy efficiency performance primarily focused on program participation and energy savings. Goals should be set and the Company's ability to attain these goals should be monitored both annually and during the review process through an "Evaluation, Monitoring, and Verification" process ("EM&V").

- An analysis of the scope, magnitude, and innovation with which the Company is promoting energy efficiency.

- An analysis of the incremental energy efficiency program offerings and/or expansions from current practices.

- An analysis of the changes in the avoided costs impacting energy efficiency program participation and savings and the degree to which non-participating customers attained capacity related savings from the Company's energy efficiency programs.

- An analysis of energy efficiency expenditures per program.

- An analysis of the breadth of energy efficiency program offerings across various customer classes.

- A comparison of actual energy efficiency savings to those included in the Company's long run planning process.

Q. Should the Commission review the Company's revenue deferral and collection experience?

A. Yes. If the Commission accepts the Company's revenue decoupling proposal then there needs to be careful scrutiny on the mechanism's deferrals and collections. Some of the areas of analysis in this category of review should include, but should not be limited to:

- An analysis of monthly, seasonal, annual, and cumulative revenue deferrals and balances.
- An analysis of any changes made to the deferral calculations.
- Comparison of estimated deferrals to those suggested in the rate case.
- An analysis of the potential impact of deferrals on earnings and overall returns.
- An analysis of the bill impacts associated with the decoupling mechanism.
- An analysis of the interest or carrying charges associated with the deferrals, if these types of costs are allowed.
- An analysis of the actual direct lost margin associated with the Company's total and incremental DSM efforts.

Q. Are there any additional criteria Staff would recommend including?

A. The Commission could include other important review criteria, particularly if it accepts the Company's revenue decoupling proposal. Two additional analyses that may not fit neatly into the categories defined above, but may be nonetheless equally important, could include:

- The degree to which the Company's corporate culture regarding the promotion of energy efficiency has meaningfully changed as a result of the adoption of revenue decoupling.

- An analysis of financial market perceptions of the Company's revenue decoupling mechanism and its potential impact on earnings.

Q. Should the Company be required to make any annual filings if the Commission adopts revenue decoupling mechanism?

A. Yes. The Company should be required to make annual filings with the Commission, including the Company's proposal to reconcile actual-to-allowed revenue. In addition, the Company should be required to provide an annual earnings surveillance report, as well as a per measure/per customer class reconciliation of its actual and forecasted energy efficiency savings and participation levels.

Q. If the Commission adopts Staff's LCFR, what conditions should the Commission apply to the mechanism?

A. Staff recommends the Commission adopt the following ratepayer protection mechanisms if the Staff's LCFR mechanism is approved:

- Adoption of an annual review period for energy efficiency performance and any lost revenue mechanism adopted by the Commission. The Company's performance should be judged against energy efficiency performance goals including new, incremental energy efficiency programs that are implemented after the LCFR mechanism is initiated.

- An annual review process that includes: (1) an energy efficiency review; (2) a customer usage analysis; and (3) other review criteria addressing internal changes in the Company's energy efficiency culture and philosophy and the financial

market perceptions of its revenue decoupling mechanism and related earnings impacts.

- Annual reporting requirements that include both a reconciliation of the LFCR mechanism and identification of per measure/per customer class total energy efficiency savings and participation levels in the prior year relative to forecasted level.

- The annual review should be conducted by a consultant selected by Staff and funded by the Company at a level of not more than $50,000 annually.

Q. Does Staff have any other recommendations regardless of whether it adopts a full decoupling mechanism or the LFCR mechanism recommended by the Staff?

A. Yes. The Commission should evaluate changes in usage pre- and post-policy adoption regardless of whether or not a revenue decoupling mechanism is adopted. Some of the customer usage statistics that should be included in this review include:

- An analysis of usage differences between new and existing customers.
- A comparison of the differences between new and existing customer UPC.
- An analysis of overall customer usage, UPC, and customer growth per class on a pre- and post-decoupling basis.
- An analysis of customer migration during the three-year review period.
- An analysis of Company activities in supporting new customer growth including the encouragement of new and economic uses of natural gas.
- A survey of customer perception, understanding, and acceptance of the decoupling mechanism and its intent.

I. Recommendations and Conclusions

Q. Would you please summarize your decoupling recommendations and conclusions?

A. Yes. Staff recommends that the Commission reject the Company's proposed revenue decoupling mechanism since:

- The proposed EEP mechanism would shift revenue recovery risk associated with changes in the economy, price, and other factors away from the Company and its shareholders and onto ratepayers. Such a shifting of risk, without any corresponding mitigation or ratepayer protection measures, will result in rates that are not fair, just, and reasonable.

- The unnecessary inclusion of a weather component in the proposed EEP provides the Company with virtually free weather-related sales insurance without any corresponding benefit to ratepayers. Even if revenue decoupling is adopted, this aspect of the Company's EEP proposal should be rejected, without some corresponding benefit to ratepayers.

- The EEP mechanism has been offered on a permanent bases and has no review or analysis period to assess its effectiveness or the emergence of any unanticipated consequences.

- The EEP mechanism is not accompanied or tied to any verifiable, performance-based energy efficiency goals and outcomes.

- The EEP mechanism is likely to make the Company whole for changes in sales that have nothing to do with its energy efficiency efforts.

Q. What are Staff's recommendations?

A. Should the Commission accept the need for decoupling, Staff recommends that the Commission approve the LFRC performance-based mechanism that would actively incent the Company to meet the Commission's energy efficiency goals, while holding it harmless for the revenue losses associated with its energy efficiency efforts if it meets the Commission's goals. If the Company is correct that cost-effective energy efficiency programs result in stranding its fixed costs (and capacity), then the only time in which this fixed cost recovery problem should arise is when the Company has met real, meaningful, and measurable energy efficiency goals. Under Staff's proposal, the Company would attain greater amounts of fixed cost recovery as it meets its Commission-defined energy efficiency goals.

Q. If the Commission adopts the Company's proposed revenue decoupling mechanism, what conditions should the Commission apply to the mechanism?

A. Staff recommends the Commission adopt the following ratepayer protection mechanisms if the Company's decoupling mechanism is approved:

- Adoption of an annual earnings review and a refund of all dollars in excess of the Company's authorized return to ratepayers during the period in which full revenue decoupling is in place.

- Adoption of a three year review period for energy efficiency performance and any lost revenue mechanism adopted by the Commission. The Company's performance should be judged against energy efficiency performance goals including new, incremental energy efficiency programs that are implemented after the decoupling mechanism is initiated. This review should include a regulatory

presumption that any lost revenue recovery mechanism will be repealed in three years unless the Company has clearly demonstrated that its disincentives for the promotion of energy efficiency have been eliminated.

- A three year review process that includes: (1) an energy efficiency review; (2) a revenue deferrals and collections review if full decoupling is adopted by the Commission; (3) a customer usage analysis; and (4) other review criteria addressing internal changes in the Company's energy efficiency culture and philosophy and the financial market perceptions of its revenue decoupling mechanism and related earnings impacts.

- Annual reporting requirements that include both the Company's proposal to reconcile actual-to-allowed revenue and an annual earnings surveillance report, and also identify per measure/per customer class total energy efficiency savings and participation levels in the prior year relative to forecasted level.

- The three year review should conducted by a consultant selected by Staff and funded by the Company at a level of not more than $100,000 per review.

Q. If the Commission adopts Staff's alternative mechanism, what conditions should the Commission apply to the mechanism?

A. Staff recommends the Commission adopt the following ratepayer protection mechanisms if the Staff's alternative mechanism is approved:

- Adoption of an annual review period for energy efficiency performance and any lost revenue mechanism adopted by the Commission. The Company's

performance should be judged against energy efficiency performance goals including new, incremental energy efficiency programs that are implemented after the LCFR mechanism is initiated.

- An annual review process that includes: (1) an energy efficiency review; (2) a customer usage analysis; and (3) other review criteria addressing internal changes in the Company's energy efficiency culture and philosophy and the financial market perceptions of its revenue decoupling mechanism and related earnings impacts.

- Annual reporting requirements that include both a reconciliation of the LFCR mechanism and identification of per measure/per customer class total energy efficiency savings and participation levels in the prior year relative to forecasted level.

- The annual review should conducted by a consultant selected by Staff and funded by the Company at a level of not more than $50,000 annually.

Q. Does Staff have any other recommendations regardless of whether the Commission adopts a full decoupling mechanism or the LFCR recommended by the Staff?

A. Yes. The Commission should evaluate changes in usage pre- and post-policy adoption regardless of whether or not a revenue decoupling mechanism is adopted. Some of the customer usage statistics that should be included in this review include:

- An analysis of usage differences between new and existing customers.
- A comparison of the differences between new and existing customer UPC.

- An analysis of overall customer usage, UPC, and customer growth per class on a pre- and post-decoupling basis.
- An analysis of customer migration during the three-year review period.
- An analysis of Company activities in supporting new customer growth including the encouragement of new and economic uses of natural gas.
- A survey of customer perception, understanding, and acceptance of the decoupling mechanism and its intent.

CLASS COST OF SERVICE STUDY

A. Introduction

Q. What is the purpose of a class cost of service study?

A. A class cost of service study ("CCOSS") is a method by which utility costs are allocated to different customer classes in order to set rates. The goal of the study is to determine the cost of providing service to each customer class and the revenue contribution each class makes in covering its allocated costs. A CCOSS generates a class-specific revenue requirement that can be used as a starting point in setting rates.

Q. How is a CCOSS performed?

A. Typically the CCOSS is performed in three distinct steps: functionalization, categorization, and allocation. The first step in this process, functionalization, simply identifies costs by their activity type or function. For instance, costs associated with transmitting natural gas are "functionalized" as transmission costs, and costs associated with providing distribution service are identified (functionalized) as distribution-related. This process continues until all costs are allocated to some type of operational function. The next step of the process "categorizes" each of these respective costs into a particular

type including demand-related costs, commodity-related costs, or customer-related costs. The last step of the process "allocates" each of these costs to a respective customer class.

Q. Is this a relatively simple process?

A. No, since some costs can be clearly identified and directly assigned to a function or category, while several others are more ambiguous and difficult to assign. The primary challenge in conducting a CCOSS is the treatment of what is known as "joint and common" costs. Given their shared or integrated nature, these joint and common costs can often be difficult to compartmentalize into any one particular function or category. Unique allocation factors, therefore, are utilized in a CCOSS to classify joint and common costs. The process of developing these cost allocation factors can become subjective and imbued with various interpretations and emphases.

Q. Earlier, you referenced a categorization process. Can you please define the three major categories of costs included in a CCOSS?

A. Yes. These categories include demand-related costs, customer-related costs, and commodity-related costs. Demand-related costs are associated with meeting maximum gas flow requirements. Transmission and large distribution mains are designed, in part, to meet peak demand day requirements such that natural gas can be delivered to households, businesses, and industries under peak load conditions usually motivated in part by weather-related usage and general economic growth. Gas supply contracts can also have a capacity component that is demand-related.

Q. How are commodity-related costs defined?

A. Commodity-related costs are defined as those that tend to change with the amount of throughput (volume) sold or transported. High pressure mains can also be allocated on some measure of throughput.

Q. What about customer-related costs?

A. Customer-related costs are those associated with connecting customers to the distribution system, metering household or business usage, and performing a variety of other customer support functions.

Q. Have you prepared an exhibit that compares the Company's allocation factors to the Staff recommended allocation factors?

A. Yes. Exhibit DED-8 compares the factors proposed by the Company to Staff recommendations. The first column lists the account name, and the second and third columns compare the Company's proposed allocation methods against Staff's recommendations, respectively.

B. Alternative CCOSS Allocation Factors and Recommendations

Q. Do you disagree with any of the assumptions or allocation factors incorporated in the Company's proposed CCOSS?

A. Yes. I disagree with a number of the allocation factors and assumptions used by the Company in its CCOSS including:

- The assumptions used by the Company to allocate distribution and other plant-related costs and expenses.
- The Company's treatment of CIAC.

- The omission of special gas procurement customers under Schedule G-30, Optional Gas Service, from the CCOSS.
- Some minor mistakes in the Company's CCOSS which it has agreed to in response to discovery have been corrected.

C. Plant Allocation Factors

Q. Can you please explain the Company's methodology for allocating distribution mains?

A. Yes. The Company's distribution mains plant allocation factor is based upon the premise that costs are created by (a) customers interconnected to the system and (b) the demand occurring on the Company's distribution system. The Company proposes a mains allocation factor based upon a 50 percent demand-based component and a 50 percent customer-based component.

Q. How should the non-customer portion of the distribution mains be allocated?

A. Staff recommends that the Commission allocate these costs on a 50-50 demand/commodity basis since these costs are partially peak related, and partially related to serving gas distribution needs throughout the course of the year. For instance, the distribution mains account includes investments that are used to regulate, measure, and treat natural gas not just during the peak, but throughout the entire year. Some throughput share should be included in the allocation factor given the peak and off-peak functions of the investments included in this account. Similarly, distribution mains serve both peak day and non-peak day loads. Allocating the non-customer portion of these investments on strictly a demand-basis does not consider the off-peak functions of these investments. Thus, including some small volumetric component is reasonable.

Q. Do cost of service manuals such as those published by the National Association of Regulatory Utility Commissioners ("NARUC") and the American Gas Association ("AGA"), support the exclusive use of demand-based allocation factors?

A. No. The NARUC Gas Distribution Rate Design Manual ("NARUC Manual") recognizes that a cost of service study often requires making a series of potentially controversial choices in allocating costs.[18] For instance, the NARUC Manual recognizes:

> The multiplicity of available methods (which in fact reflects the insoluble nature of the problems) has led many recognized experts to express grave doubts about the efficacy of cost of service analyses. ...
>
> [t]he most commonly used demand allocations for natural gas distribution utilities are the coincident demand method, the non-coincident demand method, the average and peak method, or some modification or combination of the three.[19]

Likewise, the AGA Gas Rate Fundamental's publication addresses a variety of allocation methods including the average and excess, Seaboard, and United methods of allocating costs. All three methods include a commodity component in the demand formula.[20]

Q. Do you have any other differences in the Company's plant allocation assumptions?

A. Yes. The Company allocated Account 385, Measuring and Regulating Equipment – Industrial on a 100 percent commodity basis, to all customers, including residential. These investments, however, should be allocated directly to industrial customers since

[18] The National Association of Regulatory Utility Commissioners' ("NARUC") Gas Distribution Rate Design Manual, p. 30.
[19] The National Association of Regulatory Utility Commissioners' ("NARUC") Gas Distribution Rate Design Manual, pp. 26-27.
[20] American Gas Association, Gas Rate Fundamentals, pp. 144-145.

they do not serve any other customer classes, particularly residential. These costs should also be categorized as being 50 percent demand and 50 percent commodity related.

Q. Do you have any remaining differences of opinion with the Company's plant allocation assumptions?

A. Yes. Staff disagrees with the Company's using a 100 percent demand-based allocation factor for allocating the cost of distribution plant in Account 374 (Land and Land Rights) and Account 375 (Structures and Improvements). The Company's proposed allocation is inconsistent with the same allocation factors used for plant that leverages these investments; namely, Mains (Account 376) and Measuring and Regulating Equipment (Account 378). Staff recommends that, for consistency purposes, the Commission use a composite factor consisting of Mains and Measuring and Regulating Equipment that has been provided on Exhibit DED-8.

Q. Is there a standard CCOSS model?

A. There is no standard methodology for designing a CCOSS and many different methods have been approved by state commissions. For that reason, the CCOSS should be used as a general guide only and is but one of many considerations in designing rates.

D. Customer Class Exclusions

Q. Did the Company exclude any customer classes from its CCOSS?

A. Yes. The Company excluded special gas procurement agreement customers that sign separate contracts with Southwest under Schedule G-30, Optional Gas Service. The Company simply allocated the Schedule G-30 revenues (based upon net operating margin of each class) as a credit across the remaining customer classes included in the CCOSS. Not explicitly accounting for this customer class in the CCOSS potentially masks its true

contribution, and even subsidy. The fact that the Commission, at some point in the past, approved these contracts, and that those past contract terms may have covered their respective cost of service at some point in the past, does not serve as a basis for their continued exclusion from a full CCOSS. The Commission should be apprised of the current and ongoing cost characteristics of these customers, relative to the past terms and conditions under which the original contracts were signed. The inclusion of these customers, as an individual class, will also provide information to the Commission, on a forward-going basis, about the relative cost of service characteristics of this class that may be useful in reviewing future proposed special contracts.

Q. What are your recommendations regarding the omission of Schedule G-30, Optional and Special Gas Service customers from the CCOSS?

A. Staff recommends that the Commission order the Company to provide a CCOSS in its next rate case filing that includes all Schedule G-30 customers as a separate class.

E. CIAC Allocation

Q. Would you describe the deficiencies with the Company's CIAC allocation?

A. Yes. The Company did not adequately distribute CIAC credits to each of its respective rate classes since it claims that it cannot identify the per-customer class amount of CIAC in rate base. The Company explains this omission, in part, in response to Staff Data Request 27-3, on the fact that the FERC Uniform System of Accounts ("USOA") does not contain a specific account to record CIAC. The Company suggested that there might have been such an account, but it was discontinued more than 30 years ago.[21]

[21] Response to Data Request ACC-STF-27-3.

Q. Is the Company's adherence to the FERC chart of accounts adequate?

A. No. CIAC is collected for purposes of installing new extensions to customers. The Company's record keeping should be sufficient enough to identify the customer classes under which CIAC was collected, as well as the account to which it was booked. Under the Company's cost allocation methodology, the CIAC is effectively allocated to the customer classes on the basis of the plant in service to which it was booked. The problem with this assumption is that there is no guarantee that the resulting allocation percentage closely matches the amount of CIAC actually collected from each customer class. It is likely that there could be differences between the assumed amount of CIAC that is allocated to each customer class in the CCOSS and the amount that was actually paid.

Q. What are your CIAC allocation factor recommendations?

A. Staff recommends that the Commission order the Company to maintain its books and records in a manner such that CIAC, accumulated CIAC, and amortization of CIAC can be directly assigned to the class from which the funds are collected. Direct assignments, where available, should be the preferable approach in assigning costs (or credits in this case) to customer classes.

F. Expense Allocation Factors

Q. Would you discuss your disagreements with the Company's expense account allocations?

A. Yes. Staff's disagreements with the Company's expense account allocations are similar to those expressed earlier in Staff's plant allocation recommendations. Expense allocations for plant investments should be allocated in a fashion comparable to the investments those expenses are intended to support. For example, the Company allocates the cost of Account 886 (Maintenance of Structures & Improvements) on a 100 percent demand

basis. Staff, instead, recommends a 50 percent customer, 25 percent demand, and 25 percent commodity allocation factor, consistent with my plant account recommendation discussed earlier. Likewise, the Company used an allocation factor consisting of 50 percent customer and 50 percent demand for mains expenses. Staff recommends a mains expense allocation factor based upon a 50 percent customer, 25 percent demand, and 25 percent commodity basis. The Company also allocates Account 889 (Maintenance of Measuring & Regulating Station Equipment) on a 50 percent customer and 50 percent demand basis. However, Staff recommends that these expenses be allocated on the basis of 50 percent commodity and 50 percent demand since the maintenance activities for these assets, like the assets themselves, are more closely related to demand and delivery than the number of customers on the system.

Q. Would you please discuss the mistakes the Company discovered in its CCOSS?

A. Yes. In response to Staff Data Requests 27-7 and 27-9, the Company explained that it had uncovered some errors in its CCOSS. The corrections identified by the Company include:

- In developing the weighted service cost to allocate costs in Account 380, Services, Southwest inadvertently used the residential service cost to weight the small general service category.[22] Staff corrected this in its recommended CCOSS by using the small general service cost to weight the cost of services.

[22] Response to Staff Data Request ACC-STF-27-9.

- Southwest unintentionally transposed the medium and small general service classes' service costs.[23] Staff's recommended CCOSS applied the correct service cost to the correct customer category.

- Southwest used one-half of the residential service cost for the residential Compression Natural Gas ("CNG") class. Staff's recommended CCOSS used the full amount of the residential service cost.[24]

- The Company included $23,682 for the service cost to Essential Agricultural class. Southwest, however, states that this amount is not representative and a cost of $5,660 is more appropriate: this correction has been included in Staff's recommended CCOSS.[25,26]

- The service costs for the medium and large general service were transposed and have been corrected in Staff's recommended CCOSS.[27]

- The Company inadvertently used the incorrect service cost for gas lights; Staff used the correct amount in its recommended CCOSS.[28]

- The Master Metered Mobile Home classes' meter cost should be changed from $251 to $618. Southwest states that it used the cost of a Medium General Service

[23] Response to Staff Data Request ACC-STF-27-9.
[24] Response to Staff Data Request ACC-STF-27-9.
[25] Response to Staff Data Request ACC-STF-27-9.
[26] The Company's response states that the amount should be $5,274, however, the supporting document showed the amount to be $5,660.
[27] Response to Staff Data Request ACC-STF-27-9
[28] Response to Staff Data Request ACC-STF-27-9

meter when the amount used in the last case is more appropriate.[29] Staff has made this change to its proposed CCOSS.

G. CCOSS Recommendation Summary

Q. Would you please summarize your Class Cost of Service Study recommendations?

A. Yes. Staff recommends that the Commission adopt the following alternative CCOSS allocation factors:

- Distribution mains should be allocated on a 50-50 basis with 50 percent of those investments being allocated to customers and the other 50 percent allocated on non-customer factors. This differs from the Company's proposal to allocate mains investment on a 50 percent demand/50 percent customer allocation basis.

- The non-customer component of the mains investment allocator should be divided on a 50-50 commodity-demand basis.

- Measuring and regulating equipment should be allocated on a 50 percent demand and 50 percent commodity basis, instead of the 50 percent customer and 50 percent demand allocation proposed by the Company.

- Maintenance of mains should be allocated on the basis of 50 percent customers, 25 percent demand, and 25 percent commodity, consistent with the plant account associated with these maintenance activities.

[29] Response to Staff Data Request ACC-STF-27-7.

- Measuring and regulating equipment – industrial should be allocated to industrial customers only, as opposed to the Company's method which allocated these costs to all customers.

- The Commission should order the Company to include the special procurement gas customers served under Schedule G-30 in the CCOSS submitted in its next rate case.

- The Commission should order the Company to develop an accounting process that explicitly identifies customer class-specific CIAC in such a manner that CIAC can be appropriately assigned to the classes that paid the CIAC.

- All CCOSS errors identified by the Company in response to Staff's discovery should be corrected including those associated with the allocation of services, meters, and customer installation expenses.

Q. Do your CCOSS recommendations change the class rates of return?

A. Yes, and those have been identified and compared to the Company's original CCOSS results in Exhibit DED-12. My CCOSS recommendations under the Company's current and proposed rate design are depicted on Exhibit DED-11. I have prepared Exhibit DED-10 to show the Company's CCOSS results.

Q. Have you prepared an analogous exhibit showing the CCOSS results using the Staff's recommended revenue requirement and revenue distribution?

A. Yes. These results are shown on Exhibit DED-13.

RATE DESIGN

A. Rate Design Objectives

Q. What are some of the guiding criteria or principles upon which rate design should be based?

A. There are several generally-accepted rate design principles used in utility regulation that include:

1) Rates should be fair, just, and reasonable.
2) To the extent possible, gradualism should be used to protect customers from rate shock.
3) Rate continuity should be maintained.
4) Rates should be informed by costs, but class cost of service results need not be the only factor used in rate development.
5) Rates should be understandable to customers.

Q. How are the above criteria blended to develop rates for a regulated utility?

A. While it is important to consider all of the earlier-mentioned principles, the weight of any one principle can change depending upon the relative importance of certain policy goals. Rate design should strike a balance between policy goals to ensure rates are fair, just, and reasonable. Because there is no pre-set universally-accepted formula for developing rates, judgment is often necessary in formulating a rate design that meets these objectives.

Q. Has the Commission come to similar rate design conclusions?

A. Yes. In Southwest's 2004 rate case, the Commission commented upon the subjective nature of rate design by noting:

> ...designing rates is not an exact science that may be achieved by the application of a formula tied directly to a cost of service study. Rather, the formulation of just and reasonable rates is accomplished only through consideration of multiple factors that balances the desire of the Company to recover as much of its margin as possible with recognition of the legitimate interests of customers in paying rates that are affordable, as well as advancing societal goals. As discussed below, we have attempted to determine just and reasonable rates based on these competing principles and interests.[30]

Q. How does the Company define its overall rate design goals?

A. Southwest identified four rate design objectives including designing rates that: 1) fairly and equitably recover costs; 2) work well with the energy efficiency enabling provision; 3) are understandable and generally acceptable to customers; and 4) are supportive of the Company's energy efficiency efforts.[31]

Q. Can you summarize the Company's rate design proposals?

A. Yes. The Company is not proposing any significant changes to the current structure of its rate design. Existing and proposed rates will continue to be based upon various forms of customer, demand, and volumetric-based charges. The Company intends to keep all of its basic customer charges the same and recover any remaining deficiencies through its various volumetric-based rates.[32] The Company is also not seeking any changes for the Purchased Gas Adjustor Mechanism, the Low Income Ratepayer Assistance Adjustor, the Demand Side Management Adjustor, the Gas Research Fund Adjustor, the Department of Transportation Adjustor, nor the Small Essential Agriculture User Gas Service rate.[33]

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[30] In the Matter of the Application of Southwest Gas Corporation for Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Southwest Gas Corporation Devoted to Its Operations Throughout the State of Arizona. Docket No. G-01551A-04-0876. Decision No. 68487, February 23, 2006, p. 35.
[31] Direct Testimony of Edward B. Gieseking, p. 8.
[32] Direct Testimony of Edward B. Gieseking, p. 10.
[33] Response to Data Request ACC-STF-4-1, ACC-STF-4-2, and Company's Filing Schedule H-3.

Q. Is the Company proposing any new rates?

A. Yes. The Company proposes to divide its Large General Service Class into two separate rate classes, Large-1 and Large-2. Currently, the Large General Service Class serves customers that use between 7,201 and 180,000 therms annually. Southwest notes that there is a large difference between the cost of providing service to the smaller customers in this class versus the cost to serve the larger customers. The Company's proposal would disaggregate the existing general service class into a "General Gas Service Large-1" class serving customers using between 7,201 and 50,000 therms per year, and "General Gas Service Large-2" that would serve customers using more than 50,000 therms, and up to 180,000 therms per year.[34]

Q. Does the Company propose to close any rate classes?

A. Yes. The Company proposes to close Rate Class G-75, Small Essential Agriculture Gas Service, to new customers. Since Decision No. 58377 in 1993, the Company has been moving customers from Rate Class G-75 to Rate Class G-25 when it benefits the customer.[35] In this case, Southwest has moved 42 customers to the new rate class. There are now 51 remaining customers under the existing rate schedule that, according to the Company, will need to be moved.[36]

[34] Direct Testimony of Edward B. Gieseking, p. 12.
[35] In the Matter of the Application of Southwest Gas Corporation for Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Southwest Gas Corporation Devoted to Its Operations Throughout the State of Arizona. Docket No. G-01551A-04-0876. Decision No. 68487, (February 23, 2006) at 46.
[36] Direct Testimony of Edward B. Gieseking, p. 13.

B. Revenue Distribution

Q. Would you please describe how the Company distributed its revenue requirement among its various customer classes?

A. Yes. The Company proposes to limit the increase in margin revenue for any given class at 1.25 times the system average increase. The remaining deficiency was spread to classes that had a return less than three times the requested system average Rate of Return ("ROR").[37]

Q. Is Staff's proposed revenue distribution comparable to the Company's?

A. Yes, at least generally. However, Staff's recommended revenue distribution, provided on Exhibit DED-12, is based upon Staff's recommended CCOSS results and includes a comparable gradualism component that limits rate increases to 1.25 times the system average increase of 14.6 percent, and like the Company, distributes any of the remaining revenue deficiency across classes earning less than three times the proposed system average rate of return. All customers would receive a rate increase under my recommended revenue distribution unlike the Company's that proposes a rate decrease for one customer class (i.e., natural gas engines).

Q. Would you please explain your recommended revenue distribution under the Staff's recommended revenue increase?

A. Staff's recommended revenue distribution methodology remains the same as under the Company's proposed rate increase under the Staff's recommended revenue increase.

[37] Company's Filing Schedule H-2 (Summary of Margin Spread Allocation to Classes).

C. Customer Charges

Q. What is a customer charge?

A. A customer charge is a monthly fixed charge assessed to customers based on the type of installed meter, usually defined by the pressure level of natural gas that can flow through that particular class of meter. Customer charges are typically fixed regardless of the amount of natural gas consumed.

Q. Is the Company proposing to change its customer charges?

A. No. The Company proposes to maintain its customer charges at their current level for two reasons: 1) to encourage customers to be more energy efficient, and 2) to meet the rate design objectives of customer acceptance and understandability.[38] A summary of the Company's current customer charges has been provided in Exhibit DED-17.

Q. How do the Company's residential customer charges compare with the results of its class cost of service study?

A. The customer charge for the Single Family Residential Class is 35 percent of its class cost of service, and the Multi-Family Residential Class is 44 percent of its cost of service. The customer charges for the Single Family Low-Income and the Multi-Family Low-Income Residential Classes are set at 27 percent and 33 percent of the cost of service, respectively.

Q. How do the Company's commercial customer charges compare with the results of its CCOSS?

A. The customer charge for the Transportation eligible rate class has the lowest percentage of its cost of service being recovered through a fixed charge at nine percent. The customer

[38] Direct Testimony of Edward B. Gieseking, p. 10.

charge for the Small General Service class is set at the highest percentage (67 percent) of total cost of service. The remaining classes are proposed to see customer charges that recover between 14 percent to 32 percent of their full cost of service. The Company's proposed customer charge, as a share of each class's cost of service, are provided in Exhibit DED-13.

Q. How do the Company's proposed residential customer charges compare to other natural gas distribution companies?

A. The Company's residential and commercial customer charge proposals are higher than the average residential customer charge of $10.31 and the average commercial customer charge of $18.66 as compared on Exhibit DED-14. This exhibit develops a comparable average from a survey of current residential and commercial customer charges for major local gas distribution companies ("LDCs") operating in the western U.S.[39] that are regulated by public service commissions. There are 40 gas distribution utilities in the survey with residential customer charges greater than $10.70 per month, and 70 companies with a customer charge less than the Company's current (and proposed) $10.70 per month amount. Compared to the LDCs in the West, Southwest's residential customer charge is higher than 85 percent of the sample. When comparing the Company's current (and proposed) commercial customer charge of $27.50 per month to other western LDCs, 17 utilities included in the survey have customer charges that are higher than Southwest, while 91 utilities have customer charges lower than the Company's. Southwest's commercial customer charge is greater than 93 percent of the other Western LDCs.

[39] The West region includes the states of Alaska, Arizona, California, Colorado, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming as defined by the U.S. Census Bureau.

Q. Do you agree with the Company's proposal to keep its residential and commercial customer charges the same?

A. Yes. The Company's customer charges (both residential and commercial) are relatively high when compared to other gas distribution companies. In addition, the Company's customer charges already account for a relatively large portion of its overall cost of service results (i.e., 35 percent for Single-Family Residential and 67 percent for Small General Gas Service of what the Company defines as "fixed costs"). Given these two factors, there is no need to increase customer charges, and Staff agrees with the Company's proposal to hold the existing customer charges at their current levels.

Q. Can you explain why customer charges should not be decreased at this time?

A. Yes. There is no compelling evidence indicating that customer charges should be decreased at this time. The Commission found the Company's charges to be reasonable in Southwest's last rate case and there have been no dramatic changes since that time requiring a deviation from the Commission's prior policy. Holding customer charges constant helps preserve the affordability and access of gas service for many customers, and will place emphasis volumetric charges that is consistent with the Commission's goal of encouraging energy efficiency.

D. Volumetric Charges

Q. How are utility distribution rates typically structured?

A. Distribution rates are typically based upon a two-part tariff composed of a fixed monthly customer charge and a usage-based volumetric charge. The volumetric rate can be set in a variety of fashions. Historically, many gas utilities set volumetric distribution rates on either a declining block or uniform rate basis. A declining block rate is one that ratchets rates to lower levels as usage increases. Consider as an illustration a rate structure where a

typical customer faces a charge of $0.25 per therm for the first 10 therms of consumption (first block); a rate of $0.10/therm for the next 10 therms of usage (second block); and $0.05/therm for all usage above 20 therms. A uniform rate, on the other hand, charges a fixed uniform volumetric fee on all units of consumption. An illustration of different rate designs has been provided on Exhibit DED-15.

Q. What rate structure does the Company currently have?

A. For the most part, the Company has a uniform rate structure. The only exception is the Special Residential Gas Service for Air Conditioning rate which has a declining summer block rate. A summary of the Company's current and proposed volumetric rates has been provided on Exhibit DED-17.

Q. How common are uniform rate structures?

A. Uniform volumetric rates are perhaps one of the more common forms of volumetric pricing mechanisms for U.S. LDCs and have been surveyed in Exhibit DED-16. The survey, based upon 108 gas LDCs, shows 70 utilities currently offering uniform volumetric rates, 25 utilities currently offer declining block rates, and only three have an inclining block rate structure for both their residential and small commercial ratepayers. Some companies have different rate structures for residential and small commercial classes: three utilities have a combination of uniform and declining block rate structures; six have a combination of declining and inclining block rate structures; and one has a combination of uniform and inclining block rate structures.

Q. Would you please explain the Company's volumetric rate proposals?

A. Yes. As mentioned above, most of the Company's classes have a uniform rate structure, and it is proposing no changes to the overall structure of its rates in the current rate proceeding.

Q. What is Staff's volumetric rate recommendations?

A. Staff agrees with the Company that the continuation of the existing uniform rate structure, which has been in existence for many years, satisfies the goal of rate continuity. Staff does have differing recommendations, however, with the degree to which these rates should be increased. This difference between my recommended volumetric rates and the Company's is primarily a function of my alternative CCOSS and Staff's differing revenue requirement recommendation. Staff's proposed rates are provided in Exhibit DED-17.

E. Low-Income Residential Gas Service

Q. Would you please discuss the Company's low-income residential service rate design proposals?

A. Southwest is proposing to keep the customer charge the same and to expand the 20 percent discount provided to its low-income customers to include all usage during the winter months of November through April. The discount currently applies only to the first 150 therms of monthly winter consumption. The Company claims that its low income rate proposal will simplify rates and create additional benefits without significantly impacting other customer classes.[40]

[40] Direct Testimony of Edward B. Gieseking, p. 11.

Q. Has the Commission addressed a similar proposal before?

A. Yes. The Commission rejected a similar Company proposal in its last rate case that would have applied a 15 percent discount to all low-income usage rather than the current discount of 20 percent on the first 150 therms during the winter months. In that proceeding, the Commission adopted the Staff's recommendation to maintain the existing discount of 20 percent for the first 150 therms of winter usage.[41] Staff's witness recommended maintaining the 20 percent discount on winter usage since that period tends to include the months with both the highest usage and the highest natural gas commodity rates.[42]

Q. Is the Company's low-income residential service rate design proposal in this case consistent with the Commission's energy efficiency goals?

A. No. While the Company's proposal may appear to be generous and facilitate public policy goals of helping less-advantaged customers during a trying economic period, the proposal may run afoul of the Commission's energy efficiency policies since, as the Company notes, "low income customers use nearly the same amount of gas, on average as non-low-income customers."[43] Furthermore, a proposal of this nature, at least in theory, could have the negative and unexpected consequence of reducing the economic attractiveness of

[41] In the Matter of the Application of Southwest Gas Corporation for Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Southwest Gas Corporation Devoted to Its Operations Throughout the State of Arizona. Docket No. G-01551A-04-0876. Decision No. 68487, (February 23, 2006) at 40.

[42] In the Matter of the Application of Southwest Gas Corporation for Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Southwest Gas Corporation Devoted to Its Operations Throughout the State of Arizona. Docket No. G-01551A-04-0876. Direct Testimony of Robert G. Gray, pp. 37-38.

[43] Direct Testimony of Edward B. Gieseking, p. 11. The Company's data shows that Single Family Residential Low Income customers use only slightly less (38.79 therms) in the winter compared to standard Single Family Residential customers (38.97 therms).

energy efficiency measures for low-income customers including those offered within the Company's proposed energy efficiency program.

Q. What is Staff's low-income residential gas service rate recommendations?

A. Staff recommends that the Commission reject the Company's request and continue with the existing 20 percent discount for the first 150 therms of winter usage. The Company has provided no convincing evidence to support its proposed change especially in light of its contradiction of the Commission's energy efficiency policies.

F. Special Residential Gas Service for Air Conditioning

Q. Would you please discuss the Company's Special Residential Gas Service for Air Conditioning rate design proposal?

A. The Company's rate structure for Special Residential Gas Service for Air Conditioning (Schedule No. G-15) consists of a monthly basic service charge and a per therm delivery charge that is differentiated per summer/winter season. The proposed winter delivery charge (November – April) is a uniform rate of $0.80176 per therm. In the summer months (May through October), the proposed delivery charge is structured as a declining block rate with a head block (0 – 15 therms) of $0.80176 per therm and a tail block (over 15 therms) of $0.12297 per therm. The current delivery charge is also declining, but with a much more moderate decline since the current head block rate is $0.5707 per therm and the current tail block rate is $0.28860 per therm. The Company proposes a 57 percent decrease for the tail block rate even though the overall class will see a 9.26 percent increase in overall rates.[44]

[44] Company's Application, p. 1.

Q. How did the Company develop the tail block rate for the summer differential?

A. Southwest has no cost information upon which to base this rate. Instead, the Company uses the commercial and industrial summer season rate (Rate Schedule G-40) as a proxy for the cost of the upper tail block.[45] The Company states it has little cost data to perform a meaningful cost study because there are only 90 customers taking service under Schedule No. G-15, and residential air conditioning is not separately metered.[46] Southwest claims that in the future, if demand develops, installation numbers increase, and metering options mature, it may have more cost-based information upon which to base its G-15 rates.[47]

Q. What is Staff's recommendation regarding the Company's proposal to tie the summer season differential for Rate Schedule G-15 to Rate Schedule G-40?

A. Staff recommends moving towards a uniform rate structure for this class by increasing the current tail block by 10 percent. The Company has provided no cost support for its volumetric rate proposals. Moving to a uniform rate structure is consistent with the structure of the Company's other rates and is consistent with the basic volumetric rate design of other gas utilities.

G. General Service

Q. Would you please describe the Company's General Service customer classes?

A. Yes. The General Gas Service rate class currently consists of four subclasses: Small General Gas Service; Medium General Gas Service; Large General Gas Service; and Transportation Eligible General Gas Service. Small General Gas Service customers are

[45] Company's Tariff Schedule No. G-40
[46] Response to Data Request ACC-STF-13-6.
[47] Response to Data Request ACC-STF-13-6.

defined as those with average annual usage of less than or equal to 600 therms; Medium General Gas Service customers are defined as those with usage of 601 – 7,200 therms; Large General Gas Service customers include those using 7,201 – 180,000 therms; and Transportation-Eligible Gas Service customers have usage volumes greater than 180,000 therms.[48]

Q. Would you please discuss the Company's General Service rate design proposals?

A. Yes. The Company proposes to separate the Large General Service Class into two subclasses, Large-1 and Large-2. The proposed Large-1 General Service Class would include those with annual usage between 7,201 – 50,000 therms while the Large-2 General Service Class would be defined by those customers using between 50,001 – 180,000 therms annually. The Company claims that its proposed change is cost-based given the large differential that exists between the cost of serving the smaller and larger General Service customers.[49]

Q. How large are the cost differences between the two (Large General Service) customer groups?

A. The Company's CCOSS indicates that meter costs for a typical customer in the proposed Large-1 General Service class is $800 while meter costs for the typical customer in the proposed Large-2 General Service class is more than four times larger at $3,500 per meter.[50] The Company also notes that the annual load factor for the proposed Large-2 General Service class is 12 percent larger than the Large-1 General Service class.[51]

[48] Company's Tariff Schedule No. G-25.
[49] Direct Testimony of Edward B. Gieseking, p. 12.
[50] Company's 2010 CCOSS and Rate Design Model, Tab G-1 (Meter Cost by Class).
[51] Response to Data Request ACC-STF-3-49.

Further, Large-1 customers' annual usage per customer is 14,609 therms compared to the Large-2 customers' annual UPC of 80,817 therms.

Q. Does Staff support the Company's proposal to separate the Large General Service class into two classes?

A. Yes. There appear to be sufficient differences between the two customer groups to warrant separate rates.

Q. Does Staff agree with the specific rates proposed by the Company for the new Large General Service customer classes?

A. No. The Company's proposal is likely to violate the rate design principles of gradualism and rate continuity since the changes in both level and structure of the new rates are relatively significant. For instance, Southwest proposes to reduce the customer charge for the General Service L-1 customers from $160 per month to $80.00 per month, a reduction of 50 percent. However, at the same time, the Company proposes to increase its volumetric charges from $0.29084 per therm to $0.38756 per therm, an increase of 33 percent. Southwest's proposed customer and delivery charges for the General Service L-2 customers are equally problematic. The Company proposes to increase the customer charge for the General Service L-2 customers from $160 per month to $470 a month, an increase of almost 200 percent. This is counterbalanced against a relatively moderate 9.4 percent decrease to the delivery charge, from $0.29804 per therm to $0.27 per therm.

Q. What is Staff's recommendations for the General Service L-1 customers under the Company's requested revenue requirement?

A. Staff recommends that the Commission reduce the customer charge for the General Service L-1 customers by 25 percent to $120 per month and examine further reductions to

the customer charge in the Company's next rate case. This is still a meaningful reduction for the customers taking service under this new rate, but one that is more consistent with gradualism and moving this new class closer to its overall cost of service. A $120 per month customer charge allows for a more moderate volumetric delivery charge increase of 21 percent to $0.3515 per therm.

Q. What is Staff's recommendations regarding the General Service L-2 class?

A. Staff recommends that the customer charge be increased by only 50 percent, from $160 per month to $240 per month. A more moderate increase in the customer charge for this class will leave to a more moderate, 1.6 percent increase in the delivery charge to $0.30282 per them.

H. Small Essential Agriculture User Gas Service

Q. Would you please discuss the Company's Small Essential Agriculture User Gas Service rate design proposals?

A. The Company proposes to close Rate Schedule No. G-75, Small Essential Agriculture User Gas Service, to new customers. Southwest states it has moved customers from Rate Schedule No. G-75 to Schedule No. G-25, General Gas Service, in instances where it benefits the customer. There are currently 51 customers still remaining under Rate Schedule No. G-75.[52]

Q. Has the Company made similar proposals for this class in the past?

A. Yes. The Company originally proposed to close this rate schedule back in its 1992 rate case. The Commission rejected this prior proposal and directed Southwest to gradually

[52] Direct Testimony of Edward B. Gieseking, p. 13.

move the customers on the Small Essential Agriculture Rate Schedule to the general service tariff. The Commission also specifically rejected the Company's request to close the Small Essential Agriculture tariff to new customers at the time because "closure may unfairly treat identical customers."[53]

Q. Does Staff agree with the Company's proposal?

A. Yes. Staff recommends that this rate class be closed to new entrants and that the Company continue the process of migrating customers, where beneficial, to other service schedules.

Q. Does Staff have any other rate design recommendations for the Commission's consideration?

A. Yes. Staff has expressed a strong interest to investigate alternative rate designs that may send better price signals to customers about the opportunity cost of their natural gas consumption decisions. Staff recommends that the Commission order the Company to evaluate other rate designs, inclining an inclining block rate structure, for residential and commercial customers in the next rate case. Each alternative rate design proposal offer by the company should include documentable cost support and other details indicating how the alternative rate design promotes and supports energy efficiency.

[53] In the Matter of the Application of Southwest Gas Corporation for Establishment of Just and Reasonable Rates and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Southwest Gas Corporation Devoted to Its Operations Throughout the State of Arizona. Docket No. G-01551A-04-0876. Decision No. 68487, February 23, 2006, pp. 46-48.

I. Potential Bypass and Standby Gas Service

Q. What changes does the Company propose to Rate Schedule No. B-1 – Potential Bypass/Standby Gas Service?

A. The Company proposes to remove all language related to potential bypass gas service. In response to Staff's Data Request, the Company explained that over time, Rate Schedule No. T-1 (Transportation) has evolved into the rate schedule that accommodates potential bypass transportation customers. Therefore, the bypass provision contained in currently effective Schedule No. B-1 is no longer necessary. The Company's modifications to Rate Schedule No. B-1 will apply to only the remaining standby provisions and be renamed to Schedule No. SB-1.[54]

Q. What are Staff's recommendations for Rate Schedule No. B-1?

A. Staff has no objection to the Company's proposed tariff change.

J. Revenue Comparisons and Bill Impacts

Q. Has Staff prepared an exhibit that shows a comparison of revenue under the Company's present rates and Staff's proposed rates?

A. Yes. Staff has prepared Exhibits DED-18 and DED-19, which compare total revenue (including gas costs) generated under the Company's present rates and under Staff's proposed rates for all classes except the transportation eligible, special contract and optional gas service classes. Exhibit DED-18 contains the rates and revenue under both present and proposed rates. Exhibit DED-19, summaries just the revenue impact of the Staff's recommended revenue for each class.

[54] Response to Data Request ACC-STF-24-2.

Q. What is the impact of Staff's proposed rates on Residential Class revenue?

A. Single-Family Residential revenue would increase from $446.5 million to $492.5 million, or a 10.3 percent overall increase in total revenues, including gas costs, or a 17.6 percent increase for base rate revenue alone. Likewise, the Single-Family Low Income Residential total revenue including gas costs would increase from $14.4 million to $16.1 million: an 11.6 percent to overall total revenues and a 24 percent increase in the base rate component of overall revenues. The Special Residential Gas Service Air Conditioning class would see an 12.7 percent increase in total revenue, including gas costs, and 26.4 percent in base revenues.

Q. What would the total revenue change be under Staff's proposed rates for the General Service Classes?

A. The Small General Service revenue would increase from $10.7 million to $11.2 million, or 4.3 percent. The Medium General Service Class revenues would increase from $49.9 million to $51.3 million, or 2.9 percent. The Large-1 General Service Class revenues would increase from $116.1 million to $119.1 million, or 2.5 percent. The Large-2 General Service Class revenues are proposed to increase from $34.7 million to $35.7 million, or 2.8 percent.

Q. What is the total revenue impact for the General Service Air Conditioning customers?

A. Air Conditioning total revenue would increase from $0.337 million to $0.355 million, or 5.2 percent. Base revenue would increase by 21.4 percent.

Q. How do the revenue for the Cogeneration Gas Service Class compare under the Staff's proposal?

A. The Cogeneration Gas Service class total revenue would increase from $3.8million to $4.4 million by 16.7 percent and base revenue by 21.8 percent.

Q. How do revenues change for the Small Essential Agriculture User Class revenue?

A. Small Essential Agriculture User total revenue would increase from $2.6 million to $2.7 million, or 2.0 percent. Base revenues would increase by 7.2 percent.

Q. How would revenues from the Natural Gas Engine Class change under the Staff's recommendation?

A. Total revenues for the Natural Gas Engine Class would increase from $5.4 million to $5.5 million, or by 2.4 percent. Base revenues would increase by 7.5 percent.

Q. Did Staff prepare a summary of bill impacts (or typical bill comparisons) under the Staff's proposed rates?

A. Yes. Staff prepared Exhibit DED-20, comparing the bill impacts of Staff's proposed rates.

Q. What is the typical bill impact of Staff's proposed rates on residential customers?

A. Single-Family Residential winter bills would increase from $64.89 to $71.74, or by 10.6 percent, based on the average annual usage of 39 therms. Single-Family Low Income Residential winter bills would increase from $51.76 to $57.66, or 11.4 percent, based on the average annual usage of 39 therms.

A Special Residential Gas Service for Air Conditioning customer using an average of 67 therms in the summer would see an average bill increase from $89.12 to $102.81, or 15.4 percent

Q. How would the standard bill for general service customers be impacted by the Staff's recommendation?

A. Typical Small General Service bills would increase from $58.07 to $60.65, or 4.4 percent. Typical Medium General Service Class bills would increase from $310.81 to $319.11, or 2.7 percent. Typical Large-1 General Service Class bills would increase from $1,504.80 to $1,538.265, or 2.2 percent. Typical Large-2 General Service bills would increase from $8,055.70 to $8,248.41, or 2.4 percent.

Q. What are the typical bill impacts for the Gas Service for Compression on Customer's Premises Class?

A. A typical Small Gas Service for Compression on Customer's Premises customer would see its bill increase from $558.41 to $561.25, or 0.5 percent, based on an annual usage of 528 therms. Large customers with an average annual usage of 5,186 therms would see bills increase from $5,464.57 to $5,492.42, or 0.5 percent; whereas, Residential customers with an average usage of 36 therms would see bills increase from $46.90 to $47.09, or 0.4 percent.

Q. How is the Cogeneration Class bill affected by the Staff's proposed rates?

A. The Small Cogeneration class would see an increase in bills from $33.22 to $33.40, or 0.5 percent, based on an average annual usage of 6 therms. Medium Cogeneration class customers would see bills increase from $4,886.41 to $5,036.71, or 3.1 percent, based on an average annual usage of 5,076 therms. Large Cogeneration customers' bills would

increase from $3,721.58 to $3,792.12, or 1.9 percent, based on an average annual consumption of 3,733 therms.

Q. What is the change in the typical bill for Natural Gas Engine Class customers under the Staff's recommendations?

A. As shown on DED-20, this classes' typical bill would increase from $1,623.92 to $1,655.14, or 1.9 percent, based on an average annual consumption of 1,864 therms.

K. Incremental Cost Model ("ICM")

Q. The Commission previously ordered the Company to submit an ICM for review in its next rate case. Did the Company provide this model in this proceeding?

A. Yes. The Company provided a copy of its ICM and several model examples in response to Data Request ACC-STF-3-19 and ACC-STF-3-20. The Company specifically provided its model inputs and eleven examples where it used the ICM to develop the amount of construction advances and developer-required CIAC. Southwest undertakes service and main extensions on the basis of economic feasibility, which in turn, is determined by the ICM.[55] The Commission's cost recovery policy for new customer additions are contained in Rule 6 tariff provisions.

Q. Can you summarize the Commission's Rule 6 policies for new customer cost recovery?

A. Yes. Rule 6 states that gas service and main line extensions will be made by a utility at its own cost for the "allowable investment" as calculated by an incremental contribution

[55] The policy states, "All service and main extensions are made on the basis of economic feasibility except those for master-metered mobile home parks (MMP), whose extensions shall be made in accordance with the provisions in Section B.3 hereof."

methodology.[56] The "allowable investment", according to the rule is "a determination by the Utility that revenues less the incremental cost to serve the applicant customer provides a Rate of Return on the Utility's investment no less than the overall Rate of Return authorized by the Commission in the Utility's most recent general rate case."

Q. What is the purpose of the ICM?

A. The goal of the ICM analysis is to ensure that incremental cost to serve new customers is supported by the expected incremental margin from these customers and that new customer additions do not place a burden on current customers, or shareholders.[57]

Q. Did the Commission address the ICM in the Company's last rate case?

A. Yes. The Commission ordered the Company to provide "an explanation, with sample calculations and documentation, of how it has been implementing the ICM and Rule 6 tariff provisions."[58] The Commission explained a review was necessary because it had been nearly ten years since the Company's Rule 6 portion of the tariff had been reviewed, despite the Company's indication that it made significant changes to the ICM during that period.[59]

Q. Has Staff reviewed the ICM?

A. Yes. Staff found it to be well prepared and for the most part well documented.

[56] Company Tariff Rule No. 6B(4).
[57] Direct Testimony of Robert A. Mashas, p. 22.
[58] Decision No. 70665, p. 53. (December 24, 2008)
[59] Decision No. 70665, p. 53. (December 24, 2008)

Q. What are the inputs to the ICM?

A. There are several inputs. The traditional rate case-type inputs include cost of capital, state and federal income tax rates, property tax rates, book depreciation rates and the uncollectible rates that are embedded in the new tariff rates authorized by the Commission. Other inputs include the standard service stub and extension footage per customer and cost per foot and the therm usage for heating, water heating, cooking, clothes drying, and gas logs, which the Company indicated are updated annually."[60]

Q. What are the parameters in the ICM that determine what a customer has to pay in the form of an advance or a contribution?

A. The ICM is designed to determine if a project will earn a rate of return ("ROR") and a return on equity ("ROE") allowed by the Commission in the Company's last rate case. Currently, these rates are 8.06 percent for the ROR and 10 percent for the ROE. For a project to be viable, both the three year average, and the fourth year Commission-allowed ROR and ROE, must be met. The amount of the main extension advances for construction, and the need for further contributions through CIAC, are determined based upon the three-year average achieved returns. If a development's average three-year achieved return is not equal to or greater than the Commission's allowed returns, additional advances are required. If a project that fails, in its fourth year, to achieve the target ROR and ROE, an additional contribution in the form of CIAC from the developer is required.

[60] Direct Testimony of Robert A. Mashas, pp. 23-24.

Q. Were you able to verify the default financial assumptions used in the Model and their consistency with the Commission's most recent rate case order?

A. Yes. Input assumptions were examined based upon the Commission's most recent order and were found to be consistent with the most recent order.

Q. Do you have any concerns about the application of the ICM?

A. Yes. Staff reviewed the eleven examples of the ICM for specific projects. This review raised questions concerning how the Company uses the model and its results. Exhibit DED-21 shows the ICM-estimated three and five year average ROR and ROE for a number of example projects. In almost every instance the ICM estimates RORs and ROEs in excess of the Commission's allowed ROR and ROE. [redacted]. These returns, as well as the returns for two other projects, are significantly in excess of those allowed by the Commission.

Q. Are the RORs and ROEs for the other projects close to the Commission's authorized returns?

A. No. While they are not as extreme as the previous examples, most [redacted].

Q. What are the implications of these higher than authorized rates of return?

A. These higher than authorized RORs suggest that the Company is collecting more advances for construction and/or CIAC than is necessary.

Q. Is there a way to resolve this problem in the model?

A. Yes. There is a "goal-seeking" feature in the ICM that can be used in connection with determining the needed CIAC. This optimization feature can constrain estimated project contributions to level consistent with a five year average allowed return. While the use of this optimization feature could possibly resolve the current over-earning problem, it does not address the issue of over-collecting advances for construction which is based upon the Company's policy of collecting advances for all the first year capital expenditures. It would appear that to achieve more reasonable returns the Company would need to alter its advances for construction policies and the resulting assumptions in the model.

Q. What is Staff's recommendations concerning the ICM?

A. Staff recommends that the Commission order the Company to either discontinue collecting advances and CIAC that result an ROE that is more than 50 basis points above the allowed return. In the alternative, the Company needs to demonstrate that the ICM results provided to Staff are not representative of final advances and CIAC collected from customers.

L. Rate Design Recommendations

Q. Would you please summarize Staff's rate design recommendations?

A. Yes. Staff's rate design recommendations can be summarized as follows:

- Revenue responsibilities for developing rates should be allocated on a methodology that constrains any one class from receiving a rate increase greater than 1.25 times the system average and distribute any of the remaining revenue deficiency across classes earning less than three times the proposed system average increase.

- Existing customer charges should be held at their current levels.

- The Company's existing uniform volumetric rate structure should be continued.

- Volumetric rates should be increased according to the results of my alternative class cost of service model and the Staff's recommended revenue requirement.

- Staff recommends the Commission reject the Company's low income class rate design proposal and continue the existing 20 percent discount on the first 150 therms of winter usage.

- For the Company's Special Residential Gas Service for Air Conditioning rate, Staff recommends moving towards a uniform volumetric rate for this class until such time that the Company can support a declining block rate with class-specific cost information.

- Staff agrees with the Company proposal to separate the Large General Service class. However, the Commission should reject the Company's customer and delivery charge proposals for the Large-1 and Large-2 General Service classes. Instead, Staff recommends that the Commission decrease the customer charge of the Large-1 General Service class to $120 per month and examine further decreases in the Company's next rate case. Staff also recommends the Commission increase the customer charge of the Large 2 General Service class to $240 per month.

- Staff recommends that the Commission order the Company close the Small Essential Agriculture tariff to all new customers.

- Staff has expressed a strong interest to investigate alternative rate designs that may send better price signals to customers about the opportunity cost of their natural gas consumption decisions. Staff recommends the Commission order the Company to evaluate alternative rate designs, including an inclining block rate structure for residential and commercial customers, in the next rate case. Each alternative rate design proposal offered by the Company should include documentable cost support and other details indicating how the alternative rate design promotes and supports energy efficiency.

- Staff recommends the Commission adopt the Company's proposed change for Rate Schedule No. B-1.

- Staff recommends that the Commission order the Company to either (a) discontinue collecting advances and CIAC that result in a return on equity that is more than 50 basis points above the allowed return, or (b) demonstrate that the ICM filed in this case, and used to estimate these advances, are not representative of the final advances and CIAC collected from customers.

CONCLUSIONS

Q. Would you please summarize Staff's recommendations and conclusions regarding the Company's proposed revenue decoupling mechanism?

A. Yes. Staff recommends that the Commission reject the Company's proposed revenue decoupling mechanism since:

- The proposed EEP mechanism would shift revenue recovery risk associated with changes in the economy, price, and other factors away from the Company and its shareholders and onto ratepayers. Such a shifting of risk, without any corresponding mitigation or ratepayer protection measures will result in rates that are not fair, just, and reasonable.

- The unnecessary inclusion of a weather component in the proposed EEP provides the Company with virtually free weather-related sales insurance without any corresponding benefit to ratepayers. Even if revenue decoupling is adopted, this aspect of the Company's EEP proposal should be rejected, without some corresponding benefit to ratepayers.

- The EEP mechanism has been offered on a permanent basis and has no review or analysis period to assess its effectiveness or the emergence of any unanticipated consequences.

- The EEP mechanism is not accompanied or tied to any verifiable, performance-based energy efficiency goals and outcomes.

- The EEP mechanism is highly likely to make the Company whole for changes in sales that have nothing to do with its energy efficiency efforts.

Q. Would you please describe Staff's LCFR mechanism proposals?

A. Yes. Should the Commission accept the need for decoupling, Staff recommends that the Commission approve the LFCR performance-based mechanism that would actively incent the Company to meet the Commission's energy efficiency goals, while holding the

Company harmless for the revenue losses associated with its energy efficiency efforts if it meets the Commission's goals. If the Company is correct that cost-effective energy efficiency programs result in stranding its fixed costs (and capacity), then the only time in which this fixed cost recovery problem should arise is when the Company has met real, meaningful, and measurable energy efficiency goals. Under Staff's proposal, the Company would attain greater amounts of fixed cost recovery as it meets its Commission-defined energy efficiency goals.

Q. If the Commission adopts the Company's proposed revenue decoupling mechanism, what conditions should the Commission apply to the mechanism?

A. Staff recommends the Commission adopt the following ratepayer protection mechanisms if the Company's decoupling mechanism is approved.

- Adoption of an annual earnings review and a refund of all dollars in excess of the Company's authorized return to ratepayers during the period in which full revenue decoupling is in place.

- Adoption of a three year review period for energy efficiency performance and any lost revenue mechanism adopted by the Commission. The Company's performance should be judged against energy efficiency performance goals including new, incremental energy efficiency programs that are implemented after the decoupling mechanism is initiated. This review should include a regulatory presumption that any lost revenue recovery mechanism will be discontinued in three years unless the Company has clearly demonstrated that its disincentives for the promotion of energy efficiency have been eliminated.

- A three year review process that includes: (1) an energy efficiency review; (2) a revenue deferrals and collections review if full decoupling is adopted by the Commission; (3) a customer usage analysis; and (4) other review criteria addressing internal changes in the Company's energy efficiency culture and philosophy and the financial market perceptions of its revenue decoupling mechanism and related earnings impacts.

- Annual reporting requirements that include both the Company's proposal to reconcile actual-to-allowed revenue, an annual earnings surveillance report, and a reconciliation of the forecasted to actual per measure/per customer class total energy efficiency savings and participation levels in the prior year.

- The three year review should conducted by a consultant selected by Staff and funded by the Company at a level of not more than $100,000 per review.

Q. If the Commission adopts Staff's LCFR mechanism, what conditions should the Commission apply to the mechanism?

A. Staff recommends the Commission adopt the following ratepayer protection mechanisms if the Staff's alternative mechanism is approved:

- Adoption of an annual review period for energy efficiency performance and any lost revenue mechanism adopted by the Commission. The Company's performance should be judged against energy efficiency performance goals including new, incremental energy efficiency programs that are implemented after the LCFR mechanism is initiated.

- An annual review process that includes: (1) an energy efficiency review; (2) a customer usage analysis; and (3) other review criteria addressing internal changes in the Company's energy efficiency culture and philosophy and the financial market perceptions of its revenue decoupling mechanism and related earnings impacts.

- Annual reporting requirements that include both a reconciliation of the LFCR mechanism and identification of per measure/per customer class total energy efficiency savings and participation levels in the prior year relative to forecasted level.

- The annual review should conducted by a consultant selected by Staff and funded by the Company at a level of not more than $50,000 annually.

Q. Does Staff have any other recommendations regardless of whether the Commission adopts a full decoupling mechanism or the LFCR recommended by the Staff?

A. Yes. The Commission should evaluate changes in usage pre- and post-policy adoption regardless of whether or not a revenue decoupling mechanism is adopted. Some of the customer usage statistics that should be included in this review include:

- An analysis of usage differences between new and existing customers.
- A comparison of the differences between new and existing customer UPC.
- An analysis of overall customer usage, UPC, and customer growth per class on a pre- and post-decoupling basis.
- An analysis of customer migration during the three-year review period.

- An analysis of Company activities in supporting new customer growth including the encouragement of new and economic uses of natural gas.
- A survey of customer perception, understanding, and acceptance of the decoupling mechanism and its intent.

Q. Would you please summarize Staff's CCOSS recommendations?

A. Yes. Staff recommends that the Commission adopt the following alternative CCOSS allocation factors:

- Distribution mains should be allocated on a 50-50 basis with 50 percent of those investments being allocated to customers and the other 50 percent allocated on non-customer factors. This differs from the Company's proposal to allocate mains investment on a 50 percent demand/50 percent customer allocation basis.

- The non-customer component of the mains investment allocator should be divided on a 50-50 commodity-demand basis.

- Measuring and regulating equipment should be allocated on a 50 percent demand and 50 percent commodity basis, instead of the 50 percent customer and 50 percent demand allocation proposed by the Company.

- Maintenance of mains should be allocated on the basis of 50 percent customers, 25 percent demand, and 25 percent commodity, consistent with the plant account associated with these maintenance activities.

- Measuring and regulating equipment – industrial should be allocated to industrial customers only, as opposed to the Company's method which allocated these costs to all customers.

- The Commission should order the Company to include the special procurement gas customers served under Schedule G-30 in the CCOSS submitted in its next rate case.

- The Commission should order the Company to develop an accounting process that explicitly identifies customer class-specific CIAC in such a manner that CIAC can be appropriately assigned to the classes that paid the CIAC.

- All CCOSS errors identified by the Company in response to Staff's discovery should be made including those associated with the allocation of services, meters, and customer installation expenses.

Q. Would you please summarize Staff's rate design recommendations?

A. Yes. Staff's rate design recommendations can be summarized as follows:

- Revenue responsibilities for developing rates should be allocated on a methodology that constrains any one class from receiving a rate increase greater than 1.25 times the system average and distribute any of the remaining revenue deficiency across classes earning less than three times the proposed system average rate of return.

- Existing customer charges should be held at their current levels.

- The Company's existing uniform volumetric rate structure should be continued.

- Volumetric rates should be increased according to the results of my alternative class cost of service model and the Staff's recommended revenue requirement.

- Staff recommends the Commission reject the Company's low income class rate design proposal and continue the existing 20 percent discount on the first 150 therms of winter usage.

- For the Company's Special Residential Gas Service for Air Conditioning rate, Staff recommends a gradual move towards a uniform volumetric rate for this class until such time that the Company can support a declining block rate with class-specific cost information.

- Staff agrees with the Company proposal to separate the Large General Service class. However, the Commission should reject the Company's customer and delivery charge proposals for the Large-1 and Large-2 General Service classes. Instead, Staff recommends that the Commission decrease the customer charge of the Large-1 General Service class to $120 per month and examine further decreases in the Company's next rate case. Staff also recommends the Commission increase the customer charge of the Large 2 General Service class to $240 per month.

- Staff recommends that the Commission order the Company to close the Small Essential Agriculture tariff to all new customers.

- Staff has expressed a strong interest to investigate alternative rate designs that may send better price signals to customers about the opportunity cost of their natural gas consumption decisions. I recommend the Commission order the Company to evaluate alternative rate designs, including an inclining block rate structure for residential and commercial customers, in the next rate case. Each alternative rate design proposal offered by the Company should include documentable cost support and other details indicating how the alternative rate design promotes and supports energy efficiency.

- Staff recommends the Commission adopt the Company's proposed change for Rate Schedule No. B-1.

- Staff recommends that the Commission order the Company to either (a) discontinue collecting advances and CIAC that result in a return on equity that is more than 50 basis points above the allowed return, or (b) demonstrate that the Incremental Cost Model filed in this case, and used to estimate these advances, are not representative of the final advances and CIAC collected from customers.

Q. Does this complete your Direct Testimony?

A. Yes it does.

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EDUCATION

Ph.D., Economics, Florida State University, 1995.
M.S., Economics, Florida State University, 1992.
M.S., International Affairs, Florida State University, 1988.
B.A., History, University of West Florida, 1987.
A.A., Liberal Arts, Pensacola State College, 1985.

Master's Thesis: *Nuclear Power Project Disallowances: A Discrete Choice Model of Regulatory Decisions*

Ph.D. Dissertation: *An Empirical Examination of Environmental Externalities and the Least-Cost Selection of Electric Generation Facilities*

ACADEMIC APPOINTMENTS

Louisiana State University, Baton Rouge, Louisiana

Center for Energy Studies

2007-Current	Director, Division of Policy Analysis
2006-Current	Professor
2003-Current	Associate Executive Director
2001-2006	Associate Professor
2000-2001	Research Fellow and Adjunct Assistant Professor
1999-2000	Managing Director, Distributed Energy Resources Initiative
1995-2000	Assistant Professor

E.J. Ourso College of Business Administration, Department of Economics

2006-Current	Adjunct Professor
2001-2006	Adjunct Associate Professor
1999-2000	Adjunct Assistant Professor

Florida State University, Tallahassee, Florida
College of Social Sciences, Department of Economics

1995	Instructor

PROFESSIONAL EXPERIENCE

Acadian Consulting Group, Baton Rouge, Louisiana

2001-Current	Consulting Economist/Principal
1995-2000	Consulting Economist/Principal

Econ One Research, Inc., Houston, Texas

2000-2001	Senior Economist

Florida Public Service Commission, Tallahassee, Florida
Division of Communications, Policy Analysis Section

1995	Planning & Research Economist

Division of Auditing & Financial Analysis, Forecasting Section

1993	Planning & Research Economist
1992-1993	Economist

Project for an Energy Efficient Florida &
Florida Solar Energy Industries Association, Tallahassee, Florida

1994	Energy Economist

Ben Johnson Associates, Inc., Tallahassee, Florida

1991-1992	Research Associate
1989-1991	Senior Research Analyst
1988-1989	Research Analyst

GOVERNMENT APPOINTMENTS

2007-Current	Louisiana Representative, Interstate Oil and Gas Compact Commission; Energy Resources, Research & Technology Committee.
2007-Current	Louisiana Representative, University Advisory Board Representative; Energy Council (Center for Energy, Environmental and Legislative Research).

2005	Member, Task Force on Energy Sector Workforce and Economic Development (HCR 322).
2003-2005	Member, Energy and Basic Industries Task Force, Louisiana Economic Development Council
2001-2003	Member, Louisiana Comprehensive Energy Policy Commission.

PUBLICATIONS: BOOKS AND MONOGRAPHS

1. *Power System Operations and Planning in a Competitive Market.* (2002). With Fred I. Denny. New York: CRC Press.

2. *Distributed Energy Resources: A Practical Guide for Service.* (2000). With Ritchie Priddy. London: Financial Times Energy.

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2. "Estimating the Impact of Royalty Relief on Oil and Gas Production on Marginal State Leases in the US." (2006). With Jeffrey M. Burke and Dmitry V. Mesyanzhinov. *Energy Policy* 34(12): 1389-1398.

3. "Using Competitive Bidding As A Means of Securing the Best of Competitive and Regulated Worlds." (2004). With Tom Ballinger and Elizabeth A. Downer. *NRRI Journal of Applied Regulation.* 2 (November): 69-85. (*Received 2005 Best Paper Award by NRRI*)

4. "Deregulation of Generating Assets and the Disposition of Excess Deferred Federal Income Taxes." (2004). With K.E. Hughes II. *International Energy Law and Taxation Review.* 10 (October): 206-212.

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8. "Modeling Regional Power Markets and Market Power." (2001). With Robert F. Cope. *Managerial and Decision Economics.* 22:411-429.

9. "A Data Envelopment Analysis of Levels and Sources of Coal Fired Electric Power Generation Inefficiency" (2000). With Williams O. Olatubi. *Utilities Policy.* 9 (2): 47-59.

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4. "Power System Operations, Control, and Environmental Protection in a Restructured Electric Power Industry" (1998). With Fred I. Denny. *IEEE Proceedings: Large Engineering Systems Conference on Power Engineering.* June: 294-298.

5. "New Paradigms for Power Engineering Education." (1997). With Fred I. Denny. *Proceedings of the International Association of Science and Technology for Development.* October: 499-504.

6. "Safety Regulations, Firm Size, and the Risk of Accidents in E&P Operations on the Gulf of Mexico Outer Continental Shelf" (1996). With Allan Pulsipher, Omowumi Iledare, and Bob Baumann. *Proceedings of the American Society of Petroleum Engineers: Third International Conference on Health, Safety, and the Environment in Oil and Gas Exploration and Production*, June.

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PUBLICATIONS: OTHER SCHOLARLY PROCEEDINGS

1. "A Collaborative Investigation of Baseline and Scenario Information for Environmental Impact Statements" (2005). *Proceedings of the 23rd Annual Information Technology Meetings.* U.S. Department of the Interior, Minerals Management Service, Gulf Coast Region, New Orleans, LA. January 12, 2005.

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19. "Economic Displacement Opportunities in Southeastern Power Markets." (2003). With Dmitry V. Mesyanzhinov. *USAEE Dialogue*. 11: 20-24.

20. "What's Happened to the Merchant Energy Industry? Issues, Challenges, and Outlook" (2003). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 51: 635-652.

21. "Is There a Role for the TVA in Post-Restructured Electric Markets?" (2002). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 51: 433-454.

22. "The Role of Alaska North Slope Gas in the Southcentral Alaska Regional Energy Balance." (2002). With William Nebesky and Dmitry Mesyanzhinov. *Natural Gas Journal*. 19: 10-15.

23. "Standardizing Wholesale Markets For Energy." (2002). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 51: 207-225.

24. "Do Economic Activities Create Different Economic Impacts to Communities Surrounding the Gulf OCS?" (2002). With Williams O. Olatubi. *IAEE Newsletter*. Second Quarter: 16-20.

25. "Will Electric Restructuring Ever Get Back on Track? Texas is not California." (2002). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 50: 943-960.

26. "An Assessment of the Role and Importance of Power Marketers." (2002). With K.E. Hughes II. *Oil, Gas and Energy Quarterly. 50: 713-731.*

27. "The EPA v. The TVA, et. al. Over New Source Review." (2001) With K.E. Hughes, II. *Oil, Gas and Energy Quarterly*. 50:531-543.

28. "Energy Policy by Crisis: Proposed Federal Changes for the Electric Power Industry." (2001). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 50:235-249.

29. "A is for Access: A Definitional Tour Through Today's Energy Vocabulary." (2001). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 49:947-973.

30. "California Dreaming: Are Competitive Markets Achievable?" (2001). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 49: 743-759.

31. "Distributed Energy Must Be Watched As Opportunity for Gas Companies." (2001). With Martin Collette, and Ritchie D. Priddy. *Natural Gas Journal*. January: 9-16.

32. "Clean Air, Kyoto, and the Boy Who Cried Wolf." (2000). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. December: 529-540.

33. "Energy Conservation Programs and Electric Restructuring: Is There a Conflict?" (2000). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. September: 211-224.

34. "The Post-Restructuring Consolidation of Nuclear-Power Generation in the Electric Power Industry." (2000) With K.E. Hughes II. *Oil, Gas and Energy Quarterly.* 49: 751-765.

35. "Issues and Opportunities for Small Scale Electricity Production in the Oil Patch." (2000). With Ritchie D. Priddy. *American Oil and Gas Reporter.* 49: 78-82.

36. "Distributed Energy Resources: The Next Paradigm Shift in the Electric Power Industry." (2000). With K.E. Hughes II *Oil, Gas and Energy Quarterly.* 48:593-602.

37. "Coming to a Neighborhood Near You: The Merchant Electric Power Plant." (1999). With K.E. Hughes II. *Oil, Gas, and Energy Quarterly.* 48:433-441.

38. "Slow as Molasses: The Political Economy of Electric Restructuring in the South." (1999). With K.E. Hughes II. *Oil, Gas, and Energy Quarterly.* 48: 163-183.

39. "Stranded Investment and Non-Utility Generation." (1999). With Michael T. Maloney. *Electricity Journal* 12: 50-61.

40. "Reliability or Profit? Why Entergy Quit the Southwest Power Pool." (1998). With Fred I. Denny. *Public Utilities Fortnightly.* February 1: 30-33.

41. "Electric Utility Mergers and Acquisitions: A Regulator's Guide." (1996). With Kimberly H. Dismukes. *Public Utilities Fortnightly.* January 1.

PUBLICATIONS: REPORTS AND OTHER MANUSCRIPTS

1. *The Benefits of Continued and Expanded Investments in the Port of Venice.* (2009). With Christopher Peters and Kathryn Perry. Baton Rouge, LA: LSU Center for Energy Studies. 83 pp.

2. *Examination of the Development of Liquefied Natural Gas on the Gulf of Mexico.* (2008). U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Region, New Orleans, LA OCS Study MMS 2008-017. 106 pp.

3. *Gulf of Mexico OCS Oil and Gas Scenario Examination: Onshore Waste Disposal.* (2007). With Michelle Barnett, Derek Vitrano, and Kristen Strellec. OCS Report, MMS 2007-051. New Orleans, LA: U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico Region.

4. *Economic Impact Analysis of the Proposed Lake Charles Gasification Project.* (2007). Report Prepared on Behalf of Leucadia Corporation.

5. *The Economic Impacts of New Jersey's Proposed Renewable Portfolio Standard.* (2005) Report Prepared on Behalf of the New Jersey Division of Ratepayer Advocate.

6. *The Importance of Energy Production and Infrastructure in Plaquemines Parish.* (2006). Report Prepared on Behalf of Project Rebuild Plaquemines.

7. *Louisiana's Oil and Gas Industry: A Study of the Recent Deterioration in State Drilling Activity.* (2005). With Kristi A.R. Darby, Jeffrey M. Burke, and Robert H. Baumann. Baton Rouge, LA: Louisiana Department of Natural Resources.

8. *Comparison of Methods for Estimating the NO_x Emission Impacts of Energy Efficiency and Renewable Energy Projects Shreveport, Louisiana Case Study.* (2005). With Adam Chambers, David Kline, Laura Vimmerstedt, Art Diem, and Dmitry Mesyanzhinov. Golden, Colorado: National Renewable Energy Laboratory.

9. *Economic Opportunities for a Limited Industrial Retail Choice Plan in Louisiana.* (2004). With Elizabeth A. Downer and Dmitry V. Mesyanzhinov. Baton Rouge, LA: Louisiana State University Center for Energy Studies.

10. *Economic Opportunities for LNG Development in Louisiana.* (2004). With Elizabeth A. Downer and Dmitry V. Mesyanzhinov. Baton Rouge, LA: Louisiana Department of Economic Development and Greater New Orleans, Inc.

11. *Marginal Oil and Gas Production in Louisiana: An Empirical Examination of State Activities and Policy Mechanisms for Stimulating Additional Production.* (2004). With Dmitry V. Mesyanzhinov, Jeffrey M. Burke, Robert H. Baumann. Baton Rouge, LA: Louisiana Department of Natural Resources, Office of Mineral Resources.

12. *Deepwater Program: OCS-Related Infrastructure in the Gulf of Mexico Fact Book.* (2004). With Louis Berger Associates, University of New Orleans National Ports and Waterways Institute, and Research and Planning Associates. MMS Study No. 1435-01-99-CT-30955. U.S. Department of the Interior, Minerals Management Service.

13. *The Power of Generation: The Ongoing Benefits of Independent Power Development in Louisiana.* With Dmitry V. Mesyanzhinov, Jeffrey M. Burke, and Elizabeth A. Downer. Baton Rouge, LA: LSU Center for Energy Studies, 2003.

14. *Modeling the Economic Impact of Offshore Oil and Gas Activities in the Gulf of Mexico: Methods and Application.* (2003). With Williams O. Olatubi, Dmitry V. Mesyanzhinov, and Allan G. Pulsipher. Prepared by the Center for Energy Studies, Louisiana State University, Baton Rouge, LA. OCS Study MMS2000-0XX. U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Region, New Orleans, LA.

15. *An Analysis of the Economic Impacts Associated with Oil and Gas Activities on State Leases.* (2002) With Robert H. Baumann, Dmitry V. Mesyanzhinov, and Allan G. Pulsipher. Baton Rouge, LA: Louisiana Department of Natural Resources, Office of Mineral Resources.

16. *Alaska In-State Natural Gas Demand Study.* (2002). With Dmitry Mesyanzhinov, et.al. Anchorage, Alaska: Alaska Department of Natural Resources, Division of Oil and Gas.

17. *Moving to the Front of the Lines: The Economic Impacts of Independent Power Plant Development in Louisiana.* (2001). With Dmitry Mesyanzhinov and Williams O. Olatubi. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

18. *The Economic Impacts of Merchant Power Plant Development in Mississippi.* (2001). Report Prepared on Behalf of the US Oil and Gas Association, Alabama and Mississippi Division. Houston, TX: Econ One Research, Inc.

19. *Energy Conservation and Electric Restructuring In Louisiana.* (2000). With Dmitry Mesyanzhinov, Ritchie D. Priddy, Robert F. Cope III, and Vera Tabakova. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

20. *Assessing the Environmental and Safety Risks of the Expanded Role of Independents in Oil and Gas E&P Operations on the U.S. Gulf of Mexico OCS.* (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

21. *Restructuring the Electric Utility Industry: Implications for Louisiana.* (1996). With Allan Pulsipher and Kimberly H. Dismukes. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

GRANT RESEARCH

1. *Principal Investigator.* "Energy Sector Impacts Associated with the Deepwater Horizon Oil Spill." Louisiana Department of Economic Development. Total Project: Open. Status: Completed.

2. *Principal Investigator.* "Economic Contributions and Benefits Support by the Port of Venice." Port of Venice Coalition. Total Project: $20,000. Status: Completed.

3. *Principal Investigator.* "Energy Policy Development in Louisiana." Louisiana Department of Natural Resources. Total Project: $49,500. Status: Completed.

4. *Principal Investigator.* "Preparing Louisiana for the Possible Federal Regulation of Greenhouse Gas Regulation." With Michael D. McDaniel. Louisiana Department of Economic Development. Total Project: $98,543. Status: In Progress.

5. *Principal Investigator.* "OCS Studies Review: Louisiana and Texas Oil and Gas Activity and Production Forecast; Pipeline Position Paper; and Geographical Units for Observing and Modeling Socioeconomic Impact of Offshore Activity." (2008). With Mark J. Kaiser and Allan

G. Pulsipher. U.S. Department of the Interior, Minerals Management Service. Total Project: $377,917 (3 years). Status: Completed.

6. *Principal Investigator.* "State and Local Level Fiscal Effects of the Offshore Petroleum Industry." (2007). With Loren C. Scott. U.S. Department of the Interior, Minerals Management Service. Total Project: $241,216 (2.5 years). Status: Awarded, In Progress.

7. *Principal Investigator.* "Understanding Current and Projected Gulf OCS Labor and Ports Needs." (2007). With Allan. G. Pulsipher, Kristi A. R. Darby. U.S. Department of the Interior, Minerals Management Service. Total Project: $169,906. (one year). Status: Awarded, In Progress.

8. *Principal Investigator.* "Structural Shifts and Concentration of Regional Economic Activity Supporting GOM Offshore Oil and Gas Activities." (2007). With Allan. G. Pulsipher, Michelle Barnett. U.S. Department of the Interior, Minerals Management Service. Total Project: $78,374 (one year). Status: Awarded, In Progress.

9. *Principal Investigator.* "Plaquemine Parish's Role in Supporting Critical Energy Infrastructure and Production." (2006). With Seth Cureington. Plaquemines Parish Government, Office of the Parish President and Plaquemines Association of Business and Industry. Total Project: $18,267. Status: Completed.

10. *Principal Investigator.* "Diversifying Energy Industry Risk in the Gulf of Mexico." (2006). With Kristi A. R. Darby. U.S. Department of the Interior, Minerals Management Service. Total Project: $65,302 (two years). Status: Awarded, In Progress.

11. *Principal Investigator.* "Post-Hurricane Assessment of OCS-Related Infrastructure and Communities in the Gulf of Mexico Region." (2006). U.S. Department of the Interior, Minerals Management Service. Total Project Funding: $244,837. Status: In Progress.

12. *Principal Investigator.* "Ultra Deepwater Road Mapping Process." (2005). With Kristi A. R. Darby, Subcontract with the Texas A&M University, Department of Petroleum Engineering. Funded by the Gas Technology Institute. Total Project Funding: $15,000. Status: Completed.

13. *Principal Investigator.* "An Examination of the Opportunities for Drilling Incentives on State Leases." (2004). With Robert H. Baumann and Kristi A. R. Darby. Louisiana Office of Mineral Resources. Total Project Funding: $75,000. Status: Completed.

14. *Principal Investigator.* " An Examination on the Development of Liquefied Natural Gas Facilities on the Gulf of Mexico." (2004). With Dmitry V. Mesyanzhinov and Mark J. Kaiser. U.S. Department of the Interior, Minerals Management Service. Total Project Funding $101,054. Status: Completed.

15. *Principal Investigator.* "Examination of the Economic Impacts Associated with Large Customer, Industrial Retail Choice." (2004). With Dmitry V. Mesyanzhinov. Louisiana Mid-Continent Oil and Gas Association. Total Project Funding: $37,000. Status: Completed.

16. *Principal Investigator.* "Economic Opportunities from LNG Development in Louisiana." (2003). With Dmitry V. Mesyanzhinov. Metrovision/New Orleans Chamber of Commerce and the Louisiana Department of Economic Development. Total Project Funding: $25,000. Status: Completed.

17. *Principal Investigator.* "Marginal Oil and Gas Properties on State Leases in Louisiana: An Empirical Examination and Policy Mechanisms for Stimulating Additional Production." (2002). With Robert H. Baumann and Dmitry V. Mesyanzhinov. Louisiana Office of Mineral Resources. Total Project Funding: $72,000. Status: Completed.

18. *Principal Investigator.* "A Collaborative Investigation of Baseline and Scenario Information for Environmental Impact Statements." (2002). With Dmitry V. Mesyanzhinov and Williams O. Olatubi. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $557,744. Status: Awarded, In Progress.

19. *Co-Principal Investigator.* "An Analysis of the Economic Impacts of Drilling and Production Activities on State Leases." (2002). With Robert H. Baumann, Allan G. Pulsipher, and Dmitry V. Mesyanzhinov. Louisiana Office of Mineral Resources. Total Project Funding: $8,000. Status: Completed.

20. *Principal Investigator.* "Cost Profiles and Cost Functions for Gulf of Mexico Oil and Gas Development Phases for Input Output Modeling." (1998). With Dmitry Mesyanzhinov and Allan G. Pulsipher. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $244,956. Status: Completed.

21. *Principal Investigator.* "An Economic Impact Analysis of OCS Activities on Coastal Louisiana." (1998). With Dmitry Mesyanzhinov and David Hughes. U.S. Department of Interior, Minerals Management Service. Total Project Funding: $190,166. Status: Completed.

22. *Principal Investigator.* "Energy Conservation and Electric Restructuring in Louisiana." (1997). Louisiana Department of Natural Resources." Petroleum Violation Escrow Program Funds. Total Project Funding: $43,169. Status: Completed.

23. *Principal Investigator.* "The Industrial Supply of Electricity: Commercial Generation, Self-Generation, and Industry Restructuring." (1996). With Andrew Kleit. Louisiana Energy Enhancement Program, LSU Office of Research and Development. Total Project Funding: $19,948. Status: Completed.

24. *Co-Principal Investigator.* "Assessing the Environmental and Safety Risks of the Expanded Role of Independents in Oil and Gas E&P Operations on the U.S. Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, Grant Number 95-0056. Total Project Funding: $109,361. Status: Completed.

ACADEMIC CONFERENCE PAPERS/PRESENTATIONS

1. "Analysis of Risk and Post-Hurricane Reaction." (2009). 25th Annual Information Transfer Meeting. U.S. Department of the Interior, Minerals Management Service. January 7, 2009.

2. "Legacy Litigation, Regulation, and Other Determinants of Interstate Drilling Activity Differentials." (2008). With Christopher Peters and Mark Kaiser. 28th Annual USAEE/IAEE North American Conference: Unveiling the Future of Future of Energy Frontiers. New Orleans, LA, December 3, 2008.

3. "Gulf Coast Energy Infrastructure Renaissance: Overview." (2008). 28th Annual USAEE/IAEE North American Conference: Unveiling the Future of Future of Energy Frontiers. New Orleans, LA, December 3, 2008.

4. "Understanding the Impacts of Katrina and Rita on Energy Industry Infrastructure." (2008). American Chemical Society National Meetings, New Orleans, Louisiana. April 7, 2008.

5. "Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2007). With Kristi A. R. Darby and Michelle Barnett. International Association for Energy Economics, Wellington, New Zealand, February 19, 2007.

6. "Regulatory Issues in Rate Design, Incentives, and Energy Efficiency." (2007). 34th Annual Public Utilities Research Center Conference, University of Florida. Gainesville, FL. February 16, 2007.

7. "An Examination of LNG Development on the Gulf of Mexico." (2007). With Kristi A.R. Darby. US Department of the Interior, Minerals Management Service. 24th Annual Information Technology Meeting. New Orleans, LA. January 9.

8. "OCS-Related Infrastructure on the GOM: Update and Summary of Impacts." (2007). US Department of the Interior, Minerals Management Service. 24th Annual Information Technology Meeting. New Orleans, LA. January 10.

9. "The Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2006). With Michelle Barnett. Third National Conference on Coastal and Estuarine Habitat Restoration. Restore America's Estuaries. New Orleans, Louisiana, December 11.

10. "The Impact of Implementing a 20 Percent Renewable Portfolio Standard in New Jersey." (2006). With Seth E. Cureington. Mid-Continent Regional Science Association 37th Annual Conference, Purdue University, Lafayette, Indiana, June 9.

11. "The Impacts of Hurricane Katrina and Rita on Energy infrastructure Along the Gulf Coast." (2006). Environment Canada: 2006 Artic and Marine Oilspill Program. Vancouver, British Columbia, Canada.

12. "Hurricanes, Energy Markets, and Energy Infrastructure in the Gulf of Mexico: Experiences and Lessons Learned." (2006). With Kristi A.R. Darby and Seth E. Cureington. 29th Annual IAEE International Conference, Potsdam, Germany, June 9.

13. "An Examination of the Opportunities for Drilling Incentives on State Leases in Louisiana." (2005). With Kristi A.R. Darby. 28th Annual IAEE International Conference, Taipei, Taiwan (June).

14. "Fiscal Mechanisms for Stimulating Oil and Gas Production on Marginal Leases." (2004). With Jeffrey M. Burke. International Association of Energy Economics Annual Conference, Washington, D.C. (July).

15. "GIS and Applied Economic Analysis: The Case of Alaska Residential Natural Gas Demand." (2003). With Dmitry V. Mesyanzhinov. Presented at the Joint Meeting of the East Lakes and West Lakes Divisions of the Association of American Geographers in Kalamazoo, MI, October 16-18.

16. "Are There Any In-State Uses for Alaska Natural Gas?" (2002). With Dmitry V. Mesyanzhinov and William E. Nebesky. IAEE/USAEE 22nd Annual North American Conference: "Energy Markets in Turmoil: Making Sense of It All." Vancouver, British Columbia, Canada. October 7.

17. "The Economic Impact of State Oil and Gas Leases on Louisiana." (2002). With Dmitry V. Mesyanzhinov. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.

18. "Moving to the Front of the Lines: The Economic Impact of Independent Power Plant Development in Louisiana." (2002). With Dmitry V. Mesyanzhinov and Williams O. Olatubi. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.

19. "New Consistent Approach to Modeling Regional Economic Impacts of Offshore Oil and Gas Activities in the Gulf of Mexico." (2002). With Vicki Zatarain. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.

20. "Distributed Energy Resources, Energy Efficiency, and Electric Power Industry Restructuring." (1999). American Society of Environmental Science Fourth Annual Conference. Baton Rouge, Louisiana. December.

21. "Estimating Efficiency Opportunities for Coal Fired Electric Power Generation: A DEA Approach." (1999). With Williams O. Olatubi. Southern Economic Association Sixty-ninth Annual Conference. New Orleans, November.

22. "Applied Approaches to Modeling Regional Power Markets." (1999.) With Robert F. Cope. Southern Economic Association Sixty-ninth Annual Conference. New Orleans, November 1999.

23. "Parametric and Non-Parametric Approaches to Measuring Efficiency Potentials in Electric Power Generation." (1999). With Williams O. Olatubi. International Atlantic Economic Society Annual Conference, Montreal, October.

24. "Asymmetric Choice and Customer Benefits: Lessons from the Natural Gas Industry." (1999). With Rachelle F. Cope and Dmitry Mesyanzhinov. International Association of Energy Economics Annual Conference. Orlando, Florida. August.

25. "Modeling Regional Power Markets and Market Power." (1999). With Robert F. Cope. Western Economic Association Annual Conference. San Diego, California. July.

26. "Economic Impact of Offshore Oil and Gas Activities on Coastal Louisiana" (1999). With Dmitry Mesyanzhinov. Annual Meeting of the Association of American Geographers. Honolulu, Hawaii. March.

27. "Empirical Issues in Electric Power Transmission and Distribution Cost Modeling." (1998). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association. Sixty-Eighth Annual Conference. Baltimore, Maryland. November.

28. "Modeling Electric Power Markets in a Restructured Environment." (1998). With Robert F. Cope and Dan Rinks. International Association for Energy Economics Annual Conference. Albuquerque, New Mexico. October.

29. "Benchmarking Electric Utility Distribution Performance." (1998) With Robert F. Cope and Dmitry Mesyanzhinov. Western Economic Association, Seventy-sixth Annual Conference. Lake Tahoe, Nevada. June.

30. "Power System Operations, Control, and Environmental Protection in a Restructured Electric Power Industry." (1998). With Fred I. Denny. IEEE Large Engineering Systems Conference on Power Engineering. Nova Scotia, Canada. June.

31. "Benchmarking Electric Utility Transmission Performance." (1997). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-seventh Annual Conference. Atlanta, Georgia. November 21-24.

32. "A Non-Linear Programming Model to Estimate Stranded Generation Investments in a Deregulated Electric Utility Industry." (1997). With Robert F. Cope and Dan Rinks. Institute for Operations Research and Management Science Annual Conference. Dallas Texas. October 26-29.

33. "New Paradigms for Power Engineering Education." (1997). With Fred I. Denny. International Association of Science and Technology for Development, High Technology in the Power Industry Conference. Orlando, Florida. October 27-30

34. "Cogeneration and Electric Power Industry Restructuring." (1997). With Andrew N. Kleit. Western Economic Association, Seventy-fifth Annual Conference. Seattle, Washington. July 9-13.

35. "The Unintended Consequences of the Public Utilities Regulatory Policies Act of 1978." (1997). National Policy History Conference on the Unintended Consequences of Policy Decisions. Bowling Green State University. Bowling Green, Ohio. June 5-7.

36. "Assessing Environmental and Safety Risks of the Expanding Role of Independents in E&P Operations on the Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 16th Annual Information Transfer Meeting. New Orleans, Louisiana.

37. "Empirical Modeling of the Risk of a Petroleum Spill During E&P Operations: A Case Study of the Gulf of Mexico OCS." (1996). With Omowumi Iledare, Allan Pulsipher, and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

38. "Input Price Fluctuations, Total Factor Productivity, and Price Cap Regulation in the Telecommunications Industry" (1996). With Farhad Niami. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

39. "Recovery of Stranded Investments: Comparing the Electric Utility Industry to Other Recently Deregulated Industries" (1996). With Farhad Niami and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

40. "Spatial Perspectives on the Forthcoming Deregulation of the U.S. Electric Utility Industry." (1996) With Dmitry Mesyanzhinov. Southwest Association of American Geographers Annual Meeting. Norman, Oklahoma.

41. "Comparing the Safety and Environmental Performance of Offshore Oil and Gas Operators." (1995). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 15th Annual Information Transfer Meeting. New Orleans, Louisiana.

42. "Empirical Determinants of Nuclear Power Plant Disallowances." (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

43. "A Cross-Sectional Model of IntraLATA MTS Demand." (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

ACADEMIC SEMINARS AND PRESENTATIONS

1. "Energy Regulation: Overview of Power and Gas Regulation." Lecture before School of the Coast & Environment, Course in Energy Policy and Law. October 5, 2009.

2. "Trends and Issues in Renewable Energy." Presentation before the School of the Coast & Environment, Louisiana State University. Spring Guest Lecture Series. May 4, 2007.

3. "CES Research Projects and Status." Presentation before the U.S. Department of the Interior, Minerals Management Service, Outer Continental Shelf Scientific Committee Meeting, New Orleans, LA May 22, 2007.

4. "Hurricane Impacts on Energy Production and Infrastructure." Presentation Before the 53rd Mineral Law Institute, Louisiana State University. April 7, 2006.

5. "Trends and Issues in the Natural Gas Industry and the Development of LNG: Implications for Louisiana. (2004) 51st Mineral Law Institute, Louisiana State University, Baton Rouge, LA. April 2, 2004.

6. "Electric Restructuring and Conservation." (2001). Presentation before the Department of Electrical Engineering, McNesse State University. Lake Charles, Louisiana. May 2, 2001.

7. "Electric Restructuring and the Environment." (1998). Environment 98: Science, Law, and Public Policy. Tulane University. Tulane Environmental Law Clinic. March 7, New Orleans, Louisiana.

8. "Electric Restructuring and Nuclear Power." (1997). Louisiana State University. Department of Nuclear Science. November 7, Baton Rouge, Louisiana.

9. "The Empirical Determinants of Co-generated Electricity: Implications for Electric Power Industry Restructuring." (1997). With Andrew N. Kleit. Florida State University. Department of Economics: Applied Microeconomics Workshop Series. October 17, Tallahassee, Florida.

PROFESSIONAL AND CIVIC PRESENTATIONS

1. "Energy Market Trends and Policies: Implications for Louisiana." (2011). Lakeshore Lion's Club Monthly Meeting. Baton Rouge, Louisiana. June 20, 2011.

2. "America's Natural Gas Advantage: Securing Benefits for Ratepayers Through Paradigm Shifts in Policy." Southeastern Association of Regulatory Commissioners ("SEARUC") Annual Meeting. Nashville, Tennessee. June 14, 2011.

3. "Learning Together: Building Utility and Clean Energy Industry Partnerships in the Southeast." (2011). American Solar Energy Society National Solar Conference. Raleigh Convention Center, Raleigh, North Carolina. May 20, 2011.

4. "Louisiana Energy Outlook and Trends." (2011). Executive Briefing. Counsul General of Canada. LSU Center for Energy Studies, Baton Rouge, Louisiana. May 24, 2011.

5. "Louisiana's Natural Gas Advantage: Can We Hold It? Grow It? Or Do We Need to be Worrying About Other Problems?" (2011). Louisiana Chemical Association Annual Legislative Conference, Baton Rouge, Louisiana, May 5, 2011.

6. "Energy Outlook and Trends: Implications for Louisiana. (2011). Executive Briefing, Legislative Staff, Congressman William Cassidy. LSU Center for Energy Studies, Baton Rouge, Louisiana. March 25, 2011.

7. "Regulatory Issues in Inflation Adjustment Mechanisms and Allowances." (2011). Gas Committee, National Association of State Utility Consumer Advocates ("NASUCA"). February 15, 2011.

8. "Regulatory Issues in Inflation Adjustment Mechanisms and Allowances." (2010). 2010 Annual Meeting, National Association of State Utility Consumer Advocates ("NASUCA"), Omni at CNN Center, Atlanta, Georgia, November 16, 2010.

9. "How Current and Proposed Energy Policy Impacts Consumers and Ratepayers." (2010). 122nd Annual Meeting, National Association of Regulatory Utility Commissioners ("NARUC"), Omni at CNN Center, Atlanta, Georgia, November 15, 2010.

10. "Energy Outlook: Trends and Policies." (2010). 2010 Tri-State Member Service Conference; Arkansas, Louisiana, and Mississippi Electric Cooperatives. L'Auberge du Lac Casino Resort, Lake Charles, Louisiana, October 14, 2010.

11. "Deepwater Moratorium and Louisiana Impacts." (2010). The Energy Council Annual Meeting. Gulf of Mexico Deepwater Horizon Accident, Response, and Policy. Beau Rivage Conference Center. Biloxi, Mississippi. September 25, 2010.

12. "Overview on Offshore Drilling and Production Activities in the Aftermath of Deepwater Horizon." (2010) Jones Walker Banking Symposium. The Oil Spill: What Will it Mean for Banks in the Region? New Orleans, Louisiana. August 31, 2010.

13. "Long-Term Energy Sector Impacts from the Oil Spill." (2010). Second Annual Louisiana Oil & Gas Symposium. The BP Gulf Oil Spill: Long-Term Impacts and Strategies. Baton Rouge Geological Society. August 16, 2010.

14. "Overview and Issues Associated with the Deepwater Horizon Accident." (2010). Global Interdependence Meeting on Energy Issues. Baton Rouge, LA. August 12, 2010.

15. "Overview and Issues Associated with the Deepwater Horizon Accident." (2010). Regional Roundtable Webinar. National Association for Business Economics. August 10, 2010.

16. "Deepwater Moratorium: Overview of Impacts for Louisiana." Louisiana Association of Business and Industry Meeting. Baton Rouge, LA. June 25, 2010.

17. Moderator. Senior Executive Roundtable on Industrial Energy Efficiency. U.S. Department of Energy Conference on Industrial Efficiency. Office of Renewable Energy and Energy Efficiency. Royal Sonesta Hotel, New Orleans, LA. May 21, 2010.

18. "The Energy Outlook: Trends and Policies Impacting Southeastern Natural Gas Supply and Demand Growth." Second Annual Local Economic Analysis and Research Network ("LEARN") Conference. Federal Reserve Bank of Atlanta. March 29, 2010.

19. "Natural Gas Supply Issues: Gulf Coast Supply Trends and Implications for Louisiana." Energy Bar Association, New Orleans Chapter Meeting. Jones Walker Law Firm. January 28, 2010, New Orleans, LA.

20. "Potential Impacts of Federal Greenhouse Gas Legislation on Louisiana Industry." LCA Government Affairs Committee Meeting. November 10, 2009. Baton Rouge, LA

21. "Regulatory and Ratemaking Issues Associated with Cost and Revenue Tracker Mechanisms." National Association of State Utility Consumer Advocates ("NASUCA") Annual Meeting. November 10, 2009.

22. "Louisiana's Stakes in the Greenhouse Gas Debate." Louisiana Chemical Association and Louisiana Chemical Industry Alliance Annual Meeting: The Billing Dollar Budget Crisis: Catastrophe or Change? New Orleans, LA.

23. "Gulf Coast Energy Outlook: Issues and Trends." Women's Energy Network, Louisiana Chapter. September 17, 2009. Baton Rouge, LA.

24. "Gulf Coast Energy Outlook: Issues and Trends." Natchez Area Association of Energy Service Companies. September 15, 2009, Natchez, MS.

25. "The Small Picture: The Cost of Climate Change to Louisiana." Louisiana Association of Business and Industry, U.S. Chamber of Commerce, Louisiana Oil and Gas Association, and LSU Center for Energy Studies Conference: Can Louisiana Make a Buck After Climate Change Legislation? August 21, 2009. Baton Rouge, LA.

26. "Carbon Legislation and Clean Energy Markets: Policy and Impacts." National Association of Conservation Districts, South Central Region Meeting. August 14, 2009. Baton Rouge, LA.

27. "Evolving Carbon and Clean Energy Markets." The Carbon Emissions Continuum: From Production to Consumption." Jones Walker Law Firm and LSU Center for Energy Studies Workshop. June 23, 2009. Baton Rouge, LA

28. "Potential Impacts of Cap and Trade on Louisiana Ratepayers: Preliminary Results." (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.

29. "Natural Gas Outlook." (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.

30. "Gulf Coast Energy Outlook: Issues and Trends." (2009). ISA-Lafayette Technical Conference & Expo. Cajundome Conference Center. Lafayette, Louisiana. March 12, 2009.

31. "The Cost of Energy Independence, Climate Change, and Clean Energy Initiatives on Utility Ratepayers." (2009). National Association of Business Economists (NABE). 25th Annual Washington Economic Policy Conference: Restoring Financial and Economic Stability. Arlington, VA March 2, 2009.

32. Panelist, "Expanding Exploration of the U.S. OCS" (2009). Deep Offshore Technology International Conference and Exhibition. PennWell. New Orleans, Louisiana. February 4, 2009.

33. "Gulf Coast Energy Outlook." (2008.) Atmos Energy Regional Management Meeting. Louisiana and Mississippi Division. New Orleans, Louisiana. October 8, 2008.

34. "Background, Issues, and Trends in Underground Hydrocarbon Storage." (2008). Presentation before the LSU Center for Energy Studies Industry Advisory Board Meeting. Baton Rouge, Louisiana. August 27, 2008.

35. "Greenhouse Gas Regulations and Policy: Implications for Louisiana." (2008). Presentation before the Praxair Customer Seminar. Houston, Texas, August 14, 2008.

36. "Market and Regulatory Issues in Alternative Energy and Louisiana Initiatives." (2008). Presentation before the 2008 Statewide Clean Cities Coalition Conference: Making Sense of Alternative Fuels and Advanced Technologies. New Orleans, Louisiana, March 27, 2008.

37. "Regulatory Issues in Rate Design, Incentives, and Energy Efficiency." (2007) Presentation before the New Hampshire Public Utilities Commission. Workshop on Energy Efficiency and Revenue Decoupling. November 7, 2007.

38. "Regulatory Issues for Consumer Advocates in Rate Design, Incentives, and Energy Efficiency." (2007). National Association of State Utility Consumer Advocates, Mid-Year Meeting. June 12, 2007.

39. "Regulatory and Policy Issues in Nuclear Power Plant Development." (2007). LSU Center for Energy Studies Industry Advisory Council Meeting. Baton Rouge, LA. March 23, 2007.

40. "Oil and Gas in the Gulf of Mexico: A North American Perspective." (2007). Canadian Consulate, Heads of Mission EnerNet Workshop, Houston, Texas. March 20, 2007.

41. "Regulatory Issues for Consumer Advocates in Rate Design, Incentives & Energy Efficiency. (2007). National Association of State Utility Consumer Advocates ("NASUCA") Gas Committee Monthly Meeting. February 13, 2006.

42. "Recent Trends in Natural Gas Markets." (2006). National Association of Regulatory Utility Commissioners, 118th Annual Convention. Miami, FL November 14, 2006.

43. "Energy Markets: Recent Trends, Issues & Outlook." (2006). Association of Energy Service Companies (AESC) Meeting. Petroleum Club, Lafayette, LA, November 8, 2006.

44. "Energy Outlook" (2006). National Business Economics Issues Council. Quarterly Meeting, Nashville, TN, November 1-2, 2006.

45. "Global and U.S. Energy Outlook." (2006). Energy Virginia Conference. Virginia Military Institute, Lexington, VA October 17, 2006.

46. "Interdependence of Critical Energy Infrastructure Systems." (2006). Cross Border Forum on Energy Issues: Security and Assurance of North American Energy Systems. Woodrow Wilson Center for International Scholars. Washington, DC, October 13, 2006.

47. "Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2006) The Economic and Market Impacts of Coastal Restoration: America's Wetland Economic Forum II. Washington, DC September 28, 2006.

48. "Relationships between Power and Other Critical Energy Infrastructure." (2006). Rebuilding the New Orleans Region: Infrastructure Systems and Technology Innovation Forum. United Engineering Foundation. New Orleans, LA, September 24-25, 2006.

49. "Outlook, Issues, and Trends in Energy Supplies and Prices." (2006.) Presentation to the Southern States Energy Board, Associate Members Meeting. New Orleans, Louisiana. July 14, 2006.

50. "Energy Sector Outlook." (2006). Baton Rouge Country Club Meeting. Baton Rouge, Louisiana. July 11, 2006.

51. "Oil and Gas Industry Post 2005 Storm Events." (2006). American Petroleum Institute, Teche Chapter. Production, Operations, and Regulations Annual Meeting. Lafayette, Louisiana. June 29, 2006.

52. "Concentration of Energy Infrastructure in Hurricane Regions." (2006). Presentation before the National Commission on Energy Policy Forum: Ending the Stalemate on LNG Facility Siting. Washington, DC. June 21, 2006.

53. "LNG—A Premier." (2006). Presentation Given to the U.S. Department of Energy's "LNG Forums." Los Angeles, California. June 1, 2006.

54. "Regional Energy Infrastructure, Production and Outlook." (2006). Executive Briefing for Board of Directors, Louisiana Oil and Gas Plc., Enhanced Exploration, Inc. and Energy Self-Service, Inc. Covington, Louisiana, May 12, 2006.

55. "The Impacts of the Recent Hurricane Season on Energy Production and Infrastructure and Future Outlook." Presentation before the Industrial Energy Technology Conference 2006. New Orleans, Louisiana, May 9, 2006.

56. "Update on Regional Energy Infrastructure and Production." (2006). Executive Briefing for Delegation Participating in U.S. Department of Commerce Gulf Coast Business Investment Mission. Baton Rouge, Louisiana May 5, 2006.

57. "Hurricane Impacts on Energy Production and Infrastructure." (2006). Presentation before the Interstate Natural Gas Association of America Mid-Year Meeting. Hyatt Regency Hill Country. April 21, 2006.

58. "LNG—A Premier." Presentation Given to the U.S. Department of Energy's "LNG Forums." Astoria, Washington. April 28, 2006.

59. Natural Gas Market Outlook. Invited Presentation Given to the Georgia Public Service Commission and Staff. Georgia Institute of Technology, Atlanta, Georgia. March 10, 2006.

60. The Impacts of Hurricanes Katrina and Rita on Louisiana's Energy Industry. Presentation to the Louisiana Economic Development Council. Baton Rouge, Louisiana. March 8, 2006.

61. Energy Markets: Hurricane Impacts and Outlook. Presentation to the 2006 Louisiana Independent Oil and Gas Association Annual Conference. L'Auberge du Lac Resort and Casino. Lake Charles, Louisiana. March 6, 2006

62. Energy Market Outlook and Update on Hurricane Damage to Energy Infrastructure. Presentation to the Energy Council 2005 Global Energy and Environmental Issues Conference. Santa Fe, New Mexico, December 10, 2005.

63. "Putting Our Energy Infrastructure Back Together Again." Presentation Before the 117th Annual Convention of the National Association of Regulatory Utility Commissioners (NARUC). November 15, 2005. Palm Springs, CA

64. "Hurricanes and the Outlook for Energy Markets." Presentation before the Baton Rouge Rotary Club. November 9, 2005, Baton Rouge, LA.

65. "Hurricanes, Energy Supplies and Prices." Presentation before the Louisiana Department of Natural Resources and Atchafalaya Basin Committee Meeting. November 8, 2005. Baton Rouge, LA.

66. "The Impact of the Recent Hurricane's on Louisiana's Energy Industry." Presentation before the Louisiana Independent Oil and Gas Association Board of Directors Meeting. November 8, 2005. Baton Rouge, LA.

67. "The Impact of the Recent Hurricanes on Louisiana's Infrastructure and National Energy Markets." Presentation before the Baton Rouge City Club Distinguished Speaker Series. October 13, 2005. Baton Rouge, LA.

68. "The Impact of the Recent Hurricanes on Louisiana's Infrastructure and National Energy Markets." Presentation before Powering Up: A Discussion About the Future of Louisiana's Energy Industry. Special Lecture Series Sponsored by the Kean Miller Law Firm. October 13, 2005. Baton Rouge, LA.

69. "The Impact of Hurricane Katrina on Louisiana's Energy Infrastructure and National Energy Markets." Special Lecture on Hurricane Impacts, LSU Center for Energy Studies, September 29, 2005.

70. "Louisiana Power Industry Overview." Presentation before the Clean Air Interstate Rule Implementation Stakeholders Meeting. August 11, 2005. Louisiana Department of Environmental Quality.

71. "CES 2005 Legislative Support and Outlook for Energy Markets and Policy." Presentation before the LMOGA/LCA Annual Post-Session Legislative Committee Meeting. August 10-13, 2005. Perdido Key, Florida.

72. "Electric Restructuring: Past, Present, and Future." Presentation to the Southeastern Association of Tax Administrators Annual Conference. Sheraton Hotel and Conference Facility. New Orleans, LA July 12, 2005.

73. "The Outlook for Energy." Lagniappe Studies Continuing Education Course. Baton Rouge, LA. July 11, 2005.

74. "The Outlook for Energy." Sunshine Rotary Club. Baton Rouge, LA. April 27, 2005.

75. "Background and Overview of LNG Development." Energy Council Workshop on LNG/CNG. Biloxi, Ms: Beau Rivage Resort and Hotel, April 9, 2005.

76. "Natural Gas Supply, Prices, and LNG: Implications for Louisiana Industry." Cytec Corporation Community Advisory Panel. Fortier, LA January 14, 2005.

77. "The Economic Opportunities for a Limited Industrial Retail Choice Plan." Louisiana Department of Economic Development. Baton Rouge, Louisiana. November 19, 2004.

78. "Energy Issues for Industrial Customers of Gas and Power." Louisiana Association of Business and Industry, Energy Council Meeting. Baton Rouge, Louisiana. October 11, 2004.

79. "Energy Issues for Industrial Customers of Gas and Power." Annual Meeting of the Louisiana Chemical Association and the Louisiana Chemical Industry Alliance. Point Clear, Alabama. October 8, 2004.

80. "Energy Issues for Industrial Customers of Gas and Power." American Institute of Chemical Engineers – New Orleans Section. New Orleans, LA. September 22, 2004.

81. "Natural Gas Supply, Prices and LNG: Implications for Louisiana Industry." Dow Chemical Company Community Advisory Panel Meeting. Plaquemine, LA. August 9, 2004.

82. "Energy Issues for Industrial Customers of Gas and Power." Louisiana Chemical Association Post-Legislative Meeting. Springfield, LA. August 9, 2004.

83. "LNG In Louisiana." Joint Meeting of the Louisiana Economic Development Council and the Governors Cabinet Advisory Council. Baton Rouge, LA. August 5, 2004.

84. "Louisiana Energy Issues." Louisiana Mid-Continent Oil and Gas Association Post Legislative Meetings. Sandestin, Florida. July 28, 2004.

85. "The Gulf South: Economic Opportunities Related to LNG." Presentation before the Energy Council's 2004 State and Provincial Energy and Environmental Trends Conference. Point Clear, AL, June 26, 2004.

86. "Natural Gas and LNG Issues for Louisiana." Presentation before the Rhodia Community Advisory Panel. May 20, 2004, Baton Rouge, LA.

87. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Louisiana Chemical Association Plant Managers Meeting. May 27, 2004. Baton Rouge, LA.

88. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Louisiana Chemical Association/Louisiana Chemical Industry Alliance Legislative Conference. May 26, 2004. Baton Rouge, LA.

89. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Petrochemical Industry Cluster, Greater New Orleans, Inc. May 19, 2004, Destrehan, LA.

90. "Industry Development Issues for Louisiana: LNG, Retail Choice, and Energy." Presentation before the LSU Center for Energy Studies Industry Associates. May 14, 2004, Baton Rouge, LA.

91. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Board of Directors, Greater New Orleans, Inc. May 13, 2004, New Orleans, LA.

92. "Natural Gas Outlook: Trends and Issues for Louisiana." Presentation before the Louisiana Joint Agricultural Association Meetings. January 14, 2004, Hotel Acadiana, Lafayette, Louisiana.

93. "Natural Gas Outlook" Presentation before the St. James Parish Community Advisory Panel Meeting. January 7, 2004, IMC Production Facility, Convent, Louisiana.

94. "Competitive Bidding in the Electric Power Industry." Presentation before the Association of Energy Engineers. Business Energy Solutions Expo. December 11-12, 2003, New Orleans, Louisiana.

95. "Regional Transmission Organization in the South: The Demise of SeTrans" Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. December 9, 2003. Baton Rouge, Louisiana.

96. "Affordable Energy: The Key Component to a Strong Economy." Presentation before the National Association of Regulatory Utility Commissioners ("NARUC"), November 18, 2003, Atlanta, Georgia.

97. "Natural Gas Outlook." Presentation before the Louisiana Chemical Association, October 17, 2003, Pointe Clear, Alabama.

98. "Issues and Opportunities with Distributed Energy Resources." Presentation before the Louisiana Biomass Council. April 17, 2003, Baton Rouge, Louisiana.

99. "What's Happened to the Merchant Energy Industry? Issues, Challenges, and Outlook" Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. November 12, 2002. Baton Rouge, Louisiana.

100. "An Introduction to Distributed Energy Resources." Presentation before the U.S. Department of Energy, Office of Renewable Energy and Energy Efficiency, State Energy Program/Rebuild America Conference, August 1, 2002, New Orleans, Louisiana.

101. "Merchant Energy Development Issues in Louisiana." Presentation before the Program Committee of the Center for Legislative, Energy, and Environmental Research (CLEER), Energy Council. April 19, 2002.

102. "Power Plant Siting Issues in Louisiana." Presentation before 24th Annual Conference on Waste and the Environment. Sponsored by the Louisiana Department of Environmental Quality. Lafayette, Louisiana, Cajundome. March 12, 2002.

103. "Merchant Power and Deregulation: Issues and Impacts." Presentation before the Air and Waste Management Association Annual Meeting. Baton Rouge, LA, November 15, 2001.

104. "Moving to the Front of the Lines: The Economic Impact of Independent Power Production in Louisiana." Presentation before the LSU Center for Energy Studies Merchant Power Generation and Transmission Conference, Baton Rouge, LA. October 11, 2001.

105. "Economic Impacts of Merchant Power Plant Development in Mississippi." Presentation before the U.S. Oil and Gas Association Annual Oil and Gas Forum. Jackson, Mississippi. October 10, 2001.

106. "Economic Opportunities for Merchant Power Development in the South." Presentation before the Southern Governor's Association/Southern State Energy Board Meetings. Lexington, KY. September 9, 2001.

107. "The Changing Nature of the Electric Power Business in Louisiana." Presentation before the Louisiana Department of Environmental Quality. Baton Rouge, LA, August 27, 2001.

108. "Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Interagency Group on Merchant Power Development . Baton Rouge, LA, July 16, 2001.

109. "The Changing Nature of the Electric Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Office of the Governor. Baton Rouge, LA, July 16, 2001.

110. "The Changing Nature of the Electric Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Department of Economic Development. Baton Rouge, LA, July 3, 2001.

111. "The Economic Impacts of Merchant Power Plant Development In Mississippi." Presentation before the Mississippi Public Service Commission. Jackson, Mississippi, March 20, 2001.

112. "Energy Conservation and Electric Restructuring." With Ritchie D. Priddy. Presentation before the Louisiana Department of Natural Resources. Baton Rouge, Louisiana, October 23, 2000.

113. "Pricing and Regulatory Issues Associated with Distributed Energy." Joint Conference by Econ One Research, Inc., the Louisiana State University Distributed Energy Resources Initiative, and the University of Houston Energy Institute: "Is the Window Closing for Distributed Energy?" Houston, Texas, October 13, 2000.

114. "Electric Reliability and Merchant Power Development Issues." Technical Meetings of the Louisiana Public Service Commission. Baton Rouge, LA. August 29, 2000.

115. "A Introduction to Distributed Energy Resources." Summer Meetings, Southeastern Association of Regulatory Utility Commissioners (SEARUC). New Orleans, LA. June 27, 2000.

116. Roundtable Moderator/Discussant. Mid-South Electric Reliability Summit. U.S. Department of Energy. New Orleans, Louisiana. April 24, 2000.

117. "Electricity 101: Definitions, Precedents, and Issues." Energy Council's 2000 Federal Energy and Environmental Matters Conference. Loews L'Enfant Plaza Hotel, Washington, D.C. March 11-13, 2000.

118. "LSU/CES Distributed Energy Resources Initiatives." Los Alamos National Laboratories. Office of Energy and Sustainable Systems. Los Alamos, New Mexico. February 16, 2000.

119. "Distributed Energy Resources Initiatives." Louisiana State University, Center for Energy Studies Industry Associates Meeting. Baton Rouge, Louisiana. December 15, 1999.

120. "Merchant Power Opportunities in Louisiana." Louisiana Mid-Continent Oil and Gas Association (LMOGA) Power Generation Committee Meetings. Baton Rouge, Louisiana. November 10, 1999.

121. Roundtable Discussant. "Environmental Regulation in a Restructured Market" The Big E: How to Successfully Manage the Environment in the Era of Competitive Energy. PUR Conference. New Orleans, Louisiana. May 24, 1999.

122. "The Political Economy of Electric Restructuring In the South" Southeastern Electric Exchange, Rate Section Annual Conference. New Orleans, Louisiana. May 7, 1999.

123. "The Dynamics of Electric Restructuring in Louisiana." Joint Meeting of the American Association of Energy Engineers and the International Association of Facilities Managers. Metairie, Louisiana. April 29, 1999.

124. "The Implications of Electric Restructuring on Independent Oil and Gas Operations." Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Lafayette, Louisiana, March 24, 1999.

125. "What's Happened to Electricity Restructuring in Louisiana?" Louisiana State University, Center for Energy Studies Industry Associates Meeting. March 22, 1999.

126. "A Short Course on Electric Restructuring." Central Louisiana Electric Company. Sales and Marketing Division. Mandeville, Louisiana, October 22, 1998.

127. "The Implications of Electric Restructuring on Independent Oil and Gas Operations." Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Shreveport, Louisiana, October 13, 1998.

128. "How Will Utility Deregulation Affect Tourism." Louisiana Travel Promotion Association Annual Meeting, Alexandria, Louisiana. January 15, 1998.

129. "Reflections and Predictions on Electric Utility Restructuring in Louisiana." With Fred I. Denny. Louisiana State University, Center for Energy Studies Industry Associates Meeting. November 20, 1997.

130. "Electric Utility Restructuring in Louisiana." Hammond Chamber of Commerce, Hammond, Louisiana. October 30, 1997.

131. "Electric Utility Restructuring." Louisiana Association of Energy Engineers. Baton Rouge, Louisiana. September 11, 1997.

132. "Electric Utility Restructuring: Issues and Trends for Louisiana." Opelousas Chamber of Commerce, Opelousas, Louisiana. June 24, 1997.

133. "The Electric Utility Restructuring Debate In Louisiana: An Overview of the Issues." Annual Conference of the Public Affairs Research Council of Louisiana. Baton Rouge, Louisiana. March 25, 1997.

134. "Electric Restructuring: Louisiana Issues and Outlook for 1997." Louisiana State University, Center for Energy Studies Industry Associates Meeting, Baton Rouge, Louisiana, January 15, 1997.

135. "Restructuring the Electric Utility Industry." Louisiana Propane Gas Association Annual Meeting, Alexandria, Louisiana, December 12, 1996.

136. "Deregulating the Electric Utility Industry." Eighth Annual Economic Development Summit, Baton Rouge, Louisiana, November 21, 1996.

137. "Electric Utility Restructuring in Louisiana." Jennings Rotary Club, Jennings, Louisiana, November 19, 1996.

138. "Electric Utility Restructuring in Louisiana." Entergy Services, Transmission and Distribution Division, Energy Centre, New Orleans, Louisiana, September 12, 1996

139. "Electric Utility Restructuring" Louisiana Electric Cooperative Association, Baton Rouge, Louisiana, August 27, 1996.

140. "Electric Utility Restructuring -- Background and Overview." Louisiana Public Service Commission, Baton Rouge, Louisiana, August 14, 1996.

141. "Electric Utility Restructuring." Sunshine Rotary Club Meetings, Baton Rouge, Louisiana, August 8, 1996.

142. Roundtable Moderator, "Stakeholder Perspectives on Electric Utility Stranded Costs." Louisiana State University, Center for Energy Studies Seminar on Electric Utility Restructuring in Louisiana, Baton Rouge, May 29, 1996.

143. Panelist, "Deregulation and Competition." American Nuclear Society: Second Annual Joint Louisiana and Mississippi Section Meetings, Baton Rouge, Louisiana, April 20, 1996.

EXPERT WITNESS, LEGISLATIVE, AND PUBLIC TESTIMONY; EXPERT REPORTS, RECOMMENDATIONS, AND AFFIDAVITS

1. Expert Testimony. Docket No. 11-0280 and 11-0281. (2011). Before the Illinois Commerce Commission. On the Behalf of the Illinois Attorney General, the Citizens Utility Board, and the City of Chicago, Illinois. In re: Peoples Gas Light and Coke Company and North Shore Natural Gas Company. Issues: revenue decoupling and rate design.

2. Expert Testimony. D.P.U. 11-01. (2011). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Petition of the Fitchburg Electric and Gas Company (Electric Division) for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. Issues: capital cost rider, revenue decoupling.

3. Expert Testimony. D.P.U. 11-02. (2011). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Petition of the Fitchburg Electric and Gas Company (Gas Division) for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. Issues: pipeline replacement rider, revenue decoupling.

4. Expert Affidavit. Docket No. EL-11-13 (2011). Before the Federal Energy Regulatory Commission. Petition for Preliminary Ruling, Atlantic Grid Operations. On the Behalf of the New Jersey Division of Rate Counsel. Issues: Offshore wind generation development, offshore wind transmission development, ratemaking treatment of development costs, transmission development incentives.

5. Expert Opinion. Case No. CI06-195. (2011). Before the District Court of Jefferson County, Nebraska. On the Behalf of the City of Fairbury, Nebraska and Michael Beachler. In re: Endicott Clay Products Co. vs. City of Fairbury, Nebraska and Michael Beachler. Issues: rate design and ratemaking, time of use and time differentiated rate structures, empirical analysis of demand and usage trends for tariff eligibility requirements.

6. Expert Testimony. D.P.U. 10-114. (2010). Before the Massachusetts Department of Public Utilities. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Petition of the New England Gas Company for Approval of A General Increase in Electric

Distribution Rates and Approval of a Revenue Decoupling Mechanism. Issues: infrastructure replacement rider.

7. Expert Testimony. D.P.U. 10-70. (2010). Before the Massachusetts Department of Public Utilities. Petition of the Western Massachusetts Electric Company for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; infrastructure replacement rider; performance-based regulation; inflation adjustment mechanisms; and rate design.

8. Expert Testimony. G.U.D. Nos. 998 & 9992. (2010). Before the Texas Railroad Commission. In the Matter of the Rate Case Petition of Texas Gas Services, Inc. On the Behalf of the City of El Paso, Texas. Issues: Cost of service, revenue distribution, rate design, and weather normalization.

9. Expert Testimony. B.P.U Docket No. GR10030225. (2010). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of New Jersey Natural Gas Company for Approval of Regional Greenhouse Gas Initiative Programs and Associated Cost Recovery Mechanisms Pursuant to N.J.S.A. 48:3-98.1. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy proposals, solar securitization issues, solar energy policy issues.

10. Expert Testimony. D.P.U. 10-55. (2010). Before the Massachusetts Department of Public Utilities. Investigation Into the Propriety of Proposed Tariff Changes for Boston Gas Company, Essex Gas Company, and Colonial Gas Company. (d./b./a. National Grid). On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; pipeline-replacement rider; performance-based regulation; partial productivity factor estimates, inflation adjustment mechanisms; and rate design.

11. Expert Testimony. Cause No.43839. (2010). Before the Indiana Utility Regulatory Commission. In the Matter of Southern Indiana Gas and Electric Company d/b/a/ Vectren Energy Delivery of Indiana, Inc. (Vectren South-Electric). On the behalf of the Indiana Office of Utility Consumer Counselor (OUCC). Issues: revenue decoupling, variable production cost riders, gains on off-system sales, transmission cost riders.

12. Congressional Testimony. Before the United States Congress. (2010). U.S. House of Representatives, Committee on Natural Resources. Hearing on the Consolidated Land, Energy, and Aquatic Resources Act. June 30, 2010.

13. Expert Testimony. Before the City Counsel of El Paso, Texas; Public Utility Regulatory Board. (2010). On the Behalf of the City of El Paso. In Re: Rate Application of Texas Gas Services, Inc. Issues: class cost of service study (minimum system and zero intercept analysis), rate design proposals, weather normalization adjustment, and its cost of service

adjustment clause, conservation adjustment clause proposals, and other cost tracker policy issues.

14. Expert Testimony. Docket 09-00183. (2010). Before the Tennessee Regulatory Authority. In the Matter of the Petition of Chattanooga Gas Company for a General Rate Increase, Implementation of the EnergySMART Conservation Programs, and Implementation of a Revenue Decoupling Mechanism. On the Behalf of Tennessee Attorney General, Consumer Advocate & Protection Division. Issues: revenue decoupling and energy efficiency program review and cost effectiveness analysis.

15. Expert Testimony and Exhibits. Docket No. 10-240. (2010). Before the Louisiana Office of Conservation. In Re: Cadeville Gas Storage, LLC. On the Behalf of Cardinal Gas Storage, LLC. Issues: alternative uses and relative economic benefits of conversion of depleted hydrocarbon reservoir for natural gas storage purposes.

16. Expert Testimony. Docket No. 09505-EI. (2010). Before the Florida Public Service Commission. In Re: Review of Replacement Fuel Costs Associated with the February 26, 2008 outage on Florida Power & Light's Electrical System. On the Behalf of the Florida Office of Public Counsel for the Citizens of the State of Florida. Issues: Replacement costs for power outage, regulatory policy/generation development incentives, renewable and energy efficiency incentives.

17. Expert Testimony. Docket 09-00104. (2009). Before the Tennessee Regulatory Authority. In the Matter of the Petition of Piedmont Natural Gas Company, Inc. to Implement a Margin Decoupling Tracker Rider and Related Energy Efficiency and Conservation Programs. On the Behalf of the Tennessee Attorney General, Consumer Advocate & Protection Division. Issues: revenue decoupling, energy efficiency program review, weather normalization.

18. Expert Testimony. Docket Number NG-0060. (2009). Before the Nebraska Public Service Commission. In the Matter of SourceGas Distribution, LLC Approval for a General Rate Increase. On the Behalf of the Nebraska Public Advocate. October 29, 2009. Issues: revenue decoupling, inflation trackers, infrastructure replacement riders, customer adjustment rider, weather normalization rider, weather normalization adjustments, estimation of normal weather for ratemaking purposes.

19. Expert Report and Deposition. Before the 23rd Judicial District Court, Parish of Assumption, State of Louisiana. On the Behalf of Dow Hydrocarbons and Resources, Inc. September 1, 2009. (Deposition, November 23-24, 2009). Issues: replacement and repair costs for underground salt cavern hydrocarbon storage.

20. Expert Testimony. D.P.U. 09-39. Before the Massachusetts Department of Public Utilities. (2009). Investigation Into the Propriety of Proposed Tariff Changes for Massachusetts Electric Company and Nantucket Electric Company (d./b./a. National Grid). On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue

decoupling; infrastructure rider; performance-based regulation; inflation adjustment mechanisms; revenue distribution; and rate design.

21. Expert Testimony. D.P.U. 09-30. Before the Massachusetts Department of Public Utilities. (2009). In the Matter of Bay State Gas Company Request for Increase in Rates. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; target infrastructure replacement program rider; revenue distribution; and rate design.

22. Expert Testimony. Docket EO09030249. (2009). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric and Gas Company for Approval of a Solar Loan II Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design, renewable portfolio standards, solar energy, and renewable financing/loan program design.

23. Expert Testimony. Docket EO0920097. (2009). Before the New Jersey Board of Public Utilities. In the Matter of the Verified Petition of Rockland Electric Company for Approval of an SREC-Based Financing Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design; renewable energy portfolio standards; solar energy.

24. Expert Rebuttal Report. Civil Action No.: 2:07-CV-2165. (2009). Before the U.S. District Court, Western Division of Louisiana, Lake Charles Division. Prepared on the Behalf of the Transcontinental Pipeline Corporation. Issues: expropriation and industrial use of property.

25. Expert Testimony. Docket EO06100744. (2008). Before the New Jersey Board of Public Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Atlantic City Electric Company). On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)

26. Expert Testimony. Docket EO08090840. (2008). Before the New Jersey Board of Public Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Jersey Central Power & Light Company). On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)

27. Expert Testimony. Docket UG-080546. (2008). Before the Washington Utilities and Transportation Commission. On the Behalf of the Washington Attorney General (Public

Counsel Section). Issues: Rate Design, Cost of Service, Revenue Decoupling, Weather Normalization.

28. Congressional Testimony. (2008). Senate Republican Conference: Panel on Offshore Drilling in the Restricted Areas of the Outer Continental Shelf. September 18, 2008.

29. Expert Testimony. Appeal Number 2007-125 and 2007-299. (2008). Before the Louisiana Tax Commission. On the Behalf of Jefferson Island Storage and Hub, LLC (AGL Resources). Issues: Valuation Methodologies, Underground Storage Valuation, LTC Guidelines and Policies, Public Purpose of Natural Gas Storage. July 15, 2008 and August 20, 2008.

30. Expert Testimony. Docket Number 07-057-13. (2008). Before the *Utah Public Service* Commission. In the Matter of the Application of Questar Gas Company to File a General Rate Case. On the Behalf of the Utah Committee of Consumer Services. Issues: Cost of Service, Rate Design. August 18, 2008 (Direct, Rebuttal, Surrebuttal).

31. Rulemaking Testimony. (2008). Before the Louisiana Tax Commission. Examination of Replacement Cost Tables, Depreciation and Useful Lives for Oil and Gas Properties. Chapter 9 (Oil and Gas Properties) Section. August 5, 2008.

32. Legislative Testimony. (2008). Examination of Proposal to Change Offshore Natural Gas Severance Taxes (HB 326 and Amendments). Joint Finance and Appropriations Committee of the Alabama Legislature. March 13, 2008.

33. Public Testimony. (2007). Issues in Environmental Regulation. Testimony before Gubernatorial Transition Committee on Environmental Regulation (Governor-Elect Bobby Jindal). December 17, 2007.

34. Public Testimony. (2007). Trends and Issues in Alternative Energy: Opportunities for Louisiana. Testimony before Gubernatorial Transition Committee on Natural Resources (Governor-Elect Bobby Jindal). December 13, 2007.

35. Expert Report and Recommendation: Docket Number S-30336 (2007). Before the Louisiana Public Service Commission. In re: Entergy Gulf States, Inc. Application for Approval of Advanced Metering Pilot Program. Issues: pilot program for demand response programs and advanced metering systems.

36. Expert Testimony. Docket EO07040278 (2007). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric & Gas Company for Approval of a Solar Energy Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: renewable energy market development, solar energy development, SREC markets, rate impact analysis, cost recovery issues.

37. Expert Testimony: Docket Number 05-057-T01 (2007). Before the Utah Public Service Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Direct, Rebuttal, and Surrebuttal Testimony)

38. Expert Testimony (Non-sworn rulemaking testimony) Docket Number RR-2008, (2007). Before the Louisiana Tax Commission. In re: Commission Consideration of Amendment and/or Adoption of Tax Commission Real/Personal Property Rules and Regulations. Issues: Louisiana oil and natural gas production trends, appropriate cost measures for wells and subsurface property, economic lives and production decline curve trends.

39. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29213 & 29213-A, ex parte, (2007). Before the Louisiana Public Service Commission. In re: In re: Investigation to determine if it is appropriate for LPSC jurisdictional electric utilities to provide and install time-based meters and communication devices for each of their customers which enable such customers to participate in time-based pricing rate schedules and other demand response programs. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: demand response programs, advanced meter systems, cost recovery issues, energy efficiency issues, regulatory issues.

40. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29712, ex parte, (2007) Before the Louisiana Public Service Commission. In re: Investigation into the ratemaking and generation planning implications of nuclear construction in Louisiana. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: nuclear cost power plant development, generation planning issues, and cost recovery issues.

41. Expert Testimony, Case Number U-14893, (2006). Before the Michigan Public Service Commission. In the Matter of SEMCO Energy Gas Company for Authority to Redesign and Increase Its Rates for the Sale and Transportation of Natural Gas In its MPSC Division and for Other Relief. On the behalf of the Michigan Attorney General. Issues: Rate Design, revenue decoupling, financial analysis, demand-side management program and energy efficiency policy. (Direct and Rebuttal Testimony).

42. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29380, ex parte, (2006). Before the Louisiana Public Service Commission. In re: An Investigation Into the Ratemaking and Generation Planning Implications of the U.S. EPA Clean Air Interstate Rule. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: environmental regulation and cost recovery; allowance allocations and air credit markets; ratepayer impacts of new environmental regulations.

43. Expert Affidavit Before the Louisiana Tax Commission (2006). On behalf of ANR Pipeline, Tennessee Gas Transmission and Southern Natural Gas Company. Issues: Competitive nature of interstate and intrastate transportation services.

44. Expert Affidavit Before the 19th Judicial District Court (2006). Suit Number 491, 453 Section 26. On behalf of Transcontinental Pipeline Corporation, et.al. Issues: Competitive nature of interstate and intrastate transportation services.

45. Expert Testimony: Docket Number 05-057-T01 (2006). Before the Utah Public Service Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Rebuttal and Supplemental Rebuttal Testimony)

46. Legislative Testimony (2006). Senate Committee on Natural Resources. Senate Bill 655 Regarding Remediation of Oil and Gas Sites, Legacy Lawsuits, and the Deterioration of State Drilling.

47. Expert Report: Rulemaking Docket (2005). Before the New Jersey Bureau of Public Utilities. In re: Proposed Rulemaking Changes Associated with New Jersey's Renewable Portfolio Standard. Expert Report. The Economic Impacts of New Jersey's Proposed Renewable Portfolio Standard. On behalf of the New Jersey Office of Ratepayer Advocate. Issues: Renewable Portfolio Standards, rate impacts, economic impacts, technology cost forecasts.

48. Expert Testimony: Docket Number 2005-191-E. (2005). Before the South Carolina Public Service Commission. On behalf of NewSouth Energy LLC. In re: General Investigation Examining the Development of RFP Rules for Electric Utilities. Issues: Competitive bidding; merchant development. (Direct and Rebuttal Testimony).

49. Expert Testimony: Docket No. 05-UA-323. (2005). Before the Mississippi Public Service Commission. On the behalf of Calpine Corporation. In re: Entergy Mississippi's Proposed Acquisition of the Attala Generation Facility. Issues: Asset acquisition; merchant power development; competitive bidding.

50. Expert Testimony: Docket Number 050045-EI and 050188-EI. (2005). Before the Florida Public Service Commission. On the behalf of the Citizens of the State of Florida. In re: Petition for Rate Increase by Florida Power & Light Company. Issues: Load forecasting; O&M forecasting and benchmarking; incentive returns/regulation.

51. Expert Testimony (non-sworn, rulemaking): Comments on Decreased Drilling Activities in Louisiana and the Role of Incentives. (2005). Louisiana Mineral Board Monthly Docket and Lease Sale. July 13, 2005

52. Legislative Testimony (2005). Background and Impact of LNG Facilities on Louisiana. Joint Meeting of Senate and House Natural Resources Committee. Louisiana Legislature. May 19, 2005.

53. Public Testimony. Docket No. U-21453. (2005). Technical Conference before the Louisiana Public Service Commission on an Investigation for a Limited Industrial Retail Choice Plan.

54. Expert Testimony: Docket No. 2003-K-1876. (2005). On Behalf of Columbia Gas Transmission. Expert Testimony on the Competitive Market Structure for Gas Transportation Service in Ohio. Before the Ohio Board of Tax Appeals.

55. Expert Report and Testimony: Docket No. 99-4490-J, *Lafayette City-Parish Consolidated Government, et. al. v. Entergy Gulf States Utilities, Inc. et. al.* (2005, 2006). On behalf of the City of Lafayette, Louisiana and the Lafayette Utilities Services. Expert Rebuttal Report of the Harborfront Consulting Group Valuation Analysis of the LUS Expropriation. Filed before 15th Judicial District Court, Lafayette, Louisiana.

56. Expert Testimony: ANR Pipeline Company v. Louisiana Tax Commission (2005), Number 468,417 Section 22, 19th Judicial District Court, Parish of East Baton Rouge, State of Louisiana Consolidated with Docket Numbers: 480,159; 489,776;480,160; 480,161; 480,162; 480,163; 480,373; 489,776; 489,777; 489,778;489,779; 489,780; 489,803; 491,530; 491,744; 491,745; 491,746; 491,912;503,466; 503,468; 503,469; 503,470; 515,414; 515,415; and 515,416. In re: Market structure issues and competitive implications of tax differentials and valuation methods in natural gas transportation markets for interstate and intrastate pipelines.

57. Expert Report and Recommendation: Docket No. U-27159. (2004). On Behalf of the Louisiana Public Service Commission Staff. Expert Report on Overcharges Assessed by Network Operator Services, Inc. Before the Louisiana Public Service Commission.

58. Expert Testimony: Docket Number 2004-178-E. (2004). Before the South Carolina Public Service Commission. On behalf of Columbia Energy LLC. In re: Rate Increase Request of South Carolina Electric and Gas. (Direct and Surrebuttal Testimony)

59. Expert Testimony: Docket Number 040001-EI. (2004). Before the Florida Public Service Commission. On behalf of Power Manufacturing Systems LLC, Thomas K. Churbuck, and the Florida Industrial Power Users Group. In re: Fuel Adjustment Proceedings; Request for Approval of New Purchase Power Agreements. Company examined: Florida Power & Light Company.

60. Expert Affidavit: Docket Number 27363. (2004). Before the Public Utilities Commission of Texas. Joint Affidavit on Behalf of the Cities of Texas and the Staff of the Public Utilities Commission of Texas Regarding Certified Issues. In Re: Application of Valor

Telecommunications, L.P. For Authority to Establish Extended Local Calling Service (ELCS) Surcharges For Recovery of ELCS Surcharge.

61. Expert Report and Testimony. Docket 1997-4665-PV, 1998-4206-PV, 1999-7380-PV, 2000-5958-PV, 2001-6039-PV, 2002-64680-PV, 2003-6231-PV. (2003) Before the Kansas Board of Tax Appeals. (2003). In the Matter of the Appeals of CIG Field Services Company from orders of the Division of Property Valuation. On the Behalf of CIG Field Services. Issues: the competitive nature of natural gas gathering in Kansas.

62. Expert Report and Testimony: Docket Number U-22407. Before the Louisiana Public Service Commission (2002). On the Behalf of the Louisiana Public Service Commission Staff. Company examined: Louisiana Gas Services, Inc. Issues: Purchased Gas Acquisition audit, fuel procurement and planning practices.

63. Expert Testimony: Docket Number 000824-EI. Before the Florida Public Service Commission. (2002). On the Behalf of the Citizens of the State of Florida. Company examined: Florida Power Corporation. Issues: Load Forecasts and Billing Determinants for the Projected Test Year.

64. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic Impacts of Merchant Power Generation.

65. Expert Testimony: Docket Number 24468. (2001). On the Behalf of the Texas Office of Public Utility Counsel. Public Utility Commission of Texas Staff's Petition to Determine Readiness for Retail Competition in the Portion of Texas Within the Southwest Power Pool. Company examined: AEP-SWEPCO.

66. Expert Report. (2001) On Behalf of David Liou and Pacific Richland Products, Inc. to Review Cogeneration Issues Associated with Dupont Dow Elastomers, L.L.C. (DDE) and the Dow Chemical Company (Dow).

67. Expert Testimony: Docket Number 01-1049, Docket Number 01-3001. (2001) On behalf the Nevada Office of Attorney General, Bureau of Consumer Protection. Petition of Central Telephone Company-Nevada D/b/a Sprint of Nevada and Sprint Communications L.P. for Review and Approval of Proposed Revised Performance Measures and Review and Approval of Performance Measurement Incentive Plans. Before the Public Utilities Commission of Nevada.

68. Expert Affidavit: Multiple Dockets (2001). Before the Louisiana Tax Commission. On the Behalf of Louisiana Interstate Pipeline Companies. Testimony on the Competitive Nature of Natural Gas Transportation Services in Louisiana.

69. Expert Affidavit before the Federal District Court, Middle District of Louisiana (2001). Issues: Competitive Nature of the Natural Gas Transportation Market in Louisiana. On behalf of a Consortium of Interstate Natural Gas Transportation Companies.

70. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic and Ratepayer Benefits of Merchant Power Generation and Issues Associated with Tax Incentives on Merchant Power Generation and Transmission.

71. Expert Testimony: Docket Number 01-1048 (2001). Before the Public Utilities Commission of Nevada. On the Behalf of the Nevada Office of the Attorney General, Bureau of Consumer Protection. Company analyzed: Nevada Bell Telephone Company. Issues: Statistical Issues Associated with Performance Incentive Plans.

72. Expert Testimony: Docket 22351 (2001). Before the Public Utility Commission of Texas. On the Behalf of the City of Amarillo. Company analyzed: Southwestern Public Service Company. Issues: Unbundled cost of service, affiliate transactions, load forecasting.

73. Expert Testimony: Docket 991779-EI (2000). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Competitive Nature of Wholesale Markets, Regional Power Markets, and Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.

74. Expert Testimony: Docket 990001-EI (1999). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.

75. Expert Testimony: Docket 950495-WS (1996). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Company analyzed: Southern States Utilities, Inc. Issues: Revenue Repression Adjustment, Residential and Commercial Demand for Water Service.

76. Legislative Testimony. Louisiana House of Representatives, Special Subcommittee on Utility Deregulation. (1997). On Behalf of the Louisiana Public Service Commission Staff. Issue: Electric Restructuring.

77. Expert Testimony: Docket 940448-EG – 940551-EG (1994). Before the Florida Public Service Commission. On the Behalf of the Legal Environmental Assistance Foundation. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Comparison of Forecasted Cost-Effective Conservation Potentials for Florida.

78. Expert Testimony: Docket 920260-TL, (1993). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: BellSouth Communications, Inc. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

79. Expert Testimony: Docket 920188-TL, (1992). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: GTE-Florida. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

REFEREE AND EDITORIAL APPOINTMENTS

Referee, 2010-Current, *Economics of Energy & Environmental Policy*
Referee, 1995-Current, *Energy Journal*
Contributing Editor, 2000-2005, *Oil, Gas and Energy Quarterly*
Referee, 2005, *Energy Policy*
Referee, 2004, *Southern Economic Journal*
Referee, 2002, *Resource & Energy Economics*
Committee Member, IAEE/USAEE Student Paper Scholarship Award Committee, 2003

PROPOSAL TECHNICAL REVIEWER

California Energy Commission, Public Interest Energy Research (PIER) Program (1999).

PROFESSIONAL ASSOCIATIONS

American Economic Association, American Statistical Association, Southern Economic Association, Western Economic Association, International Association of Energy Economists (IAEE), and the National Association for Business Economics (NABE).

HONORS AND AWARDS

National Association of Regulatory Utility Commissioners (NARUC). Best Paper Award for papers published in the *Journal of Applied Regulation* (2004).

Baton Rouge Business Report, Selected as "Top 40 Under 40" (2003).

Omicron Delta Epsilon (1992-Current)

Interstate Oil and Gas Compact Commission (IOGCC) "Best Practice" Award for Research on the Economic Impact of Oil and Gas Activities on State Leases for the Louisiana Department of Natural Resources (2003).

Distinguished Research Award, Academy of Legal, Ethical and Regulatory Issues, Allied Academics (2002).

Florida Public Service Commission, Staff Excellence Award for Assistance in the Analysis of Local Exchange Competition Legislation (1995).

TEACHING EXPERIENCE

Principles of Microeconomic Theory
Principles of Macroeconomic Theory

Lecturer, Environmental Management and Permitting. Lecture in Natural Gas Industry, LNG and Markets.

Lecturer, Electric Power Industry Environmental Issues, Field Course on Energy and the Environment. (Dept of Environmental Studies).

Lecturer, Electric Power Industry Trends, Principles Course in Power Engineering (Dept. of Electric Engineering).

Lecturer, LSU Honors College, Senior Course on "Society and the Coast."

Continuing Education. Electric Power Industry Restructuring for Energy Professionals.

"The Gulf Coast Energy Situation: Outlook for Production and Consumption." Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, New Orleans, LA, December 2, 2004

"The Impact of Hurricane Katrina on Louisiana's Energy Infrastructure and National Energy Markets." Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, Houston, TX, September 13, 2005.

"Forecasting for Regulators: Current Issues and Trends in the Use of Forecasts, Statistical, and Empirical Analyses in Energy Regulation." Instructional Course for State Regulatory Commission Staff. Institute of Public Utilities, Kellogg Center, Michigan State University. July 8-9, 2010.

"Regulatory and Ratemaking Issues with Cost and Revenue Trackers." Michigan State University, Institute of Public Utilities. Advanced Regulatory Studies Program. September 29, 2010.

"Demand Modeling and Forecasting for Regulators." Michigan State University, Institute of Public Utilities. Advanced Regulatory Studies Program. September 30, 2010.

"Demand Modeling and Forecasting for Regulators." Michigan State University, Institute of Public Utilities, Forecasting Workshop, Charleston, SC. March 7-9, 2011.

"Regulatory and Cost Recovery Approaches for Smart Grid Applications." Michigan State University, Institute of Public Utilities, Smart Grid Workshop for Regulators. Charleston, SC. March 7-11, 2011.

THESIS/DISSERTATIONS COMMITTEES

5 Thesis Committee Memberships (Environmental Studies, Geography)
4 Doctoral Committee Memberships (Information Systems & Decision Sciences, Agricultural and Resource Economics, Economics, Education and Workforce Development).
2 Doctoral Examination Committee Membership (Information Systems & Decision Sciences, Education and Workforce Development)
1 Senior Honors Thesis (Journalism, Loyola University)

LSU SERVICE AND COMMITTEE MEMBERSHIPS

Co-Director/Steering Committee Member, LSU Coastal Marine Institute (2009-Current).

CES Promotion Committee, Division of Radiation Safety (2006).

Search Committee Chair (2006), Research Associate 4 Position.

Search Committee Member (2005), Research Associate 4 Position.

Search Committee Member (2005), CES Communications Manager.

LSU Graduate Research Faculty, Associate Member (1997-2004); Full Member (2004-2010); Affiliate Member with Full Directional Rights (2011-current).
LSU Faculty Senate (2003-2006).

Conference Coordinator. (2005-Current) Center for Energy Studies Conference on Alternative Energy.

LSU CES/SCE Public Art Selection Committee (2003-2005).

Conference Coordinator. Center for Energy Studies Annual Energy Conference/Summit. (2003-Current).

Conference Coordinator. Center for Energy Studies Seminar Series on Electric Utility Restructuring and Wholesale Competition. (1996-2003).

Co-Chairman, Review Committee, Louisiana Port Construction and Development Priority Program Rules and Regulations, On Behalf of the LSU Ports and Waterways Institute. (1997).

LSU Main Campus Cogeneration/Turbine Project, (1999-2000).

LSU InterCollege Environmental Cooperative. (1999-2001).

LSU Faculty Senate Committee on Public Relations (1997-1999).

LSU Faculty Senate Committee on Student Retention and Recruitment (1999-2003).

PROFESSIONAL SERVICE

Advisor (2008). National Association of Regulatory Utility Commissioners ("NARUC"). Study Committee on the Impact of Executive Drilling Moratoria on Federal Lands.

Steering Committee Member, Louisiana Representative (2008-Current). Southeast Agriculture & Forestry Energy Resources Alliance. Southern Policies Growth Board.

Advisor (2007-Current). National Association of State Utility Consumer Advocates ("NASUCA"), Natural Gas Committee.

Program Committee Chairman (2007-2008). U.S. Association of Energy Economics ("USAEE") Annual Conference, New Orleans, LA

Finance Committee Chairman (2007-2008). USAEE Annual Conference, New Orleans, LA

Committee Member (2006), International Association for Energy Economics ("IAEE") Nominating Committee.

Founding President (2005-2007) Louisiana Chapter, USAEE.

Secretary (2001) Houston Chapter, USAEE.

Advisor, Louisiana LNG Buyers/Developers Summit, Office of the Governor/Louisiana Department of Economic Development/Louisiana Department of Natural Resources, and Greater New Orleans, Inc. (2004).

Energy Efficiency Resource Standards

WA: pursue all cost effective conservation: ~10% by 2025

OR: 1% annual savings by 2013

CA: save 1,500 MW, 7,000 GWh; reduce peak 1,537 MW: 2010-12

NV: 0.6% annual savings (~5%) to 2015; EE to 25% of RPS

UT: PUC examining 1% annual

CO: 11.5% energy savings by 2020

AZ: at least 22% cumulative savings by 2020; peak credits

NM: 10% retail electric sales savings by 2020 .

OK: EE up to 25% of renewable goal

TX: 25% annual savings in 2012; 30% in 2013 and beyond

HI: 30% electricity reduction by 2030

MN: 1.5% annual savings to 2015

IA: 1.5% annual; 5.4% cumulative savings by 2020

WI: 1.5% electric savings by 2014; 15% peak reductions

MI: 1% annual energy savings

IL: 2% energy reduction, 0.1% peak by 2015

IN: 2% energy savings by 2019

OH: 22% energy savings by 2025 ; 8% peak by 2018

ME: 1.4% annual energy savings by 2013

VT: 2% annual; 11% cumulative energy reductions by 2011

MA: 2.4% annual electricity savings by 2012

NY: reduce electric use 15% by 2015

CT: 1.5% annual utility savings, 10% peak

RI: reduce consumption 10% by 2022

NJ: BPU proceeding to reduce consumption, peak

DE: reduce consumption 15%; peak 10% by 2015

PA: reduce consumption 3%; peak 4.5% by 2013

MD: reduce electricity use and peak 15% by 2015

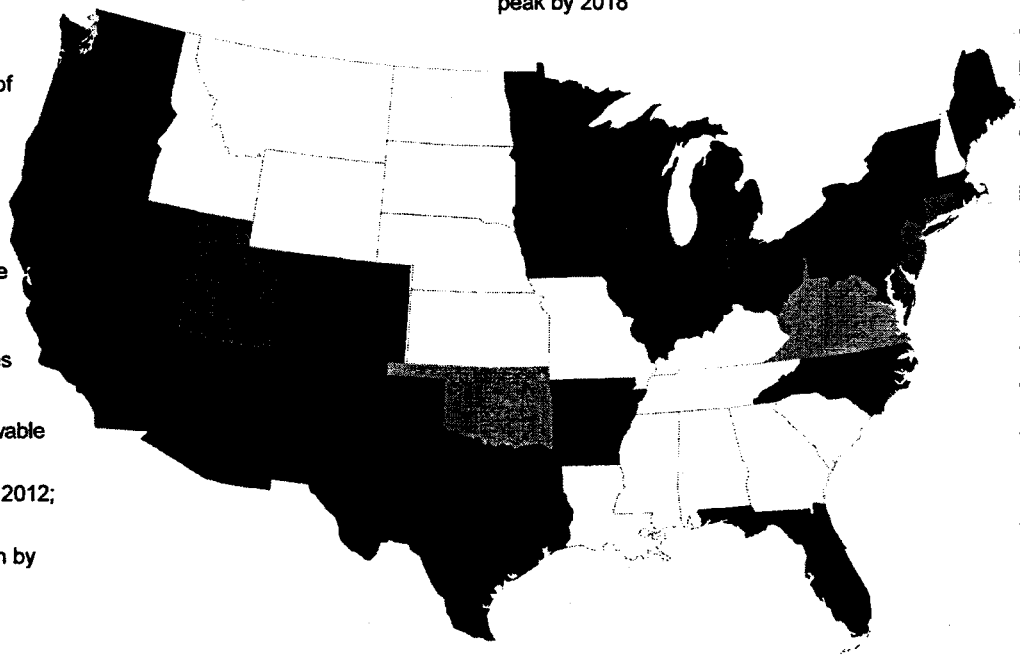
VA: reduce electric use 10% by 2022

WV: EE & DR earn credits in A&RES

AR: 0.75% electricity savings by 2013

NC: EE to meet up to 25% of RPS by 2011

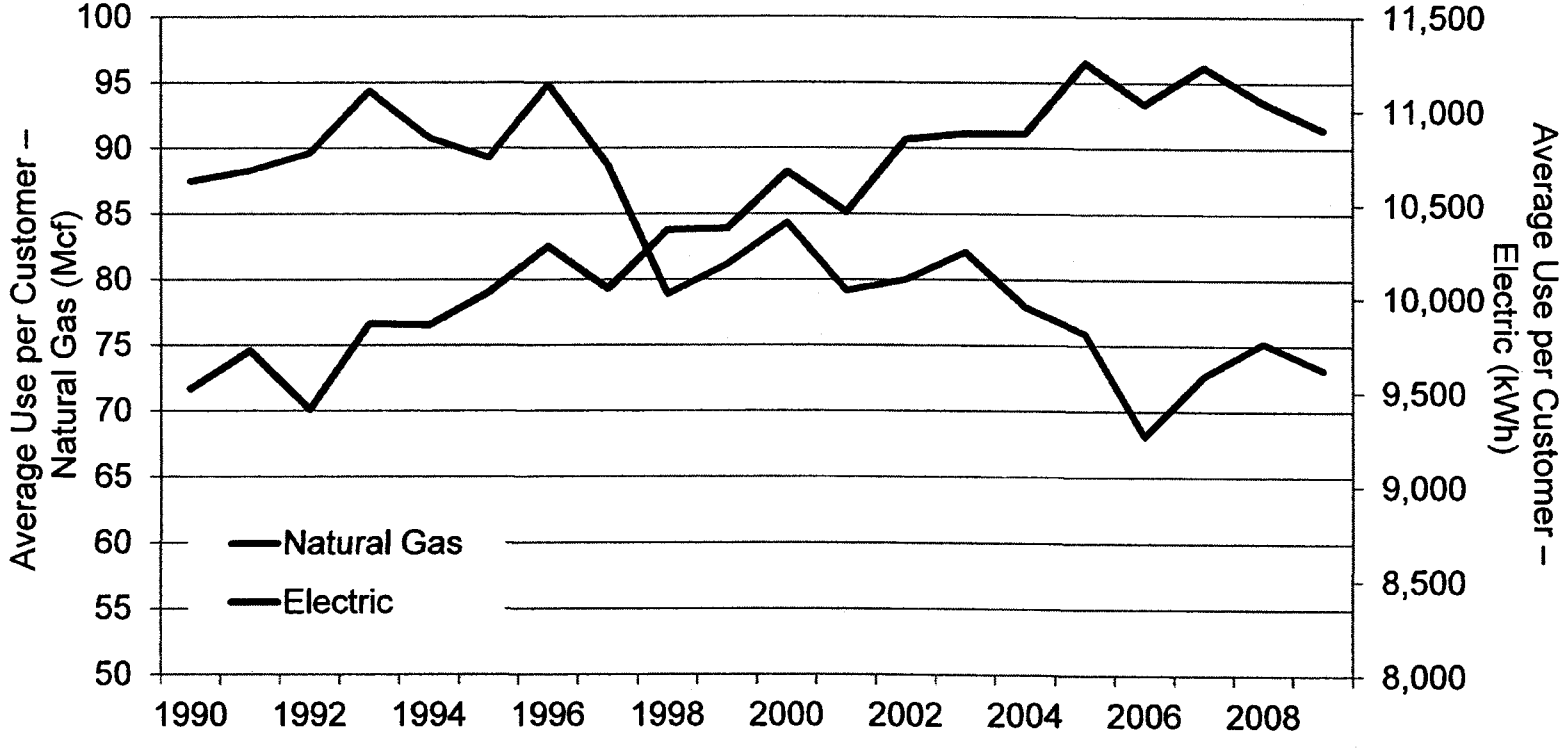
FL: 3.5% energy savings and summer and winter peak reductions by 2019



- EERS by regulation or law (stand-alone)
- EE in RPS (hybrid)
- EE in renewable goal
- EE regulations pending

Note: As of April 15, 2011.
Source: Federal Energy Regulatory Commission.

U.S. Average Residential Use Per Customer
Natural Gas and Electric



Source: Energy Information Administration, U.S. Department of Energy.

Annual Lost Base Revenues

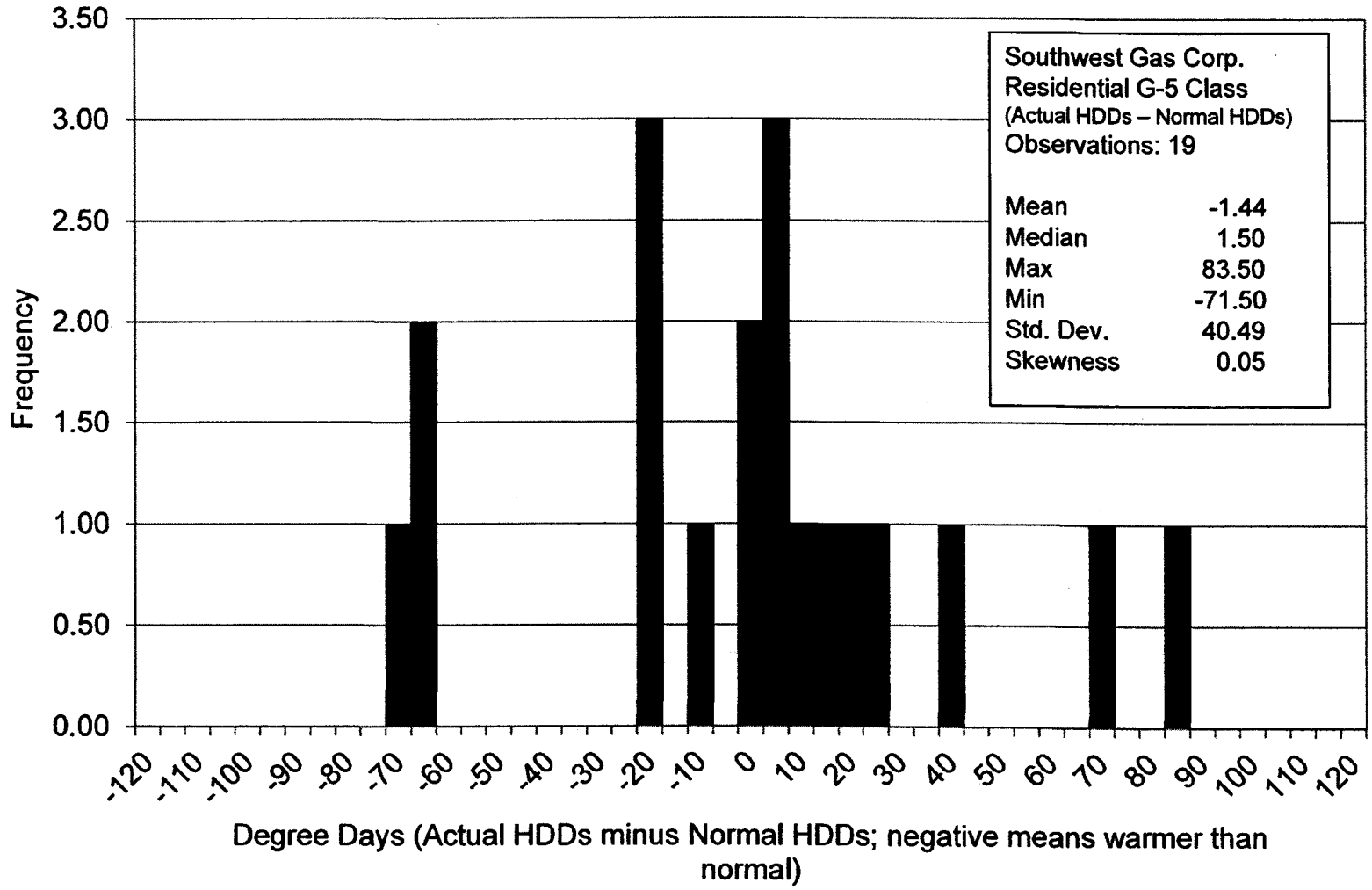
	Energy Efficiency Programs								Total Non-Gas Base Revenue ($)	EE Lost Margin as a Percent of Base Revenue (%)
	Annual Savings (therms)		Program Costs ($)		Lost Margin ($)					
Current Energy Efficiency Programs										
2007	48,651	$	861,661	$	25,630	$	399,816,248			0.01%
2008	125,825	$	1,024,247	$	66,287	$	401,119,083			0.02%
2009	163,563	$	1,199,521	$	93,345	$	409,715,094			0.02%
2010	348,405	$	1,396,821	$	198,835	$	418,246,266			0.05%
Proposed Energy Efficiency Programs										
2011	2,451,000	$	16,500,000	$	2,766,243	$	419,189,742			0.66%
2012	2,451,000	$	16,500,000	$	2,766,243	$	419,189,742			0.66%
2013	2,451,000	$	16,500,000	$	2,766,243	$	419,189,742			0.66%

Southern Connecticut Gas ROE Comparison (With and Without WNA)

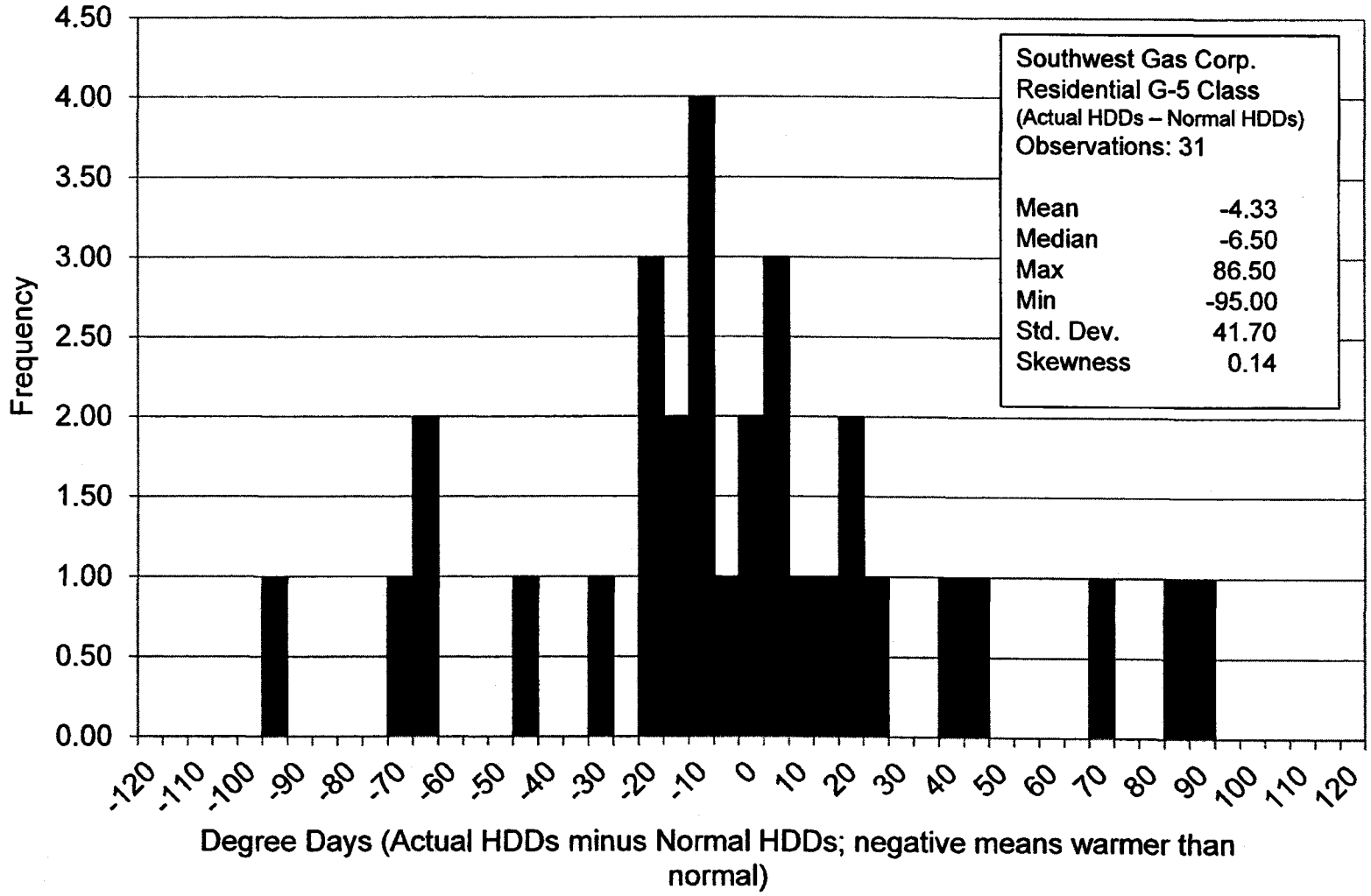
Year	Percent ROE with WNA	Percent ROE without WNA	Difference
1994	11.97%	12.05%	0.08%
1995	11.34%	9.79%	-1.55%
1996	12.38%	13.52%	1.14%
1997	12.35%	11.71%	-0.64%
1998	11.53%	8.19%	-3.34%
1999	12.46%	10.48%	-1.98%
2000	12.74%	12.28%	-0.46%
2001	15.05%	13.80%	-1.25%
2002	8.49%	6.40%	-2.09%
2003	10.44%	11.57%	1.13%
2004	10.84%	10.45%	-0.39%
2005	7.42%	7.05%	-0.37%
2006	7.04%	5.13%	-1.91%
2007	11.93%	10.98%	-0.95%
2008	11.27%	9.84%	-1.43%
Average	11.15%	10.22%	-0.93%

Source: Application of the Southern Connecticut Gas Company for a rate increase. Connecticut Department of Public Utility Control. Docket No. 08-12-07. July 17, 2009.

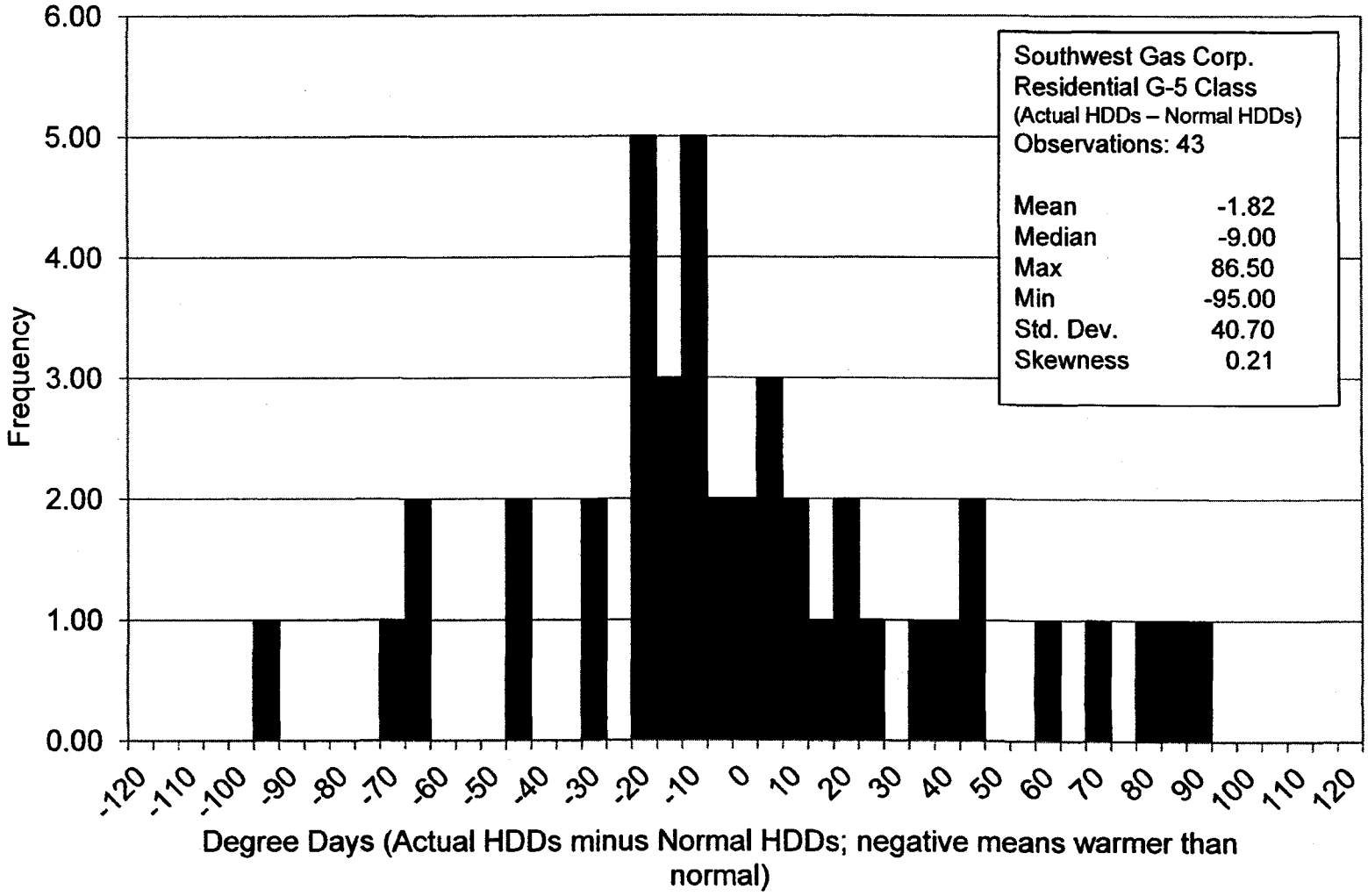
Actual HDDs less Normal HDDs
(3 years ending January 2011, heating season)



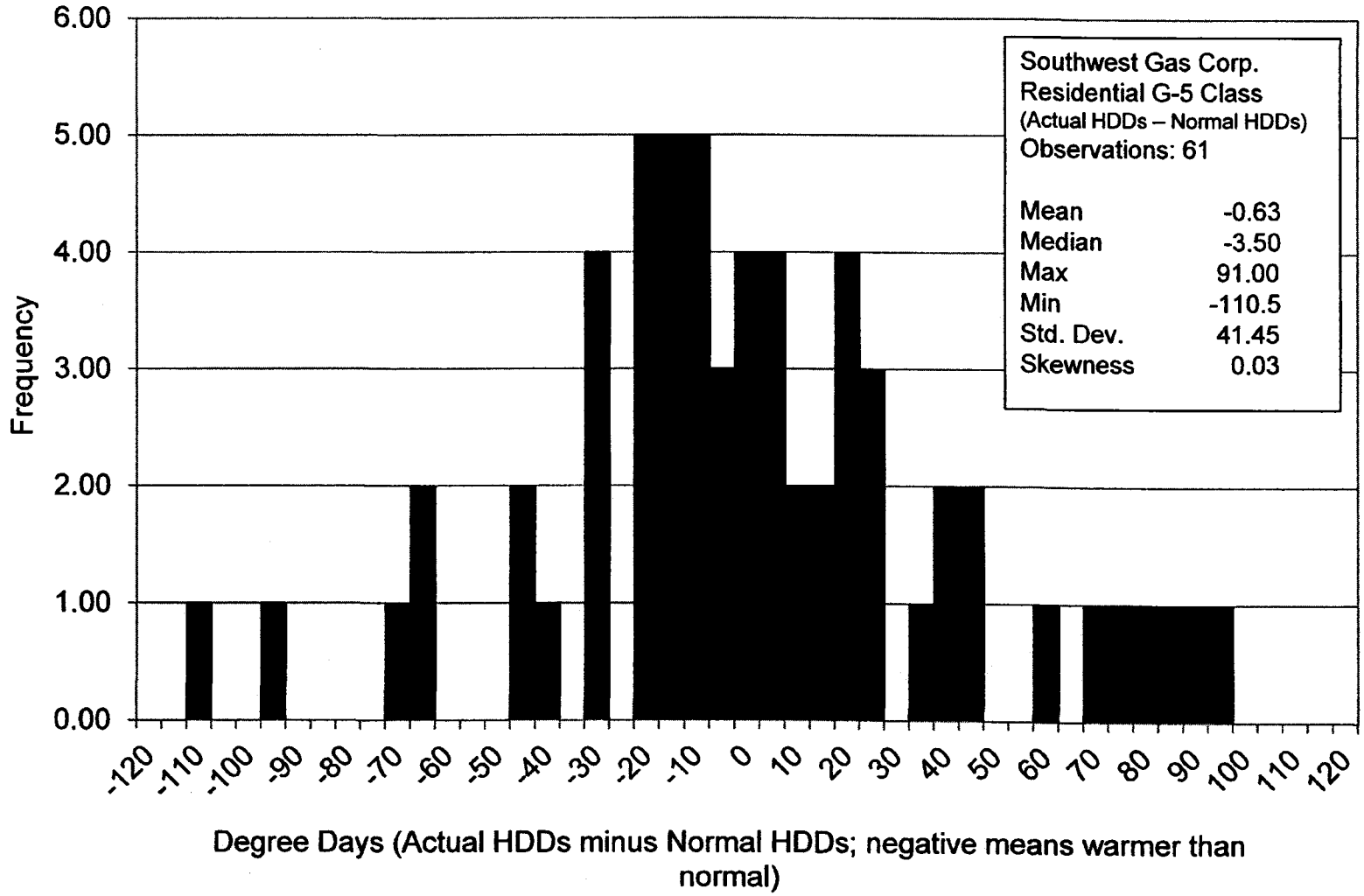
Actual HDDs less Normal HDDs
(5 years ending January 2011, heating season)



Actual HDDs less Normal HDDs
(7 years ending January 2011, heating season)

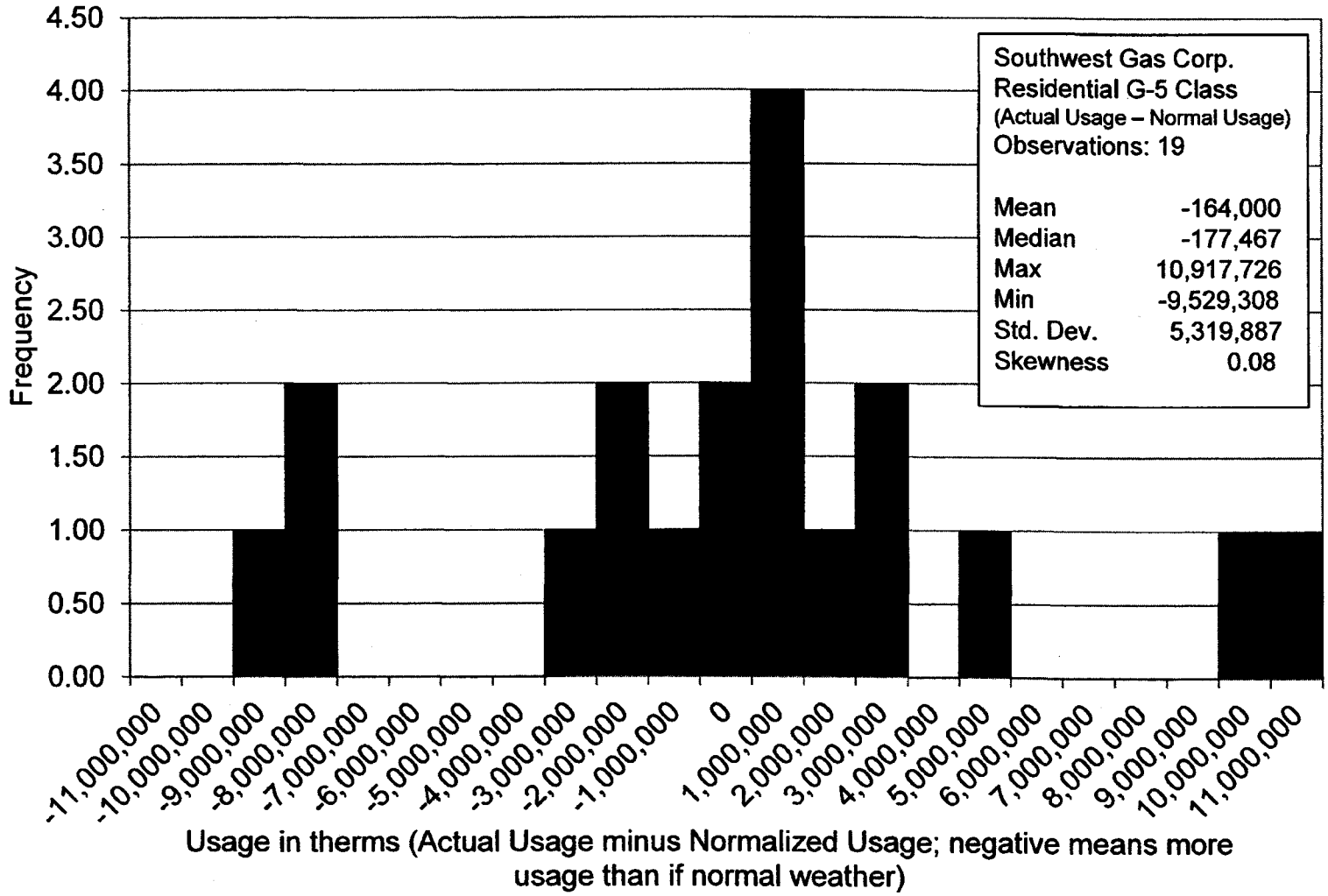


Actual HDDs less Normal HDDs
(10 years ending January 2011, heating season)

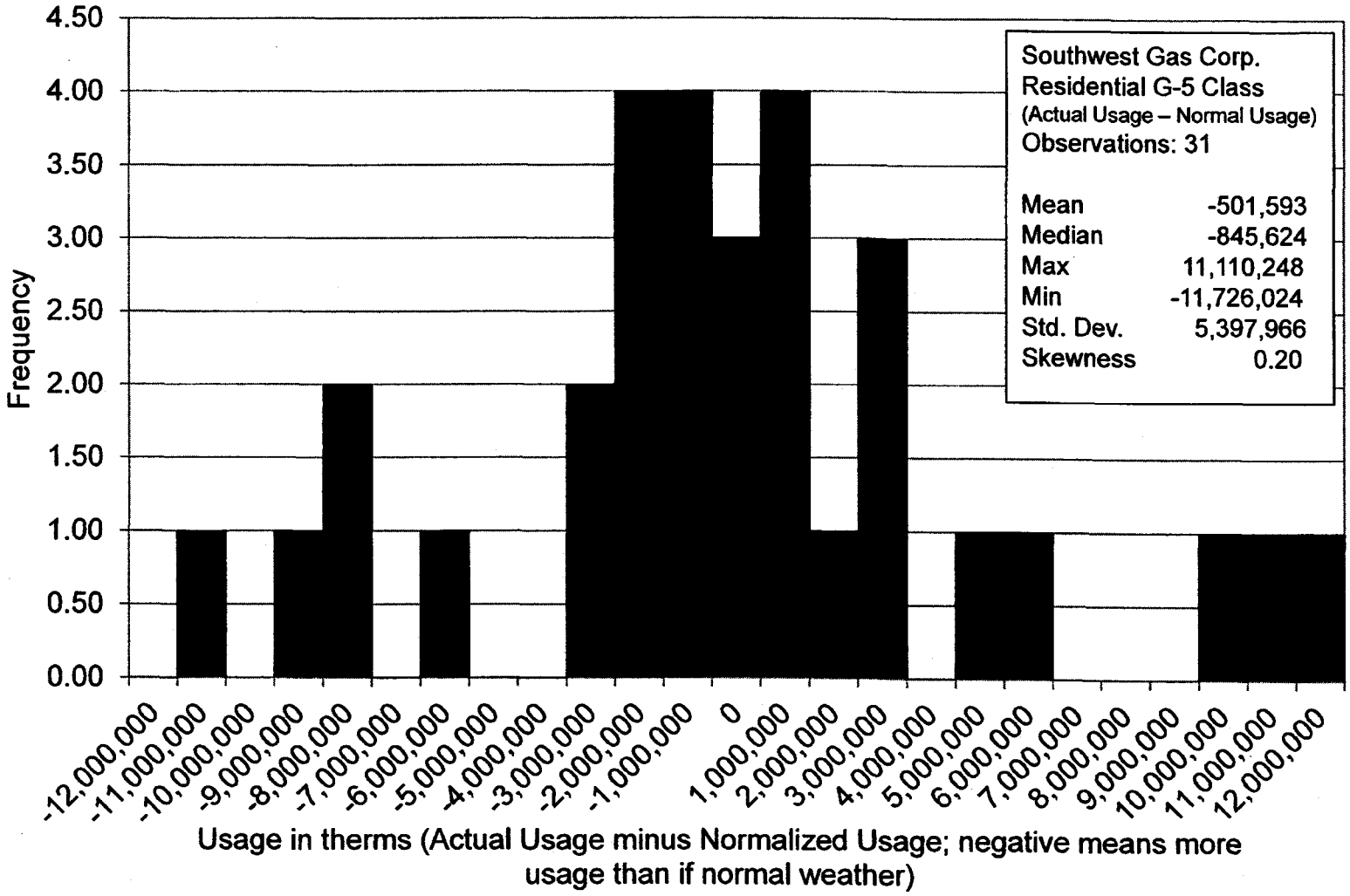


Source: Response to Staff Data Request ACC-STF-3-6.

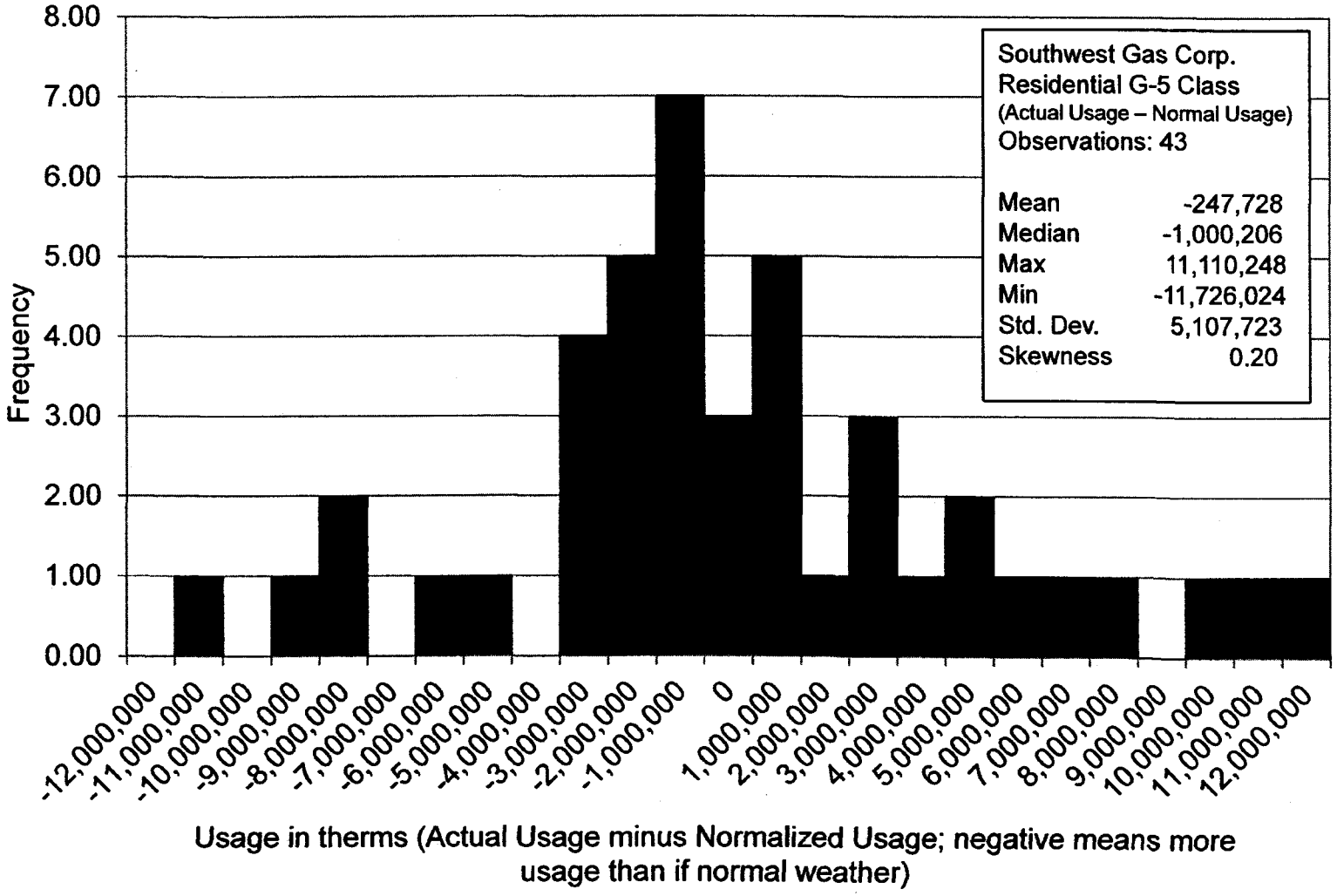
Actual Usage less Normalized Usage
(3 years ending January 2011, heating season)



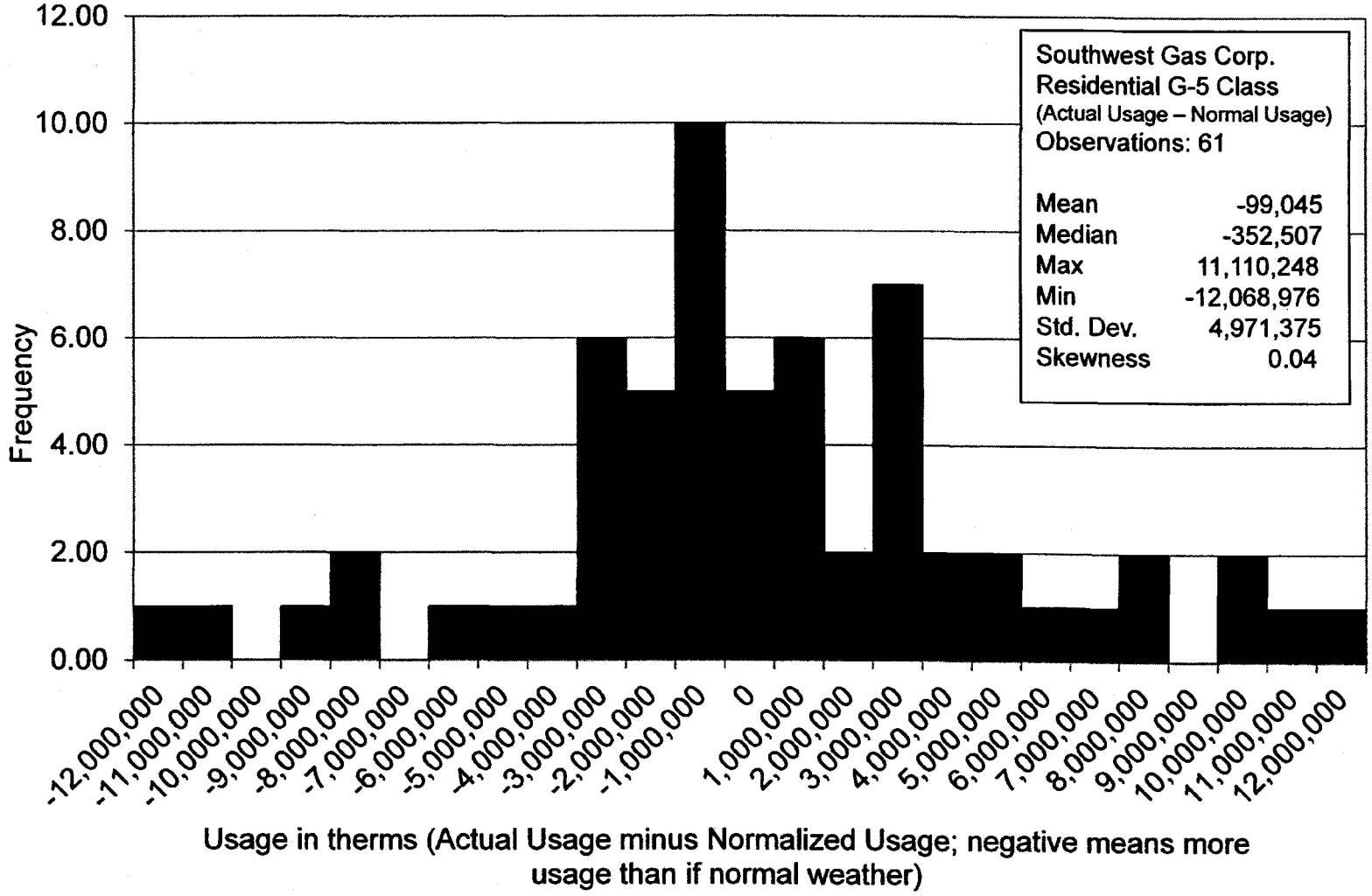
Actual Usage less Normalized Usage
(5 years ending January 2011, heating season)



Actual Usage less Normalized Usage
(7 years ending January 2011, heating season)



Actual Usage less Normalized Usage
(10 years ending January 2011, heating season)



Source: Response to Staff Data Request ACC-STF-3-6.

Ratepayer Protection Mechanisms

Company	Utility Type - Gas/ Electric	Decouping - Gas/ Electric	Date of Decision	Decision Type	Limited Recovery / Cap on Accruals	Check on Over Earnings	DSM or EE Targets	Pilot or Trial Period	Compliance Review
Arkansas Oklahoma Gas (AR)	Gas	Gas	11/20/07	Settlement		XXX			
Arkansas Western Gas (AR)	Gas	Gas	06/01/07	Settlement		XXX		XXX	
CenterPoint Energy (AR)	Gas	Gas	10/25/07	Settlement		XXX			
Pacific Gas & Electric (CA)	Electric & Gas	Electric & Gas	05/27/04	Settlement		XXX	XXX		
San Diego Gas & Electric (CA)	Electric & Gas	Electric & Gas	03/17/05	Settlement		XXX	XXX		
Southern California Gas (CA)	Gas	Gas	03/17/05	Settlement		XXX	XXX		
Southern California Edison (CA)	Electric	Electric	04/22/02	Order		XXX	XXX		
Southwest Gas (CA)	Gas	Gas	03/16/04	Order		XXX	XXX		
PSC of Colorado (CO)	Electric & Gas	Gas	06/18/07	Settlement	XXX	XXX	XXX	XXX	
United Illuminating (CT)	Electric	Electric	02/04/09	Order	XXX		XXX		XXX
HECO Companies (HI)*	Electric	Electric	08/31/40	Order		XXX			XXX
Idaho Power (ID)	Electric	Electric	03/12/07	Settlement	XXX		XXX	XXX	
North Shore Gas Company (IL)	Gas	Gas	02/05/08	Settlement	XXX			XXX	XXX
Peoples Gas Light and Coke (IL)	Electric & Gas	Gas	02/05/08	Settlement	XXX			XXX	XXX
Citizens Energy (IN)	Gas	Gas	08/29/07	Settlement			XXX	XXX	
Vectren Southern Indiana Gas (IN)	Gas	Gas	12/01/06	Settlement	XXX	XXX	XXX	XXX	
Vectren Indiana Gas (IN)	Gas	Gas	12/01/06	Settlement	XXX	XXX	XXX	XXX	
Bay State Gas (MA)	Gas	Gas	10/30/09	Order	XXX				
Boston Gas (MA)	Gas	Gas	11/02/10	Order	XXX				
Massachusetts Electric (MA)	Electric	Electric	11/30/09	Order	XXX				
New England Gas (MA)	Gas	Gas	03/31/11	Order	XXX				
Western Massachusetts Electric (MA)	Electric	Electric	01/11/11	Order	XXX				
Baltimore Gas & Electric (MD)	Electric & Gas	Gas	02/27/98	Settlement					
Delmarva Power & Light (MD)	Electric	Electric	07/19/07	Settlement					
PEPCO (MD)	Electric	Electric	07/19/07	Settlement					
Washington Gas (MD)	Gas	Gas	08/11/05	Settlement					
Consumers Energy (MI)	Electric & Gas	Electric	11/02/09	Order			XXX	XXX	XXX
Detroit Edison (MI)	Electric	Electric	01/11/10	Order			XXX	XXX	XXX
Michigan Gas Utilities (MI)	Gas	Gas	07/01/10	Order			XXX	XXX	XXX
Michigan Consolidated Gas (MI)	Gas	Gas	06/03/10	Order			XXX	XXX	XXX
CenterPoint Energy (MN)	Gas	Gas	01/11/10	Settlement	XXX		XXX	XXX	XXX
NorthWestern Energy (MT)	Electric & Gas	Electric	01/07/10	Order				XXX	XXX
Southwest Gas (NV)	Gas	Gas	11/03/09	Order			XXX		
New Jersey Natural (NJ)	Gas	Gas	10/12/06 & 1/21/10	Settlement	XXX	XXX	XXX	XXX	
South Jersey Gas (NJ)	Gas	Gas	10/12/06 & 1/21/10	Settlement	XXX	XXX	XXX	XXX	

Note: *HECO Companies include Hawaiian Electric, Hawaii Electric Light, and Maui Electric Company.

Ratepayer Protection Mechanisms

Company	Utility Type - Gas/ Electric	Decouping - Gas/ Electric	Date of Decision	Decision Type	Limited Recovery / Cap on Accruals	Check on Over Earnings	DSM or EE Targets	Pilot or Trial Period	Compliance Review
Consolidated Edison (NY)	Electric & Gas	Electric & Gas	9/25/07 & 3/25/08	Settlement			XXX	XXX	
National Gas Distribution (NY)	Gas	Gas	09/20/07	Order			XXX		
Orange and Rockland (NY)	Electric & Gas	Electric	07/23/08	Settlement					
Central Hudson Gas & Elec. (NY)	Electric & Gas	Electric & Gas	06/22/09	Settlement	XXX				
Niagara Mohawk (NY)	Electric & Gas	Gas	05/15/09	Settlement					
Piedmont Natural Gas (NC)	Gas	Gas	11/3/05 & 10/23/08	Settlement			XXX	XXX	
PSC of North Carolina (NC)	Gas	Gas	10/24/08	Settlement			XXX		
Vectren (OH)	Gas	Gas	09/13/06	Settlement			XXX	XXX	XXX
Cascade Natural Gas (OR)	Gas	Gas	04/19/06	Settlement		XXX	XXX	XXX	XXX
Northwest Natural (OR)	Gas	Gas	09/12/02	Settlement	XXX		XXX	XXX	
Portland General Electric (OR)	Electric	Electric	01/22/09	Order	XXX		XXX	XXX	XXX
Chattanooga Natural Gas (TN)	Gas	Gas	11/08/10	Order	XXX			XXX	XXX
Questar Gas (UT)	Gas	Gas	10/5/06 & 11/5/07	Order			XXX	XXX	XXX
Virginia Natural (VA)	Gas	Gas	12/23/08	Settlement			XXX	XXX	XXX
Columbia Gas of Virginia (VA)	Gas	Gas	12/04/09	Settlement			XXX	XXX	XXX
Green Mountain Power (VT)	Electric	Electric	12/22/06	Settlement	XXX	XXX	XXX	XXX	
Avista (WA)	Gas	Gas	2/1/07 & 12/22/09	Settlement	XXX	XXX	XXX	XXX	XXX
Cascade Natural Gas (WA)	Gas	Gas	01/12/07	Settlement		XXX	XXX	XXX	XXX
Wisconsin Public Service (WI)	Electric & Gas	Electric & Gas	12/30/08	Settlement	XXX		XXX	XXX	XXX
Questar Gas (WY)	Gas	Gas	06/17/09	Order			XXX	XXX	XXX

Comparison of Class Cost of Service Allocation Factors

FERC Account	Description	Staff Recommended Factor	SWG Factor
OPERATION AND MAINTENANCE EXPENSES			
Distribution Operations & Maintenance Expenses			
813	Other Gas Supply	100% Commodity	100% Commodity
870	Operation Supervision & Engineering	Accounts 871-879	Accounts 871-879
871	Distribution Load Dispatching	100% Commodity	100% Commodity
874	Mains & Services	Accounts 376 & 380 Mains and Services	Accounts 376 & 380 Mains and Services
875	Measuring & Regulating Exps. - General	Account 376	Account 376
878	Meters & House Regulators	Weighted Customers by Meter Cost	Weighted Customers by Meter Cost
879	Customer Installations Expenses	100% Customers	Weighted Customers by Meter Cost
880	Other	Accounts 871-879	Accounts 871-879
881	Rents	Accounts 871-879	Accounts 871-879
885	Maintenance Supervision & Engineering	Accounts 887-893	Accounts 887-893
886	Maintenance of Structures & Improvement	50% Customers / 25% Demand / 25% Commodity	100% Demand
887	Maintenance of Mains	50% Customers / 25% Demand / 25% Commodity	50% Customers / 50% Demand
889	Maint of Meas. & Reg. Station Equipment	50% Commodity / 50% Demand	50% Customers / 50% Demand
892	Maintenance of Services	Account 380	Account 380
893	Maintenance of Meters & House Regulators	Weighted Customers by Meter Cost	Weighted Customers by Meter Cost
894	Maintenance of Other Equipment	Accounts 887-893	Accounts 887-893
Customer Accounts Expense			
901	Supervision	Accounts 902-904	Accounts 902-904
902	Meter Reading Expense	Bills with Meters(# of customers excluding streetlighting)	Bills with Meters(# of customers excluding streetlighting)
903	Customer Accounting	100% Customers	100% Customers
904	Uncollectible Accounts	100% Customers	100% Customers
905	Miscellaneous Expense	Accounts 902-904	Accounts 902-904

Comparison of Class Cost of Service Allocation Factors

FERC Account	Description	Staff Recommended Factor	SWG Factor
Customer Service & Information Expense			
908	Customer Assistance Expense	100% Customers	100% Customers
909	Info. & Instructional Advertising Exps.	100% Customers	100% Customers
910	Msc Customer Service and Info Expense	100% Customers	100% Customers
911-13	Sales Expense	100% Customers	100% Customers
Administrative & General Expense Acts (920-935)		Total O&M Expenses other than A&G	Total O&M Expenses other than A&G
Depreciation Expense		Related Plant	Related Plant
Amortization Expense			
	Amortization Gas Plant Acquisition	Related Plant	Net Distribution Plant
	Regulatory Amortizations	Weighted Customers by Service Cost	Weighted Customers by Service Cost
Interest on Customer Deposits		Applicable Customers	Applicable Customers
Tax Adjustments			
Interest Expense		Net Distribution Plant	Net Distribution Plant
Investment Tax Credit (I.T.C.)		Net Distribution Plant	Net Distribution Plant
South Georgia - Federal		Net Distribution Plant	Net Distribution Plant
Tax Expenses			
Taxes Other Than Income Taxes		Net Distribution Plant	Net Distribution Plant
	State Income Taxes	Calculated	Calculated
	Federal Income Taxes	Calculated	Calculated

Comparison of Class Cost of Service Allocation Factors

FERC Account	Description	Staff Recommended Factor	SWG Factor
RATE BASE ACCOUNTS			
Utility Plant			
Intangible Plant			
301	Organization	Net Distribution Plant	Net Distribution Plant
302	Franchise & Consents	Net Distribution Plant	Net Distribution Plant
303	Miscellaneous Intangible Plant	Net Distribution Plant	Net Distribution Plant
Distribution Plant			
374	Land & Land Rights	Accounts 376 & 378	100% Demand
375	Structures & Improvements	Accounts 376 & 378	100% Demand
376	Mains	50% Customer / 25% Demand / 25% Commodity	50% Customers / 50% Demand
378	Measuring & Regulation Station Equip	50% Commodity / 50% Demand	50% Customers / 50% Demand
380	Services	Weighted Customers by Service Cost	Weighted Customers by Service Cost
381-82	Meters & Meter Installation	Weighted Customers by Meter Cost	Weighted Customers by Meter Cost
385	Measuring & Reg Equipment Industrial	50% Demand / 50% Commodity to Transportation, A/C, and Electric Generation Customers Only	100% Commodity to All Customers
387	Miscellaneous Equipment	100% Customers	100% Demand
389-398	**General Plant**	Net Distribution Plant	Net Distribution Plant
OTHER RATE BASE ACCOUNTS			
	Cash Working Capital	Total O&M Expenses	Total O&M Expenses
	Materials & Operating Supplies	Net Distribution Plant	Net Distribution Plant
	Prepayments	Total O&M Expenses	Net Distribution Plant
	Customer Deposits	Applicable customers	Applicable customers
	Customer Advances	Applicable customers	Applicable customers
	Deferred Income Taxes	Net Distribution Plant	Net Distribution Plant

Source: Company Class Cost of Service Study.

Class Cost of Service Study – Present Rates
Under Company's Recommended Cost Allocation Factors

Description	Total Amount	Single-Family Residential	Multi-Family Residential	MMMHP	Small General	Medium General	Large-1 General	Transportation Eligible	Large-2 General	Air Conditioning	Street Lighting	Compression Customer's Premises (CNG)	Electric Generation	Small Essential Agricultural	Natural Gas Engines
Rate Base															
Total Direct Net Plant	$1,809,906,655	$1,397,040,982	$ 39,117,897	$2,531,118	$25,709,734	$ 91,238,638	$115,249,313	$ 68,164,677	$49,836,748	$ 225,727	$370,549	$ 2,818,607	$11,841,511	$ 2,652,976	$ 3,110,178
Total Common Systems Allocable Net Plant	38,161,320	29,456,143	824,788	53,368	542,061	1,923,736	2,429,993	1,437,229	1,050,791	4,759	7,813	59,429	249,674	55,937	65,577
Cash Working Capital	(4,472,151)	(3,627,826)	(124,396)	(3,978)	(67,658)	(172,061)	(221,316)	(140,027)	(73,294)	(438)	(626)	(4,630)	(19,703)	(4,606)	(11,591)
Materials & Supplies	9,920,409	7,657,413	214,412	13,873	140,919	500,094	631,701	373,622	273,163	1,237	2,031	15,449	64,905	14,541	17,047
Prepayments	4,744,133	3,661,924	102,536	6,635	67,390	239,155	302,092	178,673	130,632	592	971	7,388	31,039	6,954	8,152
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Deposits	(62,033,165)	(57,743,519)	(2,217,488)	(9,657)	(1,095,747)	(966,753)	-	-	-	-	-	-	-	-	-
Customer Advances	(48,475,278)	(45,123,172)	(1,732,836)	(7,547)	(856,262)	(755,461)	-	-	-	-	-	-	-	-	-
Deferred Taxes	(291,236,457)	(224,800,994)	(6,294,548)	(407,288)	(4,137,011)	(14,681,414)	(18,545,025)	(10,968,531)	(8,019,343)	(36,322)	(59,626)	(453,548)	(1,905,444)	(426,895)	(500,466)
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Rate Base	$1,456,617,467	$1,106,520,949	$ 29,890,364	$2,176,524	$20,303,447	$ 77,325,935	$ 99,846,757	$ 59,045,644	$43,198,698	$ 195,555	$321,112	$ 2,442,696	$10,261,982	$ 2,298,906	$ 2,688,898
Margin															
Net Operating Margin	$ 392,027,615	$ 269,876,468	$ 7,590,591	$ 863,947	$ 7,908,814	$ 22,579,171	$ 43,845,416	$ 21,689,599	$11,254,459	$ 82,169	$ 53,386	$ 859,687	$ 2,982,640	$ 727,284	$ 1,713,984
Special Contract Margin	6,788,127	4,673,028	131,434	14,960	136,945	390,968	759,202	375,565	194,876	1,423	924	14,886	51,646	12,593	29,678
Other Revenue	12,096,356	10,449,547	869,413	2,377	145,178	248,108	275,318	49,393	26,882	472	3,536	1,277	4,792	6,177	13,884
Total Revenue	$ 410,912,098	$ 284,999,042	$ 8,591,439	$ 881,284	$ 8,190,937	$ 23,218,247	$ 44,879,936	$ 22,114,557	$11,476,217	$ 84,064	$ 57,847	$ 875,850	$ 3,039,078	$ 746,054	$ 1,757,546
Operating Expenses															
Operations & Maintenance Expenses	$ (136,804,420)	$ (110,976,336)	$ (3,805,296)	$ (121,689)	$ (2,069,671)	$ (5,263,397)	$ (6,770,127)	$ (4,283,465)	$ (2,242,076)	$ (13,391)	$ (19,145)	$ (141,637)	$ (602,718)	$ (140,894)	$ (354,577)
Administrative & General Expenses	(65,125,498)	(52,830,085)	(1,811,505)	(57,930)	(985,263)	(2,505,631)	(3,222,907)	(2,039,136)	(1,067,336)	(6,375)	(9,114)	(67,426)	(286,923)	(67,072)	(168,796)
Depreciation Expenses	(99,586,591)	(76,869,376)	(2,152,384)	(139,270)	(1,414,627)	(5,020,223)	(6,341,362)	(3,750,625)	(2,742,167)	(12,420)	(20,389)	(155,068)	(651,555)	(145,975)	(171,131)
Interest on Customer Deposits	(2,908,517)	(2,707,390)	(103,970)	(453)	(51,376)	(45,328)	-	-	-	-	-	-	-	-	-
Taxes other than Income	(27,203,877)	(20,998,259)	(587,963)	(38,044)	(386,431)	(1,371,365)	(1,732,256)	(1,024,551)	(749,072)	(3,393)	(5,570)	(42,365)	(177,984)	(39,876)	(46,746)
Total Operating Deductions	$ (331,628,903)	$ (264,381,447)	$ (8,461,117)	$ (357,385)	$ (4,907,367)	$(14,206,942)	$ (18,066,653)	$ (11,097,777)	$ (6,800,652)	$ (35,578)	$ (54,217)	$ (406,517)	$ (1,719,181)	$ (393,817)	$ (741,252)
Taxable Income															
Taxable Income before Interest Expense	$ 79,283,195	$ 20,617,595	$ 130,321	$ 523,898	$ 3,283,570	$ 9,012,305	$ 26,813,283	$ 11,016,780	$ 4,675,565	$ 48,485	$ 3,630	$ 469,333	$ 1,319,897	$ 352,237	$ 1,016,295
Interest Expenses	(42,713,744)	(32,970,090)	(623,180)	(59,734)	(606,748)	(2,153,227)	(2,719,877)	(1,608,683)	(1,176,144)	(5,327)	(8,745)	(66,519)	(279,459)	(62,610)	(73,400)
Total Taxable Income	$ 36,569,451	$ (12,352,495)	$ (792,859)	$ 464,164	$ 2,676,821	$ 6,859,078	$ 24,093,405	$ 9,408,097	$ 3,499,421	$ 43,158	$ (5,115)	$ 402,814	$ 1,040,438	$ 289,627	$ 942,895
State Income Tax															
State Income Tax	$ 2,548,159	$ (860,722)	$ (55,246)	$ 32,343	$ 186,521	$ 477,941	$ 1,678,828	$ 655,556	$ 243,840	$ 3,007	$ (356)	$ 28,068	$ 72,498	$ 20,181	$ 65,701
South Georgia State	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total State Income Tax	$ 2,548,159	$ (860,722)	$ (55,246)	$ 32,343	$ 186,521	$ 477,941	$ 1,678,828	$ 655,556	$ 243,840	$ 3,007	$ (356)	$ 28,068	$ 72,498	$ 20,181	$ 65,701
Federal Income Tax															
Federal Income Tax	$ 11,907,452	$ (4,022,121)	$ (258,164)	$ 151,137	$ 871,605	$ 2,233,398	$ 7,845,102	$ 3,063,389	$ 1,139,453	$ 14,053	$ (1,666)	$ 131,161	$ 338,779	$ 94,306	$ 307,018
Investment Tax Credit (I.T.C.)	(528,360)	(407,833)	(11,420)	(739)	(7,505)	(26,635)	(33,644)	(19,899)	(14,549)	(66)	(108)	(823)	(3,457)	(774)	(908)
South Georgia Federal	290,114	223,935	6,270	406	4,121	14,625	18,474	10,926	7,988	36	59	452	1,896	425	499
Total Federal Income Tax	$ 11,669,206	$ (4,206,019)	$ (263,314)	$ 150,804	$ 868,221	$ 2,221,388	$ 7,829,931	$ 3,054,417	$ 1,132,893	$ 14,023	$ (1,714)	$ 130,790	$ 337,220	$ 93,957	$ 306,608
Regulatory Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Income	$ 65,965,829	$ 26,684,336	$ 448,881	$ 340,751	$ 2,228,828	$ 6,312,976	$ 17,304,523	$ 7,306,807	$ 3,298,832	$ 31,456	$ 5,700	$ 316,475	$ 910,179	$ 238,099	$ 643,985
Rate of Return on Rate Base	4.47%	2.32%	1.50%	15.66%	10.98%	8.16%	17.33%	12.37%	7.64%	16.08%	1.78%	12.71%	8.87%	10.36%	23.96%

Class Cost of Service Study – Proposed Rates Under Company's Recommended Cost Allocation Factors

Description	Total Amount	Single-Family Residential	Multi-Family Residential	MMMHP	Small General	Medium General	Large-1 General	Transportation Eligible	Large-2 General	Air Conditioning	Street Lighting	Compression on Customer's Premises (CNG)	Electric Generation	Small Essential Agricultural	Natural Gas Engines
Rate Base															
Total Direct Net Plant	$ 1,809,908,655	$ 1,397,040,962	$ 39,117,897	$ 2,531,118	$ 25,709,734	$ 91,238,638	$ 115,249,313	$ 68,164,677	$ 49,836,748	$ 225,727	$ 370,549	$ 2,818,607	$ 11,841,511	$ 2,652,976	$ 3,110,178
Total Common Systems Allocable Net Plant	38,161,320	29,456,143	624,788	53,368	542,061	1,923,736	2,429,993	1,437,229	1,050,791	4,759	7,813	59,429	249,674	55,937	65,577
Cash Working Capital	(4,472,151)	(3,627,828)	(124,396)	(3,978)	(67,658)	(172,061)	(221,316)	(140,027)	(73,294)	(438)	(826)	(4,630)	(19,703)	(4,606)	(11,591)
Materials & Supplies	9,920,409	7,657,413	214,412	13,873	140,919	500,094	631,701	373,622	273,163	1,237	2,031	15,449	64,905	14,541	17,047
Prepayments	4,744,133	3,661,924	102,536	6,635	67,390	239,155	302,092	178,673	130,632	592	971	7,388	31,039	6,954	8,152
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Deposits	(62,033,165)	(57,743,519)	(2,217,488)	(9,657)	(1,095,747)	(966,753)	-	-	-	-	-	-	-	-	-
Customer Advances	(48,475,278)	(45,123,172)	(1,732,836)	(7,547)	(856,262)	(755,461)	-	-	-	-	-	-	-	-	-
Deferred Taxes	(291,236,457)	(224,800,994)	(6,294,548)	(407,288)	(4,137,011)	(14,681,414)	(18,545,025)	(10,968,531)	(8,019,343)	(36,322)	(59,626)	(453,548)	(1,905,444)	(426,896)	(500,466)
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Rate Base	$ 1,466,617,467	$ 1,106,620,949	$ 29,890,364	$ 2,176,624	$ 20,303,447	$ 77,325,935	$ 99,846,757	$ 69,045,644	$ 43,198,698	$ 196,655	$ 321,112	$ 2,442,696	$ 10,261,982	$ 2,298,906	$ 2,688,898
Margin															
Net Operating Margin	$ 465,217,053	$ 332,857,067	$ 9,361,994	$ 928,479	$ 8,499,555	$ 24,265,700	$ 47,120,407	$ 23,309,683	$ 12,095,100	$ 88,307	$ 65,845	$ 923,900	$ 3,205,425	$ 781,608	$ 1,713,984
Special Contract Margin	6,788,127	4,856,821	136,604	13,548	124,020	354,068	687,549	340,119	176,483	1,289	961	13,481	46,771	11,405	25,009
Other Revenue	12,096,356	10,449,547	869,413	2,377	145,178	248,106	275,318	49,393	26,882	472	3,536	1,277	4,792	6,177	13,884
Total Revenue	$ 484,101,636	$ 348,163,435	$ 10,368,011	$ 944,404	$ 8,768,753	$ 24,867,877	$ 48,083,273	$ 23,699,194	$ 12,298,465	$ 90,067	$ 70,341	$ 938,659	$ 3,256,989	$ 799,189	$ 1,752,877
Operating Expenses															
Operations & Maintenance Expenses	$ (136,804,420)	$ (110,976,336)	$ (3,805,296)	$ (121,669)	$ (2,069,671)	$ (5,263,397)	$ (6,770,127)	$ (4,283,465)	$ (2,242,076)	$ (13,391)	$ (19,145)	$ (141,637)	$ (602,718)	$ (140,894)	$ (354,577)
Incremental Uncollectible Expenses	(166,105)	(146,035)	(4,444)	(228)	(2,701)	(6,602)	(11,017)	(6,674)	(4,376)	(22)	(34)	(256)	(1,079)	(245)	(395)
Administrative & General Expenses	(65,125,498)	(52,830,085)	(1,811,505)	(57,930)	(985,263)	(2,505,631)	(3,222,907)	(2,039,136)	(1,067,336)	(6,375)	(9,114)	(67,426)	(286,923)	(67,072)	(168,796)
Depreciation Expenses	(99,586,591)	(76,869,376)	(2,152,384)	(139,270)	(1,414,627)	(5,020,223)	(6,341,362)	(3,750,625)	(2,742,167)	(12,420)	(20,389)	(155,088)	(651,555)	(145,975)	(171,131)
Interest on Customer Deposits	(2,908,517)	(2,707,390)	(103,970)	(453)	(51,376)	(45,328)	-	-	-	-	-	-	-	-	-
Taxes other than Income	(27,203,877)	(20,998,258)	(587,963)	(38,044)	(386,431)	(1,371,365)	(1,732,258)	(1,024,551)	(749,072)	(3,393)	(5,570)	(42,365)	(177,984)	(39,876)	(46,748)
Total Operating Deductions	$ (331,815,008)	$ (264,527,482)	$ (8,465,561)	$ (357,611)	$ (4,910,068)	$ (14,214,545)	$ (18,077,670)	$ (11,104,451)	$ (6,805,026)	$ (35,600)	$ (54,251)	$ (406,773)	$ (1,720,260)	$ (394,052)	$ (741,646)
State Income Tax															
Taxable Income before Interest Expense	$ 152,286,528	$ 83,635,953	$ 1,902,450	$ 586,792	$ 3,858,685	$ 10,653,332	$ 30,005,603	$ 12,594,744	$ 5,493,438	$ 54,467	$ 16,091	$ 531,886	$ 1,536,729	$ 405,127	$ 1,011,231
Interest Expenses	(42,713,744)	(32,970,090)	(923,180)	(59,734)	(606,748)	(2,153,227)	(2,719,877)	(1,608,683)	(1,176,144)	(5,327)	(8,745)	(66,519)	(279,459)	(62,610)	(73,400)
State Taxable Income	$ 109,572,784	$ 50,665,863	$ 979,270	$ 527,058	$ 3,251,937	$ 8,500,106	$ 27,285,726	$ 10,986,061	$ 4,317,293	$ 49,140	$ 7,346	$ 465,367	$ 1,257,270	$ 342,517	$ 937,831
State Income Tax	$ 7,635,032	$ 3,530,397	$ 68,236	$ 36,725	$ 226,595	$ 592,287	$ 1,901,269	$ 765,509	$ 300,829	$ 3,424	$ 512	$ 32,427	$ 87,607	$ 23,867	$ 65,348
South Georgia State	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total State Income Tax	$ 7,635,032	$ 3,530,397	$ 68,236	$ 36,725	$ 226,595	$ 592,287	$ 1,901,269	$ 765,509	$ 300,829	$ 3,424	$ 512	$ 32,427	$ 87,607	$ 23,867	$ 65,348
Federal Income Tax															
Taxable Income before Interest Expense	$ 152,286,528	$ 83,635,953	$ 1,902,450	$ 586,792	$ 3,858,685	$ 10,653,332	$ 30,005,603	$ 12,594,744	$ 5,493,438	$ 54,467	$ 16,091	$ 531,886	$ 1,536,729	$ 405,127	$ 1,011,231
Interest Expenses	(42,713,744)	(32,970,090)	(923,180)	(59,734)	(606,748)	(2,153,227)	(2,719,877)	(1,608,683)	(1,176,144)	(5,327)	(8,745)	(66,519)	(279,459)	(62,610)	(73,400)
Federal Taxable Income	$ 109,572,784	$ 50,665,863	$ 979,270	$ 527,058	$ 3,251,937	$ 8,500,106	$ 27,285,726	$ 10,986,061	$ 4,317,293	$ 49,140	$ 7,346	$ 465,367	$ 1,257,270	$ 342,517	$ 937,831
Federal Income Tax	$ 35,678,214	$ 16,497,413	$ 318,862	$ 171,616	$ 1,058,670	$ 2,767,736	$ 8,884,560	$ 3,577,193	$ 1,405,762	$ 16,000	$ 2,392	$ 151,529	$ 409,362	$ 111,528	$ 305,369
Investment Tax Credit (I.T.C.)	(528,360)	(407,833)	(11,420)	(739)	(7,505)	(26,635)	(33,644)	(19,899)	(14,549)	(66)	(108)	(823)	(3,457)	(774)	(908)
South Georgia Federal	290,114	223,935	6,270	406	4,121	14,625	18,474	10,926	7,988	36	59	452	1,898	425	499
Total Federal Income Tax	$ 35,439,968	$ 16,313,515	$ 313,713	$ 171,283	$ 1,055,485	$ 2,755,726	$ 8,869,389	$ 3,568,221	$ 1,399,202	$ 15,971	$ 2,343	$ 151,158	$ 407,823	$ 111,179	$ 304,960
Regulatory Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Income	$ 109,211,529	$ 63,792,041	$ 1,520,502	$ 378,784	$ 2,576,605	$ 7,305,319	$ 19,234,945	$ 8,261,014	$ 3,793,406	$ 35,072	$ 13,236	$ 348,301	$ 1,041,299	$ 270,082	$ 540,923
Rate of Return on Rate Base	7.60%	6.77%	6.09%	17.40%	12.69%	9.46%	19.26%	13.99%	8.78%	17.83%	4.12%	14.29%	10.15%	11.76%	23.84%

Source: AZ 2010 CCOSS and rate design.

Class Cost of Service Study – Present Rates Under Staff's Recommended Cost Allocation Factors

Description	Total Amount	Single-Family Residential	Multi-Family Residential	MMMHP	Small General	Medium General	Large-1 General	Transportation Eligible	Large-2 General	Air Conditioning	Street Lighting	Compression Customer's Premises (CNG)	Electric Generation	Small Essential Agricultural	Natural Gas Engines
Rate Base															
Total Direct Net Plant	$1,809,908,655	$ 1,346,606,658	$ 38,369,221	$2,407,161	$27,536,194	$ 97,399,492	$120,612,420	$ 93,599,302	$52,526,767	$ 463,520	$411,011	$ 3,549,482	$17,688,579	$ 2,730,037	$ 6,008,811
Total Common Systems Allocable Net Plant	38,161,320	28,392,752	809,002	50,754	580,591	2,053,636	2,543,073	1,973,510	1,107,509	9,773	8,666	74,840	372,958	57,562	126,694
Cash Working Capital	(4,472,151)	(3,469,691)	(114,853)	(4,972)	(70,371)	(182,692)	(275,944)	(194,199)	(94,294)	(941)	(760)	(7,566)	(35,209)	(6,046)	(14,609)
Materials & Supplies	9,920,409	7,380,974	210,308	13,194	150,930	533,863	661,097	513,033	287,908	2,541	2,253	19,455	96,954	14,964	32,935
Prepayments	4,744,133	3,680,707	121,838	5,274	74,651	193,803	292,726	206,010	100,029	998	807	8,027	37,351	6,416	15,498
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Deposits	(62,033,165)	(57,743,519)	(2,217,488)	(9,657)	(1,095,747)	(966,753)	-	-	-	-	-	-	-	-	-
Customer Advances	(48,475,278)	(45,123,172)	(1,732,836)	(7,547)	(856,262)	(755,461)	-	-	-	-	-	-	-	-	-
Deferred Taxes	(291,236,457)	(216,685,494)	(6,174,077)	(387,342)	(4,430,911)	(15,672,770)	(19,408,015)	(15,061,273)	(8,452,200)	(74,586)	(66,137)	(571,155)	(2,846,309)	(439,296)	(966,891)
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Rate Base	**$1,456,617,467**	**$1,063,039,215**	**$ 29,271,116**	**$2,066,866**	**$21,589,076**	**$ 82,603,117**	**$104,425,357**	**$ 81,036,382**	**$45,475,719**	**$ 401,306**	**$356,839**	**$ 3,073,962**	**$15,314,323**	**$ 2,363,634**	**$ 5,202,437**
Margin															
Net Operating Margin	$ 392,027,615	$ 269,876,468	$ 7,590,591	$ 863,947	$ 7,906,814	$ 22,579,171	$ 43,845,416	$ 21,689,599	$11,254,459	$ 82,169	$ 53,386	$ 859,687	$ 2,982,640	$ 727,284	$ 1,713,984
Special Contract Margin	6,788,127	4,673,028	131,434	14,960	136,945	390,968	759,202	375,565	194,876	1,423	924	14,886	51,646	12,593	29,678
Other Revenue	12,096,356	10,449,547	869,413	2,377	145,178	248,108	275,318	49,393	26,882	472	3,536	1,277	4,792	6,177	13,884
Total Revenue	**$ 410,912,098**	**$ 284,999,042**	**$ 8,591,439**	**$ 881,284**	**$ 8,190,937**	**$ 23,218,247**	**$ 44,879,936**	**$ 22,114,857**	**$11,476,217**	**$ 84,064**	**$ 57,847**	**$ 875,850**	**$ 3,039,078**	**$ 746,054**	**$ 1,757,546**
Operating Expenses															
Operations & Maintenance Expenses	$ (136,804,420)	$ (106,138,894)	$ (3,513,395)	$ (152,062)	$ (2,152,664)	$ (5,588,601)	$ (8,441,211)	$ (5,940,617)	$ (2,884,487)	$ (28,774)	$ (23,263)	$ (231,457)	$ (1,077,064)	$ (185,015)	$ (446,895)
Incremental Uncollectible Expenses	$ (65,125,498)	$ (50,527,229)	$ (1,672,545)	$ (72,399)	$ (1,024,772)	$ (2,660,444)	$ (4,018,423)	$ (2,828,020)	$ (1,373,155)	$ (13,698)	$ (11,074)	$ (110,185)	$ (512,735)	$ (88,076)	$ (212,743)
Administrative & General Expenses	(99,586,591)	(74,094,328)	(2,111,189)	(132,449)	(1,515,124)	(5,359,212)	(6,636,456)	(5,150,114)	(2,890,180)	(25,504)	(22,615)	(195,303)	(973,279)	(150,215)	(330,623)
Depreciation Expenses	(2,908,517)	(2,707,390)	(103,970)	(453)	(51,376)	(45,328)	-	-	-	-	-	-	-	-	-
Interest on Customer Deposits	(27,203,877)	(20,240,205)	(576,710)	(36,181)	(413,883)	(1,463,965)	(1,812,868)	(1,406,847)	(789,505)	(6,967)	(6,176)	(53,351)	(265,869)	(41,034)	(90,316)
Taxes other than Income	(331,628,903)	(253,708,047)	(7,977,809)	(393,564)	(5,157,819)	(15,117,550)	(20,908,958)	(15,325,598)	(7,937,327)	(74,943)	(63,130)	(590,296)	(2,828,946)	(464,340)	(1,080,577)
Total Operating Deductions	**$ (331,628,903)**														
Taxable Income		31290995.67	613629.477	487720.13	3033117.82	8100697.87	23970978	6788959	3538889.81	9120.221045	-5283.83	285554.7741	210131.989	281713.92	676969.856
Taxable Income before Interest Expense	$ 79,283,195	$ (31,779,842)	$ (905,511)	$ (56,809)	$ (649,853)	$ (2,298,623)	$ (2,846,446)	$ (2,208,938)	$ (1,239,629)	$ (10,939)	$ (9,700)	$ (83,768)	$ (417,449)	$ (64,429)	$ (141,808)
Interest Expenses	(42,713,744)	(486,847)	(291,882)	430,911	2,383,265	5,802,075	21,124,532	4,580,021	2,299,261	(1,819)	(14,984)	201,787	(207,317)	217,285	535,162
Total Taxable Income	**$ 36,569,451**														
State Income Tax		-34062.84226	-20338.3388	30025.896	166065.916	404288.604	1471957.36	319135.8407	160212.508	-126.7356772	-1044.06	14060.53172	-14445.882	15140.4327	37290.1058
State Income Tax	$ 2,548,159	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
South Georgia State	-	(34,063)	(20,338)	30,026	166,066	404,289	1,471,957	319,136	160,213	(127)	(1,044)	14,061	(14,446)	15,140	37,290
Total State Income Tax	**$ 2,548,159**														
Federal Income Tax		-159174.3713	-95040.2869	140309.88	776019.735	1889225.33	6878400.973	1491309.692	748666.98	-592.2310177	-4878.86	65704.332	-67505.061	70750.6682	174255.252
Federal Income Tax	$ 11,907,452	$ (393,110)	$ (11,201)	$ (703)	$ (8,039)	$ (26,433)	$ (35,210)	$ (27,324)	$ (15,334)	$ (135)	$ (120)	$ (1,036)	$ (5,164)	$ (797)	$ (1,754)
Investment Tax Credit (I.T.C.)	(528,360)	215,850	6,150	386	4,414	15,612	19,333	15,003	8,420	74	66	569	2,835	438	963
South Georgia Federal	290,114	(336,434)	(100,091)	139,993	772,395	1,876,404	6,862,524	1,478,989	741,753	(653)	(4,933)	65,237	(69,833)	70,391	173,464
Total Federal Income Tax	**$ 11,669,206**														
		0	0	0	0	0	0	0	0	0	0	0	0	0	0
Regulatory Amortization	$ -														
		31661492.46	734058.807	317701.22	2094656.87	5820005.04	15636496.39	4990834.342	2636924.64	9900.202851	693.198	206257.1438	294411.356	196182.185	466215.464
Net Income	**$ 65,065,829**														
		0.029783936	0.02507792	0.1537116	0.09569417	0.07045745	0.149738501	0.061587576	0.05798533	0.024670026	0.00195	0.067117357	0.01922458	0.08300023	0.08961482
Rate of Return on Rate Base	**4.47%**	**3.11%**	**2.56%**	**16.38%**	**12.28%**	**7.07%**	**13.96%**	**6.96%**	**4.91%**	**2.70%**	**1.51%**	**6.44%**	**2.09%**	**6.60%**	**6.97%**

Class Cost of Service Study – Proposed Rates Under Staff's Recommended Cost Allocation Factors

Description	Total Amount	Single-Family Residential	Multi-Family Residential	MMMHP	Small General	Medium General	Large-1 General	Transportation Eligible	Large-2 General	Air Conditioning	Street Lighting	Compression on Customer's Premises (CNG)	Electric Generation	Small Essential Agricultural	Natural Gas Engines
Rate Base															
Total Direct Net Plant	$ 1,809,908,655	$ 1,346,606,658	$ 38,369,221	$ 2,407,161	$ 27,536,194	$ 97,399,492	$ 120,612,420	$ 93,599,302	$ 52,526,767	$ 463,520	$ 411,011	$ 3,549,482	$ 17,688,579	$ 2,730,037	$ 6,008,811
Total Common Systems Allocable Net Plant	38,161,320	28,392,752	809,002	50,754	580,591	2,053,636	2,543,073	1,973,510	1,107,509	9,773	8,666	74,840	372,958	57,562	126,694
Cash Working Capital	(4,472,151)	(3,469,691)	(114,853)	(4,972)	(70,371)	(182,692)	(275,944)	(194,199)	(94,294)	(941)	(760)	(7,566)	(35,209)	(6,048)	(14,609)
Materials & Supplies	9,920,409	7,380,974	210,308	13,194	150,930	533,863	661,097	513,033	287,908	2,541	2,253	19,455	96,954	14,964	32,935
Prepayments	4,744,133	3,680,707	121,838	5,274	74,651	193,803	292,726	206,010	100,029	998	807	8,027	37,351	6,416	15,498
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Deposits	(62,033,165)	(57,743,519)	(2,217,488)	(9,657)	(1,095,747)	(966,753)	-	-	-	-	-	-	-	-	-
Customer Advances	(48,475,278)	(45,123,172)	(1,732,836)	(7,547)	(856,262)	(755,461)	-	-	-	-	-	-	-	-	-
Deferred Taxes	(291,236,457)	(216,685,494)	(6,174,077)	(387,342)	(4,430,911)	(15,672,770)	(19,408,015)	(15,061,273)	(8,452,200)	(74,586)	(66,137)	(571,155)	(2,846,309)	(439,296)	(966,891)
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Rate Base	$ 1,466,517,467	$ 1,063,039,215	$ 29,271,116	$ 2,066,866	$ 21,889,076	$ 82,603,117	$ 104,426,367	$ 81,036,382	$ 46,476,719	$ 401,306	$ 355,839	$ 3,073,082	$ 15,314,323	$ 2,363,634	$ 5,202,437
Margin															
Net Operating Margin	$ 465,217,053	$ 332,857,067	$ 9,361,994	$ 924,698	$ 8,464,941	$ 23,255,120	$ 46,928,513	$ 23,519,082	$ 12,545,302	$ 101,345	$ 65,845	$ 901,522	$ 3,678,693	$ 778,425	$ 1,834,507
Special Contract Margin	6,788,127	4,856,821	136,604	13,493	123,515	339,323	684,749	343,174	183,052	1,479	961	13,154	53,677	11,358	26,768
Other Revenue	12,096,356	10,449,547	869,413	2,377	145,178	248,108	275,318	49,393	26,882	472	3,536	1,277	4,792	6,177	13,884
Total Revenue	$ 484,101,536	$ 348,163,435	$ 10,368,011	$ 940,567	$ 8,733,634	$ 23,842,551	$ 47,888,579	$ 23,911,650	$ 12,766,237	$ 103,296	$ 70,341	$ 916,964	$ 3,737,163	$ 795,960	$ 1,875,159
Operating Expenses															
Operations & Maintenance Expenses	$ (136,804,420)	$ (106,138,894)	$ (3,513,395)	$ (152,082)	$ (2,152,954)	$ (5,568,601)	$ (8,441,211)	$ (5,940,617)	$ (2,884,487)	$ (28,774)	$ (23,263)	$ (231,457)	$ (1,077,064)	$ (185,015)	$ (446,895)
Incremental Uncollectible Expenses	(186,105)	(140,160)	(4,233)	(235)	(2,862)	(9,167)	(12,296)	(9,196)	(4,905)	(45)	(39)	(352)	(1,712)	(275)	(628)
Administrative & General Expenses	(65,125,496)	(50,527,229)	(1,672,545)	(72,399)	(1,024,772)	(2,960,444)	(4,018,423)	(2,828,020)	(1,373,155)	(13,698)	(11,074)	(110,185)	(512,735)	(88,076)	(212,743)
Depreciation Expenses	(99,586,591)	(74,094,328)	(2,111,189)	(132,449)	(1,515,124)	(5,359,212)	(6,636,456)	(5,150,114)	(2,890,180)	(25,504)	(22,615)	(195,303)	(973,279)	(150,215)	(330,623)
Interest on Customer Deposits	(2,908,517)	(2,707,390)	(103,970)	(453)	(51,376)	(45,328)	-	-	-	-	-	-	-	-	-
Taxes other than Income	(27,203,877)	(20,240,205)	(576,710)	(36,181)	(413,883)	(1,463,965)	(1,812,868)	(1,406,847)	(789,505)	(6,967)	(6,178)	(53,351)	(265,869)	(41,034)	(90,316)
Total Operating Deductions	$ (331,815,008)	$ (253,848,207)	$ (7,982,042)	$ (393,799)	$ (5,160,681)	$ (15,126,717)	$ (20,921,254)	$ (15,334,793)	$ (7,942,232)	$ (74,989)	$ (63,169)	$ (590,648)	$ (2,830,658)	$ (464,615)	$ (1,081,204)
State Income Tax															
Taxable Income before Interest Expense	$ 152,286,528	$ 94,315,228	$ 2,385,969	$ 546,768	$ 3,572,954	$ 8,715,834	$ 26,967,326	$ 8,576,856	$ 4,813,004	$ 28,307	$ 7,172	$ 325,306	$ 906,505	$ 331,345	$ 793,955
Interest Expenses	(42,713,744)	(31,779,842)	(905,511)	(56,809)	(649,853)	(2,298,623)	(2,846,446)	(2,208,938)	(1,239,629)	(10,939)	(9,700)	(83,768)	(417,449)	(64,429)	(141,808)
State Taxable Income	$ 109,572,784	$ 62,535,386	$ 1,480,457	$ 489,959	$ 2,923,101	$ 6,417,211	$ 24,120,879	$ 6,367,918	$ 3,573,375	$ 17,368	$ (2,527)	$ 241,538	$ 489,055	$ 266,916	$ 652,147
State Income Tax	$ 7,635,032	$ 4,357,466	$ 103,158	$ 34,140	$ 203,682	$ 447,151	$ 1,680,743	$ 443,717	$ 248,993	$ 1,210	$ (176)	$ 16,830	$ 34,077	$ 18,599	$ 45,442
South Georgia State	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total State Income Tax	$ 7,635,032	$ 4,357,466	$ 103,158	$ 34,140	$ 203,682	$ 447,151	$ 1,680,743	$ 443,717	$ 248,993	$ 1,210	$ (176)	$ 16,830	$ 34,077	$ 18,599	$ 45,442
Federal Income Tax															
Taxable Income before Interest Expense	$ 152,286,528	$ 94,315,228	$ 2,385,969	$ 546,768	$ 3,572,954	$ 8,715,834	$ 26,967,326	$ 8,576,856	$ 4,813,004	$ 28,307	$ 7,172	$ 325,306	$ 906,505	$ 331,345	$ 793,955
Interest Expenses	(42,713,744)	(31,779,842)	(905,511)	(56,809)	(649,853)	(2,298,623)	(2,846,446)	(2,208,938)	(1,239,629)	(10,939)	(9,700)	(83,768)	(417,449)	(64,429)	(141,808)
Federal Taxable Income	$ 109,572,784	$ 62,535,386	$ 1,480,457	$ 489,959	$ 2,923,101	$ 6,417,211	$ 24,120,879	$ 6,367,918	$ 3,573,375	$ 17,368	$ (2,527)	$ 241,538	$ 489,055	$ 266,916	$ 652,147
Federal Income Tax	$ 35,678,214	$ 20,362,272	$ 482,055	$ 159,537	$ 951,797	$ 2,089,521	$ 7,854,048	$ 2,073,471	$ 1,163,534	$ 5,655	$ (823)	$ 78,648	$ 159,242	$ 86,911	$ 212,347
Investment Tax Credit (I.T.C.)	(528,360)	(393,110)	(11,201)	(703)	(8,039)	(28,433)	(35,210)	(27,324)	(15,334)	(135)	(120)	(1,036)	(5,164)	(797)	(1,754)
South Georgia Federal	290,114	215,850	6,150	386	4,414	15,612	19,333	15,003	8,420	74	66	569	2,835	438	963
Total Federal Income Tax	$ 35,439,968	$ 20,185,012	$ 477,004	$ 159,220	$ 948,172	$ 2,076,700	$ 7,838,171	$ 2,061,150	$ 1,156,620	$ 5,594	$ (877)	$ 78,181	$ 156,914	$ 86,552	$ 211,556
Regulatory Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Income	$ 109,211,529	$ 69,772,750	$ 1,805,607	$ 353,408	$ 2,421,100	$ 6,191,963	$ 17,448,412	$ 6,071,990	$ 3,407,392	$ 21,502	$ 8,226	$ 230,295	$ 715,514	$ 226,194	$ 536,957
Rate of Return on Rate Base	7.60%	6.66%	6.17%	17.10%	11.06%	7.50%	16.71%	7.49%	7.49%	5.36%	2.31%	7.49%	4.67%	9.57%	10.32%

Source: AZ 2010 CCOSS and rate design.

Comparison of Class Rate of Returns Under Company's and Staff's CCOSS

	Company's Original CCOSS	Company's Proposed CCOSS	Staff's Recommended CCOSS
Single-Family Residential Gas Service	2.32%	5.77%	5.94%
Multi-Family Residential Gas Service	1.50%	5.09%	5.48%
Master Metered Mobile Home Park Gas Service	15.66%	17.40%	17.03%
Small General Gas Service	10.98%	12.69%	11.08%
Medium General Gas Service	8.16%	9.45%	8.09%
Large-1 General Gas Service	17.33%	19.26%	16.65%
Large-2 General Gas Service	7.64%	8.78%	7.02%
Transportation Eligible	12.37%	13.99%	7.02%
Air Conditioning Gas Service	16.08%	17.93%	4.95%
Street Lighting	1.78%	4.12%	1.94%
Gas Service for Compression on Customer's Premises	12.71%	14.26%	7.02%
Electric Cogeneration	8.87%	10.15%	4.30%
Small Essential Agriculture User Gas Service	10.36%	11.75%	9.59%
Natural Gas Engines	23.95%	23.84%	10.35%
Overall	4.47%	7.50%	7.02%

Source: Company's Class Cost of Service Study.

Class Cost of Service Study – Present Rates
Staff Recommended Revenue Requirement

Description	Total Amount	Single-Family Residential	Multi-Family Residential	MMMHP	Small General	Medium General	Large-1 General	Transportation Eligible	Large-2 General	Air Conditioning	Street Lighting	Compression Customer's Premises (CNG)	Electric Generation	Small Essential Agricultural	Natural Gas Engines
Rate Base															
Total Direct Net Plant	$ 1,809,572,803	$ 1,346,357,520	$ 38,362,434	$ 2,406,675	$ 27,531,432	$ 97,381,463	$ 120,588,399	$ 93,582,850	$ 52,516,333	$ 463,431	$ 410,926	$ 3,548,748	$ 17,685,225	$ 2,729,530	$ 6,007,837
Total Common Systems Allocable Net Plant	36,846,288	27,414,358	781,131	49,004	560,591	1,982,869	2,455,405	1,905,522	1,069,331	9,436	8,367	72,259	360,104	55,578	122,331
Cash Working Capital	(4,940,151)	(3,830,442)	(126,154)	(5,493)	(77,773)	(204,324)	(305,199)	(213,687)	(105,379)	(1,037)	(854)	(8,339)	(38,748)	(6,664)	(16,080)
Materials & Supplies	9,920,409	7,380,978	210,310	13,194	150,932	533,863	661,088	513,038	287,904	2,541	2,253	19,455	96,954	14,964	32,936
Prepayments	4,559,036	3,534,937	116,422	5,069	71,773	188,561	281,654	197,183	97,250	957	788	7,696	35,758	6,150	14,839
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Deposits	(62,033,165)	(57,743,519)	(2,217,488)	(9,657)	(1,095,747)	(966,753)	-	-	-	-	-	-	-	-	-
Customer Advances	(48,475,278)	(45,123,172)	(1,732,836)	(7,547)	(856,262)	(755,461)	-	-	-	-	-	-	-	-	-
Deferred Taxes	(292,517,552)	(217,638,773)	(6,201,290)	(389,039)	(4,450,458)	(15,741,719)	(19,493,122)	(15,127,673)	(8,489,268)	(74,914)	(66,426)	(573,655)	(2,858,818)	(441,229)	(971,167)
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Rate Base	$ 1,452,932,392	$ 1,060,351,888	$ 29,192,529	$ 2,062,206	$ 21,834,489	$ 82,418,499	$ 104,188,225	$ 80,857,253	$ 45,376,170	$ 400,415	$ 355,054	$ 3,066,163	$ 15,280,476	$ 2,358,330	$ 5,190,697
Margin															
Net Operating Margin	$ 389,982,496	$ 267,949,922	$ 7,472,016	$ 863,947	$ 7,908,814	$ 22,579,171	$ 43,845,416	$ 21,689,599	$ 11,254,459	$ 82,169	$ 53,386	$ 859,687	$ 2,982,640	$ 727,284	$ 1,713,984
Special Contract Margin	6,788,127	4,664,000	130,060	15,038	137,863	393,018	763,184	377,534	195,896	1,430	929	14,964	51,917	12,659	29,834
Other Revenue	12,096,356	10,448,939	869,321	2,383	145,227	248,246	275,586	49,525	26,951	472	3,536	1,283	4,810	6,181	13,895
Total Revenue	$ 408,866,979	$ 283,062,861	$ 8,471,399	$ 881,368	$ 8,191,703	$ 23,220,436	$ 44,884,185	$ 22,116,659	$ 11,477,306	$ 84,072	$ 57,852	$ 875,934	$ 3,039,367	$ 746,125	$ 1,757,713
Operating Expenses															
Operations & Maintenance Expenses	$ (136,838,555)	$ (106,100,435)	$ (3,494,376)	$ (152,146)	$ (2,154,245)	$ (5,659,619)	$ (8,453,780)	$ (5,918,414)	$ (2,918,927)	$ (28,719)	$ (23,646)	$ (230,968)	$ (1,073,281)	$ (184,588)	$ (445,391)
Administrative & General Expenses	(59,195,567)	(45,898,434)	(1,511,647)	(65,817)	(931,914)	(2,448,319)	(3,657,056)	(2,560,272)	(1,262,711)	(12,424)	(10,229)	(99,924)	(464,295)	(79,852)	(192,673)
Depreciation Expenses	(99,569,492)	(74,081,647)	(2,110,845)	(132,424)	(1,514,883)	(5,358,294)	(6,635,227)	(5,149,280)	(2,889,646)	(25,500)	(22,611)	(195,285)	(973,107)	(150,189)	(330,574)
Interest on Customer Deposits	(2,908,517)	(2,707,390)	(103,970)	(453)	(51,376)	(45,328)	-	-	-	-	-	-	-	-	-
Taxes other than Income	(27,065,517)	(20,137,274)	(573,781)	(35,996)	(411,784)	(1,456,520)	(1,603,623)	(1,399,705)	(785,479)	(6,931)	(6,146)	(53,078)	(264,515)	(40,825)	(89,858)
Total Operating Deductions	$ (325,577,647)	$ (248,925,180)	$ (7,794,619)	$ (386,837)	$ (5,064,201)	$ (14,968,080)	$ (20,549,686)	$ (15,027,671)	$ (7,856,763)	$ (73,574)	$ (62,632)	$ (579,255)	$ (2,775,199)	$ (455,454)	$(1,058,496)
Taxable Income															
Taxable Income before Interest Expense	$ 83,289,332	$ 34,137,681	$ 676,779	$ 494,531	$ 3,127,503	$ 8,252,356	$ 24,334,499	$ 7,088,988	$ 3,620,545	$ 10,497	$ (4,780)	$ 296,678	$ 264,168	$ 290,671	$ 699,217
Interest Expenses	(42,571,123)	(31,673,747)	(902,496)	(56,618)	(647,691)	(2,290,949)	(2,836,904)	(2,201,584)	(1,235,474)	(10,902)	(9,667)	(83,486)	(416,054)	(64,214)	(141,337)
Total Taxable Income	$ 40,718,209	$ 2,463,934	$ (225,717)	$ 437,913	$ 2,479,812	$ 5,961,407	$ 21,497,596	$ 4,887,403	$ 2,385,071	$ (405)	$ (14,448)	$ 213,192	$ (151,886)	$ 226,457	$ 557,679
State Income Tax															
State Income Tax	$ 2,830,038	$ 171,251	$ (15,688)	$ 30,436	$ 172,354	$ 414,336	$ 1,494,147	$ 339,689	$ 165,770	$ (28)	$ (1,004)	$ 14,817	$ (10,557)	$ 15,739	$ 38,774
South Georgia State	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total State Income Tax	$ 2,830,038	$ 171,251	$ (15,688)	$ 30,436	$ 172,354	$ 414,336	$ 1,494,147	$ 339,689	$ 165,770	$ (28)	$ (1,004)	$ 14,817	$ (10,557)	$ 15,739	$ 38,774
Federal Income Tax															
Federal Income Tax	$ 13,224,623	$ 800,246	$ (73,309)	$ 142,227	$ 805,403	$ 1,936,170	$ 6,982,075	$ 1,587,350	$ 774,633	$ (132)	$ (4,692)	$ 69,241	$ (49,330)	$ 73,550	$ 181,190
Investment Tax Credit (I.T.C.)	(528,360)	(393,110)	(11,201)	(703)	(8,039)	(28,433)	(35,209)	(27,324)	(15,334)	(135)	(120)	(1,036)	(5,164)	(797)	(1,754)
South Georgia Federal	290,114	215,850	6,150	386	4,414	15,612	19,333	15,003	8,420	74	66	569	2,835	438	963
Total Federal Income Tax	$ 12,986,377	$ 622,987	$ (78,360)	$ 141,910	$ 801,778	$ 1,923,349	$ 6,966,199	$ 1,575,029	$ 767,719	$ (193)	$ (4,746)	$ 68,774	$ (51,659)	$ 73,190	$ 180,399
Regulatory Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Income	$ 67,472,917	$ 33,343,444	$ 770,827	$ 322,184	$ 2,153,370	$ 5,914,672	$ 15,874,153	$ 5,174,269	$ 2,687,056	$ 10,718	$ 970	$ 213,087	$ 326,383	$ 201,741	$ 480,043
Rate of Return on Rate Base	4.64%	3.14%	2.64%	15.62%	9.86%	7.18%	15.24%	6.40%	5.92%	2.68%	0.27%	6.95%	2.14%	8.55%	9.25%

Class Cost of Service Study – Proposed Rates
Staff Recommended Revenue Requirement

Description	Total Amount	Single-Family Residential	Multi-Family Residential	MMMHP	Small General	Medium General	Large-1 General	Transportation Eligible	Large-2 General	Air Conditioning	Street Lighting	Compression on Customer's Premises (CNG)	Electric Generation	Small Essential Agricultural	Natural Gas Engines
Rate Base															
Total Direct Net Plant	$ 1,809,572,803	$ 1,346,357,520	$ 38,362,434	$ 2,406,675	$ 27,531,432	$ 97,381,463	$ 120,588,399	$ 93,582,850	$ 52,516,333	$ 483,431	$ 410,926	$ 3,548,748	$ 17,685,225	$ 2,729,530	$ 6,007,837
Total Common Systems Allocable Net Plant	36,846,288	27,414,358	781,131	49,004	560,591	1,982,869	2,455,405	1,905,522	1,069,331	9,436	8,367	72,259	360,104	55,578	122,331
Cash Working Capital	(4,940,151)	(3,830,442)	(126,154)	(5,493)	(77,773)	(204,324)	(305,199)	(213,667)	(105,379)	(1,037)	(854)	(8,339)	(38,748)	(6,664)	(16,080)
Materials & Supplies	9,920,409	7,380,978	210,310	13,194	150,932	533,863	661,088	513,038	287,904	2,541	2,253	19,455	96,954	14,964	32,936
Prepayments	4,559,036	3,534,937	116,422	5,069	71,773	188,561	281,654	197,183	97,250	957	788	7,896	35,758	6,150	14,839
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Customer Deposits	(62,033,165)	(57,743,519)	(2,217,488)	(9,657)	(1,095,747)	(966,753)	-	-	-	-	-	-	-	-	-
Customer Advances	(48,475,278)	(45,123,172)	(1,732,836)	(7,547)	(856,262)	(755,461)	-	-	-	-	-	-	-	-	-
Deferred Taxes	(292,517,552)	(217,638,773)	(6,201,290)	(389,039)	(4,450,458)	(15,741,719)	(19,493,122)	(15,127,673)	(8,489,268)	(74,914)	(66,426)	(573,655)	(2,858,818)	(441,229)	(971,167)
Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Rate Base	**$ 1,462,932,392**	**$ 1,060,351,888**	**$ 29,192,629**	**$ 2,062,206**	**$ 21,834,489**	**$ 62,416,499**	**$ 104,188,225**	**$ 80,857,253**	**$ 45,376,170**	**$ 400,416**	**$ 355,064**	**$ 3,066,163**	**$ 15,280,476**	**$ 2,358,330**	**$ 5,190,697**
Margin															
Net Operating Margin	$ 446,859,736	$ 316,799,076	$ 8,834,219	$ 912,916	$ 8,357,088	$ 23,858,966	$ 46,330,589	$ 22,548,996	$ 12,086,635	$ 97,149	$ 63,119	$ 864,948	$ 3,526,396	$ 768,507	$ 1,811,133
Special Contract Margin	6,788,127	4,812,410	134,198	13,868	126,950	362,435	703,796	342,536	183,605	1,476	959	13,139	53,569	11,674	27,512
Other Revenue	12,096,356	10,448,939	869,321	2,383	145,227	248,246	275,586	49,525	26,951	472	3,536	1,283	4,810	6,181	13,895
Total Revenue	**$ 466,744,219**	**$ 332,060,426**	**$ 9,837,739**	**$ 929,166**	**$ 8,629,265**	**$ 24,469,647**	**$ 47,309,970**	**$ 22,941,057**	**$ 12,297,191**	**$ 99,097**	**$ 67,614**	**$ 879,370**	**$ 3,584,775**	**$ 786,362**	**$ 1,852,540**
Operating Expenses															
Operations & Maintenance Expenses	$ (136,838,555)	$ (106,100,435)	$ (3,494,376)	$ (152,146)	$ (2,154,245)	$ (5,659,619)	$ (6,453,780)	$ (5,916,414)	$ (2,918,927)	$ (26,719)	$ (23,646)	$ (230,968)	$ (1,073,261)	$ (184,588)	$ (445,391)
Incremental Uncollectible Expenses	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Administrative & General Expenses	(59,195,567)	(45,898,434)	(1,511,647)	(65,817)	(931,914)	(2,448,319)	(3,657,056)	(2,560,272)	(1,262,711)	(12,424)	(10,229)	(99,924)	(464,295)	(79,852)	(192,673)
Depreciation Expenses	(99,569,492)	(74,081,647)	(2,110,845)	(132,424)	(1,514,683)	(5,358,294)	(6,635,227)	(5,149,280)	(2,889,648)	(25,500)	(22,611)	(195,285)	(973,107)	(150,189)	(330,574)
Interest on Customer Deposits	(2,908,517)	(2,707,390)	(103,970)	(453)	(51,378)	(45,328)	-	-	-	-	-	-	-	-	-
Taxes other than Income	(27,065,517)	(20,137,274)	(573,781)	(35,996)	(411,784)	(1,456,520)	(1,803,623)	(1,399,705)	(785,479)	(6,931)	(6,146)	(53,078)	(264,515)	(40,825)	(89,858)
Total Operating Deductions	**$ (326,677,647)**	**$ (248,925,180)**	**$ (7,794,619)**	**$ (386,837)**	**$ (5,064,201)**	**$ (14,968,080)**	**$ (20,549,686)**	**$ (15,027,671)**	**$ (7,856,763)**	**$ (73,574)**	**$ (62,632)**	**$ (579,256)**	**$ (2,776,199)**	**$ (455,454)**	**$ (1,058,496)**
State Income Tax															
Taxable Income before Interest Expense	$ 140,166,572	$ 83,135,246	$ 2,043,119	$ 542,329	$ 3,565,065	$ 9,501,568	$ 26,760,284	$ 7,913,386	$ 4,440,428	$ 25,523	$ 4,982	$ 300,114	$ 809,576	$ 330,908	$ 794,044
Interest Expenses	(42,571,123)	(31,673,747)	(902,496)	(56,618)	(647,691)	(2,290,949)	(2,836,904)	(2,201,584)	(1,235,474)	(10,902)	(9,667)	(83,486)	(416,054)	(64,214)	(141,337)
State Taxable Income	$ 97,595,449	$ 51,461,499	$ 1,140,623	$ 485,711	$ 2,917,374	$ 7,210,619	$ 23,923,380	$ 5,711,802	$ 3,204,954	$ 14,620	$ (4,685)	$ 216,628	$ 393,522	$ 266,695	$ 652,707
State Income Tax	$ 6,783,176	$ 3,576,729	$ 79,277	$ 33,758	$ 202,766	$ 501,160	$ 1,662,747	$ 396,987	$ 222,754	$ 1,016	$ (326)	$ 15,056	$ 27,351	$ 18,536	$ 45,365
South Georgia State	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total State Income Tax	$ 6,783,176	$ 3,576,729	$ 79,277	$ 33,758	$ 202,766	$ 501,160	$ 1,662,747	$ 396,987	$ 222,754	$ 1,016	$ (326)	$ 15,056	$ 27,351	$ 18,536	$ 45,365
Federal Income Tax															
Taxable Income before Interest Expense	$ 140,166,572	$ 83,135,246	$ 2,043,119	$ 542,329	$ 3,565,065	$ 9,501,568	$ 26,760,284	$ 7,913,386	$ 4,440,428	$ 25,523	$ 4,982	$ 300,114	$ 809,576	$ 330,908	$ 794,044
Interest Expenses	(42,571,123)	(31,673,747)	(902,496)	(56,618)	(647,691)	(2,290,949)	(2,836,904)	(2,201,584)	(1,235,474)	(10,902)	(9,667)	(83,486)	(416,054)	(64,214)	(141,337)
Federal Taxable Income	$ 97,595,449	$ 51,461,499	$ 1,140,623	$ 485,711	$ 2,917,374	$ 7,210,619	$ 23,923,380	$ 5,711,802	$ 3,204,954	$ 14,620	$ (4,685)	$ 216,628	$ 393,522	$ 266,695	$ 652,707
Federal Income Tax	$ 31,697,440	$ 16,713,871	$ 370,456	$ 157,751	$ 947,516	$ 2,341,894	$ 7,769,931	$ 1,855,102	$ 1,040,918	$ 4,748	$ (1,522)	$ 70,357	$ 127,810	$ 86,618	$ 211,989
Investment Tax Credit (I.T.C.)	(528,360)	(393,110)	(11,201)	(703)	(6,039)	(28,433)	(35,209)	(27,324)	(15,334)	(135)	(120)	(1,036)	(5,164)	(797)	(1,754)
South Georgia Federal	290,114	215,850	6,150	386	4,414	15,612	19,333	15,003	8,420	74	66	569	2,835	438	963
Total Federal Income Tax	$ 31,459,194	$ 16,536,612	$ 365,406	$ 157,434	$ 943,892	$ 2,329,073	$ 7,754,055	$ 1,842,781	$ 1,034,004	$ 4,687	$ (1,576)	$ 69,890	$ 125,481	$ 86,259	$ 211,196
Regulatory Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Net Income	**$ 101,924,201**	**$ 53,021,906**	**$ 1,698,437**	**$ 361,137**	**$ 2,418,407**	**$ 6,671,336**	**$ 17,343,483**	**$ 5,673,618**	**$ 3,183,670**	**$ 19,819**	**$ 6,883**	**$ 216,168**	**$ 656,744**	**$ 226,113**	**$ 637,481**
Rate of Return on Rate Base	7.02%	5.94%	5.48%	17.03%	11.08%	8.09%	16.66%	7.02%	7.02%	4.96%	1.94%	7.02%	4.30%	9.59%	10.36%

Source: AZ 2010 CCOSS and rate design.

Relationship of Customer Charges to Cost of Service

	Company's		Staff's	
	Proposed Customer Charge ($)	Cost of Service (%)	Proposed Customer Charge ($)	Cost of Service (%)
Single-Family Residential Gas Service	$10.70	35%	$10.70	36%
Multi-Family Residential Gas Service	$9.70	44%	$9.70	46%
Single-Family Low Income Residential Gas Service	$7.50	27%	$7.50	36%
Multi-Family Low Income Residential Gas Service	$7.50	33%	$7.50	42%
Special Residential Gas Service for Air Conditioning	$10.70	14%	$10.70	13%
Master Metered Mobile Home Park Gas Service	$66.00	13%	$66.00	13%
Small General Gas Service	$27.50	67%	$27.50	68%
Medium General Gas Service	$43.50	33%	$43.50	33%
Large-1 General Gas Service	$80.00	14%	$120.00	22%
Large-2 General Gas Service	$470.00	20%	$160.00	7%
Transportation Eligible	$950.00	9%	$950.00	10%
Air Conditioning Gas Service	$27.50 - $120	14%	$27.50 - $120	13%
Gas Service for Compression on Customer's Premises	$10.70 - $250	8%	$10.70 - $250	10%
Electric Cogeneration	$27.50 - $950	1%	$27.50 - $950	11%
Small Essential Agriculture User Gas Service	$120.00	9%	$120.00	9%
Natural Gas Engines	$125.00	14%	$125.00	14%

Source: Company's Class Cost of Service Study.

Survey of Customer Charges

State	Company	Customer Charge Residential ($/month)	Customer Charge Commercial ($/month)	State	Company	Customer Charge Residential ($/month)	Customer Charge Commercial ($/month)
AK	ENSTAR Natural Gas Company	$ 13.50	$ 29.00	HI	The Gas Company (Molokai)	$ 8.50	
AK	Fairbanks Natural Gas	$ 9.20	$ 17.25	HI	The Gas Company (Lanai)	$ 8.50	
AR	Centerpoint Energy	$ 9.75	$ 13.00	IA	Atmos Energy Corporation	$ 7.95	$ 13.00
AZ	Southwest Gas Corporation	$ 10.70	$ 27.50	ID	Avista Corporation	$ 4.00	$ 4.00
AZ	UniSource Energy Services	$ 10.00	$ 15.50	ID	Intermountain Gas Company	$ 6.50	$ 9.50
CA	Southern California Gas Company[1]	$ 5.00	$ 15.00	ID	Questar Gas Company	$ 5.00	$ 21.00
CA	Pacific Gas and Electric Company [1,2]	$ 3.00	$ 8.23	IL	Nicor Gas	$ 13.55	$ 20.80
CA	San Diego Gas and Electric Company	$ -	$ 10.00	IL	Atmos Energy Corporation	$ 9.90	$ 25.00
CA	Southwest Gas Corporation (Southern)	$ 5.00	$ 11.00	IL	Peoples Gas Light and Coke Company[3]	$ 19.50	$ 24.80
CA	Southwest Gas Corporation (Northern)	$ 5.00	$ 11.00	IN	Northern Indiana Public Service Co	$ 11.00	$ 30.00
CO	Atmos Energy Corporation	$ 10.00	$ 24.00	KS	Atmos Energy Corporation	$ 15.50	$ 37.00
CO	Black Hills Energy	$ 10.00	$ 15.00	KS	Kansas Gas Service Company	$ 12.25	$ 23.35
CO	Eastern Colorado Utility Company	$ 8.50	$ 10.00	KY	Atmos Energy Corporation	$ 12.50	$ 30.00
CO	Colorado Natural Gas	$ 10.00	$ 20.00	LA	Atmos Energy Corporation	$ 13.20	$ 21.98
CO	Public Service Co of Colorado	$ 10.00	$ 20.00	MA	Boston Gas (National Grid)	$ 10.00	$ 21.00
CO	SourceGas Distribution (Area 2)	$ 10.00	$ 20.00	MA	Essex (National Grid)	$ 10.00	$ 21.00
CO	SourceGas Distribution (Area 1)	$ 11.00	$ 22.00	MA	NSTAR Gas Company	$ 6.50	$ 15.00
CO	Westpac Utilities	$ 6.50	$ 16.00	MA	Colonial Gas Co (National Grid)	$ 8.00	$ 11.00
CT	Southern Connecticut Gas Co	$ 13.00	$ 30.00	MA	Berkshire Gas Company	$ 11.39	$ 12.48
CT	Yankee Gas Service Co	$ 13.50	$ 42.00	MA	Northern Utilities	$ 8.50	$ 24.00
CT	Connecticut Natural Gas Co	$ 13.00	$ 38.00	ME	Maine Natural Gas	$ 22.13	$ 31.61
GA	Atmos Energy Corporation	$ 12.30	$ 19.25	ME	Bangor Gas Company	$ 13.10	$ 14.65
GA	Atlanta Gas Light	$ 11.00	$ 20.00	ME	Northern Utilities	$ 4.96	$ 10.47
HI	The Gas Company (Oahu)	$ 8.50	$ 12.50	MI	Consumers Energy Company	$ 10.50	$ 11.65
HI	The Gas Company (South Hilo)	$ 8.50	$ 12.50	MI	Michigan Consolidated Gas (DTE Energy)	$ 10.50	$ 25.00
HI	The Gas Company (North Kona)	$ 8.50	$ 12.50	MO	Atmos Energy Corporation (Northeast)	$ 22.68	$ 22.68
HI	The Gas Company (Maui)	$ 8.50	$ 12.50	MO	Atmos Energy Corporation (Southeast)	$ 13.75	$ 13.75
HI	The Gas Company (Kauai)	$ 8.50	$ 12.50	MO	Atmos Energy Corporation (West)	$ 20.17	$ 20.17

Note: If a company has customer charges that differ by season, the higher charge was chosen for this table.
1 These companies have daily customer charges. The daily charge was multiplied by 365/12 to calculate the monthly customer charge.
2 Pacific Gas and Electric's commercial customer charge varies with usage.
3 The Peoples Gas Light and Coke Company customer charge is based on meter class. The customer charge for the first meter class is shown.
4 The customer charge for New York gas utilities is volumetric after a certain usage amount (usually 3-4 Ccf).
5 The Inside City Limits rate is shown.

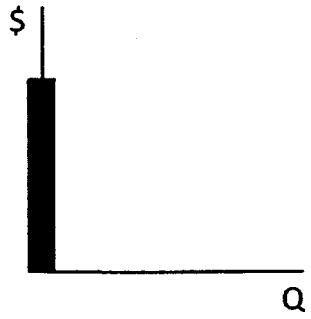
Survey of Customer Charges

State	Company	Customer Charge Residential ($/month)	Customer Charge Commercial ($/month)	State	Company	Customer Charge Residential ($/month)	Customer Charge Commercial ($/month)
MS	Atmos Energy Corporation	$ 6.95	$ 11.27	TN	Atmos Energy Corporation	$ 13.75	$ 31.15
MT	Energy West Montana	$ 6.75	$ 17.00	TN	Piedmont Natural Gas	$ 13.00	$ 29.00
MT	Montana-Dakota Utilities Co	$ 6.35	$ 10.40	TX	Atmos Energy Corporation (West TX - Inside City Limits)	$ 7.50	$ 14.50
MT	NorthWestern Energy	$ 6.90	$ 17.10	TX	Atmos Energy Corporation (West TX - Outside City Limits)	$ 8.50	$ 14.50
NC	Piedmont Natural Gas	$ 10.00	$ 22.00	TX	Atmos Energy Corporation (Amarillo - Inside City Limits)	$ 8.21	$ 15.52
NH	Northern Utilities	$ 9.50	$ 18.70	TX	Atmos Energy Corporation (Amarillo - Outside City Limits)	$ 9.50	$ 15.00
NH	EnergyNorth Natural Gas (National Grid)	$ 17.16	$ 40.37	TX	Atmos Energy Corporation (Lubbock - Inside City Limits)	$ 7.65	$ 14.90
NJ	Public Service Electric and Gas Co	$ 5.46	$ 9.80	TX	Atmos Energy Corporation (Lubbock - Outside City Limits)	$ 8.74	$ 12.26
NJ	New Jersey Natural Gas	$ 8.25	$ 25.00	TX	Atmos Energy Corporation (Fritch-Sanford)	$ 3.20	$ 3.20
NJ	South Jersey Gas Company	$ 8.92	$ 23.81	TX	Atmos Energy Corporation (Dalhart-Channing)	$ 4.30	$ 4.30
NM	New Mexico Gas Company	$ 9.59	$ 16.50	TX	Atmos Energy Corporation (Mid TX) - Dallas & Unincorporated	$ 16.00	$ 30.00
NM	Zia Natural Gas Company	$ 10.96	$ 15.15	TX	Atmos Energy Corporation (Mid TX) - All Other Cities	$ 7.00	$ 13.50
NV	Southwest Gas Corporation (Southern)	$ 9.00	$ 21.50	UT	Questar Gas Company	$ 5.00	$ 21.00
NV	Southwest Gas Corporation (Northern)	$ 9.00	$ 24.00	VA	Atmos Energy Corporation	$ 9.00	$ 20.00
NY	Consolidated Edison New York Inc[4]	$ 16.80	$ 23.10	VT	Vermont Gas Systems[1]	$ 18.67	$ 30.95
NY	Niagara Mohawk[4]	$ 17.85	$ 23.65	WA	Avista Corporation	$ 6.00	$ 6.00
NY	National Fuel Gas Distribution[4]	$ 15.54	$ 17.86	WA	Cascade Natural Gas Corporation	$ 4.00	$ 10.00
NY	Rochester Gas and Electric[4]	$ 16.30	$ 16.30	WA	Northwest Natural Gas Company	$ 3.47	$ 3.47
NY	Orange & Rockland[4]	$ 16.94	$ 27.31	WA	Puget Sound Energy	$ 10.00	$ 32.32
NY	Central Hudson Gas & Electric[4]	$ 19.00	$ 35.00	WI	Wisconsin Gas Company[1]	$ 9.43	$ 9.43
OH	Columbia Gas of Ohio (NiSource)	$ 17.81	$ 17.81	WY	Cheyenne Light Fuel and Power Company	$ 15.00	$ 20.00
OH	East Ohio Gas Company (Dominion)	$ 17.58	$ 20.00	WY	Energy West Wyoming	$ 11.00	$ 11.00
OK	Oklahoma Natural Gas Co (Rate Choice A)	$ 11.20	$ 18.75	WY	Wyoming Gas Company	$ 15.00	$ 20.00
OK	Oklahoma Natural Gas Co (Rate Choice B)	$ 26.75	$ 33.95	WY	MGTC Inc	$ 5.00	$ 5.00
OR	Avista Corporation	$ 7.00	$ 9.00	WY	Montana-Dakota Utilities Co[1]	$ 12.17	$ 27.38
OR	Cascade Natural Gas Corporation	$ 3.00	$ 3.00	WY	Questar Gas Company	$ 10.00	$ 44.00
OR	Northwest Natural Gas Company	$ 6.00	$ 8.00	WY	Wyoming Industrial Gas Company	$ 5.00	$ 5.00
SC	Piedmont Natural Gas	$ 10.00	$ 22.00				

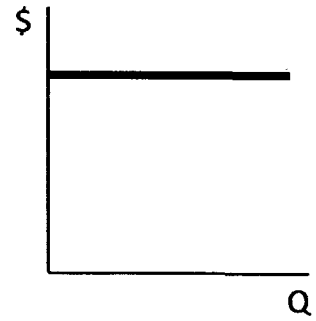
Source: Tariffs.
Note: If a company has customer charges that differ by season, the higher charge was chosen for this table.
1 These companies have daily customer charges. The daily charge was multiplied by 365/12 to calculate the monthly customer charge.
2 Pacific Gas and Electric's commercial customer charge varies with usage.
3 The Peoples Gas Light and Coke Company customer charge is based on meter class. The customer charge for the first meter class is shown.
4 The customer charge for New York gas utilities is volumetric after a certain usage amount (usually 3-4 Ccf).
5 The Inside City Limits rate is shown.

Rate Design Structures

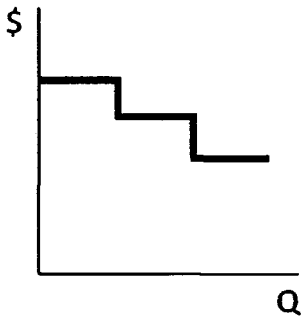
flat rate per period, no usage charge



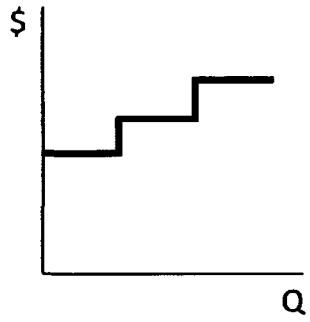
uniform: flat rate per unit



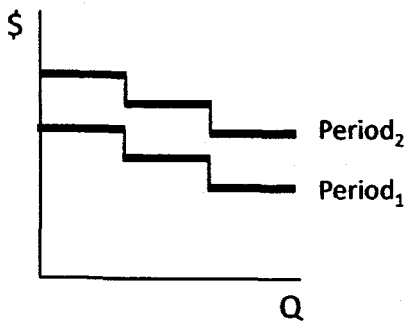
declining block



inverted block



seasonal or time-of-use



Source: Costello, Ken. *Revenue Decoupling: Supplemental* Information. The National Regulatory Research Institute. Prepared for The Basics: Practical Skills for the Changing Electric, Natural Gas and Water Industries, sponsored by the Center for Public Utilities, New Mexico State University, October 18, 2007.

Survey of Volumetric Charges

State	Company	Units	Residential First Tier	Commercial First Tier
Uniform Rate Structure				
AK	ENSTAR Natural Gas Company	Ccf	$ 0.09780	$ 0.09660
AK	Fairbanks Natural Gas	Ccf	$ 2.33500	$ 2.29100
AZ	Southwest Gas Corp	Therm	$ 0.57070	$ 0.57059
AZ	UniSource Energy Services	Therm	$ 0.32700	$ 0.28060
CO	Atmos Energy Corp	Ccf	$ 0.14385	$ 0.11242
CO	Black Hills Energy	Therm	$ 0.14109	$ 0.14109
CO	Eastern Colorado Utility Company	Ccf	$ 0.15800	$ 0.15800
CO	Colorado Natural Gas	Therm	$ 0.59500	$ 0.59500
CO	Public Service Co of Colorado	Therm	$ 0.09418	$ 0.13111
CO	Source Gas Distribution (Area 2)	Therm	$ 0.20700	$ 0.14240
CO	Source Gas Distribution (Area 1)	Therm	$ 0.22820	$ 0.18690
CO	Westpac Utilities	Therm	$ 0.21523	$ 0.16746
GA	Atmos Energy Corp	Ccf	$ 0.25920	$ 0.15950
HI	The Gas Company (Oahu)	Therm	$ 2.20530	$ 2.79562
HI	The Gas Company (South Hilo)	Therm	$ 2.60420	$ 2.53431
HI	The Gas Company (North Kona)	Therm	$ 2.60420	$ 2.45880
HI	The Gas Company (Maui)	Therm	$ 1.82550	$ 1.58550
HI	The Gas Company (Kauai)	Therm	$ 2.23100	$ 1.58550
HI	The Gas Company (Molokai)	Therm	$ 2.23630	
HI	The Gas Company (Lanai)	Therm	$ 2.76650	
ID	Avista Corporation	Therm	$ 0.37515	$ 0.37515
IL	Atmos Energy Corp	Ccf	$ 0.20150	$ 0.16080
IN	Northern Indiana Public Service Co	Therm	$ 0.11282	$ 0.10006
KS	Atmos Energy Corp	Ccf	$ 0.12953	$ 0.12953
KS	Kansas Gas Service Co	Mcf	$ 2.12300	$ 1.97460
LA	Atmos Energy Corp	Ccf	$ 0.25300	$ 0.40319
MA	Northern Utilities	Therm	$ 0.47700	$ 0.37940
ME	Bangor Gas Co	Therm	$ 0.36100	$ 0.27900
MI	Consumers Energy Co	Mcf	$ 2.42890	$ 2.14540
MI	Michigan Cons. Gas (DTE Energy)	Ccf	$ 0.23184	$ 0.24102
MO	Atmos Energy Corporation (Northeast)	Ccf	$ 0.11546	$ 0.05778
MO	Atmos Energy Corporation (Southeast)	Ccf	$ 0.08735	$ 0.04536
MO	Atmos Energy Corporation (West)	Ccf	$ 0.10682	$ 0.05944
MS	Atmos Energy Corp	Mcf	$ 1.32050	$ 1.72290
MT	Montana-Dakota Utilities Co	Dth	$ 1.12600	$ 1.35300
Uniform Rate Structure				
MT	NorthWestern Energy	Dth	$ 1.85727	$ 1.83622
NC	Piedmont Natural Gas	Therm	$ 0.97929	$ 0.87830
NJ	New Jersey Natural Gas	Therm	$ 0.50110	$ 0.46230
NJ	Public Service Electric and Gas Co	Therm	$ 0.29053	$ 0.25205
NJ	South Jersey Gas Co	Therm	$ 0.55460	$ 0.46660
NM	New Mexico Gas Company	Therm	$ 0.16460	$ 0.06480
NM	Zia Natural Gas Company	Ccf	$ 0.24360	$ 0.24360
NV	Southwest Gas Corp (Southern)	Therm	$ 0.30968	$ 0.34714
NV	Southwest Gas Corp (Northern)	Therm	$ 0.34917	$ 0.42050
OK	Oklahoma Nat. Gas Co (Rate Choice A)	Dth	$ 3.73230	$ 4.55990
OR	Avista Corporation	Therm	$ 0.40865	$ 0.32551
OR	Cascade Natural Gas Corporation	Therm	$ 0.34691	$ 0.24035
OR	Northwest Natural Gas Company	Therm	$ 0.41346	$ 0.33497
SC	Piedmont Natural Gas	Therm	$ 1.08094	$ 0.98045
TN	Atmos Energy Corp	Ccf	$ 0.13470	$ 0.20730
TN	Piedmont Natural Gas	Therm	$ 0.85919	$ 0.89397
TX	Atmos Energy Corp (West TX - Inside City Limits)	Ccf	$ 0.27514	$ 0.18484
TX	Atmos Energy Corp (Mid TX) - Dallas	Mcf	$ 0.43150	$ 0.57480
TX	Atmos Energy Corp (Mid TX) - All Other Cities	Mcf	$ 2.27070	$ 0.98770
TX	Atmos Energy Corporation (West TX - Outside City Limits)	Ccf	$ 0.11035	$ 0.18484
TX	Atmos Energy Corporation (Amarillo - Inside City Limits)	Ccf	$ 0.12862	$ 0.12617
TX	Atmos Energy Corporation (Amarillo - Outside City Limits)	Ccf	$ 0.07425	$ 0.09100
TX	Atmos Energy Corporation (Lubbock - Inside City Limits)	Ccf	$ 0.17429	$ 0.13159
TX	Atmos Energy Corporation (Lubbock - Outside City Limits)	Ccf	$ 0.09668	$ 0.09500
VA	Atmos Energy Corp	Ccf	$ 0.18850	$ 0.14370
VT	Vermont Gas Systems	Ccf	$ 0.48050	$ 0.33110
WA	Avista Corporation	Therm	$ 0.89276	$ 0.89276
WA	Cascade Natural Gas Corporation	Therm	$ 0.26248	$ 0.23179
WA	Northwest Natural Gas Company	Therm	$ 0.68290	$ 0.68279
WA	Puget Sound Energy	Therm	$ 0.37372	$ 0.31527
WI	Wisconsin Gas Co	Therm	$ 0.20910	$ 0.20910
WY	Cheyenne Light Fuel and Power Company	Dth	$ 1.85190	$ 1.72270
WY	MGTC Inc	Mcf	$ 1.94350	$ 1.94350
WY	Montana-Dakota Utilities Co	Dth	$ 0.63300	$ 0.58300
WY	Wyoming Gas Company	Ccf	$ 0.23404	$ 0.24457

Survey of Volumetric Charges

State	Company	Units	Residential First Tier	Residential Second Tier	Commercial First Tier	Commercial Second Tier
Declining Block Rate						
AR	Centerpoint Energy	Ccf	$0.34655	$0.16664	$0.15177	$0.11479
CT	Southern Connecticut Gas Co	Ccf	$0.94890	$0.34740	$0.73730	$0.19100
CT	Yankee Gas Service Co	Ccf	$0.75230	$0.49740	$0.48960	$0.27700
CT	Connecticut Natural Gas Co	Ccf	$0.88960	$0.30690	$0.67200	$0.24220
IA	Atmos Energy Corp	Therm	$0.29110	$0.17170	$0.25400	$0.13200
ID	Questar Gas Co	Dth	$2.22938	$0.92557	$2.22938	$0.92557
IL	Peoples Gas Light and Coke Co	Therm	$0.33372	$0.12360	$0.30615	$0.13084
KY	Atmos Energy Corp	Mcf	$1.10000	$0.77000	$1.10000	$0.77000
MA	Berkshire Gas Co	Therm	$0.61540	$0.32570	$0.64100	$0.37540
ME	Maine Natural Gas	Therm	$0.35600	$0.31700	$0.35600	$0.31700
ME	Northern Utilities	Ccf	$0.40260	$0.22780	$0.33850	$0.22550
MT	Energy West Montana	Ccf	$0.13500	$0.01782	$0.19850	$0.06840
NH	Northern Utilities	Therm	$0.41020	$0.29900	$0.30180	$0.19690
NH	EnergyNorth Nat. Gas (National Grid)	Therm	$0.27140	$0.22430	$0.32220	$0.20950
NY	Central Hudson Gas & Electric	Ccf	$0.84390	$0.39440	$0.55720	$0.27040
NY	National Fuel Gas Distribution	Mcf	$3.72554	$1.00813	$2.51345	$1.94282
NY	Niagara Mohawk	Therm	$0.41890	$0.06385	$0.31452	$0.18296
NY	Rochester Gas and Electric	Therm	$0.16675	$0.15549	$0.16675	$0.15549
NY	Orange & Rockland	Ccf	$0.43029	$0.41413	$0.34432	$0.33059
TX	Atmos Energy Corporation (Fritch-Sanford)	Ccf	$0.11069	$0.10354	$0.11069	$0.10354
TX	Atmos Energy Corporation (Dalhart-Channing)	Ccf	$0.11866	$0.09354	$0.11866	$0.09354
UT	Questar Gas Co	Dth	$2.22938	$0.92557	$2.22938	$0.92557
WY	Questar Gas Co	Dth	$2.00841	$1.26955	$2.00841	$1.26955
WY	Wyoming Industrial Gas Company	Therm	$0.30583	$0.24536	$0.30583	$0.24536
WY	Energy West Wyoming	Mcf	$2.20000	$2.16000	$2.20000	$2.16000

State	Company	Units	Residential First Tier	Residential Second Tier	Commercial First Tier	Commercial Second Tier
Inclining Block Rate						
MA	Boston Gas (National Grid)	Therm	$0.40870	$0.49270	$0.40650	$0.50050
MA	Essex (National Grid)	Therm	$0.40870	$0.49270	$0.24420	$0.30040
MA	Colonial Gas (National Grid)	Therm	$0.34980	$0.41670	$0.29890	$0.36370
Combination of Declining Block Rate / Inclining Block Rate						
CA	Pacific Gas and Electric Co	Therm	$0.44369	$0.70990	$0.35980	$0.11058
CA	San Diego Gas and Electric Company	Therm	$0.63422	$0.78984	$0.31346	$0.17462
CA	Southern California Gas Co	Therm	$0.33482	$0.58482	$0.52624	$0.26583
CA	Southwest Gas Corp (Northern)	Therm	$0.56131	$0.67202	$0.44975	$0.35375
CA	Southwest Gas Corp (Southern)	Therm	$0.53672	$0.69836	$0.47043	$0.36693
OH	East Ohio Gas Co (Dominion)[1]	Mcf	$1.42210	$1.42210	$1.80010	$2.62010
Combination of Uniform Rate / Declining Block Rate						
IL	Nicor Gas	Therm	$0.04850		$0.12010	$0.05490
MA	NSTAR Gas Co	Therm	$0.68710	$0.42580	$0.25290	
NY	Consolidated Edison New York Inc	Therm	$0.78590		$0.64340	$0.45200
Combination of Uniform Rate / Inclining Block Rate						
ID	Intermountain Gas Company	Therm	$0.41494		$0.36221	$0.39133

Source: Tariffs.
Note:
1 This is actually a declining rate. Tier 3 is $1.3505/Mcf, and Tier 4 is $1.3039/Mcf.

Summary of Present and Proposed Rates

Company's Present Rates			Company's Proposed Rates			Difference from Present Rates	Staff's Recommended Rates			Difference from Present Rates
Description	Sch.	Rate	Description	Sch.	Rate		Description	Sch.	Rate	
Single-Family Residential Gas Service	G-5		**Single-Family Residential Gas Service**	G-5			**Single-Family Residential Gas Service**	G-5		
Basic Service Charge per Month		$ 10.70	Basic Service Charge per Month		$ 10.70	0%	Basic Service Charge per Month		$ 10.70	0.0%
Delivery Charge per Therm			Delivery Charge per Therm				Delivery Charge per Therm			
All Usage		$ 0.57070	All Usage		$ 0.80176	40%	All Usage		$ 0.74651	30.8%
Multi-Family Residential Gas Service	G-6		**Multi-Family Residential Gas Service**	G-6			**Multi-Family Residential Gas Service**	G-6		
Basic Service Charge per Month		$ 9.70	Basic Service Charge per Month		$ 9.70	0%	Basic Service Charge per Month		$ 9.70	0.0%
Delivery Charge per Therm			Delivery Charge per Therm				Delivery Charge per Therm			
All Usage		$ 0.55343	All Usage		$ 0.80176	45%	All Usage		$ 0.74651	34.9%
Single-Family Low Income Residential Gas Service	G-10		**Single-Family Low Income Residential Gas Service**	G-10			**Single-Family Low Income Residential Gas Service**	G-10		
Basic Service Charge per Month		$ 7.50	Basic Service Charge per Month		$ 7.50	0%	Basic Service Charge per Month		$ 7.50	0.0%
Delivery Charge per Therm			Delivery Charge per Therm				Delivery Charge per Therm			
Summer (May - October)			Summer (May - October)				Summer (May - October)			
All Usage		$ 0.55343	All Usage		$ 0.80176	45%	All Usage		$ 0.74241	34.1%
Winter (November - April)			Winter (November - April)				Winter (November - April)			
First 150 Therms		$ 0.31624	All Usage		$ 0.51491	63%	First 150 Therms		$ 0.46743	47.8%
Over 150 Therms		$ 0.55343					Over 150 Therms		$ 0.74241	34.1%
Multi-Family Low Income Residential Gas Service	G-11		**Multi-Family Low Income Residential Gas Service**	G-11			**Multi-Family Low Income Residential Gas Service**	G-11		
Basic Service Charge per Month		$ 7.50	Basic Service Charge per Month		$ 7.50	0%	Basic Service Charge per Month		$ 7.50	0.0%
Delivery Charge per Therm			Delivery Charge per Therm				Delivery Charge per Therm			
Summer (May - October)			Summer (May - October)				Summer (May - October)			
All Usage		$ 0.55343	All Usage		$ 0.80176	45%	All Usage		$ 0.74241	34.1%
Winter (November - April)			Winter (November - April)				Winter (November - April)			
First 150 Therms		$ 0.31624	All Usage		$ 0.51491	63%	First 150 Therms		$ 0.46743	47.8%
Over 150 Therms		$ 0.55343					Over 150 Therms		$ 0.74241	34.1%

Summary of Present and Proposed Rates

Company's Present Rates			Company's Proposed Rates			Difference from Present Rates	Staff's Recommended Rates			Difference from Present Rates
Description	Sch.	Rate	Description	Sch.	Rate		Description	Sch.	Rate	
Special Residential Gas Service for Air Conditioning	G-15		**Special Residential Gas Service for Air Conditioning**	G-15			**Special Residential Gas Service for Air Conditioning**	G-15		
Basic Service Charge per Month		$ 10.70	Basic Service Charge per Month		$ 10.70	0%	Basic Service Charge per Month		$ 10.70	0.0%
Delivery Charge per Therm			Delivery Charge per Therm				Delivery Charge per Therm			
Summer (May - October)			Summer (May - October)				Summer (May - October)			
First 15 Therms		$ 0.57070	First 15 Therms		$ 0.80176	40%	First 15 Therms		$ 0.74651	30.8%
Over 15 Therms		$ 0.28860	Over 15 Therms		$ 0.12297	-57%	Over 15 Therms		$ 0.45241	56.8%
Winter (November - April)			Winter (November - April)				Winter (November - April)			
All Usage		$ 0.57070	All Usage		$ 0.80176	40%	All Usage		$ 0.74651	30.8%
Master Metered Mobile Home Park Gas Service	G-20		**Master Metered Mobile Home Park Gas Service**	G-20			**Master Metered Mobile Home Park Gas Service**	G-20		
Basic Service Charge per Month		$ 66.00	Basic Service Charge per Month		$ 66.00	0%	Basic Service Charge per Month		$ 66.00	0.0%
Delivery Charge per Therm			Delivery Charge per Therm				Delivery Charge per Therm			
All Usage		$ 0.40830	All Usage		$ 0.44370	9%	All Usage		$ 0.43926	7.6%
General Gas Service	G-25		**General Gas Service**	G-25			**General Gas Service**	G-25		
Basic Service Charge per Month			Basic Service Charge per Month				Basic Service Charge per Month			
Small		$ 27.50	Small		$ 27.50	0%	Small		$ 27.50	0.0%
Medium		$ 43.50	Medium		$ 43.50	0%	Medium		$ 43.50	0.0%
Large		$ 160.00	Large-1		$ 80.00	-50%	Large-1		$ 120.00	-25.0%
			Large-2		$ 470.00	194%	Large-2		$ 240.00	50.0%
Transportation Eligible		$ 950.00	Transportation Eligible		$ 950.00	0%	Transportation Eligible		$ 950.00	0.0%
Delivery Charge per Therm			Delivery Charge per Therm				Delivery Charge per Therm			
Small, All Usage		$ 0.57059	Small, All Usage		$ 0.72007	26%	Small, All Usage		$ 0.68813	20.6%
Medium, All Usage		$ 0.37996	Medium, All Usage		$ 0.42359	11%	Medium, All Usage		$ 0.41717	9.8%
Large, All Usage		$ 0.29084	Large-1, All Usage		$ 0.38756	33%	Large-1, All Usage		$ 0.35145	20.8%
			Large-2, All Usage		$ 0.26969	-7%	Large-2, All Usage		$ 0.30668	5.4%
Transportation Eligible		$ 0.10776	Transportation Eligible		$ 0.10350	-4%	Transportation Eligible		$ 0.10422	-3.3%
Demand Charge			Demand Charge				Demand Charge			
Transportation Eligible		$ 0.06234	Transportation Eligible		$ 0.07729	24%	Transportation Eligible		$ 0.07424	19.1%

Summary of Present and Proposed Rates

Company's Present Rates			Company's Proposed Rates			Difference from Present Rates	Staff's Recommended Rates			Difference from Present Rates
Description	Sch.	Rate	Description	Sch.	Rate		Description	Sch.	Rate	
Optional Gas Service	G-30		**Optional Gas Service**	G-30			**Optional Gas Service**	G-30		
Basic Service Charge per Month	As Specified on A.C.C. Sheet No. 27.		Basic Service Charge per Month	As Specified on A.C.C. Sheet No. 27.			Basic Service Charge per Month	As Specified on A.C.C. Sheet No. 27.		
Delivery Charge per Therm			Delivery Charge per Therm				Delivery Charge per Therm			
All Usage	As Specified on A.C.C. Sheet No. 28.		All Usage	As Specified on A.C.C. Sheet No. 28.			All Usage	As Specified on A.C.C. Sheet No. 28.		
Air Conditioning Gas Service	G-40		**Air Conditioning Gas Service**	G-40			**Air Conditioning Gas Service**	G-40		
Basic Service Charge per Month	As Specified on A.C.C. Sheet No. 32.		Basic Service Charge per Month	As Specified on A.C.C. Sheet No. 32.			Basic Service Charge per Month	As Specified on A.C.C. Sheet No. 32.		
Delivery Charge per Therm			Delivery Charge per Therm				Delivery Charge per Therm			
All Usage		$ 0.11010	All Usage		$ 0.12297	12%	All Usage		$ 0.13965	26.8%
Street Lighting Gas Service	G-45		**Street Lighting Gas Service**	G-45			**Street Lighting Gas Service**	G-45		
Delivery Charge per Therm of Rated Capacity			Delivery Charge per Therm of Rated Capacity				Delivery Charge per Therm of Rated Capacity			
All Usage		$ 0.61050	All Usage		$ 0.75297	23%	All Usage		$ 0.72590	18.9%
Gas Service for Compression on Customer's Premises	G-55		**Gas Service for Compression on Customer's Premises**	G-55			**Gas Service for Compression on Customer's Premises**	G-55		
Basic Service Charge per Month			Basic Service Charge per Month				Basic Service Charge per Month			
Small		$ 27.50	Small		$ 27.50	0%	Small		$ 27.50	0.0%
Large		$ 250.00	Large		$ 250.00	0%	Large		$ 250.00	0.0%
Residential		$ 10.70	Residential		$ 10.70	0%	Residential		$ 10.70	0.0%
Delivery Charge per Therm			Delivery Charge per Therm				Delivery Charge per Therm			
All Usage		$ 0.18678	All Usage		$ 0.20232	8%	All Usage		$ 0.19215	2.9%
Electric Generation Gas Service	G-60		**Electric Generation Gas Service**	G-60			**Electric Generation Gas Service**	G-60		
Basic Service Charge per Month	As Specified on A.C.C. Sheet No. 40.		Basic Service Charge per Month	As Specified on A.C.C. Sheet No. 40.			Basic Service Charge per Month	As Specified on A.C.C. Sheet No. 40.		
Delivery Charge per Therm			Delivery Charge per Therm				Delivery Charge per Therm			
All Usage		$ 0.13535	All Usage		$ 0.14591	8%	All Usage		$ 0.16496	21.9%

Summary of Present and Proposed Rates

Company's Present Rates			Company's Proposed Rates			Difference from Present Rates	Staff's Recommended Rates			Difference from Present Rates
Description	Sch.	Rate	Description	Sch.	Rate		Description	Sch.	Rate	
Small Essential Agriculture User Gas Service	G-75		**Small Essential Agriculture User Gas Service**	G-75			**Small Essential Agriculture User Gas Service**	G-75		
Basic Service Charge per Month		$ 120.00	Basic Service Charge per Month		$ 120.00	0%	Basic Service Charge per Month		$ 120.00	0.0%
Delivery Charge per Therm			Delivery Charge per Therm				Delivery Charge per Therm			
All Usage		$ 0.24396	All Usage		$ 0.26423	8%	All Usage		$ 0.26344	8.0%
Natural Gas Engine Gas Service	G-80		**Natural Gas Engine Gas Service**	G-80			**Natural Gas Engine Gas Service**	G-80		
Basic Service Charge per Month			Basic Service Charge per Month				Basic Service Charge per Month			
Off-Peak Season (October - March)		$ -	Off-Peak Season (October - March)		$ -		Off-Peak Season (October - March)		$ -	
Peak Season (April - September)		$ 125.00	Peak Season (April - September)		$ 125.00	0%	Peak Season (April - September)		$ 125.00	0.0%
Delivery Charge per Therm			Delivery Charge per Therm				Delivery Charge per Therm			
All Usage		$ 0.19069	All Usage		$ 0.19069	0%	All Usage		$ 0.20744	8.8%

Source: Company's Filing Schedule H-3.

Comparison of Company's Present and Staff's Proposed Revenues

Rate Schedule G-5, Single-Family Residential Gas Service

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charge	10,418,131		$ 10.70	$ 111,474,002
Commodity Charge				
Sales Therms		261,822,441	$0.57070	$ 149,422,067
Total - Excluding Cost of Gas				$ 260,896,069
Base Cost of Gas (per therm)		261,822,441	$0.70873	$ 185,561,419
(applies proposed base cost of gas for comparability)				
Total Revenue				$ 446,457,488

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge	10,418,131		$ 10.70	$ 111,474,002	0.0%
Commodity Charge					
Sales Therms		261,822,441	$0.74651	$ 195,453,070	
Total - Excluding Cost of Gas				$ 306,927,072	17.6%
Base Cost of Gas (per therm)		261,822,441	$0.70873	$ 185,561,419	
Total Revenue				$ 492,488,491	10.3%

Comparison of Company's Present and Staff's Proposed Revenues

Rate Schedule G-6, Multi-Family Residential Gas Service

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charge	378,334		$ 9.70	$ 3,669,840
Commodity Charge				
Sales Therms		5,862,713	$0.55343	$ 3,244,601
Total - Excluding Cost of Gas				$ 6,914,441
Base Cost of Gas (per therm)		5,862,713	$0.70873	$ 4,155,081
(applies proposed base cost of gas for comparability)				
Total Revenue				$ 11,069,522

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge	378,334		$ 9.70	$ 3,669,840	0.0%
Commodity Charge					
Sales Therms		5,862,713	$0.74651	$ 4,376,574	
Total - Excluding Cost of Gas				$ 8,046,414	16.4%
Base Cost of Gas (per therm)		5,862,713	$0.70873	$ 4,155,081	
Total Revenue				$ 12,201,495	10.2%

Comparison of Company's Present and Staff's Proposed Revenues

Rate Schedule G-10, Single-Family Low Income Residential Gas Service

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charge	415,096		$ 7.50	$ 3,113,220
Commodity Charge				
Summer		2,301,968	$0.55343	$ 1,273,978
Winter First 150 therms		8,137,766	$0.31624	2,573,487
Winter Over 150 therms		55,464	$0.55343	30,695
Total - Excluding Cost of Gas				$ 6,991,380
Base Cost of Gas (per therm)		10,495,198	$0.70873	$ 7,438,262
(applies proposed base cost of gas for comparability)				
Total Revenue				$ 14,429,642

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge	415,096		$ 7.50	$ 3,113,220	0.0%
Commodity Charge					
Summer		2,301,968	$0.74241	$ 1,709,004	
Winter First 150 therms		8,137,766	$0.46743	3,803,836	
Winter Over 150 therms		55,464	$0.74241	41,177	
Total - Excluding Cost of Gas				$ 8,667,237	24.0%
Base Cost of Gas (per therm)		10,495,198	$0.70873	$ 7,438,262	
Total Revenue				$ 16,105,499	11.6%

Comparison of Company's Present and Staff's Proposed Revenues

Rate Schedule G-11, Multi-Family Low Income Residential Gas Service

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charge	37,729		$ 7.50	$ 282,968
Commodity Charge				
Summer		210,209	$0.55343	$ 116,336
Winter First 150 therms		499,906	$0.31624	158,090
Winter Over 150 therms		330	$0.55343	183
Total - Excluding Cost of Gas				$ 557,577
Base Cost of Gas (per therm)		710,445	$0.70873	$ 503,514
(applies proposed base cost of gas for comparability)				
Total Revenue				$ 1,061,091

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge	37,729		$ 7.50	$ 282,968	0.0%
Commodity Charge					
Summer		210,209	$0.74241	$ 156,061	
Winter First 150 therms		499,906	$0.46743	233,671	
Winter Over 150 therms		330	$0.74241	245	
Total - Excluding Cost of Gas				$ 672,945	20.7%
Base Cost of Gas (per therm)		710,445	$0.70873	$ 503,514	
Total Revenue				$ 1,176,459	10.9%

Comparison of Company's Present and Staff's Proposed Revenues

Rate Schedule G-15, Special Residential Gas Service for Air Conditioning

Current Rates			Bills	Therms	Current Rate	Revenue
Basic Service Charge			1,080		$ 10.70	$ 11,556
Commodity Charge						
Summer	First	15 therms		23,038	$0.57070	$ 13,148
Summer	Over	15 therms		12,945	$0.28860	3,736
Winter				53,236	$0.57070	30,382
Total - Excluding Cost of Gas						$ 58,822
Base Cost of Gas (per therm)				89,219	$0.70873	$ 63,232
(applies proposed base cost of gas for comparability)						
Total Revenue						$ 122,054

Proposed Rates			Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge			1,080		$ 10.70	$ 11,556	0.0%
Commodity Charge							
Summer	First	15 therms		23,038	$0.74651	$ 17,198	
Summer	Over	15 therms		12,945	$0.45241	5,856	
Winter				53,236	$0.74651	39,741	
Total - Excluding Cost of Gas						$ 74,351	26.4%
Base Cost of Gas (per therm)				89,219	$0.70873	$ 63,232	
Total Revenue						$ 137,583	12.7%

Comparison of Company's Present and Staff's Proposed Revenues

Rate Schedule G-20, Master Metered Mobile Home Park (MMMHP) Gas Service

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charge	1,812		$ 66.00	$ 119,592
Commodity Charge				
Sales Therms		1,823,059	$0.40830	$ 744,355
Total - Excluding Cost of Gas				$ 863,947
Base Cost of Gas (per therm)		1,823,059	$0.70873	$ 1,292,057
(applies proposed base cost of gas for comparability)				
Total Revenue				$ 2,156,004

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge	1,812		$ 66.00	$ 119,592	0.0%
Commodity Charge					
Sales Therms		1,823,059	$0.43926	$ 800,797	
Total - Excluding Cost of Gas				$ 920,389	6.5%
Base Cost of Gas (per therm)		1,823,059	$0.70873	$ 1,292,057	
Total Revenue				$ 2,212,446	2.6%

Comparison of Company's Present and Staff's Proposed Revenues

Rate Schedule G-25, General Gas Service, Small

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charge	205,593		$ 27.50	$ 5,653,808
Commodity Charge				
Sales Therms		3,951,454	$0.57059	$ 2,254,660
Transport Therms		607	$0.57059	346
Total - Excluding Cost of Gas				$ 7,908,814
Base Cost of Gas (per therm)		3,951,454	$0.70873	$ 2,800,514
(applies proposed base cost of gas for comparability)				
Total Revenue				$ 10,709,328

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge	205,593		$ 27.50	$ 5,653,808	0.0%
Commodity Charge					
Sales Therms		3,951,454	$0.68813	$ 2,719,114	
Transport Therms		607	$0.68813	418	
Total - Excluding Cost of Gas				$ 8,373,340	5.9%
Base Cost of Gas (per therm)		3,951,454	$0.70873	$ 2,800,514	
Total Revenue				$ 11,173,854	4.3%

Comparison of Company's Present and Staff's Proposed Revenues

Rate Schedule G-25, General Gas Service, Medium

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charge	181,390		$ 43.50	$ 7,890,465
Commodity Charge				
Sales Therms		38,541,245	$0.37996	$ 14,644,131
Transport Therms		117,316	$0.37996	44,575
Total - Excluding Cost of Gas				$ 22,579,171
Base Cost of Gas (per therm)		38,541,245	$0.70873	$ 27,315,337
(applies proposed base cost of gas for comparability)				
Total Revenue				$ 49,894,508

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge	181,390		$ 43.50	$ 7,890,465	0.0%
Commodity Charge					
Sales Therms		38,541,245	$0.41717	$ 16,078,251	
Transport Therms		117,316	$0.41717	48,941	
Total - Excluding Cost of Gas				$ 24,017,657	6.4%
Base Cost of Gas (per therm)		38,541,245	$0.70873	$ 27,315,337	
Total Revenue				$ 51,332,994	2.9%

Comparison of Company's Present and Staff's Proposed Revenues

Rate Schedule G-25, General Gas Service, Large-1

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charge	84,872		$ 160.00	$ 13,579,520
Commodity Charge				
Sales Therms		102,012,194	$0.29084	$ 29,669,227
Transport Therms		2,051,536	$0.29084	596,669
Total - Excluding Cost of Gas				$ 43,845,416
Base Cost of Gas (per therm)		102,012,194	$0.70873	$ 72,299,102
(applies proposed base cost of gas for comparability)				
Total Revenue				$ 116,144,518

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge	84,872		$ 120.00	$ 10,184,640	-25.0%
Commodity Charge					
Sales Therms		102,012,194	$0.35145	$ 35,852,186	
Transport Therms		2,051,536	$0.35145	721,012	
Total - Excluding Cost of Gas				$ 46,757,838	6.6%
Base Cost of Gas (per therm)		102,012,194	$0.70873	$ 72,299,102	
Total Revenue				$ 119,056,940	2.5%

Comparison of Company's Present and Staff's Proposed Revenues

Rate Schedule G-25, General Gas Service, Large-2

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charge	5,136		$ 160.00	$ 821,760
Commodity Charge				
Sales Therms		33,135,165	$0.29084	$ 9,637,031
Transport Therms		2,735,757	$0.29084	795,668
Total - Excluding Cost of Gas				$ 11,254,459
Base Cost of Gas (per therm)		33,135,165	$0.70873	$ 23,483,885
(applies proposed base cost of gas for comparability)				
Total Revenue				$ 34,738,344

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge	5,136		$ 240.00	$ 1,232,640	50.0%
Commodity Charge					
Sales Therms		33,135,165	$0.30668	$ 10,161,892	
Transport Therms		2,735,757	$0.30668	839,002	
Total - Excluding Cost of Gas				$ 12,233,534	8.7%
Base Cost of Gas (per therm)		33,135,165	$0.70873	$ 23,483,885	
Total Revenue				$ 35,717,419	2.8%

Comparison of Company's Present and Staff's Proposed Revenues

Rate Schedule G-40, Air Conditioning Gas Service

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charge				
General Service - Small	184		$ 27.50	$ 5,060
General Service - Medium	0		$ 43.50	$ -
General Service - Large	24		$ 160.00	$ 3,840
Essential Agricultural	36		$ 120.00	$ 4,320
Total Basic Service Charges				$ 13,220
Commodity Charge				
Sales Therms		359,940	$0.11010	$ 39,629
Transport Therms		266,305	$0.11010	29,320
Total - Excluding Cost of Gas				$ 82,169
Base Cost of Gas (per therm)		359,940	$0.70873	$ 255,100
(applies proposed base cost of gas for comparability)				
Total Revenue				$ 337,269

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge					
General Service - Small	184		$ 27.50	$ 5,060	
General Service - Medium	0		$ 43.50	$ -	
General Service - Large 1	24		$ 120.00	$ 2,880	
Essential Agricultural	36		$ 120.00	$ 4,320	
Total Basic Service Charges				$ 12,260	-7.3%
Commodity Charge					
Sales Therms		359,940	$0.13965	$ 50,266	
Transport Therms		266,305	$0.13965	37,189	
Total - Excluding Cost of Gas				$ 99,715	21.4%
Base Cost of Gas (per therm)		359,940	$0.70873	$ 255,100	
Total Revenue				$ 354,815	5.2%

Comparison of Company's Present and Staff's Proposed Revenues

Rate Schedule G-45, Street Lighting Gas Service

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charge	180		$ -	$ -
Commodity Charge				
Sales Therms		87,447	$0.61050	$ 53,386
Total - Excluding Cost of Gas				$ 53,386
Base Cost of Gas (per therm)		87,447	$0.70873	$ 61,976
(applies proposed base cost of gas for comparability)				
Total Revenue				$ 115,362

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge	180		$ -	$ -	
Commodity Charge					
Sales Therms		87,447	$0.72590	$ 63,478	
Total - Excluding Cost of Gas				$ 63,478	18.9%
Base Cost of Gas (per therm)		87,447	$0.70873	$ 61,976	
Total Revenue				$ 125,454	8.7%

Comparison of Company's Present and Staff's Proposed Revenues

Rate Schedule G-55, Gas Service for Compression on Customer's Premises

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charge				
General Service - Small	192		$ 27.50	$ 5,280
General Service - Large	240		$ 250.00	$ 60,000
General Service - Residential	984		$ 10.70	$ 10,529
Total Basic Service Charges				$ 75,809
Commodity Charge				
Sales Therms - Small		101,442	$0.18678	$ 18,947
Sales Therms - Large		1,244,594	$0.18678	232,465
Sales Therms - Residential		35,148	$0.18678	6,565
Total - Excluding Cost of Gas				$ 333,786
Base Cost of Gas (per therm)		101,442	$0.70873	$ 71,895
(applies proposed base cost of gas for comparability)				
Total Revenue				$ 405,681

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge					
General Service - Small	192		$ 27.50	$ 5,280	
General Service - Large	240		$ 250.00	$ 60,000	
General Service - Residential	984		$ 10.70	$ 10,529	
Total Basic Service Charges				$ 75,809	0.0%
Commodity Charge					
Sales Therms - Small		101,442	$0.19215	$ 19,492	
Sales Therms - Large		1,244,594	$0.19215	239,149	
Sales Therms - Residential		35,148	$0.19215	6,754	
Total - Excluding Cost of Gas				$ 341,204	2.2%
Base Cost of Gas (per therm)		101,442	$0.70873	$ 71,895	
(applies proposed base cost of gas for comparability)					
Total Revenue				$ 413,099	1.8%

Comparison of Company's Present and Staff's Proposed Revenues

Rate Schedule G-60, Cogeneration Gas Service

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charge				
General Service - Small	36		$ 27.50	$ 990
General Service - Medium	24		$ 43.50	$ 1,044
General Service - Large	36		$ 160.00	$ 5,760
Essential Agricultural	12		$ 120.00	$ 1,440
Total Basic Service Charges				$ 9,234
Commodity Charge				
Sales Therms		1,235,925	$0.13535	$ 167,282
Transport Therms		20,137,894	$0.13535	2,725,664
Total - Excluding Cost of Gas				$ 2,902,180
Base Cost of Gas (per therm)		1,235,925	$0.70873	$ 875,937
(applies proposed base cost of gas for comparability)				
Total Revenue				$ 3,778,117

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge					
General Service - Small	36		$ 27.50	$ 990	
General Service - Medium	24		$ 43.50	$ 1,044	
General Service - Large 1	36		$ 120.00	$ 4,320	
Essential Agricultural	12		$ 120.00	$ 1,440	
Total Basic Service Charges				$ 7,794	-15.6%
Commodity Charge					
Sales Therms		1,235,925	$0.16496	$ 203,878	
Transport Therms		20,137,894	$0.16496	3,321,947	
Total - Excluding Cost of Gas				$ 3,533,619	21.8%
Base Cost of Gas (per therm)		1,235,925	$0.70873	$ 875,937	
Total Revenue				$ 4,409,556	16.7%

Comparison of Company's Present and Staff's Proposed Revenues

Rate Schedule G-75, Small Essential Agriculture User Gas Service

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charge	611		$ 120.00	$ 73,320
Commodity Charge				
Sales Therms		2,647,768	$0.24396	$ 645,949
Transport Therms		32,852	$0.24396	8,015
Total - Excluding Cost of Gas				$ 727,284
Base Cost of Gas (per therm)		2,647,768	$0.70873	$ 1,876,553
(applies proposed base cost of gas for comparability)				
Total Revenue				$ 2,603,837

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge	611		$ 120.00	$ 73,320	0.0%
Commodity Charge					
Sales Therms		2,647,768	$0.26344	$ 697,528	
Transport Therms		32,852	$0.26344	8,655	
Total - Excluding Cost of Gas				$ 779,503	7.2%
Base Cost of Gas (per therm)		2,647,768	$0.70873	$ 1,876,553	
Total Revenue				$ 2,656,056	2.0%

Comparison of Company's Present and Staff's Proposed Revenues

Rate Schedule G-80, Natural Gas Engine Gas Service

Current Rates	Bills	Therms	Current Rate	Revenue
Basic Service Charge	1,999		$ 125.00	$ 249,875
Commodity Charge				
Sales Therms		7,272,353	$0.19069	$ 1,386,765
Transport Therms		405,928	$0.19069	77,406
Total - Excluding Cost of Gas				$ 1,714,046
Base Cost of Gas (per therm)		7,272,353	$0.50345	$ 3,661,266
(applies proposed base cost of gas for comparability)				
Total Revenue				$ 5,375,312

Proposed Rates	Bills	Therms	Proposed Rate	Revenue	Percent Increase
Basic Service Charge	1,999		$ 125.00	$ 249,875	0.0%
Commodity Charge					
Sales Therms		7,272,353	$0.20744	$ 1,508,577	
Transport Therms		405,928	$0.20744	84,206	
Total - Excluding Cost of Gas				$ 1,842,658	7.5%
Base Cost of Gas (per therm)		7,272,353	$0.50345	$ 3,661,266	
Total Revenue				$ 5,503,924	2.4%

Source: Company's Class Cost of Service Study.

Summary of Comparison of Company's Present and Staff's Proposed Revenues

	Base Revenue		Percent	Total Revenue		Percent
	Current	Proposed	Change	Current	Proposed	Change
Rate Schedule G-5, Single-Family Residential Gas Service	$ 260,896,069	$ 306,927,072	17.6%	$ 446,457,488	$ 492,488,491	10.3%
Rate Schedule G-6, Multi-Family Residential Gas Service	$ 6,914,441	$ 8,046,414	16.4%	$ 11,069,522	$ 12,201,495	10.2%
Rate Schedule G-10, Single-Family Low Income Residential Gas Service	$ 6,991,380	$ 8,667,237	24.0%	$ 14,429,642	$ 16,105,499	11.6%
Rate Schedule G-11, Multi-Family Low Income Residential Gas Service	$ 557,577	$ 672,945	20.7%	$ 1,061,091	$ 1,176,459	10.9%
Rate Schedule G-15, Special Residential Gas Service for Air Conditioning	$ 58,822	$ 74,351	26.4%	$ 122,054	$ 137,583	12.7%
Rate Schedule G-20, Master Metered Mobile Home Park (MMMHP) Gase Service	$ 863,947	$ 920,389	6.5%	$ 2,156,004	$ 2,212,446	2.6%
Rate Schedule G-25, General Gas Service, Small	$ 7,908,814	$ 8,373,340	5.9%	$ 10,709,328	$ 11,173,854	4.3%
Rate Schedule G-25, General Gas Service, Medium	$ 22,579,171	$ 24,017,657	6.4%	$ 49,894,508	$ 51,332,994	2.9%
Rate Schedule G-25, General Gas Service, Large-1	$ 43,845,416	$ 46,757,838	6.6%	$ 116,144,518	$ 119,056,940	2.5%
Rate Schedule G-25, General Gas Service, Large-2	$ 11,254,459	$ 12,233,534	8.7%	$ 34,738,344	$ 35,717,419	2.8%
Rate Schedule G-40, Air Conditioning Gas Service	$ 82,169	$ 99,715	21.4%	$ 337,269	$ 354,815	5.2%
Rate Schedule G-45, Street Lighting Gas Service	$ 53,386	$ 63,478	18.9%	$ 115,362	$ 125,454	8.7%
Rate Schedule G-55, Gas Service for Compression on Customer's Premises	$ 333,786	$ 341,204	2.2%	$ 405,681	$ 413,099	1.8%
Rate Schedule G-60, Cogeneration Gas Service	$ 2,902,180	$ 3,533,619	21.8%	$ 3,778,117	$ 4,409,556	16.7%
Rate Schedule G-75, Small Essential Agriculture User Gas Service	$ 727,284	$ 779,503	7.2%	$ 2,603,837	$ 2,656,056	2.0%
Rate Schedule G-80, Natural Gas Engine Gas Service	$ 1,714,046	$ 1,842,658	7.5%	$ 5,375,312	$ 5,503,924	2.4%

Summary of Bill Impacts

Rate Schedule G-5, Single-Family Residential Gas Service
Customer Bill Impact

	Staff Proposed Rates						
Monthly Consumption (therms)	Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
5	$ 10.70	$ 3.54	$ 3.73	$ 0.55	$ 18.52	$ 17.65	4.9%
10	$ 10.70	$ 7.09	$ 7.47	$ 1.10	$ 26.36	$ 24.59	7.2%
11 Summer Avg.	$ 10.70	$ 7.80	$ 8.21	$ 1.21	$ 27.92	$ 25.98	7.5%
15	$ 10.70	$ 10.63	$ 11.20	$ 1.65	$ 34.18	$ 31.54	8.4%
20	$ 10.70	$ 14.17	$ 14.93	$ 2.20	$ 42.00	$ 38.49	9.1%
21	$ 10.70	$ 14.88	$ 15.68	$ 2.31	$ 43.57	$ 39.88	9.3%
25 Annual Avg.	$ 10.70	$ 17.72	$ 18.66	$ 2.75	$ 49.83	$ 45.44	9.7%
30	$ 10.70	$ 21.26	$ 22.40	$ 3.30	$ 57.66	$ 52.38	10.1%
39 Winter Avg.	$ 10.70	$ 27.64	$ 29.11	$ 4.29	$ 71.74	$ 64.89	10.6%
40	$ 10.70	$ 28.35	$ 29.86	$ 4.40	$ 73.31	$ 66.28	10.6%
50	$ 10.70	$ 35.44	$ 37.33	$ 5.50	$ 88.97	$ 80.17	11.0%
60	$ 10.70	$ 42.52	$ 44.79	$ 6.60	$ 104.61	$ 94.07	11.2%
75	$ 10.70	$ 53.15	$ 55.99	$ 8.25	$ 128.09	$ 114.91	11.5%
100	$ 10.70	$ 70.87	$ 74.65	$ 11.00	$ 167.22	$ 149.64	11.7%
125	$ 10.70	$ 88.59	$ 93.31	$ 13.75	$ 206.35	$ 184.38	11.9%
150	$ 10.70	$ 106.31	$ 111.98	$ 16.50	$ 245.49	$ 219.11	12.0%
200	$ 10.70	$ 141.75	$ 149.30	$ 22.00	$ 323.75	$ 288.59	12.2%
250	$ 10.70	$ 177.18	$ 186.63	$ 27.50	$ 402.01	$ 358.06	12.3%
300	$ 10.70	$ 212.62	$ 223.95	$ 33.00	$ 480.27	$ 427.53	12.3%
400	$ 10.70	$ 283.49	$ 298.60	$ 44.00	$ 636.79	$ 566.47	12.4%
500	$ 10.70	$ 354.37	$ 373.26	$ 55.00	$ 793.33	$ 705.42	12.5%

Summary of Bill Impacts

Rate Schedule G-6, Multi-Family Residential Gas Service
Customer Bill Impact

	Staff Proposed Rates						
Monthly Consumption (therms)	Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
5	$ 9.70	$ 3.54	$ 3.73	$ 0.55	$ 17.52	$ 16.56	5.8%
10 Summer Avg.	$ 9.70	$ 7.09	$ 7.47	$ 1.10	$ 25.36	$ 23.42	8.3%
15	$ 9.70	$ 10.63	$ 11.20	$ 1.65	$ 33.18	$ 30.28	9.6%
16 Annual Avg.	$ 9.70	$ 11.34	$ 11.94	$ 1.76	$ 34.74	$ 31.65	9.8%
20	$ 9.70	$ 14.17	$ 14.93	$ 2.20	$ 41.00	$ 37.14	10.4%
21 Winter Avg.	$ 9.70	$ 14.88	$ 15.68	$ 2.31	$ 42.57	$ 38.52	10.5%
25	$ 9.70	$ 17.72	$ 18.66	$ 2.75	$ 48.83	$ 44.00	11.0%
30	$ 9.70	$ 21.26	$ 22.40	$ 3.30	$ 56.66	$ 50.86	11.4%
40	$ 9.70	$ 28.35	$ 29.86	$ 4.40	$ 72.31	$ 64.59	12.0%
50	$ 9.70	$ 35.44	$ 37.33	$ 5.50	$ 87.97	$ 78.31	12.3%
60	$ 9.70	$ 42.52	$ 44.79	$ 6.60	$ 103.61	$ 92.03	12.6%
75	$ 9.70	$ 53.15	$ 55.99	$ 8.25	$ 127.09	$ 112.61	12.9%
100	$ 9.70	$ 70.87	$ 74.65	$ 11.00	$ 166.22	$ 146.92	13.1%
125	$ 9.70	$ 88.59	$ 93.31	$ 13.75	$ 205.35	$ 181.22	13.3%
150	$ 9.70	$ 106.31	$ 111.98	$ 16.50	$ 244.49	$ 215.52	13.4%
200	$ 9.70	$ 141.75	$ 149.30	$ 22.00	$ 322.75	$ 284.13	13.6%
250	$ 9.70	$ 177.18	$ 186.63	$ 27.50	$ 401.01	$ 352.74	13.7%
300	$ 9.70	$ 212.62	$ 223.95	$ 33.00	$ 479.27	$ 421.35	13.7%
400	$ 9.70	$ 283.49	$ 298.60	$ 44.00	$ 635.79	$ 558.56	13.8%
500	$ 9.70	$ 354.37	$ 373.26	$ 55.00	$ 792.33	$ 695.78	13.9%

Summary of Bill Impacts

Rate Schedule G-10, Single-Family Low Income Residential Gas Service
Customer Bill Impact - Summer Rates

	Staff Proposed Rates						
Monthly Consumption (therms)	Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
1	$ 7.50	$ 0.71	$ 0.74	$ 0.11	$ 9.06	$ 8.87	2.1%
2	$ 7.50	$ 1.42	$ 1.48	$ 0.22	$ 10.62	$ 10.24	3.7%
3	$ 7.50	$ 2.13	$ 2.23	$ 0.33	$ 12.19	$ 11.62	4.9%
4	$ 7.50	$ 2.83	$ 2.97	$ 0.44	$ 13.74	$ 12.99	5.8%
5	$ 7.50	$ 3.54	$ 3.71	$ 0.55	$ 15.30	$ 14.36	6.5%
6	$ 7.50	$ 4.25	$ 4.45	$ 0.66	$ 16.86	$ 15.73	7.2%
7	$ 7.50	$ 4.96	$ 5.20	$ 0.77	$ 18.43	$ 17.11	7.7%
8	$ 7.50	$ 5.67	$ 5.94	$ 0.88	$ 19.99	$ 18.48	8.2%
9	$ 7.50	$ 6.38	$ 6.68	$ 0.99	$ 21.55	$ 19.85	8.6%
10	$ 7.50	$ 7.09	$ 7.42	$ 1.10	$ 23.11	$ 21.22	8.9%
11 Summer Avg.	$ 7.50	$ 7.80	$ 8.17	$ 1.21	$ 24.68	$ 22.59	9.3%
15	$ 7.50	$ 10.63	$ 11.14	$ 1.65	$ 30.92	$ 28.08	10.1%
20	$ 7.50	$ 14.17	$ 14.85	$ 2.20	$ 38.72	$ 34.94	10.8%
25 Annual Avg.	$ 7.50	$ 17.72	$ 18.56	$ 2.75	$ 46.53	$ 41.80	11.3%
30	$ 7.50	$ 21.26	$ 22.27	$ 3.30	$ 54.33	$ 48.66	11.7%
39	$ 7.50	$ 27.64	$ 28.95	$ 4.29	$ 68.38	$ 61.01	12.1%
40	$ 7.50	$ 28.35	$ 29.70	$ 4.40	$ 69.95	$ 62.39	12.1%
50	$ 7.50	$ 35.44	$ 37.12	$ 5.50	$ 85.56	$ 76.11	12.4%
60	$ 7.50	$ 42.52	$ 44.54	$ 6.60	$ 101.16	$ 89.83	12.6%
72	$ 7.50	$ 51.03	$ 53.45	$ 7.92	$ 119.90	$ 106.30	12.8%
75	$ 7.50	$ 53.15	$ 55.68	$ 8.25	$ 124.58	$ 110.41	12.8%
100	$ 7.50	$ 70.87	$ 74.24	$ 11.00	$ 163.61	$ 144.72	13.1%
125	$ 7.50	$ 88.59	$ 92.80	$ 13.75	$ 202.64	$ 179.02	13.2%
150	$ 7.50	$ 106.31	$ 111.36	$ 16.50	$ 241.67	$ 213.32	13.3%
200	$ 7.50	$ 141.75	$ 148.48	$ 22.00	$ 319.73	$ 281.93	13.4%
250	$ 7.50	$ 177.18	$ 185.60	$ 27.50	$ 397.78	$ 350.54	13.5%
300	$ 7.50	$ 212.62	$ 222.72	$ 33.00	$ 475.84	$ 419.15	13.5%
400	$ 7.50	$ 283.49	$ 296.96	$ 44.00	$ 631.95	$ 556.36	13.6%
500	$ 7.50	$ 354.37	$ 371.21	$ 55.00	$ 788.08	$ 693.58	13.6%

Summary of Bill Impacts

Rate Schedule G-10, Single-Family Low Income Residential Gas Service
Customer Bill Impact - Winter Rates

	Staff Proposed Rates						
Monthly Consumption (therms)	Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
1	$ 7.50	$ 0.71	$ 0.47	$ 0.11	$ 8.79	$ 8.63	1.9%
2	$ 7.50	$ 1.42	$ 0.93	$ 0.22	$ 10.07	$ 9.77	3.1%
3	$ 7.50	$ 2.13	$ 1.40	$ 0.33	$ 11.36	$ 10.90	4.2%
4	$ 7.50	$ 2.83	$ 1.87	$ 0.44	$ 12.64	$ 12.04	5.0%
5	$ 7.50	$ 3.54	$ 2.34	$ 0.55	$ 13.93	$ 13.17	5.8%
6	$ 7.50	$ 4.25	$ 2.80	$ 0.66	$ 15.21	$ 14.31	6.3%
7	$ 7.50	$ 4.96	$ 3.27	$ 0.77	$ 16.50	$ 15.44	6.9%
8	$ 7.50	$ 5.67	$ 3.74	$ 0.88	$ 17.79	$ 16.58	7.3%
9	$ 7.50	$ 6.38	$ 4.21	$ 0.99	$ 19.08	$ 17.71	7.7%
10	$ 7.50	$ 7.09	$ 4.67	$ 1.10	$ 20.36	$ 18.85	8.0%
11	$ 7.50	$ 7.80	$ 5.14	$ 1.21	$ 21.65	$ 19.98	8.4%
15	$ 7.50	$ 10.63	$ 7.01	$ 1.65	$ 26.79	$ 24.52	9.3%
20	$ 7.50	$ 14.17	$ 9.35	$ 2.20	$ 33.22	$ 30.20	10.0%
25 Annual Avg.	$ 7.50	$ 17.72	$ 11.69	$ 2.75	$ 39.66	$ 35.87	10.6%
30	$ 7.50	$ 21.26	$ 14.02	$ 3.30	$ 46.08	$ 41.55	10.9%
39 Winter Avg.	$ 7.50	$ 27.64	$ 18.23	$ 4.29	$ 57.66	$ 51.76	11.4%
40	$ 7.50	$ 28.35	$ 18.70	$ 4.40	$ 58.95	$ 52.90	11.4%
50	$ 7.50	$ 35.44	$ 23.37	$ 5.50	$ 71.81	$ 64.25	11.8%
60	$ 7.50	$ 42.52	$ 28.05	$ 6.60	$ 84.67	$ 75.60	12.0%
72	$ 7.50	$ 51.03	$ 33.65	$ 7.92	$ 100.10	$ 89.22	12.2%
75	$ 7.50	$ 53.15	$ 35.06	$ 8.25	$ 103.96	$ 92.62	12.2%
100	$ 7.50	$ 70.87	$ 46.74	$ 11.00	$ 136.11	$ 121.00	12.5%
125	$ 7.50	$ 88.59	$ 58.43	$ 13.75	$ 168.27	$ 149.37	12.7%
150	$ 7.50	$ 106.31	$ 70.11	$ 16.50	$ 200.42	$ 177.75	12.8%
200	$ 7.50	$ 141.75	$ 107.24	$ 22.00	$ 278.49	$ 246.35	13.0%
250	$ 7.50	$ 177.18	$ 144.36	$ 27.50	$ 356.54	$ 314.96	13.2%
300	$ 7.50	$ 212.62	$ 181.48	$ 33.00	$ 434.60	$ 383.57	13.3%
400	$ 7.50	$ 283.49	$ 255.72	$ 44.00	$ 590.71	$ 520.79	13.4%
500	$ 7.50	$ 354.37	$ 329.96	$ 55.00	$ 746.83	$ 658.00	13.5%

Summary of Bill Impacts

Rate Schedule G-11, Multi-Family Low Income Residential Gas Service
Customer Bill Impact - Summer Rates

	Staff Proposed Rates						
Monthly Consumption (therms)	Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
1	$ 7.50	$ 0.71	$ 0.74	$ 0.11	$ 9.06	$ 8.87	2.1%
2	$ 7.50	$ 1.42	$ 1.48	$ 0.22	$ 10.62	$ 10.24	3.7%
3	$ 7.50	$ 2.13	$ 2.23	$ 0.33	$ 12.19	$ 11.62	4.9%
4	$ 7.50	$ 2.83	$ 2.97	$ 0.44	$ 13.74	$ 12.99	5.8%
5	$ 7.50	$ 3.54	$ 3.71	$ 0.55	$ 15.30	$ 14.36	6.5%
6	$ 7.50	$ 4.25	$ 4.45	$ 0.66	$ 16.86	$ 15.73	7.2%
7	$ 7.50	$ 4.96	$ 5.20	$ 0.77	$ 18.43	$ 17.11	7.7%
8	$ 7.50	$ 5.67	$ 5.94	$ 0.88	$ 19.99	$ 18.48	8.2%
9	$ 7.50	$ 6.38	$ 6.68	$ 0.99	$ 21.55	$ 19.85	8.6%
10	$ 7.50	$ 7.09	$ 7.42	$ 1.10	$ 23.11	$ 21.22	8.9%
11 Summer Avg.	$ 7.50	$ 7.80	$ 8.17	$ 1.21	$ 24.68	$ 22.59	9.3%
15	$ 7.50	$ 10.63	$ 11.14	$ 1.65	$ 30.92	$ 28.08	10.1%
19 Annual Avg.	$ 7.50	$ 13.47	$ 14.11	$ 2.09	$ 37.17	$ 33.57	10.7%
20	$ 7.50	$ 14.17	$ 14.85	$ 2.20	$ 38.72	$ 34.94	10.8%
25	$ 7.50	$ 17.72	$ 18.56	$ 2.75	$ 46.53	$ 41.80	11.3%
30	$ 7.50	$ 21.26	$ 22.27	$ 3.30	$ 54.33	$ 48.66	11.7%
40	$ 7.50	$ 28.35	$ 29.70	$ 4.40	$ 69.95	$ 62.39	12.1%
50	$ 7.50	$ 35.44	$ 37.12	$ 5.50	$ 85.56	$ 76.11	12.4%
60	$ 7.50	$ 42.52	$ 44.54	$ 6.60	$ 101.16	$ 89.83	12.6%
72	$ 7.50	$ 51.03	$ 53.45	$ 7.92	$ 119.90	$ 106.30	12.8%
75	$ 7.50	$ 53.15	$ 55.68	$ 8.25	$ 124.58	$ 110.41	12.8%
100	$ 7.50	$ 70.87	$ 74.24	$ 11.00	$ 163.61	$ 144.72	13.1%
125	$ 7.50	$ 88.59	$ 92.80	$ 13.75	$ 202.64	$ 179.02	13.2%
150	$ 7.50	$ 106.31	$ 111.36	$ 16.50	$ 241.67	$ 213.32	13.3%
200	$ 7.50	$ 141.75	$ 148.48	$ 22.00	$ 319.73	$ 281.93	13.4%
250	$ 7.50	$ 177.18	$ 185.60	$ 27.50	$ 397.78	$ 350.54	13.5%
300	$ 7.50	$ 212.62	$ 222.72	$ 33.00	$ 475.84	$ 419.15	13.5%
400	$ 7.50	$ 283.49	$ 296.96	$ 44.00	$ 631.95	$ 556.36	13.6%
500	$ 7.50	$ 354.37	$ 371.21	$ 55.00	$ 788.08	$ 693.58	13.6%

Summary of Bill Impacts

Rate Schedule G-11, Multi-Family Low Income Residential Gas Service
Customer Bill Impact - Winter Rates

Monthly Consumption (therms)	Staff Proposed Rates: Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
1	$ 7.50	$ 0.71	$ 0.47	$ 0.11	$ 8.79	$ 8.63	1.9%
2	$ 7.50	$ 1.42	$ 0.93	$ 0.22	$ 10.07	$ 9.77	3.1%
3	$ 7.50	$ 2.13	$ 1.40	$ 0.33	$ 11.36	$ 10.90	4.2%
4	$ 7.50	$ 2.83	$ 1.87	$ 0.44	$ 12.64	$ 12.04	5.0%
5	$ 7.50	$ 3.54	$ 2.34	$ 0.55	$ 13.93	$ 13.17	5.8%
6	$ 7.50	$ 4.25	$ 2.80	$ 0.66	$ 15.21	$ 14.31	6.3%
7	$ 7.50	$ 4.96	$ 3.27	$ 0.77	$ 16.50	$ 15.44	6.9%
8	$ 7.50	$ 5.67	$ 3.74	$ 0.88	$ 17.79	$ 16.58	7.3%
9	$ 7.50	$ 6.38	$ 4.21	$ 0.99	$ 19.08	$ 17.71	7.7%
10	$ 7.50	$ 7.09	$ 4.67	$ 1.10	$ 20.36	$ 18.85	8.0%
11	$ 7.50	$ 7.80	$ 5.14	$ 1.21	$ 21.65	$ 19.98	8.4%
15	$ 7.50	$ 10.63	$ 7.01	$ 1.65	$ 26.79	$ 24.52	9.3%
19 Annual Avg.	$ 7.50	$ 13.47	$ 8.88	$ 2.09	$ 31.94	$ 29.06	9.9%
20	$ 7.50	$ 14.17	$ 9.35	$ 2.20	$ 33.22	$ 30.20	10.0%
25	$ 7.50	$ 17.72	$ 11.69	$ 2.75	$ 39.66	$ 35.87	10.6%
26 Winter Avg.	$ 7.50	$ 18.43	$ 12.15	$ 2.86	$ 40.94	$ 37.01	10.6%
30	$ 7.50	$ 21.26	$ 14.02	$ 3.30	$ 46.08	$ 41.55	10.9%
40	$ 7.50	$ 28.35	$ 18.70	$ 4.40	$ 58.95	$ 52.90	11.4%
50	$ 7.50	$ 35.44	$ 23.37	$ 5.50	$ 71.81	$ 64.25	11.8%
60	$ 7.50	$ 42.52	$ 28.05	$ 6.60	$ 84.67	$ 75.60	12.0%
72	$ 7.50	$ 51.03	$ 33.65	$ 7.92	$ 100.10	$ 89.22	12.2%
75	$ 7.50	$ 53.15	$ 35.06	$ 8.25	$ 103.96	$ 92.62	12.2%
100	$ 7.50	$ 70.87	$ 46.74	$ 11.00	$ 136.11	$ 121.00	12.5%
125	$ 7.50	$ 88.59	$ 58.43	$ 13.75	$ 168.27	$ 149.37	12.7%
150	$ 7.50	$ 106.31	$ 70.11	$ 16.50	$ 200.42	$ 177.75	12.8%
200	$ 7.50	$ 141.75	$ 107.24	$ 22.00	$ 278.49	$ 246.35	13.0%
250	$ 7.50	$ 177.18	$ 144.36	$ 27.50	$ 356.54	$ 314.96	13.2%
300	$ 7.50	$ 212.62	$ 181.48	$ 33.00	$ 434.60	$ 383.57	13.3%
400	$ 7.50	$ 283.49	$ 255.72	$ 44.00	$ 590.71	$ 520.79	13.4%
500	$ 7.50	$ 354.37	$ 329.96	$ 55.00	$ 746.83	$ 658.00	13.5%

Summary of Bill Impacts

Rate Schedule G-15, Special Residential Gas Service for Air Conditioning
Customer Bill Impact - Summer Rates

	Staff Proposed Rates						
Monthly Consumption (therms)	Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
10	$ 10.70	$ 7.09	$ 7.47	$ 1.10	$ 26.36	$ 26.36	0.0%
20	$ 10.70	$ 13.46	$ 14.93	$ 2.20	$ 41.29	$ 37.08	11.4%
30	$ 10.70	$ 17.98	$ 22.40	$ 3.30	$ 54.38	$ 48.15	12.9%
40	$ 10.70	$ 22.51	$ 29.86	$ 4.40	$ 67.47	$ 59.22	13.9%
50	$ 10.70	$ 27.03	$ 37.33	$ 5.50	$ 80.56	$ 70.30	14.6%
60	$ 10.70	$ 31.56	$ 44.79	$ 6.60	$ 93.65	$ 81.37	15.1%
67 Summer Avg.	$ 10.70	$ 34.72	$ 50.02	$ 7.37	$ 102.81	$ 89.12	15.4%
70	$ 10.70	$ 36.08	$ 52.26	$ 7.70	$ 106.74	$ 92.44	15.5%
80	$ 10.70	$ 40.60	$ 59.72	$ 8.80	$ 119.82	$ 103.52	15.7%
83 Annual Avg.	$ 10.70	$ 41.96	$ 61.96	$ 9.13	$ 123.75	$ 106.84	15.8%
90	$ 10.70	$ 45.13	$ 67.19	$ 9.90	$ 132.92	$ 114.59	16.0%
99	$ 10.70	$ 49.20	$ 73.90	$ 10.89	$ 144.69	$ 124.56	16.2%
100	$ 10.70	$ 49.65	$ 74.65	$ 11.00	$ 146.00	$ 125.66	16.2%
119	$ 10.70	$ 58.25	$ 88.83	$ 13.09	$ 170.87	$ 146.70	16.5%
125	$ 10.70	$ 60.96	$ 93.31	$ 13.75	$ 178.72	$ 153.35	16.5%
150	$ 10.70	$ 72.27	$ 111.98	$ 16.50	$ 211.45	$ 181.03	16.8%
152	$ 10.70	$ 73.18	$ 113.47	$ 16.72	$ 214.07	$ 183.25	16.8%
175	$ 10.70	$ 83.58	$ 130.64	$ 19.25	$ 244.17	$ 208.71	17.0%
200	$ 10.70	$ 94.89	$ 149.30	$ 22.00	$ 276.89	$ 236.40	17.1%
250	$ 10.70	$ 117.51	$ 186.63	$ 27.50	$ 342.34	$ 291.76	17.3%
300	$ 10.70	$ 140.13	$ 223.95	$ 33.00	$ 407.78	$ 347.13	17.5%
350	$ 10.70	$ 162.75	$ 261.28	$ 38.50	$ 473.23	$ 402.50	17.6%
400	$ 10.70	$ 185.37	$ 298.60	$ 44.00	$ 538.67	$ 457.86	17.6%
450	$ 10.70	$ 207.99	$ 335.93	$ 49.50	$ 604.12	$ 513.23	17.7%
500	$ 10.70	$ 230.62	$ 373.26	$ 55.00	$ 669.58	$ 568.60	17.8%

Summary of Bill Impacts

Rate Schedule G-15, Special Residential Gas Service for Air Conditioning
Customer Bill Impact - Winter Rates

	Staff Proposed Rates						
Monthly Consumption (therms)	Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
10	$ 10.70	$ 7.09	$ 7.47	$ 1.10	$ 26.36	$ 24.59	7.2%
20	$ 10.70	$ 14.17	$ 14.93	$ 2.20	$ 42.00	$ 38.49	9.1%
30	$ 10.70	$ 21.26	$ 22.40	$ 3.30	$ 57.66	$ 52.38	10.1%
40	$ 10.70	$ 28.35	$ 29.86	$ 4.40	$ 73.31	$ 66.28	10.6%
50	$ 10.70	$ 35.44	$ 37.33	$ 5.50	$ 88.97	$ 80.17	11.0%
60	$ 10.70	$ 42.52	$ 44.79	$ 6.60	$ 104.61	$ 94.07	11.2%
67	$ 10.70	$ 47.48	$ 50.02	$ 7.37	$ 115.57	$ 103.79	11.3%
70	$ 10.70	$ 49.61	$ 52.26	$ 7.70	$ 120.27	$ 107.96	11.4%
80	$ 10.70	$ 56.70	$ 59.72	$ 8.80	$ 135.92	$ 121.85	11.5%
83 Annual Avg.	$ 10.70	$ 58.82	$ 61.96	$ 9.13	$ 140.61	$ 126.02	11.6%
90	$ 10.70	$ 63.79	$ 67.19	$ 9.90	$ 151.58	$ 135.75	11.7%
99 Winter Avg.	$ 10.70	$ 70.16	$ 73.90	$ 10.89	$ 165.65	$ 148.25	11.7%
100	$ 10.70	$ 70.87	$ 74.65	$ 11.00	$ 167.22	$ 149.64	11.7%
119	$ 10.70	$ 84.34	$ 88.84	$ 13.09	$ 196.97	$ 176.04	11.9%
125	$ 10.70	$ 88.59	$ 93.31	$ 13.75	$ 206.35	$ 184.38	11.9%
150	$ 10.70	$ 106.31	$ 111.98	$ 16.50	$ 245.49	$ 219.11	12.0%
152	$ 10.70	$ 107.73	$ 113.47	$ 16.72	$ 248.62	$ 221.89	12.0%
175	$ 10.70	$ 124.03	$ 130.64	$ 19.25	$ 284.62	$ 253.85	12.1%
200	$ 10.70	$ 141.75	$ 149.30	$ 22.00	$ 323.75	$ 288.59	12.2%
250	$ 10.70	$ 177.18	$ 186.63	$ 27.50	$ 402.01	$ 358.06	12.3%
300	$ 10.70	$ 212.62	$ 223.95	$ 33.00	$ 480.27	$ 427.53	12.3%
350	$ 10.70	$ 248.06	$ 261.28	$ 38.50	$ 558.54	$ 497.00	12.4%
400	$ 10.70	$ 283.49	$ 298.61	$ 44.00	$ 636.80	$ 566.47	12.4%
450	$ 10.70	$ 318.93	$ 335.93	$ 49.50	$ 715.06	$ 635.94	12.4%
500	$ 10.70	$ 354.37	$ 373.26	$ 55.00	$ 793.33	$ 705.42	12.5%

Summary of Bill Impacts

Rate Schedule G-20, Master Metered Mobile Home Park (MMMHP) Gas Service
Customer Bill Impact

		Staff Proposed Rates						
Monthly Consumption (therms)		Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
100		$ 66.00	$ 70.87	$ 43.93	$ 11.00	$ 191.80	$ 188.70	1.6%
200		$ 66.00	$ 141.75	$ 87.85	$ 22.00	$ 317.60	$ 311.41	2.0%
300		$ 66.00	$ 212.62	$ 131.78	$ 33.00	$ 443.40	$ 434.11	2.1%
400		$ 66.00	$ 283.49	$ 175.70	$ 44.00	$ 569.19	$ 556.81	2.2%
425	Summer Avg.	$ 66.00	$ 301.21	$ 186.69	$ 46.75	$ 600.65	$ 587.49	2.2%
500		$ 66.00	$ 354.37	$ 219.63	$ 55.00	$ 695.00	$ 679.52	2.3%
600		$ 66.00	$ 425.24	$ 263.56	$ 66.00	$ 820.80	$ 802.22	2.3%
700		$ 66.00	$ 496.11	$ 307.48	$ 77.00	$ 946.59	$ 924.92	2.3%
800		$ 66.00	$ 566.98	$ 351.41	$ 88.00	$ 1,072.39	$ 1,047.62	2.4%
900		$ 66.00	$ 637.86	$ 395.33	$ 99.00	$ 1,198.19	$ 1,170.33	2.4%
1,000		$ 66.00	$ 708.73	$ 439.26	$ 110.00	$ 1,323.99	$ 1,293.03	2.4%
1,006	Annual Avg.	$ 66.00	$ 712.98	$ 441.90	$ 110.66	$ 1,331.54	$ 1,300.39	2.4%
1,250		$ 66.00	$ 885.91	$ 549.08	$ 137.50	$ 1,638.49	$ 1,599.79	2.4%
1,500		$ 66.00	$ 1,063.10	$ 658.89	$ 165.00	$ 1,952.99	$ 1,906.55	2.4%
1,587	Winter Avg.	$ 66.00	$ 1,124.75	$ 697.11	$ 174.57	$ 2,062.43	$ 2,013.30	2.4%
2,000		$ 66.00	$ 1,417.46	$ 878.52	$ 220.00	$ 2,581.98	$ 2,520.06	2.5%
3,000		$ 66.00	$ 2,126.19	$ 1,317.78	$ 330.00	$ 3,839.97	$ 3,747.09	2.5%
4,000		$ 66.00	$ 2,834.92	$ 1,757.04	$ 440.00	$ 5,097.96	$ 4,974.12	2.5%
5,000		$ 66.00	$ 3,543.65	$ 2,196.30	$ 550.00	$ 6,355.95	$ 6,201.15	2.5%
7,500		$ 66.00	$ 5,315.48	$ 3,294.45	$ 825.00	$ 9,500.93	$ 9,268.73	2.5%
10,000		$ 66.00	$ 7,087.30	$ 4,392.60	$ 1,100.00	$ 12,645.90	$ 12,336.30	2.5%

Summary of Bill Impacts

Rate Schedule G-25, General Gas Service, Small
Customer Bill Impact

	Staff Proposed Rates						
Monthly Consumption (therms)	Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
5	$ 27.50	$ 3.54	$ 3.44	$ 0.55	$ 35.03	$ 34.45	1.7%
9 Summer Avg.	$ 27.50	$ 6.38	$ 6.19	$ 0.99	$ 41.06	$ 40.00	2.7%
10	$ 27.50	$ 7.09	$ 6.88	$ 1.10	$ 42.57	$ 41.39	2.9%
15	$ 27.50	$ 10.63	$ 10.32	$ 1.65	$ 50.10	$ 48.34	3.6%
20	$ 27.50	$ 14.17	$ 13.76	$ 2.20	$ 57.63	$ 55.29	4.2%
22 Annual Avg.	$ 27.50	$ 15.59	$ 15.14	$ 2.42	$ 60.65	$ 58.07	4.4%
25	$ 27.50	$ 17.72	$ 17.20	$ 2.75	$ 65.17	$ 62.23	4.7%
30	$ 27.50	$ 21.26	$ 20.64	$ 3.30	$ 72.70	$ 69.18	5.1%
34 Winter Avg.	$ 27.50	$ 24.10	$ 23.40	$ 3.74	$ 78.74	$ 74.74	5.4%
40	$ 27.50	$ 28.35	$ 27.53	$ 4.40	$ 87.78	$ 83.07	5.7%
50	$ 27.50	$ 35.44	$ 34.41	$ 5.50	$ 102.85	$ 96.97	6.1%
60	$ 27.50	$ 42.52	$ 41.29	$ 6.60	$ 117.91	$ 110.86	6.4%
75	$ 27.50	$ 53.15	$ 51.61	$ 8.25	$ 140.51	$ 131.70	6.7%
100	$ 27.50	$ 70.87	$ 68.81	$ 11.00	$ 178.18	$ 166.43	7.1%
125	$ 27.50	$ 88.59	$ 86.02	$ 13.75	$ 215.86	$ 201.17	7.3%
150	$ 27.50	$ 106.31	$ 103.22	$ 16.50	$ 253.53	$ 235.90	7.5%
200	$ 27.50	$ 141.75	$ 137.63	$ 22.00	$ 328.88	$ 305.36	7.7%
250	$ 27.50	$ 177.18	$ 172.03	$ 27.50	$ 404.21	$ 374.83	7.8%
300	$ 27.50	$ 212.62	$ 206.44	$ 33.00	$ 479.56	$ 444.30	7.9%
400	$ 27.50	$ 283.49	$ 275.25	$ 44.00	$ 630.24	$ 583.23	8.1%
500	$ 27.50	$ 354.37	$ 344.07	$ 55.00	$ 780.94	$ 722.16	8.1%
600	$ 27.50	$ 425.24	$ 412.88	$ 66.00	$ 931.62	$ 861.09	8.2%

Summary of Bill Impacts

Rate Schedule G-25, General Gas Service, Medium
Customer Bill Impact

Monthly Consumption (therms)		Staff Proposed Rates: Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
25		$ 43.50	$ 17.72	$ 10.43	$ 2.75	$ 74.40	$ 73.47	1.3%
50		$ 43.50	$ 35.44	$ 20.86	$ 5.50	$ 105.30	$ 103.43	1.8%
75		$ 43.50	$ 53.15	$ 31.29	$ 8.25	$ 136.19	$ 133.40	2.1%
100		$ 43.50	$ 70.87	$ 41.72	$ 11.00	$ 167.09	$ 163.37	2.3%
125		$ 43.50	$ 88.59	$ 52.15	$ 13.75	$ 197.99	$ 193.34	2.4%
150		$ 43.50	$ 106.31	$ 62.58	$ 16.50	$ 228.89	$ 223.30	2.5%
152	Summer Avg.	$ 43.50	$ 107.73	$ 63.41	$ 16.72	$ 231.36	$ 225.70	2.5%
175		$ 43.50	$ 124.03	$ 73.00	$ 19.25	$ 259.78	$ 253.27	2.6%
200		$ 43.50	$ 141.75	$ 83.43	$ 22.00	$ 290.68	$ 283.24	2.6%
220		$ 43.50	$ 155.92	$ 91.78	$ 24.20	$ 315.40	$ 307.21	2.7%
223	Annual Avg.	$ 43.50	$ 158.05	$ 93.03	$ 24.53	$ 319.11	$ 310.81	2.7%
250		$ 43.50	$ 177.18	$ 104.29	$ 27.50	$ 352.47	$ 343.17	2.7%
275		$ 43.50	$ 194.90	$ 114.72	$ 30.25	$ 383.37	$ 373.14	2.7%
290		$ 43.50	$ 205.53	$ 120.98	$ 31.90	$ 401.91	$ 391.12	2.8%
295	Winter Avg.	$ 43.50	$ 209.08	$ 123.07	$ 32.45	$ 408.10	$ 397.11	2.8%
300		$ 43.50	$ 212.62	$ 125.15	$ 33.00	$ 414.27	$ 403.11	2.8%
400		$ 43.50	$ 283.49	$ 166.87	$ 44.00	$ 537.86	$ 522.98	2.8%
500		$ 43.50	$ 354.37	$ 208.59	$ 55.00	$ 661.46	$ 642.85	2.9%
600		$ 43.50	$ 425.24	$ 250.30	$ 66.00	$ 785.04	$ 762.71	2.9%
750		$ 43.50	$ 531.55	$ 312.88	$ 82.50	$ 970.43	$ 942.52	3.0%
1,000		$ 43.50	$ 708.73	$ 417.17	$ 110.00	$ 1,279.40	$ 1,242.19	3.0%

Summary of Bill Impacts

Rate Schedule G-25, General Gas Service, Large-1
Customer Bill Impact

Monthly Consumption (therms)		Staff Proposed Rates: Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
200		$ 120.00	$ 141.75	$ 70.29	$ 22.00	$ 354.04	$ 381.91	-7.3%
400		$ 120.00	$ 283.49	$ 140.58	$ 44.00	$ 588.07	$ 603.83	-2.6%
600		$ 120.00	$ 425.24	$ 210.87	$ 66.00	$ 822.11	$ 825.74	-0.4%
800		$ 120.00	$ 566.98	$ 281.16	$ 88.00	$ 1,056.14	$ 1,047.66	0.8%
890	Summer Avg.	$ 120.00	$ 630.77	$ 312.79	$ 97.90	$ 1,161.46	$ 1,147.52	1.2%
1,000		$ 120.00	$ 708.73	$ 351.45	$ 110.00	$ 1,290.18	$ 1,269.57	1.6%
1,212	Annual Avg.	$ 120.00	$ 858.98	$ 425.96	$ 133.32	$ 1,538.26	$ 1,504.80	2.2%
1,250		$ 120.00	$ 885.91	$ 439.31	$ 137.50	$ 1,582.72	$ 1,546.96	2.3%
1,500		$ 120.00	$ 1,063.10	$ 527.18	$ 165.00	$ 1,875.28	$ 1,824.36	2.8%
1,532	Winter Avg.	$ 120.00	$ 1,085.77	$ 538.42	$ 168.52	$ 1,912.71	$ 1,859.86	2.8%
2,000		$ 120.00	$ 1,417.46	$ 702.90	$ 220.00	$ 2,460.36	$ 2,379.14	3.4%
2,500		$ 120.00	$ 1,771.83	$ 878.63	$ 275.00	$ 3,045.46	$ 2,933.93	3.8%
3,000		$ 120.00	$ 2,126.19	$ 1,054.35	$ 330.00	$ 3,630.54	$ 3,488.71	4.1%
4,000		$ 120.00	$ 2,834.92	$ 1,405.80	$ 440.00	$ 4,800.72	$ 4,598.28	4.4%
5,000		$ 120.00	$ 3,543.65	$ 1,757.25	$ 550.00	$ 5,970.90	$ 5,707.85	4.6%
7,500		$ 120.00	$ 5,315.48	$ 2,635.88	$ 825.00	$ 8,896.36	$ 8,481.78	4.9%
10,000		$ 120.00	$ 7,087.30	$ 3,514.50	$ 1,100.00	$ 11,821.80	$ 11,255.70	5.0%
15,000		$ 120.00	$ 10,630.95	$ 5,271.75	$ 1,650.00	$ 17,672.70	$ 16,803.55	5.2%

Summary of Bill Impacts

Rate Schedule G-25, General Gas Service, Large-2
Customer Bill Impact

Monthly Consumption (therms)		Staff Proposed Rates: Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
2,000		$ 240.00	$ 1,417.46	$ 613.36	$ 220.00	$ 2,490.82	$ 2,379.14	4.7%
5,000		$ 240.00	$ 3,543.65	$ 1,533.40	$ 550.00	$ 5,867.05	$ 5,707.85	2.8%
5,241	Summer Avg.	$ 240.00	$ 3,714.45	$ 1,607.31	$ 576.51	$ 6,138.27	$ 5,975.26	2.7%
7,000		$ 240.00	$ 4,961.11	$ 2,146.76	$ 770.00	$ 8,117.87	$ 7,926.99	2.4%
7,116	Annual Avg.	$ 240.00	$ 5,043.32	$ 2,182.33	$ 782.76	$ 8,248.41	$ 8,055.70	2.4%
8,000		$ 240.00	$ 5,669.84	$ 2,453.44	$ 880.00	$ 9,243.28	$ 9,036.56	2.3%
8,991	Winter Avg.	$ 240.00	$ 6,372.19	$ 2,757.36	$ 989.01	$ 10,358.56	$ 10,136.14	2.2%
10,000		$ 240.00	$ 7,087.30	$ 3,066.80	$ 1,100.00	$ 11,494.10	$ 11,255.70	2.1%
15,000		$ 240.00	$ 10,630.95	$ 4,600.20	$ 1,650.00	$ 17,121.15	$ 16,803.55	1.9%
20,000		$ 240.00	$ 14,174.60	$ 6,133.60	$ 2,200.00	$ 22,748.20	$ 22,351.40	1.8%
25,000		$ 240.00	$ 17,718.25	$ 7,667.00	$ 2,750.00	$ 28,375.25	$ 27,899.25	1.7%
30,000		$ 240.00	$ 21,261.90	$ 9,200.40	$ 3,300.00	$ 34,002.30	$ 33,447.10	1.7%
35,000		$ 240.00	$ 24,805.55	$ 10,733.80	$ 3,850.00	$ 39,629.35	$ 38,994.95	1.6%
40,000		$ 240.00	$ 28,349.20	$ 12,267.20	$ 4,400.00	$ 45,256.40	$ 44,542.80	1.6%
45,000		$ 240.00	$ 31,892.85	$ 13,800.60	$ 4,950.00	$ 50,883.45	$ 50,090.65	1.6%
50,000		$ 240.00	$ 35,436.50	$ 15,334.00	$ 5,500.00	$ 56,510.50	$ 55,638.50	1.6%
60,000		$ 240.00	$ 42,523.80	$ 18,400.80	$ 6,600.00	$ 67,764.60	$ 66,734.20	1.5%
75,000		$ 240.00	$ 53,154.75	$ 23,001.00	$ 8,250.00	$ 84,645.75	$ 83,377.75	1.5%
100,000		$ 240.00	$ 70,873.00	$ 30,668.00	$ 11,000.00	$ 112,781.00	$ 111,117.00	1.5%
150,000		$ 240.00	$ 106,309.50	$ 46,002.00	$ 16,500.00	$ 169,051.50	$ 166,595.50	1.5%
200,000		$ 240.00	$ 141,746.00	$ 61,336.00	$ 22,000.00	$ 225,322.00	$ 222,074.00	1.5%

Summary of Bill Impacts

Rate Schedule G-40, Air Conditioning Gas Service
Customer Bill Impact - Small General Service

		Staff Proposed Rates						
Monthly Consumption (therms)		Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
50		$ 27.50	$ 35.44	$ 6.98	$ 5.50	$ 75.42	$ 73.94	2.0%
100		$ 27.50	$ 70.87	$ 13.97	$ 11.00	$ 123.34	$ 120.38	2.5%
234	Winter Avg.	$ 27.50	$ 165.84	$ 32.68	$ 25.74	$ 251.76	$ 244.85	2.8%
250		$ 27.50	$ 177.18	$ 34.91	$ 27.50	$ 267.09	$ 259.71	2.8%
388	Annual Avg.	$ 27.50	$ 274.99	$ 54.18	$ 42.68	$ 399.35	$ 387.89	3.0%
500		$ 27.50	$ 354.37	$ 69.83	$ 55.00	$ 506.70	$ 491.92	3.0%
536	Summer Avg.	$ 27.50	$ 379.88	$ 74.85	$ 58.96	$ 541.19	$ 525.35	3.0%
750		$ 27.50	$ 531.55	$ 104.74	$ 82.50	$ 746.29	$ 724.12	3.1%
1,000		$ 27.50	$ 708.73	$ 139.65	$ 110.00	$ 985.88	$ 956.33	3.1%
2,000		$ 27.50	$ 1,417.46	$ 279.30	$ 220.00	$ 1,944.26	$ 1,885.16	3.1%
3,000		$ 27.50	$ 2,126.19	$ 418.95	$ 330.00	$ 2,902.64	$ 2,813.99	3.2%
5,000		$ 27.50	$ 3,543.65	$ 698.25	$ 550.00	$ 4,819.40	$ 4,671.65	3.2%
7,500		$ 27.50	$ 5,315.48	$ 1,047.38	$ 825.00	$ 7,215.36	$ 6,993.73	3.2%
10,000		$ 27.50	$ 7,087.30	$ 1,396.50	$ 1,100.00	$ 9,611.30	$ 9,315.80	3.2%
15,000		$ 27.50	$ 10,630.95	$ 2,094.75	$ 1,650.00	$ 14,403.20	$ 13,959.95	3.2%
20,000		$ 27.50	$ 14,174.60	$ 2,793.00	$ 2,200.00	$ 19,195.10	$ 18,604.10	3.2%
30,000		$ 27.50	$ 21,261.90	$ 4,189.50	$ 3,300.00	$ 28,778.90	$ 27,892.40	3.2%
40,000		$ 27.50	$ 28,349.20	$ 5,586.00	$ 4,400.00	$ 38,362.70	$ 37,180.70	3.2%
50,000		$ 27.50	$ 35,436.50	$ 6,982.50	$ 5,500.00	$ 47,946.50	$ 46,469.00	3.2%

Summary of Bill Impacts

Rate Schedule G-40, Air Conditioning Gas Service
Customer Bill Impact - Large General Service

		Staff Proposed Rates						
Monthly Consumption (therms)		Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
50		$ 120.00	$ 35.44	$ 6.98	$ 5.50	$ 167.92	$ 206.44	-18.7%
100		$ 120.00	$ 70.87	$ 13.97	$ 11.00	$ 215.84	$ 252.88	-14.6%
234	Winter Avg.	$ 120.00	$ 165.84	$ 32.68	$ 25.74	$ 344.26	$ 377.35	-8.8%
250		$ 120.00	$ 177.18	$ 34.91	$ 27.50	$ 359.59	$ 392.21	-8.3%
388	Annual Avg.	$ 120.00	$ 274.99	$ 54.18	$ 42.68	$ 491.85	$ 520.39	-5.5%
500		$ 120.00	$ 354.37	$ 69.83	$ 55.00	$ 599.20	$ 624.42	-4.0%
536	Summer Avg.	$ 120.00	$ 379.88	$ 74.85	$ 58.96	$ 633.69	$ 657.85	-3.7%
750		$ 120.00	$ 531.55	$ 104.74	$ 82.50	$ 838.79	$ 856.62	-2.1%
1,000		$ 120.00	$ 708.73	$ 139.65	$ 110.00	$ 1,078.38	$ 1,088.83	-1.0%
2,000		$ 120.00	$ 1,417.46	$ 279.30	$ 220.00	$ 2,036.76	$ 2,017.66	0.9%
3,000		$ 120.00	$ 2,126.19	$ 418.95	$ 330.00	$ 2,995.14	$ 2,946.49	1.7%
5,000		$ 120.00	$ 3,543.65	$ 698.25	$ 550.00	$ 4,911.90	$ 4,804.15	2.2%
7,500		$ 120.00	$ 5,315.48	$ 1,047.38	$ 825.00	$ 7,307.86	$ 7,126.23	2.5%
10,000		$ 120.00	$ 7,087.30	$ 1,396.50	$ 1,100.00	$ 9,703.80	$ 9,448.30	2.7%
15,000		$ 120.00	$ 10,630.95	$ 2,094.75	$ 1,650.00	$ 14,495.70	$ 14,092.45	2.9%
20,000		$ 120.00	$ 14,174.60	$ 2,793.00	$ 2,200.00	$ 19,287.60	$ 18,736.60	2.9%
30,000		$ 120.00	$ 21,261.90	$ 4,189.50	$ 3,300.00	$ 28,871.40	$ 28,024.90	3.0%
40,000		$ 120.00	$ 28,349.20	$ 5,586.00	$ 4,400.00	$ 38,455.20	$ 37,313.20	3.1%
50,000		$ 120.00	$ 35,436.50	$ 6,982.50	$ 5,500.00	$ 48,039.00	$ 46,601.50	3.1%

Summary of Bill Impacts

Rate Schedule G-45, Street Lighting Gas Service
Customer Bill Impact

Monthly Consumption (therms)		Staff Proposed Rates: Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
25		$ -	$ 17.72	$ 18.15	$ 2.75	$ 38.62	$ 35.73	8.1%
50		$ -	$ 35.44	$ 36.30	$ 5.50	$ 77.24	$ 71.46	8.1%
75		$ -	$ 53.15	$ 54.44	$ 8.25	$ 115.84	$ 107.19	8.1%
100		$ -	$ 70.87	$ 72.59	$ 11.00	$ 154.46	$ 142.92	8.1%
125		$ -	$ 88.59	$ 90.74	$ 13.75	$ 193.08	$ 178.65	8.1%
150		$ -	$ 106.31	$ 108.89	$ 16.50	$ 231.70	$ 214.38	8.1%
175		$ -	$ 124.03	$ 127.03	$ 19.25	$ 270.31	$ 250.12	8.1%
200		$ -	$ 141.75	$ 145.18	$ 22.00	$ 308.93	$ 285.85	8.1%
250		$ -	$ 177.18	$ 181.48	$ 27.50	$ 386.16	$ 357.31	8.1%
300		$ -	$ 212.62	$ 217.77	$ 33.00	$ 463.39	$ 428.77	8.1%
350		$ -	$ 248.06	$ 254.07	$ 38.50	$ 540.63	$ 500.23	8.1%
400		$ -	$ 283.49	$ 290.36	$ 44.00	$ 617.85	$ 571.69	8.1%
407	Winter Avg.	$ -	$ 288.45	$ 295.44	$ 44.77	$ 628.66	$ 581.70	8.1%
486	Annual Avg.	$ -	$ 344.44	$ 352.79	$ 53.46	$ 750.69	$ 694.61	8.1%
500		$ -	$ 354.37	$ 362.95	$ 55.00	$ 772.32	$ 714.62	8.1%
564	Summer Avg.	$ -	$ 399.72	$ 409.41	$ 62.04	$ 871.17	$ 806.09	8.1%
750		$ -	$ 531.55	$ 544.43	$ 82.50	$ 1,158.48	$ 1,071.92	8.1%
1,000		$ -	$ 708.73	$ 725.90	$ 110.00	$ 1,544.63	$ 1,429.23	8.1%
1,500		$ -	$ 1,063.10	$ 1,088.85	$ 165.00	$ 2,316.95	$ 2,143.85	8.1%

Summary of Bill Impacts

Rate Schedule G-55, Gas Service for Compression on Customer's Premises
Customer Bill Impact - Small

Monthly Consumption (therms)		Staff Proposed Rates: Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
25		$ 27.50	$ 17.72	$ 4.80	$ 2.75	$ 52.77	$ 52.64	0.2%
50		$ 27.50	$ 35.44	$ 9.61	$ 5.50	$ 78.05	$ 77.78	0.3%
75		$ 27.50	$ 53.15	$ 14.41	$ 8.25	$ 103.31	$ 102.91	0.4%
100		$ 27.50	$ 70.87	$ 19.22	$ 11.00	$ 128.59	$ 128.05	0.4%
125		$ 27.50	$ 88.59	$ 24.02	$ 13.75	$ 153.86	$ 153.19	0.4%
150		$ 27.50	$ 106.31	$ 28.82	$ 16.50	$ 179.13	$ 178.33	0.4%
175		$ 27.50	$ 124.03	$ 33.63	$ 19.25	$ 204.41	$ 203.46	0.5%
200		$ 27.50	$ 141.75	$ 38.43	$ 22.00	$ 229.68	$ 228.60	0.5%
250		$ 27.50	$ 177.18	$ 48.04	$ 27.50	$ 280.22	$ 278.88	0.5%
300		$ 27.50	$ 212.62	$ 57.65	$ 33.00	$ 330.77	$ 329.15	0.5%
350		$ 27.50	$ 248.06	$ 67.25	$ 38.50	$ 381.31	$ 379.43	0.5%
400		$ 27.50	$ 283.49	$ 76.86	$ 44.00	$ 431.85	$ 429.70	0.5%
450		$ 27.50	$ 318.93	$ 86.47	$ 49.50	$ 482.40	$ 479.98	0.5%
473	Winter Avg.	$ 27.50	$ 335.23	$ 90.89	$ 52.03	$ 505.65	$ 503.11	0.5%
500		$ 27.50	$ 354.37	$ 96.08	$ 55.00	$ 532.95	$ 530.26	0.5%
528	Annual Avg.	$ 27.50	$ 374.21	$ 101.46	$ 58.08	$ 561.25	$ 558.41	0.5%
584	Summer Avg.	$ 27.50	$ 413.90	$ 112.22	$ 64.24	$ 617.86	$ 614.72	0.5%
750		$ 27.50	$ 531.55	$ 144.11	$ 82.50	$ 785.66	$ 781.63	0.5%
1,000		$ 27.50	$ 708.73	$ 192.15	$ 110.00	$ 1,038.38	$ 1,033.01	0.5%
1,250		$ 27.50	$ 885.91	$ 240.19	$ 137.50	$ 1,291.10	$ 1,284.39	0.5%

Summary of Bill Impacts

Rate Schedule G-55, Gas Service for Compression on Customer's Premises
Customer Bill Impact - Large

		Staff Proposed Rates						
Monthly Consumption (therms)		Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
1,000		$ 250.00	$ 708.73	$ 192.15	$ 110.00	$ 1,260.88	$ 1,255.51	0.4%
2,000		$ 250.00	$ 1,417.46	$ 384.30	$ 220.00	$ 2,271.76	$ 2,261.02	0.5%
3,000		$ 250.00	$ 2,126.19	$ 576.45	$ 330.00	$ 3,282.64	$ 3,266.53	0.5%
4,000		$ 250.00	$ 2,834.92	$ 768.60	$ 440.00	$ 4,293.52	$ 4,272.04	0.5%
4,922	Summer Avg.	$ 250.00	$ 3,488.37	$ 945.76	$ 541.42	$ 5,225.55	$ 5,199.12	0.5%
5,000		$ 250.00	$ 3,543.65	$ 960.75	$ 550.00	$ 5,304.40	$ 5,277.55	0.5%
5,186	Annual Avg.	$ 250.00	$ 3,675.47	$ 996.49	$ 570.46	$ 5,492.42	$ 5,464.57	0.5%
5,450	Winter Avg.	$ 250.00	$ 3,862.58	$ 1,047.22	$ 599.50	$ 5,759.30	$ 5,730.03	0.5%
6,000		$ 250.00	$ 4,252.38	$ 1,152.90	$ 660.00	$ 6,315.28	$ 6,283.06	0.5%
7,000		$ 250.00	$ 4,961.11	$ 1,345.05	$ 770.00	$ 7,326.16	$ 7,288.57	0.5%
8,000		$ 250.00	$ 5,669.84	$ 1,537.20	$ 880.00	$ 8,337.04	$ 8,294.08	0.5%
9,000		$ 250.00	$ 6,378.57	$ 1,729.35	$ 990.00	$ 9,347.92	$ 9,299.59	0.5%
10,000		$ 250.00	$ 7,087.30	$ 1,921.50	$ 1,100.00	$ 10,358.80	$ 10,305.10	0.5%
12,500		$ 250.00	$ 8,859.13	$ 2,401.88	$ 1,375.00	$ 12,886.01	$ 12,818.88	0.5%
15,000		$ 250.00	$ 10,630.95	$ 2,882.25	$ 1,650.00	$ 15,413.20	$ 15,332.65	0.5%
17,500		$ 250.00	$ 12,402.78	$ 3,362.63	$ 1,925.00	$ 17,940.41	$ 17,846.43	0.5%
20,000		$ 250.00	$ 14,174.60	$ 3,843.00	$ 2,200.00	$ 20,467.60	$ 20,360.20	0.5%
25,000		$ 250.00	$ 17,718.25	$ 4,803.75	$ 2,750.00	$ 25,522.00	$ 25,387.75	0.5%
35,000		$ 250.00	$ 24,805.55	$ 6,725.25	$ 3,850.00	$ 35,630.80	$ 35,442.85	0.5%
50,000		$ 250.00	$ 35,436.50	$ 9,607.50	$ 5,500.00	$ 50,794.00	$ 50,525.50	0.5%

Summary of Bill Impacts

Rate Schedule G-55, Gas Service for Compression on Customer's Premises
Customer Bill Impact - Residential

	Staff Proposed Rates						
Monthly Consumption (therms)	Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
5	$ 10.70	$ 3.54	$ 0.96	$ 0.55	$ 15.75	$ 15.73	0.1%
10	$ 10.70	$ 7.09	$ 1.92	$ 1.10	$ 20.81	$ 20.76	0.2%
15	$ 10.70	$ 10.63	$ 2.88	$ 1.65	$ 25.86	$ 25.78	0.3%
20	$ 10.70	$ 14.17	$ 3.84	$ 2.20	$ 30.91	$ 30.81	0.3%
25	$ 10.70	$ 17.72	$ 4.80	$ 2.75	$ 35.97	$ 35.84	0.4%
30	$ 10.70	$ 21.26	$ 5.76	$ 3.30	$ 41.02	$ 40.87	0.4%
34 Winter Avg.	$ 10.70	$ 24.10	$ 6.53	$ 3.74	$ 45.07	$ 44.89	0.4%
36 Annual Avg.	$ 10.70	$ 25.51	$ 6.92	$ 3.96	$ 47.09	$ 46.90	0.4%
37 Summer Avg.	$ 10.70	$ 26.22	$ 7.11	$ 4.07	$ 48.10	$ 47.90	0.4%
40	$ 10.70	$ 28.35	$ 7.69	$ 4.40	$ 51.14	$ 50.92	0.4%
50	$ 10.70	$ 35.44	$ 9.61	$ 5.50	$ 61.25	$ 60.98	0.4%
60	$ 10.70	$ 42.52	$ 11.53	$ 6.60	$ 71.35	$ 71.03	0.5%
75	$ 10.70	$ 53.15	$ 14.41	$ 8.25	$ 86.51	$ 86.11	0.5%
100	$ 10.70	$ 70.87	$ 19.22	$ 11.00	$ 111.79	$ 111.25	0.5%
125	$ 10.70	$ 88.59	$ 24.02	$ 13.75	$ 137.06	$ 136.39	0.5%
150	$ 10.70	$ 106.31	$ 28.82	$ 16.50	$ 162.33	$ 161.53	0.5%
200	$ 10.70	$ 141.75	$ 38.43	$ 22.00	$ 212.88	$ 211.80	0.5%
250	$ 10.70	$ 177.18	$ 48.04	$ 27.50	$ 263.42	$ 262.08	0.5%
300	$ 10.70	$ 212.62	$ 57.65	$ 33.00	$ 313.97	$ 312.35	0.5%
400	$ 10.70	$ 283.49	$ 76.86	$ 44.00	$ 415.05	$ 412.90	0.5%
500	$ 10.70	$ 354.37	$ 96.08	$ 55.00	$ 516.15	$ 513.46	0.5%

Summary of Bill Impacts

Rate Schedule G-60, Cogeneration Gas Service
Customer Bill Impact - Small

	Staff Proposed Rates						
Monthly Consumption (therms)	Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
0 Summer Avg.	$ 27.50	$ -	$ -	$ -	$ 27.50	$ 27.50	0.0%
5	$ 27.50	$ 3.54	$ 0.82	$ 0.55	$ 32.41	$ 32.27	0.4%
6 Annual Avg.	$ 27.50	$ 4.25	$ 0.99	$ 0.66	$ 33.40	$ 33.22	0.5%
10	$ 27.50	$ 7.09	$ 1.65	$ 1.10	$ 37.34	$ 37.04	0.8%
11 Winter Avg.	$ 27.50	$ 7.80	$ 1.81	$ 1.21	$ 38.32	$ 37.99	0.9%
15	$ 27.50	$ 10.63	$ 2.47	$ 1.65	$ 42.25	$ 41.81	1.1%
25	$ 27.50	$ 17.72	$ 4.12	$ 2.75	$ 52.09	$ 51.35	1.4%
50	$ 27.50	$ 35.44	$ 8.25	$ 5.50	$ 76.69	$ 75.20	2.0%
75	$ 27.50	$ 53.15	$ 12.37	$ 8.25	$ 101.27	$ 99.06	2.2%
100	$ 27.50	$ 70.87	$ 16.50	$ 11.00	$ 125.87	$ 122.91	2.4%
125	$ 27.50	$ 88.59	$ 20.62	$ 13.75	$ 150.46	$ 146.76	2.5%
150	$ 27.50	$ 106.31	$ 24.74	$ 16.50	$ 175.05	$ 170.61	2.6%
175	$ 27.50	$ 124.03	$ 28.87	$ 19.25	$ 199.65	$ 194.46	2.7%
200	$ 27.50	$ 141.75	$ 32.99	$ 22.00	$ 224.24	$ 218.32	2.7%
250	$ 27.50	$ 177.18	$ 41.24	$ 27.50	$ 273.42	$ 266.02	2.8%
300	$ 27.50	$ 212.62	$ 49.49	$ 33.00	$ 322.61	$ 313.72	2.8%
350	$ 27.50	$ 248.06	$ 57.74	$ 38.50	$ 371.80	$ 361.43	2.9%
400	$ 27.50	$ 283.49	$ 65.98	$ 44.00	$ 420.97	$ 409.13	2.9%
450	$ 27.50	$ 318.93	$ 74.23	$ 49.50	$ 470.16	$ 456.84	2.9%
500	$ 27.50	$ 354.37	$ 82.48	$ 55.00	$ 519.35	$ 504.54	2.9%
750	$ 27.50	$ 531.55	$ 123.72	$ 82.50	$ 765.27	$ 743.06	3.0%
1000	$ 27.50	$ 708.73	$ 164.96	$ 110.00	$ 1,011.19	$ 981.58	3.0%
1250	$ 27.50	$ 885.91	$ 206.20	$ 137.50	$ 1,257.11	$ 1,220.10	3.0%

Summary of Bill Impacts

Rate Schedule G-60, Cogeneration Gas Service
Customer Bill Impact - Medium

Monthly Consumption (therms)		Staff Proposed Rates: Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
500		$ 43.50	$ 354.37	$ 82.48	$ 55.00	$ 535.35	$ 520.54	2.8%
600		$ 43.50	$ 425.24	$ 98.98	$ 66.00	$ 633.72	$ 615.95	2.9%
700		$ 43.50	$ 496.11	$ 115.47	$ 77.00	$ 732.08	$ 711.36	2.9%
800		$ 43.50	$ 566.98	$ 131.97	$ 88.00	$ 830.45	$ 806.76	2.9%
900		$ 43.50	$ 637.86	$ 148.46	$ 99.00	$ 928.82	$ 902.17	3.0%
1,000		$ 43.50	$ 708.73	$ 164.96	$ 110.00	$ 1,027.19	$ 997.58	3.0%
1,250		$ 43.50	$ 885.91	$ 206.20	$ 137.50	$ 1,273.11	$ 1,236.10	3.0%
1,500		$ 43.50	$ 1,063.10	$ 247.44	$ 165.00	$ 1,519.04	$ 1,474.62	3.0%
2,000		$ 43.50	$ 1,417.46	$ 329.92	$ 220.00	$ 2,010.88	$ 1,951.66	3.0%
3,000		$ 43.50	$ 2,126.19	$ 494.88	$ 330.00	$ 2,994.57	$ 2,905.74	3.1%
3,772	Summer Avg.	$ 43.50	$ 2,673.33	$ 622.23	$ 414.92	$ 3,753.98	$ 3,642.29	3.1%
4,000		$ 43.50	$ 2,834.92	$ 659.84	$ 440.00	$ 3,978.26	$ 3,859.82	3.1%
5,000		$ 43.50	$ 3,543.65	$ 824.80	$ 550.00	$ 4,961.95	$ 4,813.90	3.1%
5,076	Annual Avg.	$ 43.50	$ 3,597.51	$ 837.34	$ 558.36	$ 5,036.71	$ 4,886.41	3.1%
6,380	Winter Avg.	$ 43.50	$ 4,521.70	$ 1,052.44	$ 701.80	$ 6,319.44	$ 6,130.53	3.1%
7,500		$ 43.50	$ 5,315.48	$ 1,237.20	$ 825.00	$ 7,421.18	$ 7,199.10	3.1%
10,000		$ 43.50	$ 7,087.30	$ 1,649.60	$ 1,100.00	$ 9,880.40	$ 9,584.30	3.1%
12,500		$ 43.50	$ 8,859.13	$ 2,062.00	$ 1,375.00	$ 12,339.63	$ 11,969.50	3.1%
15,000		$ 43.50	$ 10,630.95	$ 2,474.40	$ 1,650.00	$ 14,798.85	$ 14,354.70	3.1%
20,000		$ 43.50	$ 14,174.60	$ 3,299.20	$ 2,200.00	$ 19,717.30	$ 19,125.10	3.1%

Summary of Bill Impacts

Rate Schedule G-60, Cogeneration Gas Service
Customer Bill Impact - Large

		Staff Proposed Rates						
Monthly Consumption (therms)		Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
2,206	Summer Avg.	$ 120.00	$ 1,563.46	$ 363.90	$ 242.66	$ 2,290.02	$ 2,264.70	1.1%
3,000		$ 120.00	$ 2,126.19	$ 494.88	$ 330.00	$ 3,071.07	$ 3,022.24	1.6%
3,733	Annual Avg.	$ 120.00	$ 2,645.69	$ 615.80	$ 410.63	$ 3,792.12	$ 3,721.58	1.9%
5,000		$ 120.00	$ 3,543.65	$ 824.80	$ 550.00	$ 5,038.45	$ 4,930.40	2.2%
5,260	Winter Avg.	$ 120.00	$ 3,727.92	$ 867.69	$ 578.60	$ 5,294.21	$ 5,178.46	2.2%
10,000		$ 120.00	$ 7,087.30	$ 1,649.60	$ 1,100.00	$ 9,956.90	$ 9,700.80	2.6%
12,500		$ 120.00	$ 8,859.13	$ 2,062.00	$ 1,375.00	$ 12,416.13	$ 12,086.00	2.7%
15,000		$ 120.00	$ 10,630.95	$ 2,474.40	$ 1,650.00	$ 14,875.35	$ 14,471.20	2.8%
17,500		$ 120.00	$ 12,402.78	$ 2,886.80	$ 1,925.00	$ 17,334.58	$ 16,856.40	2.8%
20,000		$ 120.00	$ 14,174.60	$ 3,299.20	$ 2,200.00	$ 19,793.80	$ 19,241.60	2.9%
25,000		$ 120.00	$ 17,718.25	$ 4,124.00	$ 2,750.00	$ 24,712.25	$ 24,012.00	2.9%
30,000		$ 120.00	$ 21,261.90	$ 4,948.80	$ 3,300.00	$ 29,630.70	$ 28,782.40	2.9%
35,000		$ 120.00	$ 24,805.55	$ 5,773.60	$ 3,850.00	$ 34,549.15	$ 33,552.80	3.0%
40,000		$ 120.00	$ 28,349.20	$ 6,598.40	$ 4,400.00	$ 39,467.60	$ 38,323.20	3.0%
45,000		$ 120.00	$ 31,892.85	$ 7,423.20	$ 4,950.00	$ 44,386.05	$ 43,093.60	3.0%
50,000		$ 120.00	$ 35,436.50	$ 8,248.00	$ 5,500.00	$ 49,304.50	$ 47,864.00	3.0%
75,000		$ 120.00	$ 53,154.75	$ 12,372.00	$ 8,250.00	$ 73,896.75	$ 71,716.00	3.0%
100,000		$ 120.00	$ 70,873.00	$ 16,496.00	$ 11,000.00	$ 98,489.00	$ 95,568.00	3.1%
150,000		$ 120.00	$ 106,309.50	$ 24,744.00	$ 16,500.00	$ 147,673.50	$ 143,272.00	3.1%
200,000		$ 120.00	$ 141,746.00	$ 32,992.00	$ 22,000.00	$ 196,858.00	$ 190,976.00	3.1%
300,000		$ 120.00	$ 212,619.00	$ 49,488.00	$ 33,000.00	$ 295,227.00	$ 286,384.00	3.1%
500,000		$ 120.00	$ 354,365.00	$ 82,480.00	$ 55,000.00	$ 491,965.00	$ 477,200.00	3.1%

Summary of Bill Impacts

Rate Schedule G-75, Small Essential Agriculture User Gas Service
Customer Bill Impact

Monthly Consumption (therms)		Staff Proposed Rates: Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
25		$ 120.00	$ 17.72	$ 6.59	$ 2.75	$ 147.06	$ 146.57	0.3%
50		$ 120.00	$ 35.44	$ 13.17	$ 5.50	$ 174.11	$ 173.13	0.6%
100		$ 120.00	$ 70.87	$ 26.34	$ 11.00	$ 228.21	$ 226.27	0.9%
250		$ 120.00	$ 177.18	$ 65.86	$ 27.50	$ 390.54	$ 385.67	1.3%
500		$ 120.00	$ 354.37	$ 131.72	$ 55.00	$ 661.09	$ 651.35	1.5%
1,000		$ 120.00	$ 708.73	$ 263.44	$ 110.00	$ 1,202.17	$ 1,182.69	1.6%
2,500		$ 120.00	$ 1,771.83	$ 658.60	$ 275.00	$ 2,825.43	$ 2,776.73	1.8%
4,296	Summer Avg.	$ 120.00	$ 3,044.70	$ 1,131.74	$ 472.56	$ 4,769.00	$ 4,685.32	1.8%
4,485	Annual Avg.	$ 120.00	$ 3,178.65	$ 1,181.53	$ 493.35	$ 4,973.53	$ 4,886.16	1.8%
4,641	Winter Avg.	$ 120.00	$ 3,289.22	$ 1,222.63	$ 510.51	$ 5,142.36	$ 5,051.94	1.8%
5,000		$ 120.00	$ 3,543.65	$ 1,317.20	$ 550.00	$ 5,530.85	$ 5,433.45	1.8%
7,500		$ 120.00	$ 5,315.48	$ 1,975.80	$ 825.00	$ 8,236.28	$ 8,090.18	1.8%
10,000		$ 120.00	$ 7,087.30	$ 2,634.40	$ 1,100.00	$ 10,941.70	$ 10,746.90	1.8%
15,000		$ 120.00	$ 10,630.95	$ 3,951.60	$ 1,650.00	$ 16,352.55	$ 16,060.35	1.8%
25,000		$ 120.00	$ 17,718.25	$ 6,586.00	$ 2,750.00	$ 27,174.25	$ 26,687.25	1.8%
50,000		$ 120.00	$ 35,436.50	$ 13,172.00	$ 5,500.00	$ 54,228.50	$ 53,254.50	1.8%
75,000		$ 120.00	$ 53,154.75	$ 19,758.00	$ 8,250.00	$ 81,282.75	$ 79,821.75	1.8%
100,000		$ 120.00	$ 70,873.00	$ 26,344.00	$ 11,000.00	$ 108,337.00	$ 106,389.00	1.8%

Summary of Bill Impacts

Rate Schedule G-80, Natural Gas Engine Gas Service
Customer Bill Impact

Monthly Consumption (therms)		Staff Proposed Rates: Basic Service Charge	Base Cost of Gas	Margin Rate	Monthly PGA Rate	Total Bill	Current Rates - Total Bill	Percent Increase
50		$ 125.00	$ 25.17	$ 10.37	$ 5.50	$ 166.04	$ 165.21	0.5%
100		$ 125.00	$ 50.35	$ 20.74	$ 11.00	$ 207.09	$ 205.41	0.8%
200		$ 125.00	$ 100.69	$ 41.49	$ 22.00	$ 289.18	$ 285.83	1.2%
500		$ 125.00	$ 251.73	$ 103.72	$ 55.00	$ 535.45	$ 527.07	1.6%
974	Off-Peak Avg.	$ 125.00	$ 490.36	$ 202.05	$ 107.14	$ 924.55	$ 908.23	1.8%
1,000		$ 125.00	$ 503.45	$ 207.44	$ 110.00	$ 945.89	$ 929.14	1.8%
1,500		$ 125.00	$ 755.18	$ 311.16	$ 165.00	$ 1,356.34	$ 1,331.21	1.9%
1,864	Annual Avg.	$ 125.00	$ 938.43	$ 386.67	$ 205.04	$ 1,655.14	$ 1,623.92	1.9%
2,000		$ 125.00	$ 1,006.90	$ 414.88	$ 220.00	$ 1,766.78	$ 1,733.28	1.9%
2,746	Peak Avg.	$ 125.00	$ 1,382.47	$ 569.63	$ 302.06	$ 2,379.16	$ 2,333.17	2.0%
3,000		$ 125.00	$ 1,510.35	$ 622.32	$ 330.00	$ 2,587.67	$ 2,537.42	2.0%
5,000		$ 125.00	$ 2,517.25	$ 1,037.20	$ 550.00	$ 4,229.45	$ 4,145.70	2.0%
10,000		$ 125.00	$ 5,034.50	$ 2,074.40	$ 1,100.00	$ 8,333.90	$ 8,166.40	2.1%
25,000		$ 125.00	$ 12,586.25	$ 5,186.00	$ 2,750.00	$ 20,647.25	$ 20,228.50	2.1%
50,000		$ 125.00	$ 25,172.50	$ 10,372.00	$ 5,500.00	$ 41,169.50	$ 40,332.00	2.1%
75,000		$ 125.00	$ 37,758.75	$ 15,558.00	$ 8,250.00	$ 61,691.75	$ 60,435.50	2.1%
100,000		$ 125.00	$ 50,345.00	$ 20,744.00	$ 11,000.00	$ 82,214.00	$ 80,539.00	2.1%
125,000		$ 125.00	$ 62,931.25	$ 25,930.00	$ 13,750.00	$ 102,736.25	$ 100,642.50	2.1%
150,000		$ 125.00	$ 75,517.50	$ 31,116.00	$ 16,500.00	$ 123,258.50	$ 120,746.00	2.1%

Source: Company's Class Cost of Service Study.

Responses to Staff Data Requests

Responses to Staff Data Requests Referenced in Testimony
Data Request ACC-STF-3-32
Data Request RUCO-2-10
Data Request ACC-STF-27-3
Data Request ACC-STF-27-7
Data Request ACC-STF-27-9
Data Request ACC-STF-4-1
Data Request ACC-STF-4-2
Data Request ACC-STF-13-6
Data Request ACC-STF-3-49
Data Request ACC-STF-24-2
Data Request ACC-STF-3-19
Data Request ACC-STF-3-20

493-032

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-3
(ACC-STF-3-1 to ACC-STF-3-54)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 23, 2011

Request No. ACC-STF-3-32:

Provide a recast of the Company's financial results (this would include revenue, expenses, rate base, capital, return on equity, and return on rate base) for each of the years 2006 through 2010, assuming the Company's proposed revenue decoupling mechanism had been implemented in 2006 through 2010 and using 2005 as the base year. Please provide any and all workpapers supporting this response in electronic spreadsheet form with all links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, please provide the information in the form that most closely matches what has been requested.

Respondent: Revenue Requirements

Response:

While the margin that would have been realized if the Company's proposed decoupling mechanism had been implemented in 2006 can be readily recast, recasting the Company's financial results, specifically debt expense and capital structure would require assumption and speculation on how the margin recovered through the decoupling mechanism would have been employed. A recast of return on equity and return on rate base, assuming the proposed decoupling mechanism, would also be highly speculative and cannot be determined with accuracy.

Notwithstanding, the Company has prepared two margin analyses in an attempt to provide information responsive to this request. Both analyses utilize recorded customer bills and volumes for the 48 months ended June 2010. All results are for the twelve months ended June 30 of the year indicated.

In the first analysis, the recast margin for the years ended June 2007 and 2008 are based on rates established in the Company's 2004 rate case with a test year ended August 2004 and a 347 therm residential average use. The recast margin for the years ended June 2009 and 2010 are based on rates established in the Company's 2007 rate case with a test year ended April 2007 and residential customer average annual use of 332 therms.

Margin ($Millions)				
	2007	2008	2009	2010
Recast Margin with Decoupling	352.6	360.3	374.5	386.6
Recast Margin w/o Decoupling	348.6	349.6	340.0	369.8
Annual Difference	4.0	10.7	34.5	16.8

The Company does not believe this analysis is a reasonable representation of what will likely occur on a pro forma basis since the billing determinants used to develop rates in the historical period were much higher than the normalized billing determinants used to develop rates in this proceeding.

Consequently, the Company has prepared a second analysis whereby it has recast the margin by applying the proposed rates in this proceeding to recorded customer bills and volumes for the 48 months ended June 2010.

Margin ($Millions)				
	2007	2008	2009	2010
Recast Margin with Decoupling	421.6	430.6	432.1	430.9
Recast Margin w/o Decoupling	458.9	459.4	417.2	446.3
Annual Difference	(37.3)	(28.8)	14.9	(15.4)

511-010

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

PUBLIC UTILITIES COMMISSION OF NEVADA
DATA REQUEST NO. RUCO-2
(RUCO-2-1 to RUCO-2-32)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: APRIL 18, 2011

Request No. RUCO-2-10:

What are the benefits to the ratepayer's of the Company's decoupling proposal?

Respondent: Pricing

Response:

There are several benefits to customers resulting from the proposed Energy Efficiency Enabling Provision. First, the most significant monetary benefit will come from customers experiencing lower bills due to enhanced conservation and energy efficiency efforts. Second, Southwest Gas will never retain more revenue per customer than what the Commission authorizes in a rate case proceeding. Third, customers will receive credits to bills following extreme weather events. Fourth, implementation of full revenue decoupling will likely increase the time in-between rate case filings for utility's, thus stabilizing customer's bills. The Company's proposal also results in a rate setting model whereby the only way it can become more profitable in-between rate case filings is by reducing expenses, thus incentivizing the Company to continue its strong focus on cost saving measures - which are ultimately passed through to customers as part of the rate case process.

To fully appreciate the potential monetary benefit from lower customer bills it requires taking a broad view of the Commission's energy efficiency goals which, as stated in response to RUCO-2-8, cannot be achieved without removing the financial disincentive. In the Commission's decoupling workshops, the Lawrence Berkley National Laboratories (LBNL) identified $5.2 billion in savings for Arizona Public Service (APS) and Tucson Electric Power (TEP) customers if those companies achieve their respective efficiency goals. Most of Southwest Gas' customers are also customers of either APS or TEP and will participate in these savings. Although LBNL did not quantify the lifetime savings for the natural gas energy efficiency goals, substantial savings are expected to occur if those goals are met. However, simply meeting the Company's annual energy savings targets of approximately 3 million therms will save customers $2.2 million in gas costs (at today's gas cost rates).

As noted above, implementation of the proposed EEP will also protect customers from Southwest Gas ever retaining more revenue than what the Commission authorizes in a rate case proceeding. For instance, the monthly weather adjustment component of Southwest Gas' proposed mechanism provides customers with relief from high bills resulting from colder than normal weather. Had the EEP been effective last winter, the Company's analysis shows residential customer bills would have been reduced approximately seven percent on average during the coldest month. Similarly, as noted in response to RUCO 2-2 the recent results of the Nevada decoupling mechanism resulted in a net refund to customers.

526-003

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-27
(ACC-STF-27-1 to ACC-STF-27-9)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MAY 10, 2011

Request No. ACC-STF-27-3:

State the amount of CIAC, by category, actually collected from each class of customer. If the Company does not have the requested information, please explain why it does not maintain records that would allow it to associate contributions collected from customers into their associated customer class. Provide the requested information for the calendar years 1999 through 2009 and monthly for 2010 to date. Please provide the requested information and the supporting workpapers and source documents in electronic spreadsheet format with all links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, please provide the information in the form that most closely matches what has been requested.

Respondent: Revenue Requirements

Response:

The FERC Uniform System of Accounts (US of A) does not provide a specific account to accumulate Contribution In Aid of Construction (CIAC). It is possible the US of A for natural gas companies once had an account for accrued CIAC; however, any such account was discontinued more than 30 years ago. The Company's accounting for CIAC is as follows: A work authorization (WA) created to accumulate the cost of providing service to either a new customer or groups of customers (for instance apartments, sub-developments) or in the case of existing customers who are requesting to relocate existing facilities and municipalities undergoing major road or other work involving natural gas facilities. The cost of the facilities are accumulated in these WA's. To the extent that a CIAC is associated with the particular WA, the CIAC funds received are credited to that WA. Upon completion of the work associated with the WA all charges net of CIAC are transferred to Account 101, Gas Plant In-Service. There is no operational need or requirement to account for Gas Plant In-Service by customer class, as such the Company does not maintain records of CIAC by customer class, customer requested relocations or government related franchise relocations. Since a CIAC reduces the balances in Account 101, rate base, depreciation and property tax are also reduced.

The Company can identify the amounts in CIAC dollars that have been credited to Account 101 both on a monthly and annual basis. Attached is a schedule that provides the monthly information for the calendar years 1999 through 2010.

526-007

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-27
(ACC-STF-27-1 to ACC-STF-27-9)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MAY 10, 2011

Request No. ACC-STF-27-7:

Please provide all workpapers used to develop the meter cost by class included in the sheet meter cost by class in the spreadsheet AZ 2010 ccoss and rate design spreadsheet. Explain how the Company developed the amounts provided in response to this data request and provide the supporting workpapers and source documents in electronic spreadsheet format with all links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, please provide the information in the form that most closely matches what has been requested.

Respondent: Pricing

Response:

The average meter and service cost by class used in the CCOSS is developed by the Company's Arizona engineering staff and provided to the Pricing and Tariffs Department via memorandum. Please refer to the response to ACC-STF-13-1 for a copy of the memorandum showing meter costs. The meter cost by class reflected on the referenced spreadsheet, and used in the CCOSS are taken directly from the memorandum except as noted below.

Master Meter Mobile Home - No meter cost was provided. In its application, the Company used the Medium General Service meter cost as a proxy. However, the Company recommends using the meter cost provided for this schedule in its last Arizona general rate case.

Medium General Service - The Company used the average of the costs reflected in the memorandum.

Large 1 General Service - The Company used the cost of the AL 1000 meter provided in the memorandum of $796.94.

Air Conditioning - The Company used the average of the costs reflected in the memorandum.

A revised "meter cost by class" sheet is attached. Please see response to ACC-STF-27-9 for a further discussion of these changes.

526-009

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
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ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-27
(ACC-STF-27-1 to ACC-STF-27-9)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MAY 10, 2011

Request No. ACC-STF-27-9:

Please provide all workpapers used to develop the service cost by customer class included in the sheet WP-G-1 (MSA&SRVCS Alloc Fact) in the spreadsheet AZ 2010 ccoss and rate design spreadsheet. Explain how the Company developed the amounts provided in response to this data request and provide all supporting workpapers and source documents in electronic spreadsheet format with all links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, please provide the information in the form that most closely matches what has been requested.

Respondent: Pricing

Response:

As noted in response to ACC-STF-27-7, the average service cost by class used in the CCOSS is developed by the Company's Arizona engineering staff and provided to the Pricing and Tariff Department via memorandum. A copy of the memorandum was provided in response to ACC-STF-13-1. The average service costs by class are taken directly from the memorandum except as noted below.

Master Meter Mobile Home - No service costs were provided. Therefore the Company used the service costs provided for this schedule in its last Arizona general rate case.

Small General Service - In its application, the Company applied the average residential service costs to small general service. The amounts provided in the memorandum for small general service should be used.

Medium and Large General Service - In its application, the average service costs for these schedules were transposed. The amounts provided in the memorandum for these schedules should be used.

Gas Lights - No service costs were provided. In its application, Southwest Gas inadvertantly used $711 for service costs. However, the Company recommends using the service costs provided for this schedule in its last Arizona general rate case.

Residential CNG - In its application, Southwest Gas used one-half of the residential service cost for this class of customers. The amounts provided in the memorandum should be used.

Essential Agricultural - The Company used the amount of $23,682 provided in the memorandum for Central Arizona in its application. However, this is not representative of the Company's meter cost to serve this size of customer. Therefore, the Company recommends using the Central Arizona division amount of $5,274 provided for this rate schedule in its last Arizona general rate case.

A revised sheet "WP-G-1 (MSA&SRVCS Alloc Fact)" showing these changes is attached.

Making the changes to average service costs, average meter costs and the allocation of costs included in Accts 385, etc discussed in responses to ACC-STF-27-1, ACC-STF-27-7 and ACC-STF-27-9 changes the results of the CCOSS slightly. However, these changes do not impact the results of the CCOSS sufficiently to change Southwest's proposed allocation of revenue to customer classes or resulting rate design.

496-001

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-4
(ACC-STF-4-1 to ACC-STF-4-40)
***

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 25, 2011

Request No. ACC-STF-4-1:

Is Southwest proposing any changes to the purchased gas adjustor mechanism? If so, please describe.

Respondent: Pricing & Tariffs

Response:

No.

496-002

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-4
(ACC-STF-4-1 to ACC-STF-4-40)
***

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 25, 2011

Request No. ACC-STF-4-2:

Is Southwest proposing any changes to the:

A. Low Income Ratepayer Assistance Adjustor? If so, please describe.

B. Demand Side Management Adjustor? If so, please describe.

C. Gas Research Fund Adjustor? If so, please describe.

D. Department of Transportation Adjustor? If so, please describe.

Respondent: Pricing & Tariffs

Response:

No.

506-006

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-13
(ACC-STF-13-1 to ACC-STF-13-14)
***

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: APRIL 12, 2011

Request No. ACC-STF-13-6:

Please refer to page 11, lines 24-27, and page 12, lines 1-3 of Mr. Gieseking's testimony where he states Gas is tying the summer season residential air-conditioning rate under Schedule No. G-I 5 to the air-conditioning rate provided under Schedule No. G-40. Since Southwest Gas has a very small number of customers currently taking this service, it has little cost data to perform a meaningful cost study. Therefore the distribution rate calculated for Schedule G-40 is being utilized as a proxy for the cost of providing this service to residential customers with installed natural gas cooling equipment. Please explain why the Company has very little cost data and supply the cost data the company has. Please provide any associated documentation for the information provided in response to this request. Please provide documents and workpapers in electronic form, with all spreadsheet links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, please provide the information in the form that most closely matches what has been requested.

Respondent: Pricing & Tariffs

Response:

There were only 90 residential customers served under the Residential Air Conditioning Rate, Schedule No. G-15, in the test period. In addition to natural gas air conditioners, these customers have other end uses behind their meter. Since their air conditioning use is not currently separately metered, the Company is proposing that the rate developed for Rate Schedule No. G-40, a gas air conditioning only schedule, be used as a proxy cost-based rate for residential air conditioning service. In the future, if demand develops for residential natural gas air conditioners and installation numbers increase, and as metering options for individual gas appliances mature, the Company may have more information with which to perform a cost analysis and price residential gas air conditioning.

493-049

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *
ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-3
(ACC-STF-3-1 to ACC-STF-3-54)
***

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: FEBRUARY 23, 2011

Request No. ACC-STF-3-49:

For purposes of this request, please refer to the Direct Testimony of Mr. Edward B. Gieseking, page 12, lines 7-19, where he states: In order to better align the recovery of margin with the costs of providing service, Southwest Gas seeks to refine its Large General Service schedule, Schedule No. G-25. Currently, this schedule applies to customers that use between 7,201 and 180,000 therms per year. Southwest Gas' analysis of the cost of providing service shows a large difference between the cost to serve the smaller customers in this class versus the cost to serve the larger customers. Therefore, Southwest Gas is proposing to further define its general service customers by breaking the currently existing large class into two separate classes. The new class General Gas Service Large-1 is comprised of customers that use more 7,200 and up to 50,000 therms per year. The new class General Gas Service Large-2 is comprised of customers that use more than 50,000 and up to 180,000 therms per year. Further defining this class allows a better allocation of cost and a fairer rate design.

(a) Please provide all analyses performed by the Company which show the large difference between the cost of providing service show to the smaller customers in this class versus the cost to serve the larger customers in this class.

(b) Please provide all workpapers and source documents supporting the Company's response to (a). Provide the requested documents and workpapers in electronic form with all spreadsheet links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, please provide the information in the form that most closely matches what has been requested.

(c) Please provide all analyses performed by the Company which show how the Company arrived at the usage levels for the Large-1 customer class versus the Large-2 customer class.

(d) Please provide all workpapers and source documents supporting the Company's response to (c). Provide the requested documents and workpapers in electronic form with all spreadsheet links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, please provide the information in the form that most closely matches what has been requested.

(e) Please provide all analyses performed by the Company which demonstrate that the new definition allows a better allocation of cost and a fairer rate design than the old rate design.

(f) Please provide all workpapers and source documents supporting the Company's response to (c). Provide the requested documents and workpapers in electronic form with all spreadsheet links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, please provide the information in the form that most closely matches what has been requested.

Respondent: Pricing & Tariffs

Response:

(a) and (b) The differences in the average cost of providing service are reflected in the electronic ccoss schedules provided in response to ACC-STF-1-1 under the sheet named "WP G-1 (Meter Cost by Class). This sheet reflects an average meter cost to service customers on the proposed G-25 L2 schedule that is approximately 4.4 times higher than the average meter cost to serve customers on the proposed G-25 L1 schedule. This information is also provided in the filed Workpapers, Schedule G-1, Sheet 1. Additionally, proposed schedule G-25 L2 customers' annual load factor is roughly 12% greater than that for proposed schedule G-25 L1 customers. This can be determined from information provided in the electronic ccoss under sheet named "G-1 (Peak Demand Alloc Factor).

(c) and (d) Data provided in support of the 50,000 therm usage level separating the proposed G-25 L1 and L2 schedules is provided in the Company's filed Workpapers, Schedule H-1, Sheets 64-64. This information is also provided electronically in response to ACC-STF-1-1 in the file named "G25 greater than 50,000".

(e) and (f) Please refer to the attached Excel worksheet which shows bill calculation comparisions for the proposed G-25 L1 and G-25 L2 rates and the otherwise combined G-25 rate.

523-002

SOUTHWEST GAS CORPORATION
2010 GENERAL RATE CASE
DOCKET NO. G-01551A-10-0458
* * *

ARIZONA CORPORATION COMMISSION
DATA REQUEST NO. ACC-STF-24
(ACC-STF-24-1 to ACC-STF-24-2)
* * *

DOCKET NO.: G-01551A-10-0458
COMMISSION: ARIZONA CORPORATION COMMISSION
DATE OF REQUEST: MAY 5, 2011

Request No. ACC-STF-24-2:

For purposes of this request, please refer to Rate Schedule No. SB-1 of the Company's proposed tariffs.

a. Please explain why the language regarding the bypass customers from Rate Schedule No. B-1 was removed.

b. Please provide a revised Rate Schedule No. SB-1 with language for bypass customers.

c. Please provide the source data and documents relied upon in developing your response.

Respondent: Pricing

Response:

a. Over time, Schedule No. T-1 has evolved into the rate schedule that accommodates potential bypass transportation customers and the bypass provision contained in currently effective Schedule No. B-1 is no longer necessary. Therefore, Southwest is proposing the elimination of the bypass provisions in Schedule No. B-1, modifying the schedule to accommodate only the remaining standby provisions, and renaming to Schedule No. SB-1.

b. Proposed Schedule No. SB-1 is not intended to accommodate bypass potential customers.

c. n/a.